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Rules and Regulations

Federal Register

Vol. 87, No. 118

Tuesday, June 21, 2022

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 100

[Docket Number USCG–2022–0186]

RIN 1625–AA08

Special Local Regulation; East River 4th of July Fireworks, New York, NY

AGENCY: Coast Guard, DHS.

ACTION: Final rule.

SUMMARY: The Coast Guard is establishing a special local regulation on the navigable waters of the East River and New York Harbor, New York, NY, for vessel management for the annual 4th of July fireworks displays. This special local regulation allows the Coast Guard to control vessel movement and prohibit all vessel traffic from entering the fireworks barge buffer zone, establish four separate viewing areas, and a moving protection zone around the barges while they are loaded with pyrotechnics. This rule is necessary to provide for the safety of life on the navigable waters immediately before, during, and after a fireworks display that involves multiple barge launch sites on a highly congested waterway.

DATES: This rule is effective July 4, 2022.

ADDRESSES: To view documents mentioned in this preamble as being available in the docket, go to *https://www.regulations.gov,* type USCG–2022–0186 in the ''SEARCH'' box and click ''SEARCH.'' Click on Open Docket Folder on the line associated with this rule.

FOR FURTHER INFORMATION CONTACT: If you have questions on this rule, call or email MST1 Stacy Stevenson, Waterways Management Division, U.S. Coast Guard; telephone 718–354–4000, email *D01-SMB-SecNY-Waterways@uscg.mil.*

SUPPLEMENTARY INFORMATION:

I. Table of Abbreviations

CFR Code of Federal Regulations
COTP Captain of the Port New York
DHS Department of Homeland Security
FR Federal Register
NPRM Notice of proposed rulemaking
§ Section
U.S.C. United States Code

II. Background Information and Regulatory History

On March 7, 2022 the Coast Guard received an Application for Marine Event for the annual 4th of July fireworks display. In response, on April 26, 2022, the Coast Guard published a notice of proposed rulemaking (NPRM) titled Special Local Regulation; East River 4th of July Fireworks, New York, NY (87 FR 24923). We stated why we issued the NPRM and invited comments on our proposed regulatory action related to this fireworks display. We received no comments during the comment period that ended May 27, 2022.

Under 5 U.S.C. 553(d)(3), the Coast Guard finds that good cause exists for making this rule effective less than 30 days after publication in the **Federal Register**. The comment period for the NPRM associated with the East River 4th of July Fireworks ended on May 27, 2022. The fireworks display is scheduled to begin on July 4, 2022. Thus, there is now insufficient time for a 30 day effective period before the need to enforce the special local regulation on July 4, 2022. The fireworks display will take place on July 4, 2022 to coincide with Independence Day. Delaying the enforcement of this special local regulation to allow a 30-day effective period will be impractical and contrary to the public interest because it would inhibit the Coast Guard's ability to fulfill its mission to keep the ports and waterways safe.

III. Legal Authority and Need for Rule

The Coast Guard is issuing this rule under authority in 46 U.S.C. 70034 (previously 33 U.S.C. 1231). The Captain of the Port New York (COTP) has determined that potential hazards associated with a high concentration of vessels, and a fireworks display will be a safety concern for people and vessels in the vicinity of the fireworks barges. This Special Local Regulation is necessary to ensure the safety of vessels from hazards immediately prior to, during, and immediately after the annual Macy's 4th of July fireworks show.

IV. Discussion of Comments, Changes, and the Rule

As noted above, we received no comments on our NPRM published April 26, 2022. There are no substantative changes in the regulatory text of this rule from the proposed rule in the NPRM.

This rule establishes a special local regulation annually on July 4th or July 5th from 5:30 p.m. through 11:30 p.m. This special local regulation will include a moving protection zone excluding all vessels from entering within a 25-yard radius from each loaded fireworks barge from the point of departure from the loading facility, during the transit of the New York Harbor, and until the placement in show position on the East River. The buffer zone will exclude all nonparticipating vessels from the area surrounding the barges immediately before, during, and after the display. Four separate viewing areas will be established that will separate vessels based on vessel length.

BILLING CODE 9110–04–P

Illustration showing location of regulated areas.

BILLING CODE 9110–04–C

The duration of the viewing areas are intended to ensure the safety of vessels, participants, spectators, and those transiting the area during the fireworks display. Navigation rules shall apply at all times within the areas. The Coast Guard will provide notice of the special local regulation by Local Notice to Mariners, Broadcast Notice to Mariners, and on-scene designated representatives.

V. Regulatory Analyses

We developed this rule after considering numerous statutes and Executive orders related to rulemaking. Below we summarize our analyses based on a number of these statutes and Executive orders, and we discuss First Amendment rights of protestors.

A. Regulatory Planning and Review

Executive Orders 12866 and 13563 direct agencies to assess the costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits. This rule has not been designated a ''significant regulatory action,'' under Executive Order 12866. Accordingly, this rule has not been reviewed by the Office of Management and Budget (OMB).

This regulatory action determination is based on the duration and time-of-day of the Special Local Regulation. Vessel traffic will only be restricted in the regulated area areas for approximately 6 hours, annually on either July 4th, or July 5th. Advanced public notifications will also be made to local mariners through appropriate means, which may include but not limited to Local Notice to Mariners and Broadcast Notice to Mariners.

B. Impact on Small Entities

The Regulatory Flexibility Act of 1980, 5 U.S.C. 601–612, as amended, requires Federal agencies to consider the potential impact of regulations on small entities during rulemaking. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000. The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities.

While some owners or operators of vessels intending to enter or transit within the Special Local Regulation may be small entities, for the reasons stated in section V.A above, this rule will not have a significant economic impact on any vessel owner or operator.

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we want to assist small entities in understanding this rule. If the rule would affect your small business, organization, or governmental jurisdiction and you have questions concerning its provisions or options for compliance, please call or email the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

Small businesses may send comments on the actions of Federal employees who enforce, or otherwise determine compliance with, Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman and the Regional Small Business Regulatory Fairness Boards. The Ombudsman evaluates these actions annually and rates each agency's responsiveness to small business. If you wish to comment on actions by employees of the Coast Guard, call 1–888–REG–FAIR (1–888–734–3247). The Coast Guard will not retaliate against small entities that question or complain about this rule or any policy or action of the Coast Guard.

C. Collection of Information

This rule will not call for a new collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

D. Federalism and Indian Tribal Governments

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

Also, this rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

E. Unfunded Mandates Reform Act

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

F. Environment

We have analyzed this rule under Department of Homeland Security Directive 023–01, Rev. 1, associated implementing instructions, and Environmental Planning COMDTINST 5090.1 (series), which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (42 U.S.C. 4321–4370f), and have determined that this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. This rule involves a regulated area lasting approximately 6 hours that would limit persons or vessels from transiting a portion of the East River during the scheduled event. It is categorically excluded from further review under paragraph L61 of Appendix A, Table 1 of DHS Instruction Manual 023–01–001–01, Rev. 1. A Memorandum for Record supporting this determination is available in the docket where indicated under **ADDRESSES**.

G. Protest Activities

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

List of Subjects in 33 CFR Part 100

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

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 100 as follows:

PART 100—SAFETY OF LIFE ON NAVIGABLE WATERS

■ 1. The authority citation for part 100 continues to read as follows:

Authority: 46 U.S.C. 70041; 33 CFR 1.05–1.

■ 2. Add § 100.110 to read as follows:

§ 100.110 East River 4th of July Fireworks, East River, Manhattan, NY.

(a) Regulated areas. The regulations in this section apply to the following areas:

(1) *Area ALPHA:* All navigable waters of the East River, between the east shore of Manhattan and the west shore of Roosevelt Island south of the Ed Koch Queensboro Bridge encompassed by a line connecting the following points beginning at 40°45′31.46″ N, 73°57′31.42″ W, along the shore to 40°45′6.80″ N, 73°57′53.45″ W, east to Roosevelt Island at 40°44′59.42″ N, 73°57′40.57″ W, along the west shore of Roosevelt island to the Ed Koch Queensboro Bridge at 40°45′26.02″ N, 73°57′19.15″ W, and back to the point of origin.

(2) *Area BRAVO:* All navigable waters of the East River, between the west shore of Queens and the east shore of Roosevelt Island south of the Ed Koch Queensboro Bridge encompassed by a line connecting the following points beginning at 40°45′22.89″ N, 73°57′12.06″ W, along the western shore of Roosevelt Island to 40°44′59.42″ N, 73°57′40.57″ W, east to 40°44′52.25″ N, 73°57′28.08″ W, north along the west shore to the Ed Koch Queensboro Bridge at 40°45′18.82″ N, 73°57′2.91″ W, and back to the point of origin.

(3) *Area CHARLIE:* All navigable waters of the East River encompassed by a line connecting the following points beginning at 40°45′6.80″ N, 73°57′53.45″ W, then south along the shore of Manhattan to 40°43′40.29″ N, 73°58′18.37″ W, across the East River to Brooklyn at 40°43′39.68″ N, 73°57′39.74″ W, then north along the east shore of the East River to 40°44′52.25″ N, 73°57′28.08″ W including the navigable waters of Newtown Creek to the Pulaski Bridge, back to the point of origin.

(4) *Area DELTA:* All navigable waters of the East River encompassed by a line connecting the following points beginning at 40°43′40.29″ N, 73°58′18.37″ W, then south along the shore of Manhattan to 40°43′06″ N, 073°58′25″ W, across the East River to Brooklyn at 40°42′57.34″ N, 73°58′3.03″ W, and north along the shore of Brooklyn To 40°42′15.87″ N, 73°59′19.60″ W, then along the shore of Brooklyn to 40°42′57.34″ N, 73°58′3.03″ W, and then back to the point of origin.

(5) *Area ECHO:* All navigable waters of the East River encompassed by a line connecting the following points beginning at 40°43′06″ N, 073°58′25″ W, then along the shore to the Manhattan Bridge at 40°42′34.74″ N, 73°59′30.65″ W, across the East River to Brooklyn at 40°42′15.87″ N, 73°59′19.60″ W, then along the Brooklyn side of the East River to 40°42′57.34″ N, 73°58′3.03″ W, and then back to the point of origin. These coordinates are based on (NAD 83).

(6) *Moving Protection Zone:* A moving protection zone on all navigable waters within a 50 yard radius of the participating barges while they are

loaded with explosive material will be enforced from the point of departure within the COTP New York zone until placement at the intended destination. The point of departure will be determined each year prior to enforcement of the moving protection zone and the details will be released through a Broadcast Notice to Mariners.

(b) *Definitions.* As used in this section:

Designated Representative is any Coast Guard Patrol Commander, including a Coast Guard coxswain, petty officer or other officer operating a Coast Guard vessel and a Federal, State and local officer designated by or assisting the Captain of the Port (COTP) New York in the enforcement of this section.

Official Patrol Vessel means any Coast Guard, Coast Guard Auxiliary, Federal, State or local law enforcement vessel assigned or approved by the COTP New York to assist in the enforcement of this section.

Spectator means a person or vessel not registered with the event sponsor as participants or official patrol vessels.

(c) *Regulations.* (1) In accordance with the special local regulations in § 100.35, entry into, transiting, or anchoring within the limited access area defined in paragraph (a) of this section, is prohibited, unless authorized by the COTP or a designated representative.

(2) All vessels that are authorized by the COTP or a designated representative to enter the limited access areas established in this section must adhere to the following restrictions:

(i) Area ALPHA access is limited to vessels greater than or equal to 20 meters (65.6ft) in length.

(ii) Area BRAVO access is limited to vessels less than 20 meters (65.6ft) in length.

(iii) All vessels are prohibited from entering area CHARLIE without permission from the COTP or a designated representative.

(iv) Area DELTA access is limited to vessels greater than or equal to 20 meters (65.6ft) in length.

(v) Area ECHO access is limited to vessels less than 20 meters (65.6ft) in length.

(vi) All vessels are prohibited from entering the moving protection zone defined in paragraph (a)(6) of this section without permission from the COTP or a designated representative.

(vii) Vessels desiring to utilize any of these limited access areas defined in paragraph (a) of this section must enter the area by 7:30 p.m.

(3) During periods of enforcement all persons and vessels in the limited access areas defined in paragraph (a) of this section must comply with all lawful orders and directions from the COTP New York or the COTP New York's designated representative.

(4) Vessel operators desiring to enter or operate within a limited access area defined in paragraph (a) of this section should contact the COTP New York at (718) 354–4356 or on VHF 16 to obtain permission.

(5) Spectators or other vessels must not anchor, block, loiter or impede the transit of event participants or official patrol vessels in the limited access area defined in paragraph (a) of this section during the effective dates and times unless authorized by COTP New York or designated representative.

(6) The COTP or a representative will inform the public through local notice to mariners and/or Broadcast Notices to Mariners of the enforcement period for the regulated area as well as any changes of the enforcement times.

(d) *Enforcement period.* This section will be enforced annually on July 4, from 5:30 p.m. to 11:30 p.m. In the event the fireworks display is postponed due to inclement weather, this section will be enforced on July 5, from 5:30 p.m. to 11:30 p.m.

Dated: June 14, 2022.

M.R. Sennick,

Captain, U.S. Coast Guard, Acting, Captain of the Port New York.

[FR Doc. 2022–13175 Filed 6–17–22; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 110

[Docket Number USCG–2020–0216]

RIN 1625–AA01

Anchorage Grounds; Cape Fear River Approach, North Carolina

AGENCY: Coast Guard, DHS.

ACTION: Final rule.

SUMMARY: The Coast Guard is amending the anchorage regulations for Lockwoods Folly Inlet, NC, and adjacent navigable waters, by establishing a new offshore anchorage, relocating the existing explosives anchorage, and amending the anchorage regulations. The purpose of this rule is to improve navigation and public safety by accommodating recent and anticipated future growth in cargo vessel traffic and vessel size that call on Military Ocean Terminal Sunny Point and the Port of Wilmington, North Carolina.

DATES: This rule is effective July 21, 2022.

ADDRESSES: To view documents mentioned in this preamble as being available in the docket, go to *https://www.regulations.gov,* type USCG–2020–0216 in the search box and click ''Search.'' Next, in the Document Type column, select ''Supporting & Related Material.''

FOR FURTHER INFORMATION CONTACT: If you have questions about this rulemaking, call or email Lieutenant Gregory Kennerley, Sector North Carolina, U.S. Coast Guard; telephone (910) 772–2230, email *Gregory.M.Kennerley@uscg.mil;* or Mr. Matthew Creelman, Waterways Management Branch, Fifth Coast Guard District, U.S. Coast Guard; telephone (757) 398–6230, email *Matthew.K.Creelman2@uscg.mil.*

SUPPLEMENTARY INFORMATION:

I. Table of Abbreviations

CFR Code of Federal Regulations
DHS Department of Homeland Security
FR Federal Register
NPRM Notice of proposed rulemaking
SNPRM Supplemental Notice of proposed rulemaking
§ Section
U.S.C. United States Code

II. Background Information and Regulatory History

On May 8, 2020, the Coast Guard published a notice of inquiry in the **Federal Register** (85 FR 27343) to solicit public comments on whether we should initiate a rulemaking to establish an anchorage ground offshore in the approaches to the Cape Fear River, North Carolina, and relocate the existing Lockwood's Folly Inlet explosives anchorage. After receiving favorable comments, the Coast Guard decided to propose the rulemaking. On August 17, 2021, the Coast Guard published a notice of proposed rulemaking (NPRM) in **Federal Register** (86 FR 45936) and invited comments on our proposed anchorage. After considering comments made on the NPRM, the Coast Guard issued a supplemental notice of proposed rulemaking (SNPRM) in **Federal Register** (87 FR 17047) on March 25, 2022. There we stated why we issued the SNPRM and invited comments on our revised proposed anchorage regulation. During that comment period that ended April 25, 2022, we received one comment.

III. Legal Authority and Need for Rule

The legal basis and authorities for this rule are found in 46 U.S.C.70006, 33 CFR 1.05–1, DHS Delegation No. 0170.1, which collectively authorize the Coast

Guard to propose, establish, and define regulatory anchorage grounds.

This rule is necessary to accommodate recent and anticipated future growth in cargo vessel traffic and vessel size that call on Military Ocean Terminal Sunny Point and the Port of Wilmington, improve navigation and public safety, and to preserve areas traditionally used for anchoring.

IV. Discussion of Comments, Changes, and the Rule

As noted above, we received one comment on our SNPRM published March 25, 2022. That comment requested that we consider revising the regulatory language used to describe the anchorage coordinates in order to aid cartography and comprehension. The comment recommended revising paragraphs (a)(1) and (a)(2) by removing text reading, ''The waters bound by a line connecting the following points:'', and replacing it with, ''The corner coordinates of the anchorage follow:''. The Coast Guard agrees with this recommendation and the intent to assist cartography. The revision has been implemented into the regulatory text at the end of this rulemaking, all other regulatory text remains the unchanged.

This rule formally establishes an anchorage ground, Anchorage A, approximately eight nautical miles southwest of the Oak Island Light. This rule also increases the size and relocates Lockwoods Folly Inlet explosives anchorage to adjacent Anchorage A on its western boundary; and renames it Anchorage B. The specific coordinates for these anchorage grounds are included in the regulatory text at the end of this document.

V. Regulatory Analyses

We developed this rule after considering numerous statutes and Executive orders related to rulemaking. Below we summarize our analyses based on a number of these statutes and Executive orders, and we discuss First Amendment rights of protestors.

A. Regulatory Planning and Review

Executive Orders 12866 and 13563 direct agencies to assess the costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits. This rule has not been designated a ''significant regulatory action,'' under Executive Order 12866. Accordingly, this rule has not been reviewed by the Office of Management and Budget (OMB).

This regulatory action determination is based on the size, location, and historical vessel traffic data pertaining to the anchorage locations. The regulation designates and preserves an approximately 22 square mile deep water area traditionally used by cargo ships for anchoring near existing traffic lanes. It also relocates the existing explosives anchorage approximately five nautical miles further offshore, increasing separation distances between vessels laden with explosives and the public, and expands its size from approximately five to seven square miles. This regulatory action provides for commercial vessel anchorage needs, while enhancing the navigation safety, environmental stewardship, and public safety.

B. Impact on Small Entities

The Regulatory Flexibility Act of 1980, 5 U.S.C. 601–612, as amended, requires Federal agencies to consider the potential impact of regulations on small entities during rulemaking. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000. The Coast Guard received no comments from the Small Business Administration on this rulemaking. The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities.

While some owners or operators of vessels intending to use the anchorages may be small entities, for the reasons stated in section IV. A above, this rule would not have a significant economic impact on any vessel owner or operator. The towns and communities along the Cape Fear River approaches have an economy based on tourism and numerous small entities and businesses. The establishment of Anchorage A and Anchorage B will increase controls over vessels that currently anchor in the general vicinity and increase the distance between anchored vessels and the shore and beaches, lessening impacts these small entities may currently experience.

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we want to assist small entities in understanding this rule. If the rule would affect your small business, organization, or governmental jurisdiction and you have questions concerning its provisions or options for compliance, please call or email the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

Small businesses may send comments on the actions of Federal employees who enforce, or otherwise determine compliance with, Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman and the Regional Small Business Regulatory Fairness Boards. The Ombudsman evaluates these actions annually and rates each agency's responsiveness to small business. If you wish to comment on actions by employees of the Coast Guard, call 1–888–REG–FAIR (1–888–734–3247). The Coast Guard will not retaliate against small entities that question or complain about this rule or any policy or action of the Coast Guard.

C. Collection of Information

This rule will not call for a new collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

D. Federalism and Indian Tribal Governments

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

Also, this rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

E. Unfunded Mandates Reform Act

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

F. Environment

We have analyzed this rule under Department of Homeland Security Directive 023–01, Rev. 1, associated implementing instructions, and Environmental Planning COMDTINST 5090.1 (series), which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (42 U.S.C. 4321–4370f), and have determined that this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. This rule involves establishing an anchorage ground, Anchorage A, in an area traditionally used by cargo ships for anchoring in the approaches to the Cape Fear River, NC; and increasing the size of and relocating the Lockwoods Folly Inlet explosives anchorage to an area adjacent to Anchorage A (on its western boundary), expanding its use, and renaming it Anchorage B. It is categorically excluded from further review under paragraph L[59(a)] of Appendix A, Table 1 of DHS Instruction Manual 023–01–001–01, Rev. 1. A Record of Environmental Consideration supporting this determination is available in the docket. For instructions on locating the docket, see the **ADDRESSES** section of this preamble.

G. Protest Activities

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

List of Subjects in 33 CFR Part 110

Anchorage grounds.

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 110 as follows:

PART 110—ANCHORAGE REGULATIONS

■ 1. The authority citation for part 110 continues to read as follows:

Authority: 33 U.S.C. 2071; 46 U.S.C. 70006, 70034; 33 CFR 1.05–1; Department of Homeland Security Delegation No. 0170.1.

■ 2. Revise § 110.170 to read as follows:

§ 110.170 Cape Fear, NC.

(a) The anchorage grounds. All coordinates in this section are based on the World Geodetic System (WGS 84).

(1) *Anchorage A.* The corner coordinates of the anchorage are:

TABLE 1 TO PARAGRAPH (a)(1)

Latitude	Longitude
33°47′59.09″ N	78°14′58.67″ W
33°47′59.09″ N	78°06′24.74″ W
33°46′01.22″ N	78°06′24.74″ W
33°46′01.22″ N	78°14′58.67″ W

(2) *Anchorage B.* Explosives Anchorage. The corner coordinates of the anchorage follow:

TABLE 2 TO PARAGRAPH (a)(2)

Latitude	Longitude
33°47′59.09″ N	78°17′14.00″ W
33°47′59.09″ N	78°14′58.67″ W
33°46′01.22″ N	78°14′58.67″ W
33°46′01.22″ N	78°17′14.00″ W

(b) *Definitions.* As used in this section—

Cargoes of particular hazard means ‘‘cargo of particular hazard’’ as defined in § 126.3 of this title.

Class 1 (explosive) materials means Division 1.1, 1.2, 1.3, and 1.4 explosives, as defined in 49 CFR 173.50.

Dangerous cargo means ‘‘certain dangerous cargo’’ as defined in § 160.204 of this title.

U.S. naval vessel means any vessel owner, operated, chartered, or leased by the U.S. Navy; and any vessel under the operational control of the U.S. Navy or Combatant Command.

(c) *General regulations.* (1) Vessels in the Atlantic Ocean near Cape Fear River Inlet awaiting berthing space within the Port of Wilmington shall only anchor within the anchorage grounds defined and established in paragraph (a) of this section, except in cases of emergency.

(2) Vessels anchoring under circumstances of emergency outside the anchorage areas shall be shifted to new positions within the anchorage grounds immediately after the emergency ceases.

(3) Vessels may anchor anywhere within the anchorage grounds provided such anchoring does not interfere with the operations of any other vessel at anchorage; except a vessel may not anchor within 1,500 yards of a vessel carrying or handling dangerous cargoes, cargoes of a particular hazard, or Class 1 (explosive) materials. Vessels shall lie at anchor with as short of a chain or cable as conditions permit.

(4) Prior to entering the anchorage grounds, all vessels must notify the Coast Guard Captain of the Port Sector North Carolina (COTP) via VHF–FM channel 16.

(5) No vessel may anchor within the anchorage grounds for more than 72 hours without the prior approval of the COTP. To obtain this approval, contact the COTP via VHF–FM channel 16.

(6) The COTP may close the anchorage grounds and direct vessels to depart the anchorage during periods of severe weather or at other times as deemed necessary in the interest of port safety or security.

(7) The COTP may prescribe specific conditions for vessels anchoring within the anchorage grounds, including but not limited to, the number and location of anchors, scope of chain, readiness of engineering plant and equipment, usage of tugs, and requirements for maintaining communications guards on selected radio frequencies.

(d) *Regulations for vessels handling or carrying dangerous cargoes, cargoes of a particular hazard, or Class 1 (explosive) materials.* This paragraph applies to every vessel, except U.S. naval vessels, handling or carrying dangerous cargoes, cargoes of a particular hazard, or Class 1 (explosive) materials.

(1) Unless otherwise directed by the Captain of the Port, each commercial vessel handling or carrying dangerous cargoes, cargoes of a particular hazard, or Class 1 (explosive) materials must be anchored within Anchorage B of paragraph (a)(2) of this section.

(2) Vessels requiring the use of Anchorage B of paragraph (a)(2) of this section must display by day a red flag (Bravo flag) in a prominent location and by night a fixed red light. In lieu of a fixed red light, by night a red flag may be illuminated by spotlight.

Dated: June 14, 2022.

S.N. Gilreath,

Rear Admiral Lower Half, U.S. Coast Guard, Commander, Fifth Coast Guard District.

[FR Doc. 2022–13173 Filed 6–17–22; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket No. USCG–2022–0521]

Safety Zone; Military Ocean Terminal Concord Safety Zone, Suisun Bay, Military Ocean Terminal Concord, CA

AGENCY: Coast Guard, DHS.

ACTION: Notification of enforcement of regulation.

SUMMARY: The Coast Guard will enforce the safety zone in the navigable waters of Suisun Bay, off Concord, CA, in support of explosive on-loading to Military Ocean Terminal Concord (MOTCO) from June 16, 2022 through

June 21, 2022. This safety zone is necessary to protect personnel, vessels, and the marine environment from potential explosion within the explosive arc. The safety zone is open to all persons and vessels for transitory use, but vessel operators desiring to anchor or otherwise loiter within the safety zone must obtain the permission of the Captain of the Port San Francisco or a designated representative. All persons and vessels operating within the safety zone must comply with all directions given to them by the Captain of the Port San Francisco or a designated representative.

DATES: The regulations in 33 CFR 165.1198 will be enforced from 12:01 a.m. on June 16, 2022 until 11:59 p.m. on June 21, 2022.

FOR FURTHER INFORMATION CONTACT: If you have questions about this notification of enforcement, call or email Lieutenant William Harris, Coast Guard Sector San Francisco, Waterways Management Division, 415–399–7443, *SFWaterways@uscg.mil.*

SUPPLEMENTARY INFORMATION: The Coast Guard will enforce the safety zone in 33 CFR 165.1198 for the Military Ocean Terminal Concord, CA (MOTCO) regulated area from 12:01 a.m. on June 16, 2022 until 11:59 p.m. on June 21, 2022, or as announced via marine local broadcasts. This safety zone is necessary to protect personnel, vessels, and the marine environment from potential explosion within the explosive arc. The regulation for this safety zone, § 165.1198, specifies the location of the safety zone which encompasses the navigable waters in the area between 500 yards of MOTCO Pier 2 in position 38°03′30″ N, 122°01′14″ W and 3,000 yards of the pier. During the enforcement periods, as reflected in § 165.1198(d), if you are the operator of a vessel in the regulated area you must comply with the instructions of the COTP or the designated on-scene patrol personnel. Vessel operators desiring to anchor or otherwise loiter within the safety zone must contact Sector San Francisco Vessel Traffic Service at 415–556–2760 or VHF Channel 14 to obtain permission.

In addition to this notification of enforcement in the **Federal Register**, the Coast Guard plans to provide notification of this enforcement period via marine information broadcasts.

Dated: June 15, 2022.

Taylor Q. Lam,

Captain, U.S. Coast Guard, Captain of the Port San Francisco.

[FR Doc. 2022–13299 Filed 6–16–22; 11:15 am]

BILLING CODE 9110–04–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R04–OAR–2021–0610; FRL–9081–02–R4]

Air Plan Approval; North Carolina; North Carolina BART Rule Revisions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing approval of a North Carolina State Implementation Plan (SIP) revision, submitted through a letter dated April 13, 2021. The SIP revision includes changes to North Carolina's SIP-approved rule addressing best available retrofit technology (BART) for regional haze. EPA is approving North Carolina's SIP revision because the changes are consistent with Clean Air Act (CAA or Act) requirements.

DATES: This rule is effective July 21, 2022.

ADDRESSES: EPA has established a docket for this action under Docket Identification No. EPA–R04–OAR–2021–0610. All documents in the docket are listed on the *www.regulations.gov* website. Although listed in the index, some information may not be publicly available, *i.e.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy at the Air Regulatory Management Section, Air Planning and Implementation Branch, Air and Radiation Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street SW, Atlanta, Georgia 30303–8960. EPA requests that if at all possible, you contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to schedule your inspection. The Regional Office's official hours of business are Monday through Friday 8:30 a.m. to 4:30 p.m., excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: Michele Notarianni, Air Regulatory Management Section, Air Planning and Implementation Branch, Air and Radiation Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street SW, Atlanta, Georgia 30303–8960. Ms. Notarianni can be reached via telephone at (404) 562–9031 or electronic mail at *notarianni.michele@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

Regional haze is visibility impairment that is produced by a multitude of sources and activities which are located across a broad geographic area and emit fine particulate matter ($PM_{2.5}$) (*e.g.,* sulfates, nitrates, organic carbon, elemental carbon, and soil dust) and their precursors (*e.g.,* sulfur dioxide, nitrogen oxides, and in some cases, ammonia and volatile organic compounds). Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which impairs visibility by scattering and absorbing light. Visibility impairment (*i.e.,* light scattering) reduces the clarity, color, and visible distance that one can see.

In sections 169A and 169B of the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. The CAA establishes as a national goal the prevention of any future, and the remedying of any existing, anthropogenic impairment of visibility in 156 national parks and wilderness areas designated as mandatory Class I federal areas. Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, often uncontrolled, older stationary sources in order to address visibility impacts from these sources, often referred to as BART sources. The BART process includes evaluating retrofit controls for certain older sources, built between 1962 and 1977, which are identified as causing or contributing to visibility impairment at one or more Class I areas.

On April 27, 2022 (87 FR 24930), EPA proposed approval of an April 13, 2021, SIP revision from North Carolina, which modifies North Carolina's SIP-approved rule at 15A North Carolina Administrative Code (NCAC) 02D .0543, *Best Available Retrofit Technology* (NC BART Rule) and applies to BART-eligible sources.[1] *See* 87 FR 24930. Comments on the April 27, 2022, NPRM were due on or before May 27, 2022. No public comments, adverse or otherwise, were received on the April 27, 2022, NPRM. For additional background on regional haze, BART, and the NC BART Rule, see the April 27, 2022 NPRM.

II. Incorporation by Reference

In this document, EPA is finalizing regulatory text that includes incorporation by reference. In

[1] The North Carolina SIP revision is dated April 13, 2021, and was submitted to EPA on April 14, 2021.

accordance with requirements of 1 CFR 51.5, as descried in Section I of the preamble, EPA is finalizing the incorporation by reference of North Carolina rule 15A NCAC 02D .0543, entitled ''*Best Available Retrofit Technology,*'' which became state effective November 1, 2020. EPA has made, and will continue to make, these materials generally available through *www.regulations.gov* and at the EPA Region 4 Office (please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section of this preamble for more information). Therefore, these materials have been approved by EPA for inclusion in the SIP, have been incorporated by reference by EPA into that plan, are fully federally enforceable under sections 110 and 113 of the CAA as of the effective date of the final rulemaking of EPA's approval, and will be incorporated by reference in the next update to the SIP compilation.[2]

III. Final Action

EPA is finalizing approval of North Carolina's April 13, 2021, SIP revision, which makes changes to North Carolina's SIP-approved rule addressing BART for regional haze, because the rule changes are consistent with CAA requirements.

IV. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable Federal regulations. *See* 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. This action merely approves state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

- Is not a significant regulatory action subject to review by the Office of Management and Budget under Executive Orders 12866 (58 FR 51735, October 4, 1993) and 13563 (76 FR 3821, January 21, 2011);
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Is not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and
- Does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

The SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction. In those areas of Indian country, the rule does not have tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), nor will it impose substantial direct costs on tribal governments or preempt tribal law.

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this action 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**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by August 22, 2022. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. *See* section 307(b)(2).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

Dated: June 13, 2022.

Daniel Blackman,

Regional Administrator, Region 4.

For the reasons stated in the preamble, the EPA amends 40 CFR part 52 as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 52 continues to read as follows:

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

Subpart II—North Carolina

■ 2. In § 52.1770 amend the table in paragraph (c)(1) by revising the entry for ''Section .0543.''

The revision reads as follows:

§ 52.1770 Identification of plan.

* * * * *

(c) * * *

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[2] *See* 62 FR 27968 (May 22, 1997).

(1) EPA-APPROVED NORTH CAROLINA REGULATIONS

State citation	Title/subject	State effective date	EPA approval date	Explanation
* * * * * * *				
Section .0543	Best Available Retrofit Technology	11/1/2020	6/21/2022, [Insert citation of publication].	
* * * * * * *				

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[FR Doc. 2022–13161 Filed 6–17–22; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 622

[Docket No. 140722613–4908–02; RTID 0648–XC105]

Coastal Migratory Pelagic Resources of the Gulf of Mexico and Atlantic Region; Commercial Closure for Atlantic Spanish Mackerel in the Northern Zone

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Temporary rule; closure.

SUMMARY: NMFS implements an accountability measure (AM) for commercial Spanish mackerel in the northern zone of the Atlantic exclusive economic zone (EEZ). NMFS projects that the commercial quota for Spanish mackerel in the northern zone of the Atlantic EEZ will be reached by June 21, 2022. Therefore, NMFS closes the northern zone in the Atlantic EEZ to commercial harvest of Spanish mackerel on June 21, 2022. This closure is necessary to protect the Spanish mackerel resource in the Atlantic.

DATES: This temporary rule is effective at 12:01 a.m., eastern time, on June 21 2022, until February 28, 2023.

FOR FURTHER INFORMATION CONTACT: Mary Vara, NMFS Southeast Regional Office, telephone: 727–824–5305, or email: *mary.vara@noaa.gov.*

SUPPLEMENTARY INFORMATION: The fishery for coastal migratory pelagic fish in the Atlantic includes king mackerel, Spanish mackerel, and cobia on the east coast of Florida, and is managed under the Fishery Management Plan for Coastal Migratory Pelagic Resources of the Gulf of Mexico and Atlantic Region (FMP). The FMP was prepared by the Gulf of Mexico and South Atlantic Fishery Management Councils. The FMP is implemented by NMFS under the authority of the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) through regulations at 50 CFR part 622. All weights described for Spanish mackerel in the Atlantic EEZ apply as either round or gutted weight.

The commercial annual catch limit (equal to the commercial quota) for the Atlantic migratory group of Spanish mackerel (Atlantic Spanish mackerel) is 3.33 million lb (1.51 million kg). Atlantic Spanish mackerel are divided into northern and southern zones for management purposes. The northern zone commercial quota for Atlantic Spanish mackerel is 662,670 lb (300,582 kg) for the current fishing year, which is March 1, 2022, through February 28, 2023 (50 CFR 622.384(c)(2)(i)).

The northern zone for Atlantic Spanish mackerel extends in Federal waters from New York through North Carolina. The northern boundary of the northern zone extends from an intersection point off New York, Connecticut, and Rhode Island at 41°18′16.249″ N latitude and 71°54′28.477″ W longitude, and proceeds southeast to 37°22′32.75″ N latitude and the intersection point with the outward boundary of the EEZ. The southern boundary of the northern zone extends from the North Carolina and South Carolina state border along a line in a direction of 135°34′55″ from true north beginning at 33°51′07.9″ N latitude and 78°32′32.6″ W longitude to the intersection point with the outward boundary of the EEZ (50 CFR 622.369(b)(2)). See Figure 2 of appendix G to part 622—Spanish Mackerel for an illustration of the management zones.

Regulations at 50 CFR 622.388(d)(1)(i) require NMFS to close the commercial sector for Atlantic Spanish mackerel in the northern zone when the commercial quota for that zone is reached, or is projected to be reached, by filing such a notification with the Office of the Federal Register. NMFS projects that the commercial quota of 662,670 lb (300,582 kg) for Atlantic Spanish mackerel in the northern zone will be reached by June 21, 2022. Accordingly, the commercial sector for Atlantic Spanish mackerel in the northern zone is closed effective at 12:01 a.m., eastern time, on June 21, 2022, through February 28, 2023, the end of the current fishing year.

During the commercial closure, a person on a vessel that has been issued a valid Federal commercial permit to harvest Atlantic Spanish mackerel may continue to retain this species in the northern zone under the recreational bag and possession limits specified in 50 CFR 622.382(a)(1)(iii) and (a)(2)(i), if recreational harvest of Atlantic Spanish mackerel in the northern zone has not been closed (50 CFR 622.384(e)(1)).

Also during the closure, Atlantic Spanish mackerel from the northern zone, including those fish harvested under the recreational bag and possession limits, may not be purchased or sold. This prohibition does not apply to Atlantic Spanish mackerel from the northern zone that were harvested, landed ashore, and sold prior to the closure and were held in cold storage by a dealer or processor (50 CFR 622.384(e)(2)).

Classification

NMFS issues this action pursuant to section 305(d) of the Magnuson-Stevens Act. This action is required by 50 CFR 622.8(b), 622.384(e)(2), and 622.388(d)(1)(i), which were issued pursuant to section 304(b) of the Magnuson-Stevens Act, and is exempt from review under Executive Order 12866.

Pursuant to 5 U.S.C. 553(b)(B), there is good cause to waive prior notice and an opportunity for public comment on this action, as notice and comment are unnecessary and contrary to the public interest. Such procedures are unnecessary because the rule implementing the commercial quota and the associated AM has already been subject to notice and public comment, and all that remains is to notify the public of the closure. Such procedures are also contrary to the public interest because of the need to immediately implement the closure to protect Atlantic Spanish mackerel, because the capacity of the fishing fleet allows for rapid harvest of the commercial quota. Prior notice and opportunity for public comment would require time and could result in a harvest that exceeds the established commercial quota.

For the same reasons, there is good cause to waive the 30-day delay in the effectiveness of this action under 5 U.S.C. 553(d)(3).

Authority: 16 U.S.C. 1801 *et seq.*

Dated: June 16, 2022.

Kelly Denit,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2022–13296 Filed 6–16–22; 4:15 pm]

BILLING CODE 3510–22–P

Proposed Rules

Federal Register
Vol. 87, No. 118
Tuesday, June 21, 2022

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–2022–0687; Project Identifier MCAI–2021–01405–T]

RIN 2120–AA64

Airworthiness Directives; Bombardier, Inc., 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 Bombardier, Inc., Model BD–700–2A12 airplanes. This proposed AD was prompted by a determination that the baggage bay line fire extinguishing tube assembly might not have been installed with the correct torque. This proposed AD would require re-torqueing the baggage bay line fire extinguishing tube assembly to the correct torque values, and applying corrosion inhibiting compound on the discharge tubes. 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 August 5, 2022.

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 Bombardier Business Aircraft Customer Response Center, 400 Côte-Vertu Road West, Dorval, Québec H4S 1Y9, Canada; telephone 514–855–2999; email *ac.yul@aero.bombardier.com;* internet *https://www.bombardier.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.

Examining the AD Docket

You may examine the AD docket at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2022–0687; 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: Elizabeth Dowling, Aerospace Engineer, Mechanical Systems and Administrative Services Section, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone 516–228–7300; email *9-avs-nyaco-cos@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–2022–0687; Project Identifier MCAI–2021–01405–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 the 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 Elizabeth Dowling, Aerospace Engineer, Mechanical Systems and Administrative Services Section, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone 516–228–7300; email *9-avs-nyaco-cos@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

Transport Canada Civil Aviation (TCCA), which is the aviation authority for Canada, has issued TCCA AD CF–2021–48, dated December 15, 2021 (CF–2021–48) (also referred to after this as the Mandatory Continuing Airworthiness Information, or the MCAI), to correct an unsafe condition for certain for certain Bombardier, Inc., Model BD–700–2A12 airplanes. You may examine the MCAI in the AD docket at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2022–0687.

This proposed AD was prompted by a determination that the baggage bay line fire extinguishing tube assembly might not have been installed with the correct torque. Although the baggage bay is accessible to the crew during flight with portable fire extinguishers, incorrect torqueing of the baggage bay line fire extinguishing tube assembly could lead to loss of the built-in fire extinguishing system for the baggage bay. The FAA is proposing this AD to address improper torqueing, which may lead to loss of the fire extinguishing system, which could prevent extinguishing a fire and possibly result in damage to the airplane and injury to occupants. See the MCAI for additional background information.

Related Service Information Under 1 CFR Part 51

Bombardier Inc. has issued Service Bulletin 700–26–7503, dated April 22, 2021. This service information describes procedures for re-torqueing the baggage bay line fire extinguishing tube assembly to the correct torque values, and applying corrosion inhibiting compound on the discharge tubes. 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.

FAA's Determination

This product has been approved by the aviation authority of another country, and is approved for operation in the United States. Pursuant to the FAA's bilateral agreement with the State of Design Authority, the FAA has been notified of the unsafe condition described in the MCAI and service information referenced above. The FAA is proposing this AD because the FAA evaluated all the relevant information and determined the unsafe condition described previously is likely to exist or develop on other products of the same type design.

Proposed AD Requirements in This NPRM

This proposed AD would require accomplishing the actions specified in the service information already described.

Costs of Compliance

The FAA estimates that this AD, if adopted as proposed, would affect 42 airplanes of U.S. registry. The FAA estimates the following costs to comply with this proposed AD:

ESTIMATED COSTS FOR REQUIRED ACTIONS

Labor cost	Parts cost	Cost per product	Cost on U.S. operators
1 work-hour × $85 per hour = $85	$5	$90	$3,780

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:

Bombardier, Inc.: Docket No. FAA–2022–0687; Project Identifier MCAI–2021–01405–T.

(a) Comments Due Date

The FAA must receive comments on this airworthiness directive (AD) by August 5, 2022.

(b) Affected ADs

None.

(c) Applicability

This AD applies to Bombardier, Inc., Model BD–700–2A12 airplanes, certificated in any category, serial numbers (S/Ns) 70006 through 70044 inclusive, 70046 through 70052 inclusive, 70055, 70056, and 70062.

(d) Subject

Air Transport Association (ATA) of America Code 26, Fire protection.

(e) Unsafe Condition

This AD was prompted by a determination that the baggage bay line fire extinguishing tube assembly might not have been installed with the correct torque. The FAA is issuing this AD to address improper torqueing, which may lead to loss of the fire extinguishing system, which could prevent extinguishing a fire and possibly result in damage to the airplane and injury to occupants.

(f) Compliance

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

(g) Re-Torque Fire Extinguishing Tube Assembly

Within 28 months after the effective date of this AD: Re-torque the baggage bay line fire extinguishing tube assembly to the correct torque values, and apply corrosion inhibiting compound on the discharge tubes, in accordance with the Accomplishment Instructions of Bombardier Service Bulletin 700–26–7503, dated April 22, 2021.

(h) No Reporting Requirement

Although Bombardier Service Bulletin 700–26–7503, dated April 22, 2021, specifies to submit certain information to the manufacturer, this AD does not include that requirement.

(i) Other FAA AD Provisions

The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, New York 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 ATTN: Program Manager, Continuing Operational Safety, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone 516–228–7300. 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, New York ACO Branch, FAA; or Transport Canada Civil Aviation (TCCA); or Bombardier, Inc.'s TCCA Design Approval Organization (DAO). If approved by the DAO, the approval must include the DAO-authorized signature.

(j) Related Information

(1) Refer to Mandatory Continuing Airworthiness Information (MCAI) TCCA AD CF–2021–48, dated December 15, 2021, for related information. This MCAI may be found in the AD docket on the internet at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2022–0687.

(2) For more information about this AD, contact Elizabeth Dowling, Aerospace Engineer, Mechanical Systems and Administrative Services Section, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone 516–228–7300; email *9-avs-nyaco-cos@faa.gov.*

(3) For service information identified in this AD, contact Bombardier Business Aircraft Customer Response Center, 400 Côte-Vertu Road West, Dorval, Québec H4S 1Y9, Canada; telephone 514–855–2999; email *ac.yul@aero.bombardier.com;* internet *https://www.bombardier.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.

Issued on June 13, 2022.

Christina Underwood,

Acting Director, Compliance & Airworthiness Division, Aircraft Certification Service.

[FR Doc. 2022–13171 Filed 6–17–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2022–0688; Project Identifier MCAI–2022–00409–T]

RIN 2120–AA64

Airworthiness Directives; Deutsche Aircraft GmbH (Type Certificate Previously Held by 328 Support Services GmbH; AvCraft Aerospace GmbH; Fairchild Dornier GmbH; Dornier Luftfahrt GmbH) 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 all Deutsche Aircraft GmbH (Type Certificate Previously Held by 328 Support Services GmbH; AvCraft Aerospace GmbH; Fairchild Dornier GmbH; Dornier Luftfahrt GmbH) Model 328–100 and –300 airplanes. This proposed AD was prompted by a safety analysis that lithium batteries installed in the personal electronic devices (PED) are a potential risk of an in-flight fire in the flight deck stowage boxes. This proposed AD would require installing a placard and stowing the fire gloves on the left-hand (LH) flap door of the flight deck step; and installing the placards on the LH and right-hand (RH) flight deck stowage boxes. This proposed AD would also require revising the existing airplane flight manual (AFM) to include emergency procedures, as specified in a European Union Aviation Safety Agency (EASA) AD, which is proposed for incorporation by reference. 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 August 5, 2022.

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 material that will be incorporated by reference (IBR) in this AD, contact EASA, Konrad-Adenauer-Ufer 3, 50668 Cologne, Germany; telephone +49 221 8999 000; email *ADs@easa.europa.eu;* internet *www.easa.europa.eu.* You may find this material on the EASA website at *https://ad.easa.europa.eu.* You may view this material 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 in the AD docket at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2022–0688.

Examining the AD Docket

You may examine the AD docket at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2022–0688; 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, the mandatory continuing airworthiness information (MCAI), any comments received, and other information. The street address for Docket Operations is listed above.

FOR FURTHER INFORMATION CONTACT: Todd Thompson, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th St., Des Moines, WA 98198; telephone 206–231–3228; email *Todd.Thompson@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–2022–0688; Project Identifier MCAI–2022–00409–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 Todd Thompson, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th St., Des Moines, WA 98198; telephone 206–231–3228; email *Todd.Thompson@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

EASA, which is the Technical Agent for the Member States of the European Union, has issued EASA AD 2022–0050, dated March 22, 2022 (EASA AD 2022–0050) (also referred to as the MCAI), to correct an unsafe condition for all Deutsche Aircraft GmbH (Type Certificate Previously Held by 328 Support Services GmbH; AvCraft Aerospace GmbH; Fairchild Dornier GmbH; Dornier Luftfahrt GmbH) Model 328–100 and 328–300 airplanes.

This proposed AD was prompted by a safety analysis that lithium batteries installed in the PED are a potential risk of an in-flight fire in the flight deck stowage boxes. EASA issued Continuing Airworthiness Review Item (CARI) 25–09, requesting type certificate holders to investigate the potential risk of in-flight fire of lithium batteries installed in PED. The investigation was conducted on the effect of a PED fire on a critical system component, and the development of smoke in the flight deck. Deutsche Aircraft GmbH Model 328–100 and –300 airplanes have the stowages for PED located in the proximity of oxygen lines, oxygen mask boxes, and other critical system components in the flight deck. The safety analysis was performed at all possible locations, and concluded that in case of a PED fire, the panels of the side console forward stowage may not be able to withstand the released heat, and the oxygen supply line can be damaged. The FAA is proposing this AD to address the potential risk of an in-flight fire of the lithium batteries installed in the PED, which could result in an oxygen fed fire in the flight deck, possibly resulting in an uncontrolled fire. See the MCAI for additional background information.

Related Service Information Under 1 CFR Part 51

EASA AD 2022–0050 specifies procedures for installing a ''FIRE GLOVES'' pictogram placard and stowing the fire gloves on the LH flap door of the flight deck step; and installing the ''NO PED STOWAGE'' placards on the LH and RH flight deck stowage boxes. EASA AD 2022–0050 also specifies revising the airplane flight manual (AFM) to include emergency procedures to address smoke including PED smoke removal.

This material 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.

FAA's Determination

These products have been approved by the aviation authority of another country and are approved for operation in the United States. Pursuant to the FAA's bilateral agreement with the State of Design Authority, it has notified the FAA of the unsafe condition described in the MCAI referenced above. The FAA is issuing this NPRM after determining that the unsafe condition described previously is likely to exist or develop in other products of these same type designs.

Proposed AD Requirements in This NPRM

This proposed AD would require accomplishing the actions specified in EASA AD 2022–0050 described previously, except for any differences identified as exceptions in the regulatory text of this proposed AD.

EASA AD 2022–0050 requires operators to ''inform all flight crews'' of revisions to the AFM, and thereafter to ''operate the aeroplane accordingly.'' However, this proposed AD would not specifically require those actions as those actions are already required by FAA regulations. FAA regulations require operators furnish to pilots any changes to the AFM (for example, 14 CFR 121.137), and to ensure the pilots are familiar with the AFM (for example, 14 CFR 91.505). As with any other flight crew training requirement, training on the updated AFM content is tracked by the operators and recorded in each pilot's training record, which is available for the FAA to review. FAA regulations also require pilots to follow the procedures in the existing AFM including all updates. 14 CFR 91.9 requires that any person operating a civil aircraft must comply with the operating limitations specified in the AFM. Therefore, including a requirement in this proposed AD to operate the airplane according to the revised AFM would be redundant and unnecessary.

Explanation of Required Compliance Information

In the FAA's ongoing efforts to improve the efficiency of the AD process, the FAA developed a process to use some civil aviation authority (CAA) ADs as the primary source of information for compliance with requirements for corresponding FAA ADs. The FAA has been coordinating this process with manufacturers and CAAs. As a result, the FAA proposes to incorporate EASA AD 2022–0050 by reference in the FAA final rule. This proposed AD would, therefore, require compliance with EASA AD 2022–0050 in its entirety through that incorporation, except for any differences identified as exceptions in the regulatory text of this proposed AD. Using common terms that are the same as the heading of a particular section in EASA AD 2022–0050 does not mean that operators need comply only with that section. For example, where the AD requirement refers to ''all required actions and compliance times,'' compliance with this AD requirement is not limited to the section titled ''Required Action(s) and Compliance Time(s)'' in EASA AD 2022–0050. Service information required by EASA AD 2022–0050 for compliance will be available at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2022–0688 after the FAA final rule is published.

Costs of Compliance

The FAA estimates that this proposed AD would affect 35 airplanes of U.S. registry. The FAA estimates the following costs to comply with this proposed AD:

ESTIMATED COSTS FOR REQUIRED ACTIONS

Labor cost	Parts cost	Cost per product	Cost on U.S. operators
2 work-hours × $85 per hour = $170	$350	$520	$18,200

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:

Deutsche Aircraft GmbH (Type Certificate Previously Held by 328 Support Services GmbH; AvCraft Aerospace GmbH; Fairchild Dornier GmbH; Dornier Luftfahrt GmbH): Docket No. FAA–2022–0688; Project Identifier MCAI–2022–00409–T.

(a) Comments Due Date

The FAA must receive comments on this airworthiness directive (AD) by August 5, 2022.

(b) Affected ADs

None.

(c) Applicability

This AD applies to all Deutsche Aircraft GmbH (Type Certificate Previously Held by 328 Support Services GmbH; AvCraft Aerospace GmbH; Fairchild Dornier GmbH; Dornier Luftfahrt GmbH) Model 328–100 and 328–300 airplanes, certificated in any category.

(d) Subject

Air Transport Association (ATA) of America Code 11, Placards and markings and 25, Equipment/furnishings.

(e) Unsafe Condition

This AD was prompted by a safety analysis that lithium batteries installed in personal electronic devices (PED) are a potential risk of an in-flight fire in the flight deck stowage boxes. The PED fire could spread out of the flight deck stowage boxes to the oxygen supply lines and other critical system components. The FAA is issuing this AD to address the potential risk of in-flight fire of lithium batteries installed in PED, which could result in an oxygen fed fire in the flight deck, possibly resulting in an uncontrolled fire.

(f) Compliance

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

(g) Requirements

Except as specified in paragraphs (h) and (i) of this AD: Comply with all required actions and compliance times specified in, and in accordance with, European Union Aviation Safety Agency (EASA) AD 2022–0050, dated March 22, 2022 (EASA AD 2022–0050).

(h) Exceptions to EASA AD 2022–0050

(1) Where EASA AD 2022–0050 refers to its effective date, this AD requires using the effective date of this AD.

(2) Where paragraph (2) of EASA AD 2022–0050 specifies to ''inform all flight crews, and, thereafter, operate the aeroplane accordingly'', this AD does not require those actions as those actions are already required by existing FAA operating regulations.

(3) Where paragraph (2) of EASA AD 2022–0050 specifies to amend or use the airplane flight manual (AFM), replace the text ''amend the applicable AFM by incorporating the AFM emergency procedure or use the AFM'' with ''amend the applicable existing AFM by incorporating the information specified in the AFM emergency procedure.''

(4) The ''Remarks'' section of EASA AD 2022–0050 does not apply to this AD.

(i) No Reporting Requirements

Although the service information referenced in EASA AD 2022–0050 specifies reporting, this AD does not include that requirement.

(j) Additional 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 (k)(2) 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 EASA; or Deutsche Aircraft GmbH's EASA Design Organization Approval (DOA). If approved by the DOA, the approval must include the DOA-authorized signature.

(k) Related Information

(1) For EASA AD 2022–0050, contact EASA, Konrad-Adenauer-Ufer 3, 50668 Cologne, Germany; telephone +49 221 8999 000; email *ADs@easa.europa.eu;* internet

www.easa.europa.eu. You may find this EASA AD on the EASA website at *https://ad.easa.europa.eu.* You may view this material 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. This material may be found in the AD docket at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2022–0688.

(2) For more information about this AD, contact Todd Thompson, Aerospace Engineer, Large Aircraft Section, International Validation Branch, FAA, 2200 South 216th Street, Des Moines, WA 98198; telephone 206–231–3228; email *Todd.Thompson@faa.gov.*

Issued on June 14, 2022.

Christina Underwood,

Acting Director, Compliance & Airworthiness Division, Aircraft Certification Service.

[FR Doc. 2022–13097 Filed 6–17–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2022–0689; Project Identifier MCAI–2022–00215–T]

RIN 2120–AA64

Airworthiness Directives; Airbus SAS Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to supersede Airworthiness Directive (AD) 2019–26–11, which applies to certain Airbus SAS Model A319–112, –115, and –132; A320–214, –216, –232, –233, –251N, and –271N; and A321–211, –231, –232, –251N, and –253N airplanes; and AD 2021–23–15, which applies to certain Airbus SAS Model A319–111, –112, –113, –114, –115, –131, –132, and –133; A320–211, –212, –214, –216, –231, –232, and –233; and A321–111, –112, –131, –211, –212, –213, –231, and –232 airplanes. AD 2019–26–11 requires replacing the affected bumpers with serviceable bumpers. AD 2021–23–15 requires modifying the waste compartment door of each affected galley. Since the FAA issued AD 2019–26–11 and AD 2021–23–15, it was determined that additional airplanes are subject to the unsafe conditions described in those ADs. This proposed AD would continue to require the actions in AD 2019–26–11 and AD 2021–23–15, and would add airplanes to the applicability, as specified in a European Union Aviation Safety Agency (EASA) AD, which is proposed for incorporation by reference. 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 August 5, 2022.

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:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For material that will be incorporated by reference (IBR) in this AD, contact EASA, Konrad-Adenauer-Ufer 3, 50668 Cologne, Germany; telephone +49 221 8999 000; email *ADs@easa.europa.eu;* internet *www.easa.europa.eu.* You may find this material on the EASA website at *https://ad.easa.europa.eu.* You may view this material 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 in the AD docket at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2022–0689.

Examining the AD Docket

You may examine the AD docket at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2022–0689; 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, the mandatory continuing airworthiness information (MCAI), any comments received, and other information. The street address for Docket Operations is listed above.

FOR FURTHER INFORMATION CONTACT: Vladimir Ulyanov, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th St., Des Moines, WA 98198; telephone 206–231–3223; email *vladimir.ulyanov@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–2022–0689; Project Identifier MCAI–2022–00215–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 Vladimir Ulyanov, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th St., Des Moines, WA 98198; telephone 206–231–3223; email *vladimir.ulyanov@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 issued AD 2019–26–11, Amendment 39–21022 (85 FR 6755, February 6, 2020) (AD 2019–26–11), which applies to certain Airbus SAS Model A319–112, A319–115, A319–132, A320–214, A320–216, A320–232, A320–233, A320–251N, A320–271N, A321–

211, A321–231, A321–232, A321–251N, and A321–253N airplanes. AD 2019–26–11 requires replacing affected container/galley end stop bumpers with serviceable bumpers. The FAA issued AD 2019–26–11 to address deformed end stops, which could break or lose their function to maintain the container/galley in position on the airplane. This condition, if not corrected, could lead to container/galley detachment under certain forward loading conditions, possibly resulting in injury to airplane occupants.

The FAA also issued AD 2021–23–15, Amendment 39–21813 (86 FR 68894, December 6, 2021) (AD 2021–23–15), which applies to certain Airbus SAS Model A319–111, –112, –113, –114, –115, –131, –132, and –133 airplanes; Model A320–211, –212, –214, –216, –231, –232, and –233 airplanes; and Model A321–111, –112, –131, –211, –212, –213, –231, and –232 airplanes. AD 2021–23–15 requires modifying the waste compartment door of each affected galley. The FAA issued AD 2021–23–15 to address failure of the galley door and release of trolleys during a rejected take-off or an emergency landing, which could result in injury to occupants and damage to the airplane.

Actions Since AD 2019–26–11 and AD 2021–23–15 Were Issued

Since the FAA issued AD 2019–26–11 and AD 2021–23–15, it was determined that additional airplanes are subject to the unsafe conditions addressed by AD 2019–26–11 and AD 2021–23–15.

EASA, which is the Technical Agent for the Member States of the European Union, has issued EASA AD 2022–0026, dated February 16, 2022 (EASA AD 2022–0026) (also referred to as the MCAI), to correct an unsafe condition for certain Airbus SAS Model A319–111, A319–112, A319–113, A319–114, A319–115, A319–131, A319–132, A319–133, A320–211, A320–212, A320–214, A320–215, A320–216, A320–231, A320–232, A320–233, A320–251N, A320–271N, A321–111, A321–112, A321–131, A321–211, A321–212, A321–213, A321–231, A321–232, A321–251N and A321–253N airplanes. Model A320–215 airplanes are not certificated by the FAA and are not included on the U.S. type certificate data sheet; this AD therefore does not include those airplanes in the applicability.

This proposed AD was prompted by a report that during re-engineering of galley G5, a 9G forward full scale qualification test was performed, and the door of the waste compartment opened before the required load was reached, and by reports of finding container/galley end stop bumpers damaged in service. This proposed AD was also prompted by the determination that additional airplanes are subject to the unsafe condition. The FAA is proposing this AD to address potential failure of the galley door and release of waste bins during a rejected take-off or an emergency landing, and potential container detachment from the galley under certain forward loading conditions, possibly resulting in damage to the airplane and injury to occupants. See the MCAI for additional background information.

Explanation of Retained Requirements

Although this proposed AD does not explicitly restate the requirements of AD 2019–26–11 and AD 2021–23–15, this proposed AD would retain all of the requirements of AD 2019–26–11 and AD 2021–23–15. Those requirements are referenced in EASA AD 2022–0026, which, in turn, is referenced in paragraph (g) of this proposed AD.

Related Service Information Under 1 CFR Part 51

EASA AD 2022–0026 specifies procedures for modifying the affected galleys by replacing the affected bumpers with serviceable bumpers; for modifying the waste compartment door of each affected galley by installing a door catch bracket and a new striker, and for re-identifying the affected galleys.

This material 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.

FAA's Determination

These products have been approved by the aviation authority of another country and are approved for operation in the United States. Pursuant to the FAA's bilateral agreement with the State of Design Authority, it has notified the FAA of the unsafe condition described in the MCAI and service information referenced above. The FAA is issuing this NPRM after determining that the unsafe condition described previously is likely to exist or develop in other products of these same type designs.

Proposed AD Requirements in This NPRM

This proposed AD would require accomplishing the actions specified in EASA AD 2022–0026 described previously, except for any differences identified as exceptions in the regulatory text of this proposed AD.

Explanation of Required Compliance Information

In the FAA's ongoing efforts to improve the efficiency of the AD process, the FAA developed a process to use some civil aviation authority (CAA) ADs as the primary source of information for compliance with requirements for corresponding FAA ADs. The FAA has been coordinating this process with manufacturers and CAAs. As a result, the FAA proposes to incorporate EASA AD 2022–0026 by reference in the FAA final rule. This proposed AD would, therefore, require compliance with EASA AD 2022–0026 in its entirety through that incorporation, except for any differences identified as exceptions in the regulatory text of this proposed AD. Using common terms that are the same as the heading of a particular section in EASA AD 2022–0026 does not mean that operators need comply only with that section. For example, where the AD requirement refers to "all required actions and compliance times," compliance with this AD requirement is not limited to the section titled "Required Action(s) and Compliance Time(s)" in EASA AD 2022–0026. Service information required by EASA AD 2022–0026 for compliance will be available at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2022–0689 after the FAA final rule is published.

Costs of Compliance

The FAA estimates that this proposed AD affects 1,507 airplanes of U.S. registry. The FAA estimates the following costs to comply with this proposed AD:

ESTIMATED COSTS FOR REQUIRED ACTIONS

Action	Labor cost	Parts cost	Cost per product	Cost on U.S. operators
Retained actions from AD 2019–26–11 (274 airplanes).	Up to 54 work-hours × $85 per hour = Up to $4,590.	$0	Up to $4,590	Up to $1,257,660.

ESTIMATED COSTS FOR REQUIRED ACTIONS—Continued

Action	Labor cost	Parts cost	Cost per product	Cost on U.S. operators
Retained actions from AD 2021–23–15 (141 airplanes).	5 work-hours × $85 per hour = $425	0	$425	$59,925.
New proposed actions (Up to 1,092 airplanes).	Up to 59 work-hours × $85 per hour = Up to $5,105.	0	Up to $5,105	Up to $5,476,380.

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

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:

a. Removing Airworthiness Directive (AD) 2019–26–11, Amendment 39–21022 (85 FR 6755, February 6, 2020); and AD 2021–23–15, Amendment 39–21813 (86 FR 68894, December 6, 2021); and

b. Adding the following new AD:

Airbus SAS: Docket No. FAA–2022–0689; Project Identifier MCAI–2022–00215–T.

(a) Comments Due Date

The FAA must receive comments on this airworthiness directive (AD) by August 5, 2022.

(b) Affected ADs

This AD replaces AD 2019–26–11, Amendment 39–21022 (85 FR 6755, February 6, 2020) (AD 2019–26–11); and AD 2021–23–15, Amendment 39–21813 (86 FR 68894, December 6, 2021) (AD 2021–23–15).

(c) Applicability

This AD applies to the Airbus SAS airplanes specified in paragraphs (c)(1) through (3) of this AD, certificated in any category, as identified in European Union Aviation Safety Agency (EASA) AD 2022–0026, dated February 16, 2022 (EASA AD 2022–0026).

(1) Model A319–111, –112, –113, –114, –115, –131, –132, and –133 airplanes.

(2) Model A320–211, –212, –214, –216, –231, –232, –233, –251N, and –271N airplanes.

(3) Model A321–111, –112, –131, –211, –212, –213, –231, –232, –251N, and –253N airplanes.

(d) Subject

Air Transport Association (ATA) of America Code 25, Equipment/Furnishings.

(e) Unsafe Condition

This AD was prompted by a report that during re-engineering of galley G5, a 9G forward full scale qualification test was performed, and the door of the waste compartment opened before the required load was reached, and by reports of finding container/galley end stop bumpers damaged in service. This AD was also prompted by the determination that additional airplanes are subject to the unsafe condition. The FAA is issuing this AD to address potential failure of the galley door and release of waste bins during a rejected take-off or an emergency landing, and potential container detachment from the galley under certain forward loading conditions, possibly resulting in damage to the airplane and injury to occupants.

(f) Compliance

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

(g) Requirements

Except as specified in paragraph (h) of this AD: Comply with all required actions and compliance times specified in, and in accordance with, EASA AD 2022–0026.

(h) Exceptions to EASA AD 2022–0026

(1) Where EASA AD 2022–0026 refers to December 11, 2018 (the effective date of EASA AD 2018–0255), this AD requires using January 10, 2022 (the effective date of AD 2021–23–15).

(2) Where EASA AD 2022–0026 refers to May 29, 2019 (the effective date of EASA AD 2019–0106), this AD requires using March 12, 2020 (the effective date of AD 2019–26–11).

(3) Where EASA AD 2022–0026 refers to its effective date, this AD requires using the effective date of this AD.

(4) The "Remarks" section of EASA AD 2022–0026 does not apply to this AD.

(i) Additional 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 (j)(2) 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 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 (i)(2) of this AD, if any service information contains procedures or tests that are identified as RC, those procedures and tests must be done to comply with this AD; any procedures or tests that are not identified as RC are recommended. Those procedures and tests that are 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 procedures and tests identified as RC can be done and the airplane can be put back in an airworthy condition. Any substitutions or changes to procedures or tests identified as RC require approval of an AMOC.

(j) Related Information

(1) For EASA AD 2022–0026, contact EASA, Konrad-Adenauer-Ufer 3, 50668 Cologne, Germany; telephone +49 221 8999 000; email *ADs@easa.europa.eu;* internet *www.easa.europa.eu.* You may find this EASA AD on the EASA website at *https://ad.easa.europa.eu.* You may view this material 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. This material may be found in the AD docket at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2022–0689.

(2) For more information about this AD, contact Vladimir Ulyanov, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th St., Des Moines, WA 98198; telephone 206–231–3223; email *vladimir.ulyanov@faa.gov.*

Issued on June 14, 2022.

Christina Underwood,

Acting Director, Compliance & Airworthiness Division, Aircraft Certification Service.

[FR Doc. 2022–13094 Filed 6–17–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2022–0690; Project Identifier AD–2021–01360–E]

RIN 2120–AA64

Airworthiness Directives; General Electric Company Turboshaft Engines

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to adopt a new airworthiness directive (AD) for all General Electric Company (GE) CT7–8A model turboshaft engines. This proposed AD was prompted by the manufacturer revising the airworthiness limitations section (ALS) of the existing engine maintenance manual (EMM) to incorporate reduced life limits for certain stage 1 turbine aft cooling plates, stage 2 turbine forward cooling plates, turbine interstage seals, and stage 4 turbine disks. This proposed AD would require revising the ALS of the existing EMM and the operator's existing approved maintenance or inspection program, as applicable, to incorporate reduced life limits for these parts. 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 August 5, 2022.

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 General Electric Company, 1 Neumann Way, Cincinnati, OH 45215; phone: (513) 552–3272; email: *aviation.fleetsupport@ae.ge.com;* website: *https://www.ge.com.* You may view this service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 1200 District Avenue, Burlington, MA 01803. For information on the availability of this material at the FAA, call (817) 222–5110.

Examining the AD Docket

You may examine the AD docket at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2022–0690; 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: Sungmo Cho, Aviation Safety Engineer, ECO Branch, FAA, 1200 District Avenue, Burlington, MA 01803; phone: (781) 238–7241; email: *Sungmo.D.Cho@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–2022–0690; Project Identifier AD–2021–01360–E'' 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 Sungmo Cho, Aviation Safety Engineer, ECO Branch, FAA, 1200 District Avenue, Burlington, MA 01803. 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 was notified that the manufacturer revised the ALS of the existing EMM to incorporate reduced life limits for certain stage 1 turbine aft cooling plates, stage 2 turbine forward cooling plates, turbine interstage seals, and stage 4 turbine disks (life-limited parts) installed on CT7–8A model turboshaft engines. Additionally, the manufacturer published service information that introduced the reduced life limits. The life limits were reduced by the manufacturer as the result of an analysis of the life management models for these parts. This condition, if not addressed, could result in uncontained part release, damage to the engine, damage to the helicopter, and possible loss of control of the helicopter.

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

The FAA reviewed GE CT7–8 Service Bulletin 72–0062, Revision 01, dated December 22, 2021. This service information provides the reduced life limits for certain life-limited parts.

Proposed AD Requirements in This NPRM

This proposed AD would require revising the ALS of the applicable GE CT7–8 EMM and the operator's existing approved maintenance or inspection program, as applicable, to incorporate reduced life limits for certain life-limited parts.

Costs of Compliance

The FAA estimates that this AD, if adopted as proposed, would affect 126 engines installed on helicopters 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
Revise ALS of EMM and the operator's existing approved maintenance or inspection program.	1 work-hour × $85 per hour = $85.	$0	$85	$10,710

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:

General Electric Company: Docket No. FAA–2022–0690; Project Identifier AD–2021–01360–E.

(a) Comments Due Date

The FAA must receive comments on this airworthiness directive (AD) by August 5, 2022.

(b) Affected ADs

None.

(c) Applicability

This AD applies to General Electric Company CT7–8A model turboshaft engines.

(d) Subject

Joint Aircraft System Component (JASC) Code 7240, Turbine Engine Combustion Section; 7250, Turbine Section.

(e) Unsafe Condition

This AD was prompted by the manufacturer revising the airworthiness limitations section (ALS) of the existing engine maintenance manual (EMM) to incorporate reduced life limits for certain stage 1 turbine aft cooling plates, stage 2 turbine forward cooling plates, turbine interstage seals, and stage 4 turbine disks. The FAA is issuing this AD to prevent failure of the stage 1 turbine aft cooling plates, stage 2 turbine forward cooling plates, turbine interstage seals, and stage 4 turbine disks. The unsafe condition, if not addressed, could result in uncontained part release, damage to the engine, damage to the helicopter, and possible loss of control of the helicopter.

(f) Compliance

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

(g) Required Actions

(1) Within 90 days after the effective date of this AD, revise the ALS of the existing GE CT7–8 Turboshaft EMM and the operator's existing approved maintenance or inspection program, as applicable, by incorporating the following reduced life limits:

(i) For stage 1 turbine aft cooling plate, part number (P/N) 6064T09P02, change the life limit cycles from 6,600 cycles since new (CSN) to 4,900 CSN;

(ii) For stage 2 turbine forward cooling plate, P/N 4106T80P01, change the life limit cycles from 8,000 CSN to 7,200 CSN;

(iii) For turbine interstage seal, P/N 4111T86P03, change the life limit cycles from 29,200 CSN to 19,000 CSN; and

(iv) For stage 4 turbine disk, P/N 6068T32P04, change the life limit cycles from 24,100 CSN to 12,100 CSN.

(2) After performing the actions required by paragraph (g)(1) of this AD, except as provided in paragraph (h) of this AD, no alternative life limits may be approved.

(h) Alternative Methods of Compliance (AMOCs)

(1) The Manager, ECO 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 (i) of this AD and email to: *ANE-AD-AMOC@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.

(i) Related Information

For more information about this AD, contact Sungmo Cho, Aviation Safety Engineer, ECO Branch, FAA, 1200 District Avenue, Burlington, MA 01803; phone: (781) 238–7241; email: *Sungmo.D.Cho@faa.gov.*

Issued on June 14, 2022.

Christina Underwood,

Acting Director, Compliance & Airworthiness Division, Aircraft Certification Service.

[FR Doc. 2022–13154 Filed 6–17–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2022–0684; Project Identifier MCAI–2021–01204–T]

RIN 2120–AA64

Airworthiness Directives; Bombardier, Inc., 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 Bombardier, Inc., Model BD–700–2A12 airplanes. This proposed AD was prompted by a report of a lateral offset observed on the head-up display (HUD) of several airplanes between the synthetic vision system (SVS) and actual runway due to mechanical misalignment of the HUD during manufacturing and assembly. This proposed AD would require revising the existing Airplane Flight Manual (AFM) to prohibit steep approach landing (SAL) and enhanced flight vision system (EFVS) operations. This proposed AD would also require calibrating the HUD. 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 August 5, 2022.

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 Bombardier Business Aircraft Customer Response Center, 400 Côte-Vertu Road West, Dorval, Québec H4S 1Y9, Canada; telephone 1–514–855–2999; email *ac.yul@aero.bombardier.com;* internet *https://www.bombardier.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.

Examining the AD Docket

You may examine the AD docket at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2022–0684; 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: Thomas Niczky, Aerospace Engineer, Airframe and Mechanical Systems Section, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone 516–228–7347; email *9-avs-nyaco-cos@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–2022–0684; Project Identifier MCAI–2021–01204–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 the 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 Thomas Niczky, Aerospace Engineer, Airframe and Mechanical Systems Section, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone 516–228–7347; email *9-avs-nyaco-cos@faa.gov.* Any commentary that the FAA receives that is not specifically designated as CBI will be placed in the public docket for this rulemaking.

Background

Transport Canada Civil Aviation (TCCA), which is the aviation authority for Canada, has issued TCCA AD CF–2021–36, dated November 1, 2021 (TCCA AD CF–2021–36) (also referred to after this as the Mandatory

Continuing Airworthiness Information, or the MCAI), to correct an unsafe condition for certain Bombardier, Inc., Model BD–700–2A12 airplanes. You may examine the MCAI in the AD docket at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2022–0684.

This proposed AD was prompted by a report indicating that during production, a lateral offset was observed on the HUD of several airplanes between the SVS and actual runway. An investigation determined the cause of the offset to be mechanical misalignment of the HUD during manufacturing and assembly. The FAA is proposing this AD to address a lateral offset between SVS and actual runway, which could create an incorrect aircraft reference display on the HUD and lead to excessive deviation during landing, particularly affecting SAL or EFVS operations. See the MCAI for additional background information.

Related Service Information Under 1 CFR Part 51

Bombardier has issued the following documents to prohibit SAL and EFVS operations until the HUD has been calibrated.

- Section 6., Service Bulletins, of Chapter 1—Introduction, of the Bombardier Global 7500 AFM, Publication No. CSP 700–7000–1, Revision 14, dated October 21, 2021.
- Supplement 7—Enhanced Flight Vision System (EFVS) Operations, of Chapter 7—Supplements, of the Bombardier Global 7500 AFM, Publication No. CSP 700–7000–1, Revision 14, dated October 21, 2021.
- Supplement 20—Steep Approaches with Published Glidepath Angles from 4.5 to 5.5 Degrees, of Chapter 7—Supplements, of the Bombardier Global 7500 AFM, Publication No. CSP 700–7000–1, Revision 14, dated October 21, 2021.

(For obtaining this material in the Bombardier Global 7500 AFM, Publication No. CSP 700–7000–1, use Document Identification No. GL 7500 AFM.)

Bombardier has issued the following documents, which specify procedures for calibrating the HUD (and second HUD if installed). The procedures include an inspection of the HUD mounting brackets and sill beams for damage and contamination (*e.g.,* drill shavings and adhesive) of the mating surfaces and injection holes, an inspection for voids in the structural adhesive, and applicable corrective actions. Corrective actions include replacing damaged brackets and backfilling voids with structural adhesive. These documents are distinct since they apply to different airplane configurations.

- Bombardier Service Bulletin 700–34–7521, Revision 03, dated July 27, 2021.
- Bombardier Service Bulletin 700–34–7521, Revision 04, dated December 6, 2021, including Appendix 1, dated November 10, 2021.
- Bombardier Service Bulletin 700–34–7523, Revision 01, dated December 8, 2021.

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.

Other Related Service Information

Earlier revisions of Service Bulletins 700–34–7521 and 700–34–7523 included a typographical error on the metric values on the ''External Target Board'' table. This error was corrected in Bombardier Service Bulletin 700–34–7521, Revision 03, dated July 27, 2021; Bombardier Service Bulletin 700–34–7521, Revision 04, dated December 6, 2021, including Appendix 1, dated November 10, 2021; and Bombardier Service Bulletin 700–34–7523, Revision 01, dated December 8, 2021. This error is further described in the Retroactive Action section in these Service Bulletins. The FAA has determined that the earlier revisions would be acceptable for compliance with the proposed requirements under certain conditions in their entirety if imperial values were used. However, if the metric values specified in the earlier revisions were used, the HUD calibration is not considered completed for the purposes of Supplement 7—Enhanced Flight Vision System (EFVS) Operations, and Supplement 20—Steep Approaches with Published Glidepath Angles from 4.5 to 5.5 Degrees, of Chapter 7—Supplements, of the Bombardier Global 7500 AFM, Publication No. CSP 700–7000–1, until retroactive actions are also done as specified in paragraphs (i)(1), (2), (3), and (5) of this proposed AD.

FAA's Determination

This product has been approved by the aviation authority of another country, and is approved for operation in the United States. Pursuant to the FAA's bilateral agreement with the State of Design Authority, the FAA has been notified of the unsafe condition described in the MCAI and service information referenced above. The FAA is proposing this AD because the FAA evaluated all the relevant information and determined the unsafe condition described previously is likely to exist or develop on other products of the same type design.

Proposed AD Requirements in This NPRM

This proposed AD would require accomplishing the actions specified in the service information already described.

Costs of Compliance

The FAA estimates that this AD, if adopted as proposed, would affect 40 airplanes of U.S. registry. The FAA estimates the following costs to comply with this proposed AD:

ESTIMATED COSTS FOR REQUIRED ACTIONS

Action	Labor cost	Parts cost	Cost per product	Cost on U.S. operators
HUD calibration	39 work-hours (for 36 airplanes with 1 HUD) or 108 work-hours (for 4 airplanes with 2 HUDs) × $85 per hour.	$7,400 per HUD	$10,715 (1 HUD) or $23,980 (2 HUDs).	$481,660
AFM revision	1 work-hour × $85 per hour	$0	$85	3,400

The FAA estimates that replacement brackets would cost up to $1,200 (per HUD) if required for any on-condition corrective actions in this proposed AD. The FAA has received no definitive data on which to base the work-hour estimates for this replacement. The FAA has no way of determining the number of aircraft that might need this on-condition action.

The FAA has included all known costs in its cost estimate. According to the manufacturer, however, some or all of the costs of this proposed AD may be covered under warranty, thereby reducing the cost impact on affected operators.

Paperwork Reduction Act

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a currently valid OMB Control Number. The OMB Control Number for this information collection is 2120–0056. The time for public reporting for this collection of information, including reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information, is provided in the Costs of Compliance section already described. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Information Collection Clearance Officer, Federal Aviation Administration, 10101 Hillwood Parkway, Fort Worth, TX 76177–1524.

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:

Bombardier, Inc.: Docket No. FAA–2022–0684; Project Identifier MCAI–2021–01204–T.

(a) Comments Due Date

The FAA must receive comments on this airworthiness directive (AD) by August 5, 2022.

(b) Affected ADs

None.

(c) Applicability

This AD applies to Bombardier, Inc., Model BD–700–2A12 airplanes, certificated in any category, serial numbers 70006 through 70084 inclusive.

(d) Subject

Air Transport Association (ATA) of America Code 34, Navigation.

(e) Unsafe Condition

This AD was prompted by a report of a lateral offset observed on the head-up display (HUD) of several airplanes between the synthetic vision system (SVS) and actual runway. The FAA is issuing this AD to address this offset, which could create an incorrect aircraft reference display on the HUD, and lead to excessive deviation during landing, particularly affecting steep approach landing (SAL) or enhanced flight vision system (EFVS) operations.

(f) Compliance

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

(g) Revision of the Existing Airplane Flight Manual (AFM)

Within 30 days after the effective date of this AD, revise the existing AFM to include the information in the sections of the AFM specified in paragraphs (g)(1) through (3) of this AD.

(1) Section 6., Service Bulletins, of Chapter 1—Introduction, of the Bombardier Global 7500 AFM, Publication No. CSP 700–7000–1, Revision 14, dated October 21, 2021.

Note 1 to paragraph (g)(1): For obtaining the sections of the Bombardier Global 7500 AFM, Publication No. CSP 700–7000–1, specified in paragraphs (g)(1) through (3) of this AD, use Document Identification No. GL 7500 AFM.

(2) Supplement 7—Enhanced Flight Vision System (EFVS) Operations, of Chapter 7—Supplements, of the Bombardier Global 7500 AFM, Publication No. CSP 700–7000–1, Revision 14, dated October 21, 2021.

(3) Supplement 20—Steep Approaches with Published Glidepath Angles from 4.5 to 5.5 Degrees, of Chapter 7—Supplements, of the Bombardier Global 7500 AFM, Publication No. CSP 700–7000–1, Revision 14, dated October 21, 2021.

(h) HUD Calibration

Within 27 months after the effective date of this AD, calibrate the HUD and second HUD (if installed), including a general visual inspection of the of the HUD mounting brackets and sill beams for damage and contamination (*e.g.,* drill shavings and adhesive) of the mating surfaces and injection holes, a general visual inspection for voids in the structural adhesive, and applicable corrective actions, in accordance with the Accomplishment Instructions of Bombardier Service Bulletin 700–34–7521, Revision 04, dated December 6, 2021, including Appendix 1, dated November 10, 2021; and Bombardier Service Bulletin 700–34–7523, Revision 01, dated December 8, 2021; as applicable. All corrective actions must be done before further flight.

(i) Credit for Previous Actions

This paragraph provides credit for actions required by paragraph (h) of this AD, if those actions were performed before the effective date of this AD using the service information identified in, and meeting the applicable conditions specified in, paragraphs (i)(1) through (5) of this AD.

(1) Credit is allowed for Bombardier Service Bulletin 700–34–7521, dated April 1, 2021, if the retroactive actions identified in Bombardier Service Bulletin 700–34–7521, Revision 03, dated July 27, 2021; or Bombardier Service Bulletin 700–34–7521, Revision 04, dated December 6, 2021; are done within 27 months after the effective date of this AD.

(2) Credit is allowed for Bombardier Service Bulletin 700–34–7521, Revision 01, dated April 30, 2021, if the retroactive actions identified in Bombardier Service Bulletin 700–34–7521, Revision 03, dated July 27, 2021; or Bombardier Service Bulletin 700–34–7521, Revision 04, dated December 6, 2021; are done within 27 months after the effective date of this AD.

(3) Credit is allowed for Bombardier Service Bulletin 700–34–7521, Revision 02,

dated July 12, 2021, if the retroactive actions identified in Bombardier Service Bulletin 700–34–7521, Revision 03, dated July 27, 2021; or Bombardier Service Bulletin 700–34–7521, Revision 04, dated December 6, 2021; are done within 27 months after the effective date of this AD.

(4) Credit is allowed for Bombardier Service Bulletin 700–34–7521, Revision 3, dated July 27, 2021.

(5) Credit is allowed for Bombardier Service Bulletin 700–34–7523, dated April 1, 2021, if the retroactive actions identified in Bombardier Service Bulletin 700–34–7523, Revision 01, dated December 8, 2021, are done within 27 months after the effective date of this AD.

(j) Other FAA AD Provisions

The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, New York 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 ATTN: Program Manager, Continuing Operational Safety, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone 516–228–7300. 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, New York ACO Branch, FAA; or Transport Canada Civil Aviation (TCCA); or Bombardier, Inc.'s TCCA Design Approval Organization (DAO). If approved by the DAO, the approval must include the DAO-authorized signature.

(k) Related Information

(1) Refer to Mandatory Continuing Airworthiness Information (MCAI) TCCA AD CF–2021–36, dated November 1, 2021, for related information. This MCAI may be found in the AD docket on the internet at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2022–0684.

(2) For more information about this AD, contact Thomas Niczky, Aerospace Engineer, Airframe and Mechanical Systems Section, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone 516–228–7347; email *9-avs-nyaco-cos@faa.gov.*

(3) For service information identified in this AD, contact Bombardier Business Aircraft Customer Response Center, 400 Côte-Vertu Road West, Dorval, Québec H4S 1Y9, Canada; telephone 1–514–855–2999; email *ac.yul@aero.bombardier.com;* internet *https://www.bombardier.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.

Issued on June 13, 2022.

Christina Underwood,

Acting Director, Compliance & Airworthiness Division, Aircraft Certification Service.

[FR Doc. 2022–13170 Filed 6–17–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Parts 1162 and 1166

[Docket Nos. FDA–2021–N–1349 and FDA–2021–N–1309]

RIN 0910–AI60 and 0910–AI28

Establishment of Tobacco Product Standards for Menthol in Cigarettes and Characterizing Flavors in Cigars; Extension of Comment Period

AGENCY: Food and Drug Administration, Department of Health and Human Services (HHS).

ACTION: Proposed rules; extension of comment period.

SUMMARY: The Food and Drug Administration (FDA, the Agency, or we) is extending the comment period for two proposed rules that appeared in the **Federal Register** of May 4, 2022, which are a tobacco product standard that would prohibit menthol as a characterizing flavor in cigarettes (''Tobacco Product Standard for Menthol in Cigarettes''; Docket No. FDA–2021–N–1349) and a tobacco product standard that would prohibit characterizing flavors (other than tobacco) in all cigars (''Tobacco Product Standard for Characterizing Flavors in Cigars''; Docket No. FDA–2021–N–1309). The Agency is taking this action in response to requests for an extension to allow interested persons additional time to submit comments.

DATES: FDA is extending the comment period on the proposed rules published in the **Federal Register** on May 4, 2022 (87 FR 26454 and 87 FR 26396). Submit either electronic or written comments by August 2, 2022.

ADDRESSES: You may submit comments as follows. Please note that late, untimely filed comments will not be considered. The *https://www.regulations.gov* electronic filing system will accept comments until 11:59 p.m. Eastern Time at the end of August 2, 2022. Comments received by mail/hand delivery/courier (for written/paper submissions) will be considered timely if they are postmarked or the delivery service acceptance receipt is on or before that date.

Electronic Submissions

Submit electronic comments in the following way:

- *Federal eRulemaking Portal: https://www.regulations.gov.* Follow the instructions for submitting comments. Comments submitted electronically, including attachments, to *https://www.regulations.gov* will be posted to the docket unchanged. Because your comment will be made public, you are solely responsible for ensuring that your comment does not include any confidential information that you or a third party may not wish to be posted, such as medical information, your or anyone else's Social Security number, or confidential business information, such as a manufacturing process. Please note that if you include your name, contact information, or other information that identifies you in the body of your comments, that information will be posted on *https://www.regulations.gov.*
- If you want to submit a comment with confidential information that you do not wish to be made available to the public, submit the comment as a written/paper submission and in the manner detailed (see ''Written/Paper Submissions'' and ''Instructions'').

Written/Paper Submissions

Submit written/paper submissions as follows:

- *Mail/Hand Delivery/Courier (for written/paper submissions):* Dockets Management Staff (HFA–305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.
- For written/paper comments submitted to the Dockets Management Staff, FDA will post your comment, as well as any attachments, except for information submitted, marked and identified, as confidential, if submitted as detailed in ''Instructions.''

Instructions: All submissions received must include the Docket No. FDA–2021–N–1349 for ''Tobacco Product Standard for Menthol in Cigarettes'' and/or Docket No. FDA–2021–N–1309 for ''Tobacco Product Standard for Characterizing Flavors in Cigars.'' Received comments, those filed in a timely manner (see **ADDRESSES**), will be placed in the docket and, except for those submitted as ''Confidential Submissions,'' publicly viewable at *https://www.regulations.gov* or at the Dockets Management Staff between 9 a.m. and 4 p.m., Monday through Friday, 240–402–7500.

- Confidential Submissions—To submit a comment with confidential information that you do not wish to be made publicly available, submit your comments only as a written/paper submission. You should submit two copies total. One copy will include the information you claim to be confidential with a heading or cover note that states ''THIS DOCUMENT CONTAINS CONFIDENTIAL INFORMATION.'' The Agency will review this copy, including the claimed confidential information, in its consideration of comments. The second copy, which will have the claimed confidential information redacted/blacked out, will be available for public viewing and posted on *https://www.regulations.gov.* Submit both copies to the Dockets Management Staff. If you do not wish your name and contact information to be made publicly available, you can provide this information on the cover sheet and not in the body of your comments and you must identify this information as ''confidential.'' Any information marked as ''confidential'' will not be disclosed except in accordance with 21 CFR 10.20 and other applicable disclosure law. For more information about FDA's posting of comments to public dockets, see 80 FR 56469, September 18, 2015, or access the information at: *https://www.govinfo.gov/content/pkg/FR-2015-09-18/pdf/2015-23389.pdf.*

Docket: For access to the docket to read background documents or the electronic and written/paper comments received, go to *https://www.regulations.gov* and insert the docket number, found in brackets in the heading of this document, into the ''Search'' box and follow the prompts and/or go to the Dockets Management Staff, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852, 240–402–7500.

FOR FURTHER INFORMATION CONTACT: Beth Buckler or Nate Mease, Center for Tobacco Products, Food and Drug Administration, 10903 New Hampshire Ave., Silver Spring, MD 20993–0002, 877–287–1373, *CTPRegulations@fda.hhs.gov.*

SUPPLEMENTARY INFORMATION: In the **Federal Register** of May 4, 2022 (87 FR 26454 and 87 FR 26396), FDA published two proposed rules: (1) a tobacco product standard that would prohibit menthol as a characterizing flavor in cigarettes (''Tobacco Product Standard for Menthol in Cigarettes''; Docket No. FDA–2021–N–1349) and (2) a tobacco product standard that would prohibit characterizing flavors (other than tobacco) in all cigars (''Tobacco Product Standard for Characterizing Flavors in Cigars''; Docket No. FDA–2021–N–1309). Both proposed rules published with a 60-day comment period. Comments on the proposed rules will inform FDA's rulemakings to establish tobacco product standards for menthol in cigarettes and characterizing flavors in cigars.

Interested persons were originally given until July 5, 2022, to comment on the proposed rules. We have received a number of requests for a 60-day extension of the comment period for both proposed rules, which conveyed concern that the current 60-day comment period does not allow sufficient time to develop a meaningful response to the proposed rules. Several organizations have requested that FDA close the comment period after 60 days, conveying that 60 days is enough time to receive meaningful responses and stressed a public health urgency with both product standards.

FDA has considered the requests and is extending the comment period for the proposed rules by an additional 30 days, until August 2, 2022. We believe that a 90-day comment period is appropriate as it allows adequate time for interested persons to fully consider the proposed rules, including specific requests for comments, and develop and submit comments without significantly lengthening the rulemaking proceedings.

Dated: June 14, 2022.

Lauren K. Roth,

Associate Commissioner for Policy.

[FR Doc. 2022–13209 Filed 6–17–22; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF JUSTICE

28 CFR Part 0

[BOP Docket No. 1179; AG Order No. 5439–2022]

RIN 1120–AB79

Home Confinement Under the Coronavirus Aid, Relief, and Economic Security (CARES) Act

AGENCY: Office of the Attorney General, Department of Justice.

ACTION: Proposed rule.

SUMMARY: The Coronavirus Aid, Relief, and Economic Security Act (''CARES Act'') authorizes the Director of the Bureau of Prisons (''Director''), during the covered emergency period and upon a finding by the Attorney General that emergency conditions resulting from the Coronavirus Disease 2019 (''COVID–19'') pandemic materially affect the functioning of the Bureau of Prisons (''Bureau'' or ''BOP''), to lengthen the maximum amount of time for which a prisoner may be placed in home confinement. This proposed rule affirms that the Director has the authority to allow prisoners placed in home confinement under the CARES Act to remain in home confinement after the expiration of the covered emergency period.

DATES: Comments are due on or before July 21, 2022.

ADDRESSES: Please submit electronic comments through the *regulations.gov* website. In the alternative, written comments may be mailed to the Rules Unit, Office of General Counsel, Bureau of Prisons, 320 First Street NW, Washington, DC 20534.

FOR FURTHER INFORMATION CONTACT: Crista Colvin, Office of General Counsel, Bureau of Prisons, phone (202) 353–4885.

SUPPLEMENTARY INFORMATION:

I. Posting of Public Comments

Please note that all comments received are considered part of the public record and made available for public inspection online at *www.regulations.gov.* If you want to submit personal identifying information (such as your name, address, etc.) as part of your comment, but do not want it to be posted online, you must include the phrase ''PERSONAL IDENTIFYING INFORMATION'' in the first paragraph of your comment. You must also locate all the personal identifying information you do not want posted online in the first paragraph of your comment and identify what information you want redacted.

If you want to submit confidential business information as part of your comment but do not want it to be posted online, you must include the phrase ''CONFIDENTIAL BUSINESS INFORMATION'' in the first paragraph of your comment. You must also prominently identify the confidential business information to be redacted within the comment. If a comment has so much confidential business information that it cannot be effectively redacted, all or part of that comment may not be posted at *www.regulations.gov.*

Personal identifying information identified and located as set forth above will be placed in the agency's public docket file, but not posted online. Confidential business information identified and located as set forth above will not be placed in the public docket file, nor will it be posted online. If you want to inspect the agency's public docket file in person by appointment, please see the **FOR FURTHER INFORMATION CONTACT** paragraph.

II. Discussion

A. Overview

The CARES Act authorizes the Director of the Bureau of Prisons to lengthen the amount of time a prisoner may be placed in home confinement beyond the statutory maximum normally allowed under 18 U.S.C. 3624(c)(2) as the Director deems appropriate.[1] That authority under the CARES Act exists during the period for which there is a declaration of national emergency with respect to the COVID–19 pandemic and for 30 days after the termination of that declaration, provided that the Attorney General has made a finding that the emergency conditions materially affect the functioning of the Bureau of Prisons. The President declared the COVID–19 outbreak a national emergency beginning March 1, 2020; that national emergency was extended on February 24, 2021, and again on February 18, 2022, and is still in effect as of June 15, 2022.[2] The Attorney General made the relevant finding with respect to the Bureau on April 3, 2020. *See* Memorandum for the BOP Director from the Attorney General, *Re: Increasing Use of Home Confinement at Institutions Most Affected by COVID–19,* at 1 (Apr. 3, 2020), *available at https://www.bop.gov/coronavirus/docs/bop_memo_home_confinement_april3.pdf* (''April 3 Memo'').

Following guidance from the Attorney General, the Director has exercised his discretion under the CARES Act to place thousands of inmates in home confinement during the pandemic emergency. These actions removed vulnerable inmates from congregate settings where COVID–19 spreads easily and quickly and also reduced crowding in BOP correctional facilities. Inmates placed in home confinement are considered in the custody of the Bureau and are subject to ongoing supervision, including monitoring, drug and alcohol testing, and check-in requirements. They are not permitted to leave their residences except for work or other preapproved activities such as counseling. Inmates who violate these conditions may be disciplined and returned to secure custody. Violations of the conditions of home confinement requiring return have been rare during the pandemic emergency, however, and very few inmates placed in home confinement under the CARES Act have committed new crimes.

Although the CARES Act plainly states that the Director's authority to lengthen the maximum period of home confinement exists during the covered emergency period, the Act is silent about what happens to an inmate who was placed in home confinement under this authority, but who has more than the lesser of ten percent of her sentence or six months remaining in her term of imprisonment after the covered emergency period expires. As explained in a recent opinion of the Office of Legal Counsel (''OLC''), and supported by the interpretation of the Bureau, the statute allows such individuals to remain in home confinement after the covered emergency period ends, as the Director deems appropriate. This interpretation is supported by the text, structure, and purpose of the CARES Act and therefore is the better reading of the statute, as more fully explained in OLC's December 21, 2021 opinion. *See Discretion to Continue the Home-Confinement Placements of Federal Prisoners After the COVID–19 Emergency,* 45 Op. O.L.C. __(Dec. 21, 2021), *available at https://www.justice.gov/olc/file/1457926/download* (''*Home-Confinement Placements*''). This interpretation, which the Department adopts in promulgating this rulemaking, also aligns with the Bureau's consistent position that the more appropriate reading of the statute is to permit the Bureau to conduct individualized assessments—as it does in making prisoner placements in other contexts—to determine whether any inmate should be returned to secure custody after the COVID–19 emergency ends.

The Department's interpretation of the statute is also consistent with Congressional support for increasing the use of home confinement as part of reentry programming, as the Second Chance Act of 2007 and the First Step Act of 2018 demonstrate. In addition, implementation of this interpretation is operationally sound and provides flexibility in managing BOP-operated institutions as well as cost savings for the Bureau. Indeed, there is evidence that the Bureau can appropriately manage public safety concerns related to inmates in home confinement, and there are penological, rehabilitative, and societal benefits of allowing inmates to effectively prepare for life after the conclusion of their criminal sentences. Finally, as a practical matter, this interpretation permits the Bureau to consider whether returning CARES Act inmates to secure custody would increase crowding in BOP facilities and risk new, potentially serious COVID–19 outbreaks in prisons even after the broader national emergency has passed.

For all of these reasons, the Department proposes to provide the Director with express authority and discretion to allow prisoners who have been placed in home confinement under the CARES Act to remain in home confinement after the conclusion of the covered emergency period.

B. Background

On March 13, 2020, the President of the United States declared that a national emergency existed with respect to the outbreak of COVID–19, beginning on March 1, 2020.[3] COVID–19 is caused by an extremely contagious virus known as SARS–CoV–2 that has spread quickly around the world.[4] COVID–19 most often causes respiratory symptoms, but can also attack other parts of the body. The virus spreads when an infected person breathes out droplets and particles, and another person breathes in air that contains these droplets and particles, or they land on another person's eyes, nose, or mouth.[5] Individuals in close contact with an infected person—generally less than 6 feet apart—are most likely to get infected. Although COVID–19 often presents with mild symptoms, some people become severely ill and die.[6] Older adults and individuals with underlying medical conditions are at increased risk of severe illness or death. As of April 26, 2022, over 988,000 people in the United States have died from COVID–19.[7]

The United States Centers for Disease Control and Prevention (''CDC'') within the Department of Health and Human Services has recognized that the

[1] *See* Coronavirus Aid, Relief, and Economic Security Act, Public Law 116–136, sec. 12003(b)(2), 134 Stat. 281, 516 (2020) (''CARES Act'').

[2] Proclamation 9994, Declaring a National Emergency Concerning the Novel Coronavirus Disease (COVID–19) Outbreak, 85 FR 15337 (Mar. 18, 2020); *see also* Continuation of the National Emergency Concerning the Coronavirus Disease 2019 (COVID–19) Pandemic, 86 FR 11599 (Feb. 26, 2021); Continuation of the National Emergency Concerning the Coronavirus Disease 2019 (COVID–19) Pandemic, 87 FR 10289 (Feb. 23, 2022).

[3] Proclamation 9994, Declaring a National Emergency Concerning the Novel Coronavirus Disease (COVID–19) Outbreak, 85 FR 15337 (Mar. 13, 2020).

[4] U.S. Centers for Disease Control and Prevention, Basics of COVID–19 (updated Nov. 4, 2021), *available at https://www.cdc.gov/coronavirus/2019-ncov/your-health/about-covid-19/basics-covid-19.html* (last visited Apr. 26, 2022).

[5] U.S. Centers for Disease Control and Prevention, How COVID–19 Spreads (updated July 14, 2021), *available at https://www.cdc.gov/coronavirus/2019-ncov/prevent-getting-sick/how-covid-spreads.html* (last visited Apr. 26, 2022).

[6] U.S. Centers for Disease Control and Prevention, Basics of COVID–19 (updated Nov. 4, 2021), *available at https://www.cdc.gov/coronavirus/2019-ncov/your-health/about-covid-19/basics-covid-19.html* (last visited Apr. 26, 2022).

[7] U.S. Centers for Disease Control and Prevention, COVID Data Tracker, *available at https://covid.cdc.gov/covid-data-tracker/#datatracker-home* (last visited Apr. 26, 2022).

COVID–19 pandemic presents unique challenges for correctional facilities, such as those the Bureau manages.[8] These challenges include a high risk of rapid transmission due to congregate living settings, and a high risk of severe disease due to the high prevalence of pre-existing conditions and risk factors associated with severe COVID–19 illness in prison populations. In a letter to the Attorney General and the Director dated March 23, 2020, a bipartisan group of United States Senators expressed concern about the potential for COVID–19 spread among, in particular, vulnerable Bureau staff and inmates, and called upon the Bureau to use available statutory authorities to increase its utilization of home confinement to mitigate the risk.[9]

On March 26, 2020, the Attorney General issued a memorandum instructing the Director to prioritize use of home confinement, where authorized, to protect the health and safety of inmates and Bureau staff by minimizing the risk of COVID–19 spread in Bureau facilities, while continuing to keep communities safe.[10] The Attorney General directed that the determination of whether to place an inmate in home confinement should be made on an individualized basis, taking into account the totality of the inmate's circumstances, the statutory requirements, and the following non-exhaustive discretionary factors:

- The age and vulnerability of the inmate to COVID–19;
- The security level of the facility housing the inmate, with priority given to inmates residing in low and minimum security facilities;
- The inmate's conduct in prison;
- The inmate's risk score under the Prisoner Assessment Tool Targeting Estimated Risk and Needs (''PATTERN''); [11]
- Whether the inmate had a reentry plan that would prevent recidivism and maximize public safety; and
- The inmate's crime of conviction and the danger the inmate would pose to the community.[12]

The Attorney General's memorandum explained that some offenses would render an inmate ineligible for home confinement, and that other serious offenses would weigh more heavily against consideration for home confinement. It further explained that inmates who engaged in violent or gang-related activity while in prison, those who incurred a violation within the past year, or those with a PATTERN score above the ''minimum'' range would not receive priority consideration under the memorandum.[13]

Prior to the passage of the CARES Act, Congress had enacted three main sources of statutory authority to allow the Bureau to place inmates in home confinement as part of reentry programming. First, 18 U.S.C. 3624(c)(2) authorizes the Director to transfer inmates to home confinement for the shorter of either 10 percent of the term of imprisonment or six months. That provision also directs the Bureau to ''place prisoners with lower risk levels and lower needs on home confinement for the maximum amount of time permitted'' ''to the extent practicable.'' Second, Congress created a pilot program in the Second Chance Act of 2007 (''SCA''), which it reauthorized and modified in the First Step Act of 2018 (''FSA''), authorizing the Attorney General to place eligible elderly and terminally ill offenders in home confinement after they have served two-thirds of their term of imprisonment.[14] Third, the FSA established earned time credits that eligible inmates could accrue through participating in recidivism-reducing programs and then apply for transfer to pre-release custody, including home confinement, without regard for the time frames set forth in 18 U.S.C. 3624(c)(2).[15]

The day after the Attorney General's first memorandum, on March 27, 2020, the President signed into law the CARES Act, which expanded the authority of the Director to place inmates in home confinement in response to the COVID–19 pandemic upon a finding by the Attorney General. Specifically, the Act states:

> During the covered emergency period, if the Attorney General finds that emergency conditions will materially affect the functioning of the Bureau, the Director of the Bureau may lengthen the maximum amount of time for which the Director is authorized to place a prisoner in home confinement under the first sentence of section 3624(c)(2) of title 18, United States Code, as the Director determines appropriate.[16]

The term ''covered emergency period'' refers to the period beginning on the date the President declared a national emergency with respect to COVID–19 and ending 30 days after the date on which the national emergency declaration terminates.[17]

On April 3, 2020, the Attorney General issued a second memorandum for the Director, finding that emergency conditions were materially affecting the functioning of the Bureau, and acknowledging that the Bureau was ''experiencing significant levels of infection at several of our facilities.'' [18] The Attorney General instructed the Director to use the expanded home confinement authority provided in the CARES Act to place the most vulnerable inmates at the facilities most affected by COVID–19 in home confinement, following quarantine to prevent the spread of COVID–19 into the community, and guided by the factors set forth in the March 26, 2020 memorandum. The second memorandum made clear that although the Bureau should maximize the use of home confinement, particularly at affected institutions, the Bureau must continue to make an individualized determination whether home confinement is appropriate for each

[8] CDC, Considerations for Modifying COVID–19 Prevention Measures in Correctional and Detention Facilities (June 22, 2021), *available at https://www.cdc.gov/coronavirus/2019-ncov/downloads/community/correction-detention/COVID-Corrections-considerations-for-loosening-restrictions-Webinar.pdf* (last visited Apr. 26, 2022).

[9] Letter for Attorney General Barr & Director Carvajal from Senator Richard J. Durbin *et al.* (Mar. 23, 2020), *available at https://www.durbin.senate.gov/imo/media/doc/Letter.%20to%20DOJ%20and%20BOP%20on%20COVID-19%20and%20FSA%20provisions%20-%20final%20bipartisan%20text%20with%20signature%20blocks.pdf* (last visited Apr. 26, 2022) (''Conditions of confinement do not afford individuals the opportunity to take proactive steps to protect themselves, and prisons often create the ideal environment for the transmission of contagious disease. For these reasons, it is important that consistent with the law and taking into account public safety and health concerns, that the most vulnerable inmates are released or transferred to home confinement, if possible.'').

[10] Memorandum for the Director, Bureau of Prisons from the Attorney General, *Re: Prioritization of Home Confinement As Appropriate in Response to COVID–19 Pandemic* (Mar. 26, 2020), *available at https://www.bop.gov/coronavirus/docs/bop_memo_home_confinement.pdf.*

[11] PATTERN is a tool that measures an inmate's risk of recidivism and provides her with opportunities to reduce her risk score. *See, e.g.,* Federal Bureau of Prisons, PATTERN Risk Assessment, *https://www.bop.gov/inmates/fsa/pattern.jsp.* It was created pursuant to the First Step Act of 2018. *See* Pub. L. 115–391, sec. 101(a), 132 Stat. 5194, 5196–97 (2018).

[12] By April 2021, the Bureau clarified that the criminal history check covered both an inmate's crime of conviction and her broader criminal history. *See* Memorandum for Chief Executive Officers from Andre Matevousian *et al.,* BOP RE: *Home Confinement* (Apr. 13, 2021), *available at: http://www.bop.gov/foia/docs/Home%20Confinemet%20memo_2021_04_13.pdf.*

[13] This criterion was later updated to include low and minimum PATTERN scores. *See id.*

[14] *See* FSA, Pub. L. 115–391, sec. 603(a), 132 Stat. 5194, 5238 (2018), *codified at* 34 U.S.C. 60541.

[15] *See* FSA sec. 101, 132 Stat. at 5210–13, *codified at* 18 U.S.C. 3624(g). The Bureau recently published a final rule codifying Bureau procedures regarding time credits that govern pre-release custody placements under section 3624(g). *See* FSA Time Credits, 87 FR 2705 (Jan. 19, 2022).

[16] CARES Act sec. 12003(b)(2).

[17] *Id.* sec. 12003(a)(2).

[18] *See* April 3 Memo at 1.

inmate considered and must continue to act consistently with its obligation to preserve public safety.

The Bureau subsequently issued internal guidance that, in addition to adopting the criteria in the Attorney General's memoranda, prioritized for home confinement inmates who had served 50 percent or more of their sentences or those who had 18 months or less remaining in their sentences and had served more than 25 percent of that sentence.[19] That guidance also instructed that pregnant inmates should be considered for placement in a community program, to include home confinement. BOP later clarified that inmates with low or minimum PATTERN scores qualify equally for home confinement, and that the factors assessed to ensure inmates are suitable for home confinement include verifying that an inmate's current or a prior offense was not violent, a sex offense, or terrorism-related.[20] It further implemented a requirement that inmates placed in home confinement receive instruction about how to protect themselves and others from COVID–19 transmission, based on guidance from CDC.[21]

Since March 2020, following the Attorney General's directive, the Bureau has significantly increased the number of inmates placed in home confinement under the CARES Act and other preexisting authorities. Between March 26, 2020, and January 10, 2022, the Bureau placed in home confinement a total of 36,809 inmates.[22] The majority of those inmates have since completed their sentences; as of January 10, 2022, there were 7,726 inmates in home confinement.[23] According to the Bureau, 4,902 of these inmates were placed in home confinement pursuant to the CARES Act.

When an inmate is placed in home confinement, he or she is not considered released from the custody of the Bureau of Prisons; rather, he or she continues serving a sentence imposed by a Federal court and administered by the Bureau of Prisons.[24] Although inmates in home confinement are transferred from correctional facilities and placed in the community, they are required to remain in the home during specified hours, and are permitted to leave only for work or other preapproved activities, such as occupational training or therapy.[25] Inmates in home confinement must submit to drug and alcohol testing, and counseling requirements. Supervision staff monitor inmates' compliance with the conditions of home confinement by electronic monitoring equipment or, in a few cases for medical or religious accommodations, frequent telephone and in-person contact. An inmate's failure to comply with the conditions of home confinement results in disciplinary action, which may include a return to secure custody or prosecution for escape.

Management of inmates in home confinement since the beginning of the COVID–19 pandemic, the largest community confinement population in recent history, has been robust. According to the Bureau, as of March 4, 2022, a small percentage of inmates placed in home confinement pursuant to the CARES Act—357 out of approximately 9,500 total individuals—had been returned to secure custody as a result of violations of the conditions of home confinement. Of this number, only 8 were returned for new criminal conduct (6 for drug-related conduct, 1 for smuggling non-citizens, and 1 for escape with prosecution).[26] These data suggest that inmates placed on longer-term home confinement under the CARES Act can be and have been successfully managed, with only a limited number requiring return to secure custody for disciplinary reasons. Additional observation and research will need to be conducted to determine if this very low level of recidivism can be maintained, or if it was affected by the unique external circumstances caused by the global pandemic.

Many inmates placed in home confinement during the COVID–19 pandemic have reached the end of their term of incarceration, or will do so within the next six months. However, according to the Bureau, as of January 10, 2022, there were 2,826 total inmates placed in home confinement under the CARES Act with release dates in more than 12 months. Of this total, there were 2,272 inmates with release dates in more than 18 months; 593 inmates with release dates in 5 years or more; and 27 inmates with release dates in 10 years or more. Many of these individuals—all of whom have been successfully serving their sentences in the community—may have release dates more than six months after the expiration of the covered emergency period when it expires, and therefore may not then be eligible for placement in home confinement under 18 U.S.C. 3624(c)(2).

For all the reasons set forth above, the Department proposes to promulgate this rulemaking under the Attorney General's authority, *see* 5 U.S.C. 301; 18 U.S.C. 4001(b)(1), to codify the Director's discretion to allow inmates placed in home confinement pursuant to the CARES Act to remain in home confinement after the covered emergency period expires. This rulemaking reflects the interpretation of the CARES Act set forth in OLC's December 21, 2021 opinion, is consistent with recent legislation from Congress supporting expanded use of home confinement, and advances the best interests of inmates and the Bureau from penological, rehabilitative, public health, and public safety perspectives.

C. Statutory Authority

Section 12003(b)(2) of the CARES Act authorizes the Director to place inmates in home confinement, notwithstanding the time limits set forth in 18 U.S.C. 3624(c)(2), during and for 30 days after the termination of the national emergency declaration concerning COVID–19, provided that the Attorney General has made a finding that emergency conditions are materially affecting BOP's functioning. By the Act's plain terms, the Director's authority to place an inmate in home confinement under the CARES Act expires at the end of the covered emergency period, or if the Attorney General revokes his finding. The Act is silent, however, as to whether the Director has discretion to determine whether specific individuals placed in home confinement under the CARES Act may remain there after the expiration of the covered emergency period, or whether all inmates who are not eligible for home confinement under another authority must be returned to secure custody. The Department has concluded that the most reasonable reading of the CARES Act permits the Bureau to continue to make

[19] *See, e.g.,* Memorandum for Chief Executive Officers from Andre Matevousian *et al.,* BOP, *Re: Home Confinement* (Nov. 16, 2020), *available at https://www.bop.gov/foia/docs/Updated_Home_Confinement_Guidance_20201116.pdf.*

[20] *See* Memorandum for Chief Executive Officers from Andre Matevousian *et al.,* BOP, *Re: Home Confinement* (Apr. 13, 2021), *available at https://www.bop.gov/foia/docs/Home%20Confinement%20memo_2021_04_13.pdf.*

[21] *See id.*

[22] *See* Federal Bureau of Prisons, Frequently Asked Questions regarding potential inmate home confinement in response to the COVID–19 pandemic, *https://www.bop.gov/coronavirus/faq.jsp* (last visited Jan. 11, 2022).

[23] *See id.* (last visited Jan. 11, 2022).

[24] *See* 18 U.S.C. 3621(a) (''A person who has been sentenced to a term of imprisonment . . . shall be committed to the custody of the Bureau of Prisons until the expiration of the term imposed . . . .'').

[25] Federal Bureau of Prisons Program Statement 7320.01, CN–2, Home Confinement (updated Dec. 15, 2017), *available at https://www.bop.gov/policy/progstat/7320_001_CN-2.pdf.*

[26] The term ''escape with prosecution'' indicates that a United States Attorney's Office has decided to prosecute an inmate for escape under 18 U.S.C. 751. Where a United States Attorney's Office does not prosecute, BOP imposes administrative sanctions.

individualized determinations about the conditions of confinement for inmates placed in home confinement under the CARES Act, as it does with respect to all prisoners,[27] following the end of the covered emergency period. In its recent opinion, OLC concluded that section 12003(b)(2) does not require the Bureau to return to secure custody inmates on CARES Act home confinement following the end of the covered emergency period.[28] The Department incorporates the analysis from OLC's opinion into the preamble of this notice of proposed rulemaking.

Even if the relevant provision of the CARES Act were considered ambiguous, however, the Department's interpretation represents a reasonable reading that would warrant deference under *Chevron, U.S.A., Inc.* v. *Natural Resource Defense Council, Inc.,* 467 U.S. 837 (1984).[29]

1. Language and Structure of the CARES Act

As the OLC opinion explains, the Department's reading of the CARES Act is grounded in the language of the relevant provision, section 12003(b)(2).[30] That section makes a single change to the Bureau's home confinement authority—to allow the Director to ''lengthen'' the duration for which prisoners can be placed in home confinement relative to the maximum time periods set forth in 18 U.S.C. 3624(c)(2).[31] Once the Director has lengthened a prisoner's amount of time in home confinement under the CARES Act and placed the prisoner in home confinement, no further action under the CARES Act is needed. After the placement is made, the Bureau's ongoing management of the inmate is further authorized by other Federal statutes.[32] The CARES Act does not mandate that any period of home confinement lengthened during the covered emergency period must end after the expiration of that period.

This view is reinforced by the structure of the CARES Act, and particularly by a comparison of section 12003(b)(2) with the section of the CARES Act that immediately follows it. That section, 12003(c)(1), provides that:

> During the covered emergency period, if the Attorney General finds that emergency conditions will materially affect the functioning of the Bureau, the Director of the Bureau shall promulgate rules regarding the ability of inmates to conduct visitation through video teleconferencing and telephonically, free of charge to inmates, during the covered emergency period.[33]

This section differs from section 12003(b)(2) in important ways. It uses the term ''covered emergency period'' twice, at the beginning and the end of the section. The first use establishes that the authority of the Bureau of Prisons to promulgate rules about video and telephonic visitations exists during the covered emergency period. The second use refers to the requirement that the Bureau provide such services, free of charge, and suggests that these services were required to be provided only during the covered emergency period. In comparison, section 12003(b)(2) uses the term ''covered emergency period'' at the beginning of the section only, referring to the time period during which the Director may ''lengthen'' a term of home confinement. Section 12003(b)(2) ends with the phrase ''as the Director determines appropriate,'' which explicitly delegates authority to the Director to determine the appropriate amount to lengthen a period of home confinement.

For all of these reasons, and for the additional reasons the operative OLC opinion explains in more detail, the Department believes that the best reading of the CARES Act is that an inmate whose period of home confinement the Director properly lengthened during the covered emergency period may remain in home confinement, at the Director's discretion, including after the covered emergency period ends.

2. OLC's Previous Opinion

The Department recognizes that OLC previously advised, in January 2021, that the Bureau would be required to recall all prisoners placed in home confinement under the CARES Act who were not otherwise eligible for home confinement under 18 U.S.C. 3624(c)(2) after the expiration of the covered emergency period (or if the Attorney General were to revoke his findings).[34] At the time of this previous opinion, the Bureau was of the view that the consequences of its proper exercise of discretion to lengthen the maximum period of home confinement during the covered emergency period could continue after the expiration of the COVID–19 emergency.[35] Even after OLC issued this initial opinion, the Bureau's view remained that the stronger interpretation of the CARES Act did not require all prisoners in CARES Act home confinement to be returned to secure facilities at the end of the covered emergency period.[36]

The January 2021 OLC opinion based its conclusion on three principal determinations.[37] First, it found that because Congress passed the CARES Act to provide various forms of temporary relief, the Act was best read to limit its effects to the covered emergency period. Second, it reasoned that Congress must have defined the covered emergency period to extend 30 days beyond the end of the declared national emergency in order to provide the Bureau with time to return prisoners to secure custody. And third, it reasoned that the authority ''to place'' a prisoner in home confinement required the exercise of ongoing legal authority due to the Bureau's frequent interactions with inmates in home confinement, and that authority would not exist after the expiration of the covered emergency period.

But upon the Attorney General's further review of the statutory language, and in the face of a growing body of evidence demonstrating the success of CARES Act home confinement placements, the Attorney General requested that OLC reconsider its earlier opinion. During the course of this reconsideration, the Bureau provided OLC with additional materials supporting its consistent interpretation of the CARES Act. The Bureau also explained that home confinement decisions have historically been made on an individualized basis, which serves penological goals. OLC reexamined the relevant text, structure, purpose, and legislative history, along with the Bureau's additional materials demonstrating its consistent analysis of its own authority, and concluded the stronger interpretation of section 12003(b)(2) was not to require the wholesale return of CARES Act inmates to secure custody.

As noted above, *see supra* Part C.1, the current OLC opinion explains the textual basis for this view, including the absence of a statutory limit on the length of CARES Act home-confinement placements and the contrast between CARES Act sections 12003(b)(2) and 12003(c)(1). But the current opinion also explains the rationale underlying its

[27] *See* 18 U.S.C. 3621(a) (''A person who has been sentenced to a term of imprisonment . . . shall be committed to the custody of the Bureau of Prisons until the expiration of the term imposed . . . .'').

[28] *See Home-Confinement Placements,* 45 Op. O.L.C. __.

[29] *See id.* at *2, *15.

[30] *See id.* at *7–9.

[31] CARES Act sec. 12003(b)(2), 134 Stat. at 516.

[32] *See* 18 U.S.C. 3621(a), (b).

[33] CARES Act sec. 12003(c)(1), 134 Stat. at 516.

[34] *See Home Confinement of Federal Prisoners After the COVID–19 Emergency,* 45 Op. O.L.C. __ (Jan. 15, 2021), *available at https://www.justice.gov/olc/file/1355886/download.*

[35] *See id.* at *4.

[36] *See Home-Confinement,* 45 Op. O.L.C. __, at *2, *5–7.

[37] *See id.* at *4–5.

departure from the three principal determinations upon which the January 2021 OLC opinion was grounded. First, OLC recognized that the temporary nature of many programs created by the CARES Act does not require that extended home confinement placements must end along with the covered emergency period for two reasons.[38] As an initial matter, the extended home confinement program is time-limited: the Director's authority to place inmates on extended home confinement lapses after the expiration of the covered emergency period. In addition, the consequences of temporary CARES Act authorities may extend past the emergency period. For example, although the authority to provide loans under the CARES Act's Paycheck Protection Program was limited, the loans granted pursuant to that authority will mature over time.[39]

Second, OLC did not interpret the 30-day grace period following the end of the national emergency as necessarily suggesting that Congress intended the Bureau to use that time to return CARES Act inmates to secure custody.[40] There is no legislative history to support such a reading, and there are other plausible explanations for the grace period, including broader forms of administrative convenience and benefit, such as letting BOP finish processing home-confinement placements that were in progress and to which BOP had already devoted resources. Moreover, the 30-day grace period also applies to section 12003(c), which provides for free video and teleconferencing for inmates during the covered emergency period. This undercuts the rationale that Congress included the 30-day grace period for any particular reason other than administrative convenience.

Finally, OLC concluded that the appropriate action to focus on in determining the meaning of section 12003(b)(2) is the authority to ''lengthen'' the maximum period of home confinement, which is a discrete act.[41] The term ''to place'' derives from a different statute—18 U.S.C. 3624(c)(2)—and even assuming the act of ''placement'' involves an ongoing process, the Bureau fully completes the act of ''lengthening'' the time for which an individual may be placed in home confinement under the CARES Act when an inmate is transferred to home confinement under the Act. Once the Bureau has appropriately lengthened an inmate's maximum period of home confinement under the CARES Act, sections 3624(c)(2), 3621(a), and 3621(b) provide the Bureau with ongoing authority to manage that placement.

This proposed rule accords with OLC's revised views and codifies the Director's authority to allow inmates placed in home confinement under the CARES Act to remain in home confinement after the end of the covered emergency period.

3. Chevron Deference

Even if section 12003(b)(2) of the CARES Act were found to be ambiguous, the Department believes its view would be entitled to deference as a reasonable reading of a statute it administers. Under *Chevron,* if a court concludes that such a statute is ambiguous—a determination typically referred to as *Chevron* step one—it must defer to the agency's interpretation as long as it is ''based on a permissible construction of the statute'' under *Chevron* step two. *Chevron,* 467 U.S. at 843.

At the outset, the Department has authority to promulgate rules to manage the Bureau of Prisons, and to administer CARES Act section 12003(b)(2). Congress vested the Attorney General with broad control over the ''control and management of Federal penal and correctional institutions'' and the ability to ''promulgate rules for the government thereof.''[42] Congress also delegated general authority to the heads of executive departments, including the Attorney General, to issue regulations for the ''government of [the] department, the conduct of its employees, [and] the distribution and performance of its business.''[43] Congress plainly intended the Department to use its discretion, drawing on the expertise of the Attorney General and the Director, to administer section 12003(b)(2) of the CARES Act. First, that section empowers the Attorney General to make a finding, during the pandemic emergency, that the pandemic has materially affected the functioning of the Bureau. Second, the Attorney General's finding, in turn, triggers the Director's discretion to lengthen the maximum amount of time an inmate may be placed in home confinement, ''as the Director determines appropriate.''[44] This proposed rule, which codifies the Department's understanding of its authority under the CARES Act in furtherance of the management of Bureau institutions, is issued pursuant to these authorities and, when finalized, is intended to have the force of law.

Although the Department believes its understanding of CARES Act section 12003(b)(2) is the best reading of the statute for the reasons explained above, were a court to disagree and find the statute unclear, the Department's interpretation would be reasonable for those same reasons and the additional reasons explained below. As has already been discussed, the Department's interpretation of the CARES Act is aligned with the relevant statutory language, structure, purpose, and history. The Department's interpretation is also consistent with congressional action demonstrating an interest in increasing the Bureau's use of home confinement. It is in the best operational interests of the Bureau and the institutions it manages. And it is in the best penological interests of affected inmates. For these additional reasons, detailed further below, if the statute is deemed ambiguous, the Department's interpretation of section 12003(b)(2) represents a reasonable exercise of the Attorney General's and the Director's policy discretion that would be entitled to deference.

D. Congressional Intent

The Department's interpretation of the CARES Act is consistent with bipartisan legislation signaling Congress's interest in expanding the use of home confinement and placing inmates in home confinement for longer periods of time. Such legislative efforts have been part of Congress's broader push to manage prison populations, facilitate inmates' successful reentry into communities, and reduce recidivism risk.[45] These efforts were undertaken over years of bipartisan negotiations and garnered broad support across the political spectrum, beginning with the Second Chance Act of 2007 and

[38] *See id.* at *12.

[39] *See* CARES Act sec. 1102, 134 Stat. at 286–97; *id.* at sec. 1109, 134 Stat. at 304–06.

[40] *See Home-Confinement Placements,* 45 Op. O.L.C. __, at *11–12.

[41] *See id.* at *7–9.

[42] 18 U.S.C. 4001(b)(1).

[43] 5 U.S.C. 301.

[44] CARES Act sec. 12003(b)(2), 134 Stat. 516.

[45] *See, e.g.,* H.R. Rep. No. 115–699, at 22–24 (2018) (''The federal prison system needs to be reformed through the implementation of corrections policy reforms designed to enhance public safety by improving the effectiveness and efficiency of the federal prison system in order to control corrections spending, manage the prison population, and reduce recidivism.''); H.R. Rep. No. 110–140, at 1–5 (2007) (''The Second Chance Act will strengthen overall efforts to reduce recidivism, increase public safety, and help States and communities to better address the growing population of ex-offenders returning to their communities. The bill focuses on development and support of programs that provide alternatives to incarceration, expand the availability of substance abuse treatment, strengthen families, and expand comprehensive re-entry services. The bill is a product of multi-year bipartisan negotiations and enjoys support from across the political spectrum.'').

continuing in the First Step Act of 2018.[46]

In the SCA, Congress increased the Bureau's discretion to place inmates in home confinement in two ways. First, it instructed the Director to ensure, to the extent practicable, that a prisoner spends a portion of the final months of her term of imprisonment in conditions designed to prepare her for reentry into the community, including community correctional facilities, and explicitly provided the Director with discretion to place inmates in home confinement for a period not to exceed the last six months or 10 percent of their terms of imprisonment.[47] Second, the SCA established a pilot program to allow the Bureau to place eligible non-violent elderly offenders in home confinement for longer periods.

Congress further expanded the Bureau's use of home confinement through the FSA in three contexts. First, the FSA demonstrated Congress's interest in increasing the amount of time low-risk offenders spend in home confinement, while continuing to leave decisions about individual prisoners to the Bureau's discretion, by providing that ''[t]he Bureau of Prisons shall, to the extent practicable, place prisoners with lower risk levels and lower needs on home confinement for the maximum amount of time permitted under [18 U.S.C. 3624(c)(2)].''[48] Second, the FSA reauthorized and expanded the pilot program to place eligible elderly offenders in home confinement by lowering the age requirement from 65 to 60 years old, reducing the amount of the sentence imposed an inmate must have served to qualify for the program, and allowing it to be applied to eligible terminally ill inmates regardless of age.[49] Third, the FSA created an incentive for eligible inmates to participate in programs shown to reduce their risk of recidivism by allowing individuals to earn time credits, which may be used for earlier transfer to prerelease custody, including home confinement, notwithstanding the time limits included in 18 U.S.C. 3624(c)(2).[50] The statute provides that an inmate placed in home confinement under this incentive program ''shall remain in home confinement until the prisoner has served not less than 85 percent of the prisoner's imposed term of imprisonment,'' and that the Bureau should provide progressively less restrictive conditions on inmates who demonstrate continued compliance with the conditions of prerelease custody.[51]

Although the CARES Act was a response to the emergency conditions presented by the COVID–19 pandemic, Congress's expansion of the Bureau's home confinement authority as part of that response is consistent with its recent and clear indication of support for expanding the use of home confinement based on the needs of individual offenders. These indications of congressional intent further bolster the Department's view that any ambiguity in the CARES Act should be read to provide the Director with discretion to allow inmates placed in home confinement who have been successfully serving their sentences in the community to remain there, rather than return such inmates to secure custody *en masse* without making an individualized assessment or identifying a penological, rehabilitative, public health, or public safety basis for the action. As explained below, in the Bureau's expert assessment, whether an inmate should remain in home confinement is a decision best made upon careful consideration of the appropriate management of Bureau institutions, penological, rehabilitative, public health, and public safety goals, and the totality of the circumstances of individual offenders.

E. Operational Benefits

Allowing certain inmates who were placed in home confinement under the CARES Act to remain in home confinement after the expiration of the covered emergency period will also afford a number of operational benefits. These benefits include operational flexibility in managing BOP-operated institutions and cost savings for the Bureau. It is further supported by evidence demonstrating that the Bureau can appropriately manage public safety concerns related to inmates in home confinement, and by the penological, rehabilitative, public health, public safety, and societal benefits of allowing inmates to effectively prepare for successful reentry after the conclusion of their criminal sentences. Finally, this interpretation permits the Bureau to take into account whether returning CARES Act inmates to secure custody, thereby increasing populations in BOP facilities, risks new, potentially serious COVID–19 outbreaks in prisons even after the broader national emergency has passed.

One of the vital tools in operating a correctional system is the ability to effectively manage bedspace based on the needs of the offender, security requirements, and agency resources. Congress has explicitly provided the Bureau responsibility for maintaining custody of Federal inmates[52] and discretion to designate the place of those inmates' imprisonment.[53] Courts have recognized the Bureau's authority to administer inmates' sentences,[54] supporting this management principle. The Bureau's ability to control populations in BOP-operated institutions as well as, where appropriate, in the community, allows the Bureau flexibility to respond to circumstances as varied as increased prosecutions or responses to local or national emergencies or natural disasters. Providing the Bureau with discretion to determine whether any inmate placed in home confinement under the CARES Act should return to secure custody will increase the Bureau's ability to respond to outside circumstances and manage its resources in an efficient manner that considers both public safety and the needs of individual inmates.

Supervision of inmates in home confinement is also significantly less costly for the Bureau than housing inmates in secure custody. In Fiscal Year (FY) 2019, the cost of incarceration fee (COIF) for a Federal inmate in a Federal facility was $107.85 per day; in FY 2020, it was $120.59 per day.[55] In contrast, according to the Bureau, an inmate in home confinement costs an

[46] The House of Representatives passed the Second Chance Act by a vote of 347 to 62, and the Senate passed the Act without amendment by unanimous consent. *See* H.R. 1593—Second Chance Act of 2007, Congress.gov, *available at https://www.congress.gov/bill/110th-congress/house-bill/1593/actions?r=5&s=5* (last visited Apr. 28, 2022). The House of Representatives passed the First Step Act by a vote of 358 to 36, and the Senate passed the Act by a vote of 87 to 12. *See* S. 756—First Step Act of 2018, Congress.gov, *available at https://www.congress.gov/bill/115th-congress/senate-bill/756/actions?r=6&s=9* (last visited Apr. 28, 2022).

[47] SCA, Public Law 110–199, sec. 251(a), 122 Stat. 657, 692–93 (2008).

[48] FSA sec. 602, 132 Stat. 5238.

[49] *Id.* sec. 603(a), 132 Stat. 5238.

[50] *Id.* sec. 101, 132 Stat. at 5198, *codified in relevant part at* 18 U.S.C. 3632(d); *id.* at sec. 102, 132 Stat. 5210–13, *codified at* 18 U.S.C. 3624(g).

[51] *See* 18 U.S.C. 3624(g)(2)(A)(iv), (g)(4).

[52] 18 U.S.C. 3621(a) (''A person who has been sentenced to a term of imprisonment . . . shall be committed to the custody of the Bureau of Prisons until the expiration of the term imposed . . . .'').

[53] *See* 18 U.S.C. 3621(b) (providing that ''[t]he Bureau of Prisons shall designate the place of the prisoner's imprisonment,'' taking into account factors such as facility resources; the offense committed; the inmate's history and characteristics; recommendations of the sentencing court; and any pertinent policy of the United States Sentencing Commission). Section 3621(b) also authorizes the Bureau to direct the transfer of a prisoner at any time, subject to the same individualized assessment. *See id.*

[54] *See, e.g., United States* v. *Wilson,* 503 U.S. 329, 335 (1992); *Rodriguez* v. *Copenhaver,* 823 F.3d 1238, 1242 (9th Cir. 2016).

[55] Annual Determination of Average Cost of Incarceration Fee (COIF), 86 FR 49060, 49060 (Sept. 1, 2021).

average of $55 per day—less than half of the cost of an inmate in secure custody in FY 2020. Although the Bureau's decision to place an inmate in home confinement is based on many factors, where the Bureau deems home confinement appropriate, that decision has the added benefit of reducing the Bureau's expenditures. Such cost savings were among the intended benefits of the First Step Act.[56]

As the extremely low percentage of inmates placed on CARES Act home confinement returned to secure custody shows, the Bureau can effectively manage public safety concerns associated with the low-risk inmates placed in home confinement under the CARES Act for longer periods of time. Indeed, of the nearly 5,000 inmates placed in home confinement under the CARES Act, as of January 8, 2022, only 322 had been returned to secure custody for any reason, and only eight for committing a new crime. Individuals placed in home confinement under the CARES Act, like other inmates in home confinement, remain in the custody of the Bureau. Before being placed in home confinement, inmates sign agreements which require consent to submit to home visits and drug and alcohol testing, acknowledgement of monitoring requirements, and an affirmation that they will not engage in criminal behavior or possess firearms. Under these agreements, individuals placed in home confinement are subject to electronic monitoring; check-in requirements; drug and alcohol testing; and transfer back to secure correctional facilities for any significant disciplinary infractions or violations of the agreement.[57] CARES Act inmates who remain in home confinement after the covered emergency period would continue to be subject to these requirements until the end of their sentences, and possibly into a term of supervised release. Data show that these procedures have been working to preserve public safety where inmates were placed on extended home confinement under the CARES Act, and the Department expects that such measures will continue to be effective after the end of the covered emergency period.[58] Thus, in the Department's view, the aspects of a criminal sentence that preserve public safety can be managed in this context while also allowing individuals to more effectively prepare for life when their criminal sentences conclude.

Congress has demonstrated through the passage of the SCA and the FSA an increasing interest in appropriately preparing inmates for reintegration into society, and an ongoing reevaluation of the societal benefits of incarceration versus non-custodial rehabilitative programs.[59] Home confinement provides penological benefits as one of the last steps in a reentry program. An inmate would usually be moved over the course of a sentence to progressively less secure conditions of confinement—often from a secure prison, to a residential reentry center, to home confinement—to provide transition back into the community with support, resources, and supervision from the agency.[60] Under typical circumstances, inmates who have made the transition to home confinement would not be returned to a secure facility absent a disciplinary reason, because the purpose of home confinement is to allow inmates to readjust to life in the community. Removal from the community would therefore frustrate this goal. And the widespread return of prisoners to secure custody without a disciplinary reason would be unprecedented. Moreover, as findings in the SCA indicate, inmates who are provided the types of benefits home confinement can afford, such as opportunities to rebuild ties to family and to return to the workplace and to the community, may ultimately be less likely to recidivate.[61] Although placements under the CARES Act were not made for reentry purposes, the best use of Bureau resources and the best outcome for affected offenders is to allow the agency to make individualized assessments of CARES Act placements with a focus on inmates' eventual reentry into the community. Allowing the Bureau discretion to determine whether inmates who have been successfully serving their sentences in the community should remain in home confinement will allow the Bureau to ground those decisions upon case-by-case assessments consistent with penological, rehabilitative, public health, and public safety goals, rather than categorically requiring all inmates placed on CARES Act home confinement to be treated the same.[62]

Finally, the Bureau needs flexibility to consider whether continued home confinement for CARES Act inmates is in the interest of the public health, and whether reintroduction of CARES Act inmates into secure facilities would create the risk of new outbreaks of COVID–19 among the prison population—even after the conclusion of the broader pandemic emergency. It is now well established that congregate living settings, and correctional facilities in particular, heighten the risk of COVID–19 spread due to multiple factors.[63] Data have shown that

[56] *See, e.g.,* H.R. Rep. No. 115–699, at 22–24 (''The federal prison system needs to be reformed through the implementation of corrections policy reforms designed to enhance public safety by improving the effectiveness and efficiency of the federal prison system in order to control corrections spending, manage the prison population, and reduce recidivism.'').

[57] *See* Federal Bureau of Prisons Program Statement 7320.01, CN–2, Home Confinement (updated Dec. 15, 2017), *available at https://www.bop.gov/policy/progstat/7320_001_CN-2.pdf.*

[58] Previous research has similarly shown that inmates can maintain accountability in home confinement programs. *See, e.g.,* Darren Gowen, *Overview of the Federal Home Confinement Program 1988–1996,* 64 Fed. Prob. 11, 17 (2000) (finding that 89 percent of 17,000 individuals placed in home confinement between 1988 and 1996 successfully completed their terms without incident). In addition, studies have found that efforts to decarcerate prisons in other contexts, which were not limited to home confinement measures, did not harm public safety. *See, e.g.,* Jody Sundt *et al., Is Downsizing Prisons Dangerous? The Effect of California's Realignment Act on Public Safety,* 15 Criminology & Pub. Policy 315 (2016).

[59] *See, e.g.,* H.R. Rep. No. 115–699, at 22 – 24; SCA sec. 3(a), 122 Stat. at 658 (''The purposes of the Act are . . . to rebuild ties between offenders and their families, while the offenders are incarcerated and after reentry into the community, to promote stable families and communities; . . . to encourage the development and support of, and to expand the availability of, evidence-based programs that enhance public safety and reduce recidivism, such as substance abuse treatment, alternatives to incarceration, and comprehensive reentry services . . . .'').

[60] Congress demonstrated support for this type of logical progression toward reentry in the First Step Act. *See* FSA sec. 101, 132 Stat. 5212, *codifed at* 18 U.S.C. 3624(g)(4) (''In determining appropriate conditions for prisoners placed in prerelease custody pursuant to this subsection, the Director of the Bureau of Prisons shall, to the extent practicable, provide that increasingly less restrictive conditions shall be imposed on prisoners who demonstrate continued compliance with the conditions of such prerelease custody, so as to most effectively prepare such prisoners for reentry.'').

[61] *See* SCA sec. 3(b), 122 Stat. 658–60 (''According to the Bureau of Prisons, there is evidence to suggest that inmates who are connected to their children and families are more likely to avoid negative incidents and have reduced sentences. . . . Released prisoners cite family support as the most important factor in helping them stay out of prison. . . . Transitional jobs programs have proven to help people with criminal records to successfully return to the workplace and the community, and therefore can reduce recidivism.'').

[62] Such individualized assessments are consistent with direction the Bureau has received from Congress in other contexts. For example, Congress has made clear that the Bureau must base its determination of an inmate's place of imprisonment on an individualized assessment that takes into account factors including the inmate's history and characteristics. *See* 18 U.S.C. 3621(b).

[63] *See, e.g.,* CDC, For People Living in Prisons and Jails (updated Feb. 15, 2022), *available at https://www.cdc.gov/coronavirus/2019-ncov/need-extra-precautions/living-prisons-jails.html* (last visited Apr. 29, 2022); Nat'l Academies of Sciences, Engineering, and Medicine, *Decarcerating Correctional Facilities during COVID–19: Advancing Health, Equity, and Safety* 23–44 (2020), *available at https://doi.org/10.17226/25945* (last visited Apr. 29, 2022).

increased crowding in prisons, which makes social distancing difficult, is associated with increased incidence of COVID–19.[64] Although COVID–19 vaccines are widely available and effective at preventing infection, serious illness, and death, not all incarcerated persons will elect to receive COVID–19 vaccinations,[65] and breakthrough infections may occur even in fully vaccinated persons, who are then able to spread the disease.[66] More contagious variants of the virus that causes COVID–19 could exacerbate the spread, and it is unknown whether currently available vaccines will be effective against new variants that may arise. Accordingly, it is appropriate for the Department to consider whether the reintroduction into prison populations of individuals placed in home confinement, in part, upon consideration of their vulnerability to COVID–19 [67] and the resulting increased crowding in prison settings could lead to new COVID–19 outbreaks, including breakthrough cases in fully vaccinated inmates and infections in the most vulnerable prisoners.

For all of these reasons, the Department believes that it is not only statutorily authorized, but also operationally appropriate for the Director to have the discretion to allow individuals placed in home confinement under the CARES Act to remain in home confinement after the end of the covered emergency period. Following the issuance of a final rule, the Bureau will develop, in consultation with the Department, guidance to explain criteria that it will use to make individualized determinations as to whether any inmate placed in home confinement under the CARES Act should be returned to secure custody.

III. Regulatory Certifications

A. Regulatory Flexibility Act

The Attorney General, under the Regulatory Flexibility Act (5 U.S.C. 605(b)), reviewed this proposed rule and by approving it certifies that it will not have a significant economic impact upon a substantial number of small entities for the following reasons: This regulation pertains to the correctional management of offenders committed to the custody of the Attorney General or the Director of the Bureau of Prisons, and its economic impact is limited to the Bureau's appropriated funds.

B. Executive Orders 12866 and 13563

This proposed rule has been drafted and reviewed in accordance with section 1(b) of Executive Order 12866 (Regulatory Planning and Review) and section 1(b) of Executive Order 13563 (Improving Regulation and Regulatory Review).

This proposed rule falls within a category of actions that the Office of Management and Budget (OMB) has determined to constitute a ''significant regulatory action'' under section 3(f) of Executive Order 12866 because it may raise novel legal or policy issues arising out of implementation of section 12003(b)(2) of the CARES Act and, accordingly, it was reviewed by OMB.

The Department has assessed the costs and benefits of this rulemaking as required by Executive Order 12866 section 1(b)(6) and has made a reasoned determination that the benefits of this rulemaking justify its costs.

The economic impact of this proposed rule is limited to a specific subset of inmates who were placed in home confinement pursuant to the CARES Act and are not otherwise eligible for home confinement at the end of the covered emergency period. As of January 10, 2022, 4,902 inmates had been placed in home confinement under the CARES Act; 2,826 of those inmates had release dates in more than 12 months. The Department expects these numbers will continue to fluctuate as inmates continue to serve their sentences and the Bureau continues to conduct individualized assessments to make home confinement placements under the CARES Act for the duration of the covered emergency period.

The Bureau has realized significant cost savings by placing eligible inmates in home confinement under the CARES Act relative to housing those inmates in secure facilities, and it expects those cost savings to continue for inmates who remain in home confinement under the CARES Act following the end of the covered emergency period. Although the Bureau has not yet published the average cost of incarceration fees (COIF) for Fiscal Year (FY) 2021, in FY 2020 the average COIF for a Federal inmate in a Federal facility was $120.59 per day.[68] The average cost for an inmate in home confinement was $55 per day, representing a cost savings of approximately $65.59 per day, per inmate, or approximately $23,940.35 per year, per inmate. Although the numbers will likely differ for FY 2021 and beyond, the Department and the Bureau expect that the proposed rule will benefit them as a result of the avoidance of costs the Bureau would otherwise expend to confine the affected inmates in secure custody. Because the affected inmates are currently serving their sentences in home confinement, there will be no new costs associated with this proposed rulemaking.

As explained above, the proposed rule will also have operational, penological, and health benefits. These include increasing the Bureau's ability to control inmate populations in BOP facilities and in the community, allowing it to be responsive to changed circumstances; empowering the Bureau to make individualized assessments as to whether inmates placed in home confinement should remain in home confinement after the end of the covered emergency period, taking into account, for example, penological goals and the benefits associated with an inmate establishing family connections and finding employment opportunities in the community; and allowing the Bureau to weigh the ongoing risk of new COVID–19 outbreaks in BOP facilities against the benefit of returning any inmate to secure custody.

The Department has determined that there is no countervailing risk to the public safety that outweighs the benefits of this rulemaking. The percentage of inmates placed in home confinement under the CARES Act that have had to be returned to secure custody for any violation of the rules of home confinement is very low; the number of inmates who were returned as a result of new criminal activity is a fraction of that. The vast majority of inmates on CARES Act home confinement have complied with the terms of the program and have been successfully serving their sentences in the community. Thus, in

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[64] Abigail I. Leibowitz *et al., Association Between Prison Crowding and COVID–19 Incidence Rates in Massachusetts Prisons, April 2020–January 2021,* 181 JAMA Internal Med. 1315 (2021); *see also* Nat'l Academies of Sciences, Engineering, and Medicine, *Decarcerating Correctional Facilities during COVID–19: Advancing Health, Equity, and Safety* 26–27 (2020), *available at https://doi.org/10.17226/25945* (last visited Apr. 29, 2022).

[65] Early studies demonstrated that around 64 percent of persons incarcerated in BOP institutions who were offered COVID–19 vaccinations accepted them. *See* Liesl M. Hagan *et al., COVID–19 vaccination in the Federal Bureau of Prisons, December 2020–April 2021,* 39 Vaccine 5883 (2021).

[66] CDC, The Possibility of COVID–19 after Vaccination: Breakthrough Infections (updated Dec. 17, 2021), *available at https://www.cdc.gov/coronavirus/2019-ncov/vaccines/effectiveness/why-measure-effectiveness/breakthrough-cases.html* (last visited Apr. 29, 2022).

[67] *See* Memorandum for the Director, Bureau of Prisons from the Attorney General, *Re: Prioritization of Home Confinement As Appropriate in Response to COVID–19 Pandemic* (Mar. 26, 2020), *available at https://www.bop.gov/coronavirus/docs/bop_memo_home_confinement.pdf* (directing the Bureau to consider, among other discretionary factors, ''the age and vulnerability of [an] inmate to COVID–19'' when assessing which inmates should be placed in home confinement).

[68] Annual Determination of Average Cost of Incarceration Fee (COIF), 86 FR 49060, 49060 (Sept. 1, 2021).

the Department's assessment, public safety considerations do not undercut the benefits associated with allowing inmates placed in home confinement under the CARES Act to remain in home confinement after the expiration of the covered emergency period.

Other potential costs relate to inmates serving longer sentences in home confinement as a result of the CARES Act. These inmates might lose the opportunity to participate in potentially beneficial programming and treatment offered only in BOP facilities, which they might have otherwise taken advantage of if placed in secure custody. In addition, most sentencing courts anticipated that offenders would be incarcerated in a secure facility, and there may be concern that placing inmates in home confinement for longer periods might not appropriately honor the intent of the courts, the interests of prosecuting United States Attorney's Offices,[69] any impact on victims or witnesses, possible deterrence effects in the community, or other aspects of the agency's mission. These costs are all mitigated, however, by retaining the Director's discretion to determine whether any inmate should be returned to secure custody based on an individualized assessment. The Department and the Bureau will consider the factors referenced in this paragraph when developing common criteria to govern these case-by-case assessments, thereby promoting operational efficiency and equitable treatment of offenders.

D. Executive Order 12988 (Civil Justice Reform)

This proposed rule meets the applicable standards set forth in sections 3(a) and 3(b)(2) of Executive Order 12988 (Civil Justice Reform).

E. Executive Order 13132 (Federalism)

This proposed rule will not have substantial direct effects on the States, on the relationship between the Federal Government and the States, or on distribution of power and responsibilities among the various levels of government. Therefore, under Executive Order 13132, the Attorney General determines that this proposed regulation does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

[69] The Bureau, in its discretion, forwards certain home confinement cases to the prosecuting United States Attorney's Office for the input of prosecutors, taking any objections into account when approving or denying those cases.

F. Unfunded Mandates Reform Act of 1995

This proposed rule will not result in the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100 million or more (adjusted annually for inflation) in any one year, and it will not significantly or uniquely affect small governments. Therefore, no actions are necessary under the provisions of the Unfunded Mandates Reform Act of 1995, 2 U.S.C. 1501 *et seq.*

G. Congressional Review Act

This proposed rule is not a major rule as defined by the Congressional Review Act, 5 U.S.C. 804.

H. Paperwork Reduction Act of 1995

This proposed rule does not impose any new reporting or recordkeeping requirements under the Paperwork Reduction Act of 1995, 44 U.S.C. 3501–3521.

List of Subjects in 28 CFR Part 0

Authority delegations (Government agencies), Government employees, National defense, Organization and functions (Government agencies), Privacy, Reporting and recordkeeping requirements, Whistleblowing.

Accordingly, by virtue of the authority vested in me as Attorney General, including 5 U.S.C. 301, 18 U.S.C. 4001 and 28 U.S.C. 509, 510, part 0 of title 28 of the Code of Federal Regulations is proposed to be amended as follows:

PART 0—ORGANIZATION OF THE DEPARTMENT OF JUSTICE

■ 1. The authority citation for part 0 continues to read as follows:

Authority: 5 U.S.C. 301; 28 U.S.C. 509, 510, 515–519.

■ 2. In § 0.96, add paragraph (u) to read as follows:

§ 0.96 Delegations.

* * * * *

(u) With respect to the authorities granted under the Coronavirus Aid, Relief, and Economic Security (CARES) Act (Pub. L. 116–136):

(1) During the ''covered emergency period'' as defined by the CARES Act, when the Attorney General determines that emergency conditions will materially affect the functioning of the Bureau of Prisons (Bureau), lengthening the maximum amount of time for which the Director is authorized to place a prisoner in home confinement under 18 U.S.C. 3624(c)(2), as the Director determines appropriate.

(2) After the expiration of the ''covered emergency period'' as defined by the CARES Act, permitting any prisoner placed in home confinement under the CARES Act who is not yet otherwise eligible for home confinement under separate statutory authority to remain in home confinement under the CARES Act for the remainder of her sentence, as the Director determines appropriate.

(3) This section concerns only inmates placed in home confinement under the CARES Act. It has no effect on any other inmate, including those placed in home confinement under separate statutory authorities.

Dated: June 14, 2022.

Merrick B. Garland,

Attorney General.

[FR Doc. 2022–13217 Filed 6–17–22; 8:45 am]

BILLING CODE 4410–05–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2021–0200; FRL–8515–02–OAR]

RIN 2060–AV23

New Source Performance Standards Review for Industrial Surface Coating of Plastic Parts for Business Machines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing amendments to the Standards of Performance for Industrial Surface Coating of Plastic Parts for Business Machines as the preliminary results of the review of the new source performance standards required by the Clean Air Act. Specific to affected facilities that commence construction, modification, or reconstruction after June 21, 2022, the EPA is, in new subpart TTTa, proposing volatile organic compound (VOC) emission limitations for prime, color, texture, and touch-up coating operations. We are also proposing in subparts TTTa and TTT to include a requirement for electronic submission of periodic compliance reports.

DATES: Comments must be received on or before August 22, 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 July 21, 2022.

Public hearing: If anyone contacts us requesting a public hearing on or before June 27, 2022, we will hold a virtual public hearing. See **SUPPLEMENTARY INFORMATION** for information on requesting and registering for a public hearing.

ADDRESSES: You may send comments, identified by Docket ID No. EPA–HQ–OAR–2021–0200, 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–2021–0200 in the subject line of the message.

• *Fax:* (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2021–0200.

• *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA–HQ–OAR–2021–0200, 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 **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Ms. Lisa Sutton, Minerals and Manufacturing Group, Sector Policies and Programs Division (D243–04), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–3450; fax number: (919) 541–4991; and email address: *sutton.lisa@epa.gov.*

SUPPLEMENTARY INFORMATION:

Participation in virtual public hearing. Please note that because of 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.

To request a virtual public hearing, contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov.* If requested, the virtual hearing will be held on July 12, 2022. The hearing will convene at 10:00 a.m. Eastern Time (ET) and will conclude at 4:00 p.m. ET. 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/stationary-sources-air-pollution/surface-coating-plastic-parts-business-machines-industrial-surface.*

If a public hearing is requested, the EPA will begin pre-registering speakers for the hearing no later than 1 business day after a request has been received. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/stationary-sources-air-pollution/surface-coating-plastic-parts-business-machines-industrial-surface* 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 July 5, 2022. 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/stationary-sources-air-pollution/surface-coating-plastic-parts-business-machines-industrial-surface.*

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 *sutton.lisa@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.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/stationary-sources-air-pollution/surface-coating-plastic-parts-business-machines-industrial-surface.* While the EPA expects the hearing to go forward as set forth in this document, please monitor our website or contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the services of a translator or a special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by June 28, 2022. The EPA may not be able to arrange accommodations without advance notice.

Docket. The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2021–0200. 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 either electronically in *Regulations.gov* or in hard copy at the EPA Docket Center, Room 3334, WJC West Building, 1301 Constitution Avenue NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

Instructions. Direct your comments to Docket ID No. EPA–HQ–OAR–2021–0200. 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 electronically to *https://www.regulations.gov/* any information that you consider to be CBI or other information whose disclosure is restricted by statute. This type of information should be submitted as discussed in the *Submitting CBI* section of this document.

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.*

Submitting CBI. Do not submit information containing CBI to the EPA through *https://www.regulations.gov/.* 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, note the docket ID, mark the outside of the digital storage media as CBI, and 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 the *Instructions* section of this document. 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 and note the docket ID. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2.

Our preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g.,* Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described above, should include clear CBI markings and note the docket ID. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link. If sending CBI information through the postal service, please send it 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–2021–0200. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

Preamble acronyms and abbreviations. Throughout this notice the use of "we," "us," or "our" is intended to refer to the EPA. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ACT Alternative Control Techniques document
ADI Applicability Determination Index database
ANSI American National Standards Institute
ASTM ASTM International
BACT best achievable control technology
BID background information document
BSER best system of emission reduction
CAA Clean Air Act
CBI Confidential Business Information
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
CTG Control Techniques Guidelines document
CDX Central Data Exchange
ECHO Enforcement and Compliance History Online database
EIS Emissions Inventory System database
EJ environmental justice
EMI/RFI electromagnetic interference/radio frequency interference
EPA Environmental Protection Agency
FR Federal Register
GHG greenhouse gas
HVLP high-volume, low-pressure
ICR information collection request
kg VOC/l kilograms volatile organic carbon per liter
km kilometer
lb VOC/gal pounds volatile organic carbon per gallon
LAER lowest achievable emission rate
Mg megagram
Mg/yr megagrams per year
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NEI National Emissions Inventory
NESHAP national emission standards for hazardous air pollutants
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement Act
OAQPS Office of Air Quality Planning and Standards
OMB Office of Management and Budget
PDF portable document format
PRA Paperwork Reduction Act
RACT reasonably available control technology
RBLC RACT/BACT/LAER Clearinghouse
RFA Regulatory Flexibility Act
RIN Regulatory Information Number
RTO regenerative thermal oxidizer
RTR risk and technology review
scf standard cubic feet
SIC standard industrial classification
SSM startup, shutdown, and malfunctions
TE transfer efficiency
tpy tons per year
UMRA Unfunded Mandates Reform Act
U.S.C. United States Code
UV/EB ultraviolet/electron beam
VCS voluntary consensus standard
VOC volatile organic compound(s)

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

I. General Information

A. Does this action apply to me?

The source category that is the subject of this proposal is surface coating of plastic parts for business machines regulated under CAA section 111, New Source Performance Standards. These surface coating operations may be (but are not necessarily) among establishments indexed under the 2022 North American Industry Classification System (NAICS) code 333310—Commercial and Service Industry Machinery Manufacturing. This NAICS code merely provides a guide for readers regarding the entities that this proposed action is likely to affect. Three stationary sources that currently perform surface coating of plastic parts for business machines and are subject to the New Source Performance Standards (NSPS) subpart TTT will be affected by the portions of this proposal that amend NSPS subpart TTT. With respect to the proposed requirements to be added in NSPS new subpart TTT a, which is specific to affected facilities that are constructed, modified, or reconstructed after June 21, 2022, the EPA estimates that over the next 8 years following this proposal, no new, modified, or reconstructed facilities that perform surface coating of plastic parts for business machines will be affected by this proposal. Information supporting that estimate is provided in the memorandum *Best System of Emission Reduction (BSER) Review for Surface Coating of Plastic Parts for Business Machines (40 CFR part 60, subpart TTT)* (BSER Review memorandum), available in the docket for this action. The proposed standards, once promulgated, will be directly applicable to the affected sources. Federal, state, local, and tribal government entities would not be affected by this proposed action.

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

In addition to being available in the docket, an electronic copy of this action is available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this proposed action at *https://www.epa.gov/stationary-sources-air-pollution/surface-coating-plastic-parts-business-machines-industrial-surface.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the proposal and key technical documents at this same website.

A redline/strikeout version of the regulatory language showing the edits that would be necessary to incorporate the changes to NSPS subpart TTT and NSPS subpart TTT a proposed in this action is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2021–0200). Following signature by the Administrator, the EPA will also post a copy of this document at *https://www.epa.gov/stationary-sources-air-pollution/surface-coating-plastic-parts-business-machines-industrial-surface.*

II. Background

A. What is the statutory authority for this action?

The EPA's authority for this proposed rule is CAA section 111, which governs the establishment of standards of performance for stationary sources. Section 111(b)(1)(A) of the CAA requires the EPA Administrator to list categories of stationary sources that in the Administrator's judgment cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for new (and modified or reconstructed) sources in each source category pursuant to CAA section 111(b)(1)(B). These standards are referred to as new source performance standards, or NSPS. The EPA has the authority to define the scope of the source categories, determine the pollutants for which standards should be developed, set the emission level of the standards, and distinguish among classes, type and sizes within categories in establishing the standards.

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years review and, if appropriate, revise'' new source performance standards. However, the Administrator need not review any such standard if the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. When conducting a review of an existing performance standard, the EPA has the discretion and authority to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to reflect ''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 nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' The term ''standard of performance'' in CAA section 111(a)(1) makes clear that the EPA is to determine both the best system of emission reduction (BSER) for the regulated sources in the source category and the degree of emission limitation achievable through application of the BSER. The EPA must then, under CAA section 111(b)(1)(B), promulgate standards of performance for new sources that reflect that level of stringency. 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. Pursuant to the definition of new source in CAA section 111(a)(2), standards of performance apply to facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Under CAA section 111(a)(4), ''modification'' means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Changes to an existing facility that do not result in an increase in emissions are not considered modifications. Under the provisions in 40 CFR 60.15, reconstruction means the replacement of components of an existing facility such that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and (2) it is technologically and economically feasible to meet the applicable standards. Pursuant to CAA section 111(b)(1)(B), the standards of performance or revisions thereof shall become effective upon promulgation.

B. What is the source category?

1. Background on the Source Category

The surface coating of plastic parts for business machines was listed as a source category for regulation under section 111 of the CAA in 1986, based on the Administrator's determination that emissions from facilities that surface coat plastic business machine parts cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. See 51 FR 869 (January 8, 1986). The NSPS for surface coating of plastic parts for business machines was proposed on January 8, 1986 (51 FR 854), and promulgated at 40 CFR part 60, subpart TTT, on January 29, 1988 (53 FR 2672) (1988 NSPS). Subpart TTT applies to affected facilities that commence construction, reconstruction, or modification after January 8, 1986.

The 1988 NSPS established VOC emission limits calculated for each type of coating used at each spray booth during each nominal 1-month period. Subsequent to promulgation of the NSPS, in 1988 the EPA issued a correction because of an inadvertent inclusion of delegable functions in the list of nondelegable functions in 40 CFR 60.726 (53 FR 19300, May 27, 1988). In 1989, the EPA issued a final rule (54 FR 25458, June 15, 1989) to clarify that electromagnetic interference and radio frequency interference (EMI/RFI) shielding coatings that are applied to the surface of plastic business machine parts to attenuate EMI/RFI signals were exempt from the regulation.

In general, plastic parts are coated to provide color, texture, and protection, improve appearance and durability, attenuate EMI/RFI signals, and conceal mold lines and flaws. Examples of plastic parts specific to the coatings industry sector for the surface coating of plastic parts for business machines include plastic housings for electronic office equipment, such as computers and copy machines, and for medical equipment.[1] Structural foam injection molding and straight injection molding are among predominant forming techniques used to manufacture plastic parts that are used in business machines. The surface coating of plastic parts for business machines may be performed within several industries, including business machine manufacturers, independent plastic molders and coaters, and ''coating only'' shops. Sources that perform surface coating of plastic parts for business machines include job shops that must accommodate a wide variety of coatings and wide range of part shapes.

In the 1986 NSPS proposal and the 1988 NSPS, the EPA identified the spray booth as the affected facility subject to subpart TTT. In the 1986 proposed NSPS, the EPA explained why the spray booth, a narrow and simple equipment grouping, was selected as the affected facility.[2] The term ''spray booth'' means the structure housing the spray application equipment and ancillary equipment associated with the enclosure. It includes not only the enclosure and ventilation system for spray coating but also the spray gun(s) and ancillary equipment such as pumps and hoses associated with the enclosure.[3] The 1988 NSPS applies to these sources regardless of production capacity.

As used in the affected facility (spray booth), the types of coatings subject to VOC emission limits in the 1988 NSPS include prime coats, color coats, texture coats, and touch-up coats. The VOC emission sources covered in the 1988 NSPS are: (1) the spray booths; (2) the flash-off areas; and (3) the curing ovens.[4] According to the regulation at 40 CFR 60.722(b), all VOC emissions that are caused by coatings applied in each affected facility, regardless of the actual point of discharge of emissions into the atmosphere, shall be included in determining compliance with the emission limits. Thus, as the EPA explained in the 1988 NSPS, VOC emissions from the flash-off area and oven are covered by the standards on the basis that the coatings application that takes place in the spray booth is the cause of VOC emissions from the flash-off area and oven.[5]

Typically, a plastic part is surface coated in a spray booth that houses either automatic or manual spray application equipment (one or more spray guns). After being coated, the part is moved, whether manually or by conveyor, to a flash-off area and then to a curing oven. The purpose of the flash-off area is to allow sufficient time for some portion of the solvents from a newly applied coating to evaporate, sometimes between coats, because the coating may not dry correctly unless it is given the recommended flash time. The flash-off area is usually very large and not enclosed, and indoor VOC concentrations resulting from flash-off are typically reduced by dilution ventilation for worker safety.[6] Whether a batch oven or a conveyor oven, the curing oven applies enough heat to the newly coated part to create a chemical reaction that stabilizes the newly applied coating. For surface coating of plastic parts for business machines, coatings are typically cured at a relatively low temperature, near 60 degrees Celsius (140 degrees Fahrenheit).

Regardless of the type of coating in use at a facility that surface coats plastic parts for business machines, approximately 80 percent of total VOC emissions occur in the spray booth. Most of the solvent-laden air in these facilities comes from the spray booth and flash-off areas, and the concentration of VOC in that air is very low because it must be diluted to protect workers from breathing harmful levels of organic solvents. The Occupational Safety and Health Administration (OSHA) has specific requirements for the design and construction of spray booths (see 29 CFR 1910.107(b)) and requires a minimum velocity of air into all openings of a spray booth (see 29 CFR 1910.94(c)(6), table G–10). An induced air flow is maintained in a spray booth not only to keep solvent concentrations at a safe level but also to remove overspray in order to minimize contamination. The VOC from these areas can be captured and ducted to a control device, but the high volume of air and low concentration of VOC make this a costly method of control. For example, the cost of using a thermal incinerator with primary heat recovery to control VOC emissions from the spray

[1] Alternative Control Techniques Document: Surface Coating of Automotive/Transportation and Business Machine Plastic Parts, EPA 453/R–94–017, February 1994, p. 2–1.

[2] Proposed rule, ''*Standards of Performance for New Stationary Sources: Industrial Surface Coating; Plastic Parts for Business Machines*'' (51 FR 854, January 8, 1986) (1986 proposed NSPS) at pp. 862–63.

[3] 1986 proposed NSPS, 51 FR 854 at 855 and 862.

[4] In this source category, approximately 80 percent of the emissions occur in the spray booths, 10 percent occur in the flash-off areas, and 10 percent occur in the ovens (1986 proposed NSPS, 51 FR 854 at 858/3).

[5] 53 FR 2672 at 2674.

[6] 1986 proposed NSPS, 51 FR 854 at 858/3.

booths and flash-off areas for a medium-sized model plant was estimated in the EPA's 1985 document titled *Surface Coating of Plastic Parts for Business Machines—Background Information for Proposed Standards,* EPA–450/3–85–019a, December 1985 (1985 BID), available in the docket for this action, to be $11,000 to $21,000 per megagram (Mg) ($10,000 to $19,000 per ton) of VOC controlled.[7] The specific cost depends in part on the booth ventilation rate.

2. Coatings Used in the Source Category

Low-VOC-content coatings have been developed for surface coating operations generally; as demonstrated by sources' compliance with VOC emission limits in the EPA's Control Techniques Guidelines for Miscellaneous Metal and Plastic Parts Coatings, EPA–453/R–08–003, September 2008 (2008 CTG) as well as state regulations, coatings manufacturers have been successful in reformulating coating products to meet more stringent limits.

The types of coatings currently in use for application to plastic business machine parts include conventional solvent-based coatings, higher-solids coatings, and waterborne coatings, all of which emit VOC to the atmosphere when organic solvents evaporate from the coatings during coating and curing processes. The properties of the different plastics determine the types of coatings that can be used on them. For instance, some plastics are damaged by the organic solvents in solvent-based or waterborne coatings. Also, adhesion characteristics can differ between plastics.

The constituents of a coating typically include a mixture of solvents and solids. If a coating needs to be made thinner before use, the owner or operator may add additional solvents to dilute the coating. The solvents portion of the coating (sometimes referred to as the volatiles portion) can include water and exempt solvents as well as regulated VOCs. The solids portion of the coating typically includes pigments, binders, and additives. The solids portion is what is intended to be applied to and remain on the product being coated. As a product is sprayed with coating, some of the solids will adhere to the product being coated. Even under optimal conditions, however, some of the solids will be excess spray that is discarded as waste. When calculated as a percentage of the total volume of a coating, the solids may be referred to as ''volume solids.'' When comparing a gallon of a coating with a higher volume solids (*e.g.,* 60 percent volume solids) and a gallon of coating with a lower volume solids (*e.g.,* 30 percent volume solids), one cannot simply conclude that the higher-solids coating will emit less VOC. To calculate the mass of VOC in that gallon of coating, one must know the makeup of the solvents portion and the coating's VOC density (or solids density).

Although a coating's solids content and regulated VOC content are not directly inversely proportional to each other, they are closely related. To evaluate coating reformulation options and to estimate total VOC emissions from coating operations, the EPA often relies on a material balance approach that is based on our determination that all of the coating's VOC content will evaporate and will be emitted unless captured and routed to a control device.[8]

3. Spray Application Technology

The type of coating to be used is a factor in selecting the appropriate spray application technique (type of spray gun, choice of fluid nozzle size, amount of thinning). Higher-solids coatings are especially suited to application by a conventional (air atomized) spray gun, which allows a lot of air pressure to atomize the coating. Coatings of lower viscosity may be sprayed with, *e.g.,* a high-volume, low-pressure (HVLP) spray gun, an airless air-assisted spray gun, or an electrostatic air spray gun, which waste less coating compared to a conventional spray gun.

The transfer efficiency (TE) is the ratio of the coating solids that adhere to a part to the total amount of coating solids used. More simply, the TE of the spray application method indicates the amount of coating solids that will land on the intended target. Thus, TE also indicates the amount of excess coating sprayed, which is referred to as overspray. Improving TE reduces total coating consumption and results in decreased VOC emissions. Thus, owners and operators of surface coating operations are economically motivated to maximize the efficiency of their spray application methods. Even so, owners and operators are constrained in the extent to which TE can be improved: the type of plastic being coated affects the choice of coating, which in turn affects the choice of and efficiency of the spray application technique.

4. Format of VOC Content Data and Emission Limits

Emission limits for coatings operations, such as those recommended in CTGs and adopted by many state and local agencies, are sometimes expressed in terms of pounds of VOC per gallon of coating less water. Those units are directly useful, however, only for cases where compliance is achieved with low-VOC-content coatings alone. When add-on controls or transfer efficiency improvements are used, compliance calculations must be done on an equivalent solids basis.[9]

Coatings regulations and information from coatings manufacturers, when providing VOC content in terms of mass of VOC per volume of coating material, typically provide VOC content information (whether in metric or English units) in one or more of the following three formats. In the first format, ''as supplied,'' VOC content of the material is characterized as it leaves the coatings manufacturer site. In the second format, ''as applied,'' VOC content of the coating is characterized ''at application'' or ''as used.'' The coating has been mixed according to manufacturer's instructions, which may include a maximum amount of thinning with non-exempt compound solvents. The third format, ''VOC per unit of applied coating solids,'' considers the transfer efficiency of the application method to account for overspray. The NSPS subpart TTT limits are in this third format. The format of the 1988 NSPS was selected over a format that was based on mass of VOC per unit volume of coating consumed, because the latter format would not give credit for improving TE.[10]

Additional details on the development of the 1988 NSPS for surface coating of plastic parts for business machines can be found in the 1985 BID.[11]

C. How do the current standards regulate emissions?

1. Best System of Emission Reduction in the 1988 NSPS

In the 1986 proposed NSPS, the EPA evaluated regulatory options that considered EMI/RFI shielding and exterior coating processes together. To simplify examination of those regulatory alternatives for the proposal, the EPA chose to present the cost,

[7] 1985 BID, p. 4–14.

[8] EPA. AP–42, April 1981, section 4.2.2.1.2. Emissions from surface coating for an uncontrolled facility can be estimated by assuming that all VOC in the coatings is emitted.

[9] EPA. *A Guideline for Surface Coating Calculations,* EPA–340/1–86–016, July 1986, p. 2.

[10] 51 FR 854 at 863.

[11] *Surface Coating of Plastic Parts for Business Machines—Background Information for Proposed Standards,* EPA–450/3–85–019a, December 1985, available in the docket for this action.

environmental, and energy impacts and cost effectiveness of control options for EMI/RFI shielding and exterior coating separately. For EMI/RFI shielding, the EPA evaluated four control options in the 1986 proposed NSPS. Three of those control options concerned VOC emissions from coatings, and the fourth concerned a non-VOC-emitting process, zinc-arc spray. For each of the four EMI/RFI shielding options considered, the cost effectiveness compared to the baseline was judged to be unreasonable. As a result, the EPA did not regulate EMI/RFI shielding in the 1988 NSPS. None of the currently affected facilities subject to NSPS subpart TTT is engaged in application of EMI/RFI shielding on plastic parts for business machines. Accordingly, the EPA is not proposing to address EMI/RFI shielding options in NSPS subpart TTTa.

For exterior coatings, in the 1986 proposed NSPS, the EPA evaluated eight control options. All eight of those control options concerned VOC emissions from coatings. For fog coating, the 1988 NSPS selected the application of waterborne coatings applied at a TE of 25 percent as the BSER. For prime, color (except fog coating), texture, and touch-up coating, the EPA selected the application of organic-solvent-based coatings containing 60 percent solids—at 40 percent TE for prime and color coats and at 25 percent TE for texture and touch-up coats—as the BSER.

2. Emission Limits in the 1988 NSPS

The 1988 NSPS established emission limits that are based on the BSER (a combination of coating formulation and application technology). For prime and color coats, and for fog coating, affected facilities must limit VOC emissions to no more than 1.5 kilograms of VOC per liter (kg VOC/l), or 13 pounds of VOC per gallon (lb VOC/gal) of coating solids applied. For texture and touch-up coats, affected facilities subject to the 1988 NSPS must limit VOC emissions to no more than 2.3 kg VOC/l (19 lb VOC/gal) of coating solids applied.

Noteworthy is that the regulation at 40 CFR 60.721 defines ''coating solids applied'' to mean the coating solids that adhere to the surface of the plastic business machine part being coated. Thus, the TE of the spray application technology is taken into account in the setting of the VOC emission limits of the 1988 NSPS and in calculation of compliance with those emission limits. It may be helpful to think of the denominator in those emission limits in terms of coating solids *deposited.*

3. Demonstrating Compliance With the 1988 NSPS

To demonstrate compliance with the 1988 NSPS emission limits, the owner or operator of an affected facility is provided equations (in 40 CFR 60.723(b)(i)) that factor in both VOC content and TE. The equations calculate the mass of VOC used for each type of coating used, the total volume of coating solids consumed for each coating type, and the volume-weighted average transfer efficiency, all used to calculate the volume-weighted average mass of VOC emitted per unit volume of coating solids applied.

For purposes of compliance calculations, the regulation at 40 CFR 60.723 specifies the default TE to be used, depending on the application technology employed. A TE of 0.25 is the default value when air atomized spray is the application method used, and a TE of 0.40 is the default value when either air-assisted airless spray or electrostatic air spray is the application method used.

Because TE is a factor in calculations for demonstrating compliance with the VOC emission limits in the 1988 NSPS, the owner or operator at a surface coating facility is afforded some flexibility as to which combination of coating formulation and application technique to use for a given plastic part. For example, compliance with a limit of 1.5 kg VOC/l (13 lb VOC/gal) coating solids applied (the limit for both prime and color coating) can be achieved with a higher-VOC-content coating and a more efficient spray application method or with a lower-VOC-content coating and a less efficient spray application method. (Remember that the regulation at 40 CFR 60.721 defines ''coating solids applied'' to mean the coating solids that adhere to the surface of the plastic business machine part being coated.)

The 1988 NSPS requires that the owner or operator of an affected facility conduct an initial performance test and thereafter a performance test each nominal 1-month period, for each affected facility. Each monthly period, the owner or operator will calculate the volume-weighted average mass of VOC in coatings emitted per unit volume of coating solids applied (*i.e.,* deposited), for each type of coating (prime, color, texture, and touch-up) used during that period. Each 1-month calculation is considered a performance test.[12] Following an initial report, the owner or operator will submit a statement of compliance on a semiannual basis or, if the affected facility is not in compliance with the application emission limits, will submit a report of noncompliance on a quarterly basis.

4. Options for Case-by-Case Approval in the 1988 NSPS

The 1988 NSPS provides that if an owner or operator can demonstrate to the satisfaction of the Administrator that TE values other than those specified in subpart TTT are appropriate, the Administrator will approve their use on a case-by-case basis. Similarly, the Administrator will on a case-by-case basis approve a TE value for an application method not listed in the regulation.

Finally, facilities are not required to use the formulas and compliance demonstrations based on coating content and TE. Consistent with CAA section 111(b)(5), the 1988 NSPS expressly allows that compliance with subpart TTT can achieved through the use of add-on controls, if the owner or operator at an affected facility can demonstrate to the Administrator on a case-by-case basis that VOC emissions reductions through use of add-on controls are within the otherwise applicable limits.[13] The EPA is proposing to include in the new subpart TTTa these same case-by-case compliance approaches.

D. Background on Sources Subject to Subpart TTT

The EPA is aware of three stationary sources, located among three states, that currently perform surface coating of plastic parts for business machines. Of those three sources, two are small entities. Based on our review, the EPA has determined that all three sources are currently subject to the 1988 NSPS at 40 CFR part 60, subpart TTT, because they have affected surface coating operations that were constructed, reconstructed, or modified after January 8, 1986. The number of affected facilities (spray booths subject to NSPS subpart TTT) per stationary source ranges from one to ten. We also determined that none of the three sources are currently subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Plastic Parts at 40 CFR part 63, subpart PPPP, since each is an area source and so not subject to major source requirements under CAA section 112. None of the currently affected facilities subject to NSPS subpart TTT is engaged in application of EMI/RFI shielding on plastic parts for business machines. Add-on controls are not used by any of the three sources that are actively engaged in the surface coating of plastic

[12] 40 CFR 60.723(b)(i).

[13] 40 CFR 60.723(b)(2)(iv).

parts for business machines, and no new plants are expected to be built that rely on add-on control for VOC emissions.

The EPA has determined that all three sources currently subject to the 1988 NSPS at 40 CFR part 60, subpart TTT, use low-VOC-coatings in combination with efficiency in spray application technology to comply with the emission limitations. The EPA also found that, through use of low-VOC-content coatings in combination with efficiency in spray application technology, one of the three sources actively engaged in the surface coating of plastic parts for business machines is complying with air permit limits that are more stringent than the VOC emission limits of the 1988 NSPS.[14] That source is subject to New York State regulations requiring that all sources applying surface coatings to plastic parts for business machines in New York must comply with these more stringent VOC emission limits.[15] These New York emission limits are identical to the VOC emission limits recommended for surface coating of business machines in table 4 of the 2008 CTG.

E. What data collection activities were conducted to support this action?

A full discussion of the EPA's data collection activities for the NSPS review is found in the BSER Review memorandum, available in the docket for this action. This section of the preamble provides a summary of those activities.

For review of the NSPS at 40 CFR part 60, subpart TTT, and development of the proposed new NSPS subpart TTTa, the EPA collected information from a typical variety of data sources.

To compile a list of sources subject to subpart TTT (facility list), we queried the Enforcement and Compliance History Online (ECHO) database, which provides integrated compliance and enforcement information for approximately 800,000 regulated sources nationwide. Using the feature in ECHO to search on NSPS subpart TTT, the EPA identified 17 sources as potentially subject to NSPS subpart TTT. Of the 17 sources, nine had permit documents indicating that they were subject to the NSPS at the time of review. Upon contacting these nine individual sources, we learned that only three of those sources currently perform surface coating of plastic parts for business machines.

The EPA recognizes that not all states submit data to ECHO for the smallest sources, and so we sought to supplement the information from ECHO by collecting information on reasonably available control technology (RACT), best available control technology (BACT), and lowest achievable emission rate (LAER) determinations in the EPA's RACT/BACT/LAER Clearinghouse.[16] The EPA established the RACT/BACT/LAER Clearinghouse, or RBLC, to provide a central database of air pollution technology information—including past RACT, BACT, and LAER decisions contained in New Source Review (NSR) permits—to promote the sharing of information among permitting agencies and to aid in future case-by-case determinations. Data in the RBLC are not limited to sources subject to RACT, BACT, and LAER requirements. Noteworthy prevention and control technology decisions and information are included even if they are not related to past RACT, BACT, or LAER decisions. Our search of the RBLC resulted in one potential addition to the facility list, but we found that the source does not currently perform surface coating of plastic parts for business machines and so did not include it in the facility list.

The EPA also queried the EPA's Applicability Determination Index (ADI),[17] which is a web-based database containing memoranda issued by EPA on applicability and compliance issues associated with NSPS, NESHAP, and chlorofluorocarbons (CFC). Recently issued determinations are added to the database on a quarterly basis. Our search of the ADI did not result in any additions to the facility list.

Further, the EPA queried the EPA's Emissions Inventory System (EIS) database, which includes emissions data and supporting information from the 2017 National Emissions Inventory (NEI). Our search of the EIS did not result in any additions to the facility list.

For assistance in development of the facility list, and to confirm information compiled, we consulted: the industry trade association, the American Coatings Association; a major industrial coatings manufacturer, The Sherwin-Williams Company; and numerous EPA Regional Office contacts. Our communications with these representatives did not result in any additions to the facility list.

F. What other relevant background information and data are available?

In addition to the data sources described in section II.E of this preamble, the EPA reviewed the following information sources for advances in technologies, changes in cost, and other factors to review the standards in the 1988 NSPS for surface coating of plastic parts for business machines. The additional information sources include:

- Operating permits for 18 sources.
- Compliance demonstration reports for two sources.
- Publicly available inspection reports for one source.
- Alternative Control Techniques Document: Surface Coating of Automotive/Transportation and Business Machine Plastic Parts, EPA–453/R–94–017, February 1994, available in the docket for this action.
- Control Techniques Guidelines for Miscellaneous Metal and Plastic Parts Coatings, EPA–453/R–08–003, September 2008, available in the docket for this action.
- Background documents and industry supplied data for supporting regulatory actions promulgated subsequent to the 1988 NSPS, including the 2004 Plastic Parts NESHAP and the 2020 RTR amendments to the 2004 Plastic Parts NESHAP.

III. How does the EPA perform the NSPS review?

As noted in section II.A of this preamble, CAA section 111 requires the EPA, at least every 8 years to review and, if appropriate revise the standards of performance applicable to new, modified, and reconstructed sources. If the EPA revises the standards of performance, they must reflect the degree of emission limitation achievable through the application of the BSER taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements. CAA section 111(a)(1).

In reviewing an NSPS to determine whether it is ''appropriate'' to revise the standards of performance, the EPA evaluates the statutory factors, which may include consideration of the following information:

[14] Records prepared by Xerox Corporation; required under 40 CFR 60.723(b)(2)(iii) and codified in the source's Air State Facility air permit issued December 10, 2019, by New York State Department of Environmental Conservation.

[15] Official Compilation of Codes, Rules and Regulations of the State of New York—Surface Coating Processes; 6 CRR—NY 228–1.4. In table B6, under Business Machine Coatings, the VOC content limit for primers, topcoats, texture coats, and touchup and repair is 0.35 kg per liter of coating (minus water and excluded compounds) at application, and the VOC content limit for fog coats is 0.26 kg per liter of coating (minus water and excluded compounds) at application. As comparison, these values are between 61 and 93 percent of the NSPS subpart TTT values, depending on coating type (and assuming a 40 percent transfer efficiency in converting to the NSPS format).

[16] See *https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information.*

[17] See *https://cfpub.epa.gov/adi/index.cfm.*

• Expected growth for the source category, including how many new facilities, reconstructions, and modifications may trigger NSPS in the future.

• Pollution control measures, including advances in control technologies, process operations, design or efficiency improvements, or other systems of emission reduction, that are ''adequately demonstrated'' in the regulated industry.

• Available information from the implementation and enforcement of current requirements indicating that emission limitations and percent reductions beyond those required by the current standards are achieved in practice.

• Costs (including capital and annual costs) associated with implementation of the available pollution control measures.

• The amount of emission reductions achievable through application of such pollution control measures.

• Any nonair quality health and environmental impact and energy requirements associated with those control measures.

In evaluating whether the cost of a particular system of emission reduction is reasonable, the EPA considers various costs associated with the particular air pollution control measure or a level of control, including capital costs and operating costs, and the emission reductions that the control measure or particular level of control can achieve. The Agency considers these costs in the context of the industry's overall capital expenditures and revenues. The Agency also considers cost-effectiveness analysis as a useful metric and a means of evaluating whether a given control achieves emission reduction at a reasonable cost. A cost-effectiveness analysis 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.

After the EPA evaluates the statutory factors, the EPA compares the various systems of emission reductions and determines which system is ''best.'' The EPA then establishes a standard of performance that reflects the degree of emission limitation achievable through the implementation of the BSER. In doing this analysis, the EPA can determine whether subcategorization is appropriate based on classes, types, and sizes of sources, and may identify a different BSER and establish different performance standards for each subcategory. The result of the analysis and BSER determination leads to standards of performance that apply to facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Because the new source performance standards reflect the best system of emission reduction under conditions of proper operation and maintenance, in doing its review, the EPA also evaluates and determines the proper testing, monitoring, recordkeeping and reporting requirements needed to ensure compliance with the emission standards.

See sections II.E and II.F of this preamble for information on the specific data sources that were reviewed as part of this action.

IV. Analytical Results and Proposed Rule Summary and Rationale

A. What are the preliminary results and proposed decisions based on our NSPS review, and what is the rationale for those proposed decisions?

This action presents the EPA's review of the requirements of 40 CFR part 60, subpart TTT pursuant to CAA 111(b)(1)(B). As described in section III of this preamble, the statutory review of NSPS subpart TTT for surface coating of plastic parts for business machines focused on whether there are any emission reduction techniques that are used in practice that achieve greater emission reductions than those currently required by NSPS subpart TTT for surface coating operations and whether any of these developments in practices have become the ''best system of emissions reduction.''

In the 1988 NSPS, the EPA determined the BSER to be a combination of application technology and coating formulation. Control techniques commonly used to reduce VOC emissions from general surface coating processes include use of more efficient coating application techniques, low-VOC-content coatings, and add-on controls. In reviewing the NSPS for surface coating of plastic parts for business machines, the EPA considered each of these emission reduction techniques.

Subsequent to the promulgation of the 1988 NSPS, the EPA promulgated other regulatory actions pursuant to CAA sections 112 and 183(e) that also regulate or otherwise address emissions from the same surface coating operations covered by NSPS subpart TTT. These regulatory actions include: (i) the Alternative Control Techniques Document: Surface Coating of Automotive/Transportation and Business Machine Plastic Parts, EPA 453/R–94–017, February 1994 (1994 ACT); (ii) the National Emission Standards for Hazardous Air Pollutants: Surface Coating of Plastic Parts and Products, promulgated at 40 CFR part 63 subpart PPPP on April 19, 2004 (69 FR 20968) (Plastic Parts NESHAP); (iii) the Control Techniques Guidelines for Miscellaneous Metal and Plastic Parts Coatings, EPA–453/R–08–003, September 2008 (2008 CTG); and (iv) the Plastic Parts NESHAP risk and technology review (RTR) promulgated on July 8, 2020 (85 FR 41100).

Although the NESHAP and CTG requirements for surface coating of plastic parts are different in some respects from the NSPS for surface coating of plastic parts for business machines, due to the differences in CAA authorities, pollutants, emission limits and format, they apply to overlapping operations and were therefore considered in our review.

Based on this review, we have preliminarily determined that there are emission reduction techniques used in practice that achieve greater emission reductions than those currently required by NSPS subpart TTT for surface coating operations. The results and proposed decisions based on the analyses performed pursuant to CAA section 111(b) are presented in more detail later in this preamble. Pursuant to this review we are proposing revised standards in a new NSPS subpart, TTTa, that would apply to facilities that begin construction, reconstruction, or modification after June 21, 2022.

For sources that are subject to NSPS subpart TTT, we are proposing certain revisions to subpart TTT that would not change the applicability of NSPS subpart TTT or the emission limits for VOC in subpart TTT. The proposed revisions pertaining to electronic submission of reports would apply to all affected facilities that commence construction, modification, or reconstruction after January 8, 1986 (*i.e.,* all affected facilities under both subpart TTT and proposed subpart TTTa). With respect to affected facilities subject to subpart TTT, none of these amendments would significantly increase the cost of the rule or result in a change in VOC emissions.

B. What are the results of our review of powder coatings and UV/EB coatings formulation?

The 2008 CTG identified the substitution of higher-solvent coatings with coatings containing little or no solvents as one way to reduce VOC emissions.[18] These coatings include powder coatings, waterborne coatings, higher-solids coatings, and ultraviolet-cured coatings (either powder or liquid). However, the 2008 CTG also concluded that many of the low-VOC coatings or coatings with no solvents would not meet the performance requirements of certain plastic coating applications and therefore are not viable options for all plastic parts coating operations.

Among low-VOC-content coatings that the EPA considered in this NSPS review are thermal (heat-cured) powder coatings and UV/EB (ultraviolet/electron beam)-cured powder coatings. Powder coatings are essentially 100 percent solids. Powder coatings emit little or no VOC, but they typically require curing temperatures that exceed the temperature limitations of the plastic parts. For that reason, the EPA is not proposing thermal powder coatings as the BSER for surface coating of plastic parts for business machines. With respect to powder coatings that can be cured with ultraviolet or infrared radiation instead of heat, the EPA recognized in the 1985 BID (p. 3–17) that coatings manufacturers are developing such powder coatings. The use of UV/EB-cured coatings was not in practice in the coatings industry when the 1988 NSPS was being developed. Due to development in technology, use of UV/EB-cured coatings is technically feasible in many coating operations. A source subject to NSPS subpart TTT or subpart TTTa may adopt UV/EB technology as part of its compliance strategy. However, in promulgating the Plastic Parts NESHAP in 2004, the EPA determined that incremental emission reduction of requiring UV/EB-cured coatings would be relatively small and that the additional cost was not warranted.[19] Since 2004, there have been no improvements in UV/EB technology that would justify a change in this conclusion. Among sources that perform surface coating of plastic parts for business machines, the EPA did not identify any sources using UV/EB technology and based on the information from the Plastic Parts NESHAP analysis, emission reductions from UV/EB-cured coatings would be small and not cost effective. Accordingly, the EPA is not proposing use of either thermal powder coating or UV/EB options as the potential BSER for this NSPS review.

C. What are the results of our review of spray application technology?

As part of our NSPS review and BSER analysis, we evaluated whether there are changes in the transfer efficiency (via application technology) as well as in the formulation of coatings. The spray applicator types through which the BSER was determined in 1988 continue to be in use at sources that perform surface coating of plastic parts for business machines, which include job shops that must use the types of spray applicators that accommodate a wide variety of coatings and wide range of part shapes. For conventional and air-assisted airless spray application technology, trade literature shows that TE values of 0.25 and 0.40, respectively, continue to be representative of the spray technologies in use.[20] A provision of subpart TTT allows a source to request the Administrator's approval to use some value other than subpart TTT default TE values for compliance purposes. However, in analysis of data collected in our review, we learned of no cases where a source needed to use a TE value other than (*i.e.,* higher than) the subpart TTT default TE values in order to comply with subpart TTT. On this basis, the EPA is proposing to retain the menu of subpart TTT default TE values and their associated spray applicator types in new subpart TTTa. The EPA is proposing also to allow a subpart TTTa affected facility, for a given type of coating application equipment at a given coating operation, to use a different (higher) TE with the Administrator's case-by-case approval. The EPA solicits comment on the proposed use of current subpart TTT default TE values in subpart TTTa. As described in the BSER Review memorandum (available in the docket for this action), the use of higher-efficiency spray application technology, such as HVLP spray guns, has grown among surface coating operations generally. We are also soliciting data, information, analysis, and other input with respect to the ability of new, modified, or reconstructed sources to perform some or all surface coating of plastic parts for business machines through use of HVLP spray technology and whether a default transfer efficiency as high as 0.65 would be appropriately used, without case-by-case approval by the Administrator, in calculations of compliance with VOC emission limits under NSPS subpart TTTa.

D. What regulatory options did we identify, and how did we evaluate them?

1. Options Identified

For this NSPS review, as a result of the information and findings described in this preamble, we evaluated two regulatory options that rely on coating formulation and are more stringent than the current NSPS. The first option we evaluated is a VOC emission limit representative of the 2008 CTG's level of control (option 1, or the CTG-based option). The second option we evaluated is a VOC emission limit representative of the 1994 ACT's ''Level 2'' level of control (option 2, or the ACT-based option).

As a third option, in our NSPS review we evaluated the use of an add-on control device—a regenerative thermal oxidizer (RTO)—to remove a portion of VOC emissions that enter the spray booth exhaust. The EPA recognizes that other add-on control devices, such as adsorbers, absorbers, and concentrators, might be just as effective as an RTO alone for control of VOC emissions from coating operations generally. However, our review here focused on the RTO because performance of other devices can be influenced by specific compounds while an RTO is not so selective in terms of VOC destruction.

As a starting point in identifying potential control options, the EPA found the use of a prime coating, or primer, to be common. For example, for prime coating, the 1988 NSPS established an emission limit of 1.5 kg VOC/l (13 lb VOC/gal) of coating solids applied. As described in section II.D of this preamble, one of the three active affected facilities, Xerox, is complying with a New York air permit emission limit of 0.35 kg VOC/l (2.9 lb VOC/gal) of prime coating minus water and excluded compounds at application, and it is doing so entirely through use of currently available coating formulations. That New York limit is identical to the VOC emission limit that is recommended in the 2008 CTG as RACT for primer coatings used in surface coating of business machines.[21] In the format of the 1988 NSPS, the EPA calculates the 2008 CTG's equivalent VOC emission limit to be 1.4 kg VOC/l (12 lb VOC/gal) coating solids applied. That is, for prime coating, the 2008 CTG level and one active source's air permit emission limit are more stringent than the 1988 NSPS limit (the baseline) by

[18] EPA. Control Techniques Guidelines for Miscellaneous Metal and Plastic Parts Coatings. EPA–453/R–08–003. September 2008.

[19] EPA. National Emission Standards for Hazardous Air Pollutants (NESHAP): Surface Coating of Plastic Parts and Products—Summary of Public Comments and Responses on Proposed Rule. EPA–453/R–03–007. August 2003.

[20] BSER Review memorandum.

[21] VOC emission limit of 0.35 kg VOC/l (2.9 lb VOC/gal) of coating as applied, excluding water and exempt compounds. 2008 CTG, Table 4, p. 34.

0.1 kg VOC/l coating solids applied (deposited). For that reason, the EPA evaluated as regulatory option 1 (the CTG-based option) a tightening of VOC emission limits to the levels recommended in the 2008 CTG.

The EPA, in its 1994 ACT, presented a reformulation control level (Level 2, as later described in this preamble) at 0.28 kg VOC/l (2.3 lb VOC/gal) coating, less water and exempt solvents, as a control option (short of recommendation as RACT) for ''primer'' for coating of plastic parts for business machines. In the format of the 1988 NSPS, the EPA calculates the 1994 ACT's equivalent VOC emission limit to be 0.43 kg VOC/l (3.6 lb VOC/gal) coating solids applied. That is, for prime coating, the 1994 ACT level is more stringent than the 1988 NSPS limit (the baseline) by 1.1 kg VOC/l coating solids applied (deposited). For that reason, the EPA evaluated as regulatory option 2 (the ACT-based option) a tightening of VOC emission limits to the reformulation ''Level 2'' presented in the 1994 ACT. The EPA, in its 1994 ACT, developed three control levels to estimate potential VOC emissions reductions. Two of the ACT levels, Level 1 and Level 2, were based on reformulation (*i.e.,* use of waterborne or higher-solids coatings); the third ACT control level, Level 3, was based on thermal incineration. We did not use the 1994 ACT's ''Level 1'' level of control as the basis for the ACT-based option for the reason that it is not significantly different overall from the 1988 NSPS level of control. For the 1994 ACT's ''Level 3'' level of control, estimated cost effectiveness was unacceptably high, ranging from $6,900 (large plant) to $34,000 (small plant) per ton of VOC removed. Nevertheless, for the NSPS review, the EPA did evaluate an RTO (a type of thermal incineration) as regulatory option 3.

2. Model Plant

Based on information the EPA collected from current affected facilities, a trade association, and a coatings manufacturer, we expect no new, modified, or reconstructed sources to become subject to the new NSPS subpart TTTa over the next 8 years. Therefore, for purposes of our review, the EPA evaluated the identified regulatory options in terms of impacts on affected facilities—cost, environmental, and energy impacts, as well as cost effectiveness of control options—based on a representative model plant (which we call ''model plant A''). Model plant A, with total plant VOC emissions of 27.2 megagrams per year (Mg/yr) (30.0 tons per year (tpy)), was developed using information from the three stationary sources currently subject to NSPS subpart TTT.

Additional detailed information on model plant A and how the EPA estimated emission reductions and cost effectiveness for the evaluated options is provided in the memorandum *Estimated Costs/Impacts 40 CFR 60 Subpart TTT* (Costs/Impacts memorandum), available in the docket for this action.

3. Representative Coating Approach and Baseline Emissions

Multiple coating applications are performed in the spray booth (color coating, prime coating, texture coating, and touch-up coating) and each coating type has its own VOC limit. To evaluate coating formulation options, the EPA adopted a ''representative coating'' approach. This approach allows standardization of coating variables across options so that the EPA could estimate comparable emission reductions between two coating formulation-based regulatory options evaluated in this NSPS review.

To grasp why the EPA employed a ''representative coating'' approach, consider first a calculation of the baseline VOC emission rate. Without employing some standardizing assumptions about our coating variables, four coating types (color coating, prime coating, texture coating, and touch-up coating) would contribute to that baseline (1988 NSPS level of control), each coating type with a corresponding coating limit (VOC content). To calculate a given option's VOC emission reduction from the baseline, a straightforward calculation would be based on the same set of coating types, and with the same correspondence of coating limit to coating type. However, in this NSPS review, we have a different set of coating types contributing to emissions when we consider a VOC emission rate representative of a 2008 CTG-based level of control (option 1). Yet another set of coating types, with another correspondence of coating limits, contributes to emissions when we consider a VOC emission rate representative of a 1994 ACT-based level of control (option 2). Thus, without some standardization of assumptions, no direct comparison can be made between options.

In the 1986 NSPS proposal, the EPA based its proposed control options on the expectation that prime and color coats represent approximately one-half of the exterior coating solids applied.[22] Toward an ''apples to apples'' comparison for our analysis, the EPA reconciled multiple emission limits within a given control option by calculating VOC emission reductions that are based on an average of the emission limits applicable to prime coating and color coating (or topcoat, as described in the 2008 CTG). For each regulatory option where this approach is used, the EPA applies the average of the prime coating and color coating emission limits as a ''representative coating'' limit for VOC.

As the baseline (the 1988 NSPS) level of control for evaluation of regulatory options, the EPA is using an emission limit of 1.5 kg VOC/l (13 lb VOC/gal) coating solids applied as the representative coating limit. In the 1988 NSPS, the VOC emission limit both for prime coating and for color coating is 1.5 kg VOC/l (13 lb VOC/gal) coating solids applied; the representative coating limit is the average of those limits.

4. Option 1, CTG-Based Formulation

To evaluate the CTG-based option, the EPA is using an emission limit of 1.4 kg VOC/l (12 lb VOC/gal) coating solids applied as the representative coating limit; this limit is derived from the 2008 CTG. In the 2008 CTG, the VOC emission limit both for primer and for topcoat (which the EPA believes to be equivalent to color coat) is, upon conversion by calculation to the NSPS format, 1.4 kg VOC/l (12 lb VOC/gal) coating solids applied.

For option 1, based on the 2008 CTG recommended VOC emission limits, the estimated reduction in VOC emissions per facility (model plant A) would be 1.5 Mg/yr, (1.7 tpy) if option 1's representative coating comprised the entirety of the facility's 15,100 l/yr (4,000 gal/yr) of coating solids deposited. Option 1 (the CTG-based option) represents a level of VOC emission control demonstrated in practice by at least one of the three sources actively engaged in surface coating of plastic parts for business machines. In the Cost/Impacts memorandum (available in the docket for this action), table 4 shows VOC content of a representative list of compliant coatings currently available and identifies those we found to be currently in use at one or more sources. Because at least one source is already achieving the CTG-based option's level of control entirely through use of a variety of currently available coating formulations, the EPA assumes the cost effectiveness of option 1 (the CTG-based option) for the representative coating to be $0 per ton of VOC reduction, as

[22] 1986 proposed NSPS, 51 FR 854 at 860.

explained in section IV.D.7 of this preamble.

The 1988 NSPS treats fog coating operations as a special type of color coating [23] and at 40 CFR 60.721 defines ''fog coat'' (also known as mist coating and uniforming) to mean a thin coating applied to plastic parts that have molded-in color or texture or both to improve color uniformity. The EPA recognizes that even though the 1988 NSPS applies the same VOC emission limit for fog coating (1.5 kg VOC/l coating solids applied) as for other color coating, the 2008 CTG recommends a more stringent VOC emission limit for ''fog coat,'' at 0.95 kg VOC/l coating solids applied when the EPA calculates the limit in the format of the NSPS. The CTG's recommended limit for fog coat is lower than that for its other coating types (primer, topcoat, texture coat, and touch-up and repair), which are at 1.4 kg VOC/l coating solids applied when the EPA calculates the limit in the format of the NSPS. The CTG based its recommended limit for fog coat on a Michigan regulation (see 2008 CTG at p. E–9). In considering the limitations of the data available for this review, we are proposing to follow in new subpart TTTa the same approach used for subpart TTT, which is to treat fog coating as a type of color coating and to apply the same level of VOC emission control to fog coating and other color coating. Notwithstanding the VOC emission limits proposed for new subpart TTTa, an affected facility that is subject to more stringent federally enforceable requirements, such as a state's SIP-approved RACT limit for fog coating that is lower than proposed for the NSPS, would be required to comply with the applicable provisions of those rules. The EPA solicits comment on the proposed approach for fog coating.

The EPA also recognizes that we did not, in the 2008 CTG, recommend the CTG's control approaches for sources that emit VOC below a certain emissions rate. (The CTG describes that cutoff to be sources where the total actual VOC emissions from all miscellaneous metal product and plastic parts surface coating operations, including related cleaning activities, at the source are below 6.8 kg/day (15 lb/day), or an equivalent level of 2.7 tons per 12-month rolling period, before consideration of controls.) For option 1 (the CTG-based option), which relies on a combination of coating formulation and application technique for compliance, we see no reason why the EPA should exempt the lowest-emitting sources from having to meet the same VOC emission limits in subpart TTTa that would apply to the higher-emitting ones. The EPA solicits comment on whether a minimum VOC emission rate cutoff for applicability of the NSPS would be necessary.

We found no significant nonair quality impacts or energy requirements associated with option 1 (the CTG-based option). We are soliciting data, information, analysis, and other input with respect to the energy and other impacts that are presented in the Costs/Impacts memorandum, available in the docket for this action.

5. Option 2, ACT-Based Formulation

To evaluate the ACT-based option, the EPA is using an emission limit of 0.72 kg VOC/l (6.0 lb VOC/gal) coating solids applied as the representative coating limit; this limit is derived from the 1994 ACT. In the 1994 ACT, under earlier-described Level 2, the VOC emission limit for primer is, upon conversion by calculation to the NSPS format, 0.43 kg VOC/l (3.6 lb VOC/gal) coating solids applied, and the VOC emission limit for color coat is, upon conversion by calculation to the NSPS format, 1.0 kg VOC/l (8.4 lb VOC/gal) coating solids applied, for an average equal to 0.72 kg VOC/l (6.0 lb VOC/gal) coating solids applied.

For option 2, the estimated reduction in VOC emissions per facility (model plant A) would be 11.8 Mg/yr (13.0 tpy), if option 2's representative coating comprised the entirety of the facility's 15,100 l/yr (4,000 gal/yr) of coating solids deposited. Option 2 (the ACT-based option) represents a more stringent level of VOC emission control than the 1988 NSPS and what is demonstrated in practice by any of the three sources actively engaged in surface coating of plastic parts for business machines. The EPA reviewed compliance demonstration records collected from two active sources and coating manufacturers' Environmental Data Sheets for coatings that are marketed to operations that perform surface coating of plastic parts for business machines and that are representative of products in use for that purpose. The EPA then used the VOC content values (in the format of lb VOC/gal of coating, less water and exempt solvents) to calculate, in the format of the NSPS, a conservatively low VOC emission rate for each coating (13 unique coatings), assuming a TE of 0.40 (the higher of the NSPS default TE values). Comparing those calculated emission rates to the VOC emission limits at the option 2 (ACT-based) level of control, we found that all but four of the coatings would be able to achieve the option 2 level of control without reformulation.[24] Only one of the 13 coatings could achieve the option 2 level of control without reformulation, if applied using a conventional air-atomized spray gun (for which the default TE is 0.25). For compliance with the option 2 level of control, the EPA has estimated an annualized cost of $29,300 per reformulation and assumes that one facility (model plant A) would bear the cost of reformulation of one product among each of four coating types, totaling $117,306 per year. On that basis, the EPA estimates the cost effectiveness of option 2 (the ACT-based option) for the representative coating to be $9,024/ton VOC reduction. Thus, we propose to determine that this ACT-based option is not as cost effective as the CTG-based option. We found no significant nonair quality impacts or energy requirements associated with this option. We are soliciting data, information, analysis, and other input with respect to the energy and other impacts that are presented in the Costs/Impacts memorandum, available in the docket for this action.

6. Option 3, Regenerative Thermal Oxidizer

In addition to the BSER evaluation of transfer efficiency and coating formulation described in earlier sections of this preamble, in our NSPS review we evaluated whether there are add-on controls that could be considered the BSER for this source category. As an initial point, none of the three sources that currently perform surface coating of plastic parts for business machines use add-on controls to comply with NSPS subpart TTT. Nonetheless, we evaluated add-on controls because they are available, are adequately demonstrated in surface coatings operations more generally, and can in practice achieve emission reductions beyond those required by the current standards.

Under this option, the EPA estimates, the RTO would remove approximately 95 percent of the 80 percent of total VOC emissions that are estimated to enter the spray booth exhaust due to coating operations. The estimated reduction in VOC emissions per source (model plant A) would be 20.7 Mg/yr (22.8 tpy). The EPA used a publicly available tool to estimate cost effectiveness of the RTO option to be $6,299/ton VOC reduction. The incremental cost effectiveness of this option compared to option 2 (the ACT-based option) was estimated to be $2,725/ton of VOC reduced less than

[23] See explanation in 1986 proposed NSPS (51 FR 854 at 862 and 864) as to why NSPS subpart TTT treats fog coating as a type of color coating.

[24] EPA. *Costs/Impacts memorandum.*

option 2. The cost-effectiveness analysis indicates that add-on controls, when compared to reformulation, can achieve a greater reduction at a lower cost. As described in the Costs/Impacts memorandum, available in the docket for this action, we estimated a $917,808 total capital investment cost per source associated with the RTO option. However, we expect that a new source smaller than that represented by model plant A would achieve a smaller mass reduction in VOC, which would increase the cost effectiveness value beyond $6,299/ton VOC reduction.

As required by CAA section 111, the EPA evaluated the nonair quality health and environmental impacts and energy requirements associated with the add-on control option. Indirect or secondary air emissions impacts are impacts that would result from the increased electricity usage and natural gas consumption associated with the operation of control devices to meet the proposed NSPS subpart TTTa. To evaluate this RTO option, these impacts were calculated on a per source basis and were based on model plant A. The energy impacts associated with the electricity and natural gas consumption associated with the operation of an RTO to control VOC emissions from the spray booth to meet proposed NSPS subpart TTTa include an estimated average electricity consumption of 93,700 kilowatt-hours per year per source and an estimated average natural gas consumption of 3,149 thousand standard cubic feet (mscf) per year per source compared to that of the current NSPS subpart TTT. For the RTO option, we estimated a greenhouse gas (GHG) impact (GHG emissions production) on a per source basis to be 167 Mg carbon dioxide equivalent. We are soliciting data, information, analysis, and other input with respect to the energy requirements and other impacts presented here. Additional detailed information is provided in the Costs/Impacts memorandum, available in the docket for this action.

Of the options evaluated, the RTO option provides for greater VOC emission reductions than the coating formulation options; however, there are secondary impacts associated with the RTO option (impacts that would result from the increased electricity usage and natural gas consumption associated with the operation of control devices). Regarding cost effectiveness, as described in the Costs/Impacts memorandum, available in the docket for this action, the estimated RTO cost effectiveness value of $6,299/ton VOC reduction, was calculated using the annual emissions attributed to model plant A (27.2 Mg, or 30 tons). The annual emission rate for model plant A is closer to the potential emissions than to the actual emissions of the three sources that are currently subject to NSPS subpart TTT. In addition, we expect that a new source would be smaller than that represented by model plant A and have lower VOC concentration which will lead to higher $/ton value than the one estimated for Option 3.

Even though no VOC concentration data are available for any of the three active sources, a new source—especially if smaller than that represented by model plant A—could produce a VOC concentration in the spray booth exhaust lower than the value used for model plant A *i.e.,* 167 parts per million by volume (ppmv). As can be calculated using the EPA Air Pollution Control Cost Manual spreadsheet for incinerators and oxidizers (see Cost/Impacts memorandum for additional information), control of a lower VOC concentration through use of an RTO would require more auxiliary fuel and electricity than what was accounted for in our cost effectiveness value for the RTO option. On that basis, we can expect a cost effectiveness value beyond $6,299/ton VOC reduction for new sources smaller than the model plant. Given the uncertainty of the cost effectiveness value, we are not recommending the RTO option as the BSER.

7. Summary of Regulatory Options and Proposed Determination of BSER

For the three regulatory options that the EPA identified and evaluated in this NSPS review (described earlier in this preamble), the EPA compared costs and emission reductions to the baseline of the requirements in the 1988 NSPS subpart TTT. The EPA calculated costs and emission reductions (and cost effectiveness) based on model plant A. See table 1, Baseline and Regulatory Options Evaluated for New, Modified, or Reconstructed Sources after June 21, 2022.

TABLE 1—BASELINE AND REGULATORY OPTIONS EVALUATED FOR NEW, MODIFIED, OR RECONSTRUCTED SOURCES AFTER JUNE 21, 2022

Option evaluated	Representative coating limit for VOC	Estimated per-facility VOC emission reduction	Cost effectiveness, $/ton of VOC reduced
Baseline—Comply with VOC emission limits of 1988 NSPS.	1.5 kg VOC/l (13 lb VOC/gal) coating solids applied.	Not applicable	Not applicable.
Option 1—Comply with VOC emission limits based on 2008 CTG.	1.4 kg VOC/l (12 lb VOC/gal) coating solids applied.	1.5 Mg/yr (1.7 tpy)	$0 [Note 1].
Option 2—Comply with VOC emission limits based on 1994 ACT.	0.72 kg VOC/l (6.0 lb VOC/gal) coating solids applied.	11.8 Mg/yr (13.0 tpy)	$9,024.
Option 3—Employ add-on control (RTO) to reduce VOC emissions from spray booth.	Not applicable	20.7 Mg/yr (22.8 tpy)	$6,299.

Note 1: The EPA assumes this cost to be $0/ton based on the lack of cost data available and on our understanding of the availability of other low-VOC-content coatings.

The EPA assumes the cost effectiveness of option 1 (the CTG-based option) to be $0 per ton of VOC reduction, on expectation that new, modified, and reconstructed sources will be able to achieve that option's level of control entirely through use of currently available coating formulations at the same cost. We lack information sufficient to determine the incremental costs that sources may incur to make necessary substitutions of current coatings with lower-VOC-content coatings. However, we expect the costs to be minimal because we expect compliance can be achieved through substitution with reformulated coatings that are currently available. We recognize that there are aspects of coatings substitution for which we do not have cost comparison data. Multiple factors could affect both direct and indirect costs as well as coating performance; these include consideration of application method, durability, and color. We specifically solicit information on what factors may be relevant in evaluating the cost effectiveness of option 1 and any data available on these factors. Because the option 1 level of control, somewhat more stringent than that of the 1988 NSPS, is demonstrated in practice and is the most cost effective of all three regulatory options that the EPA evaluated, the EPA proposes to determine that option 1 represents the BSER and that the 2008 CTG's VOC emission limits for primer, topcoat, texture coat, and touch-up and repair represent the degree of emission limitation achievable through application of the BSER.

We are soliciting data, information, analysis, and other input with respect to the emission reductions, and the cost effectiveness identified for each of the regulatory options presented later in this preamble.

E. What are the proposed requirements for emissions from sources subject to the proposed NSPS subpart TTTa?

Based on the NSPS review and proposed determination presented in section IV.D, the EPA is proposing revised VOC emission limits for application of coatings onto plastic parts for business machines at affected facilities that commence construction, reconstruction, or modification after June 21, 2022. The proposed VOC emission limits reflect the EPA's preliminary determination that a combination of coating formulation and efficiency in application technology represents the updated BSER for surface coating of plastic parts for business machines. The proposed standard for NSPS subpart TTTa based on this updated BSER would limit VOC emissions from prime coating, color coating, texture coating, and touch-up coating to 1.4 kg VOC/l (12 lb VOC/gal) coating solids applied. Just as in subpart TTT, new subpart TTTa would treat fog coating as a type of color coating.

F. What compliance dates are we proposing?

Pursuant to CAA section 111(b)(1)(B), the effective date of the final rule requirements in NSPS subparts TTT and TTTa will be the promulgation date. Affected sources that commence construction, or reconstruction, or modification after June 21, 2022 must comply with all requirements of the subpart TTTa, no later than the effective date of the final rule or upon startup, whichever is later.

Affected facilities for which construction, modification, or reconstruction began on or after January 8, 1986, but on or before June 21, 2022 would continue to comply with the applicable standards under the NSPS in 40 CFR part 60 subpart TTT.

G. What other actions are we proposing, and what is the rationale for those actions?

1. Testing Requirements

In performing an NSPS review, the EPA also evaluates and determines the proper testing, monitoring, recordkeeping, and reporting requirements needed to ensure compliance with the emission standards. The NSPS at 40 CFR 60 subpart TTT lists EPA Method 24 as the method for determination of VOC content of each coating as received. In the alternative, 40 CFR 60.725 allows use of ''other methods . . . to determine the VOC content of each coating if approved by the Administrator before testing.'' In performing this NSPS review, we looked at whether there are voluntary consensus standards (VCS) available and practical for use as alternatives to EPA Method 24 for industrial surface coating of plastic parts for business machines. The results of our VCS search are provided in the memorandum *Voluntary Consensus Standard Results for New Source Performance Standards Review for Industrial Surface Coating of Plastic Parts for Business Machines,* which is available in the docket for this action. The complete list of acceptable VCS is listed in section VIII.I. of this preamble, and the VCS that we propose to incorporate by reference (IBR) under 40 CFR 60.17 as potential alternatives to EPA Method 24 are listed in section VII of this preamble. These changes are proposed for use with NSPS subparts TTT and TTTa.

2. Electronic Submission of Reports

The EPA is proposing that owners or operators of facilities that perform surface coating of plastic parts for business machines subject to the NSPS at 40 CFR part 60, subpart TTT, submit electronic copies of required performance test reports, quarterly reports of noncompliance, and semiannual statements of compliance, through the EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI). 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. The proposed rule requires that the performance test reports, quarterly reports of noncompliance, and semiannual statements of compliance be submitted as a portable document format (PDF) upload in CEDRI. The same requirements are being proposed in subpart TTTa. The proposed requirements would apply to all affected facilities that commence construction, modification, or reconstruction after January 8, 1986 (*i.e.,* all affected facilities under both subpart TTT and proposed subpart TTTa).

Additionally, the EPA has identified two broad circumstances in which extensions to the electronic submission of reports may be provided. These circumstances are (1) outages of the EPA's CDX or CEDRI which preclude an owner or operator from accessing the system and submitting required reports and (2) *force majeure* events, which are defined as events that will be or have been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevent an owner or operator from complying with the requirement to submit a report electronically. Examples of *force majeure* events are acts of nature, acts of war or terrorism, or equipment failure or safety hazards beyond the control of the facility. The EPA is providing these potential extensions to protect owners or operators from noncompliance in cases where they cannot successfully submit a report by the reporting deadline for reasons outside of their control. In both circumstances, the decision to accept the claim of needing additional time to report is within the discretion of the Administrator, and reporting should occur as soon as possible.

The electronic submittal of the reports addressed in this proposed rulemaking will increase the usefulness of the data contained in those reports, is in keeping with current trends in data availability and transparency, will further assist in the protection of public health and the environment, will improve compliance by facilitating the ability of regulated facilities to demonstrate compliance with requirements and by facilitating the ability of delegated state, local, tribal, and territorial air agencies and the EPA to assess and determine compliance, and will ultimately reduce burden on regulated facilities, delegated air agencies, and the EPA. Electronic submission of reports also eliminates 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 submission of reports is consistent with the EPA's plan [25] to implement Executive Order 13563 and is in keeping with the EPA's Agency-wide policy [26] developed in response to the White House's Digital Government Strategy.[27] For more information on the benefits of electronic submission of reports, see the memorandum *Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules,* referenced earlier in this section.

3. Startup, Shutdown, and Malfunction (SSM)

In its 2008 decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. Specifically, the court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), holding that under section 302(k) of the CAA, emissions standards or limitations must be continuous in nature and that the SSM exemption violates the CAA's requirement that some section 112 standards apply continuously. Consistent with *Sierra Club* v. *EPA,* we are proposing standards in this rule that apply at all times. The NSPS general provisions in 40 CFR 60.8(c) currently exempt non-opacity emission standards during periods of SSM. We are proposing that new NSPS subpart TTTa include specific requirements at 40 CFR 60.723a(c) that override the general provisions with respect to SSM. This proposal would make all standards in subpart TTTa apply at all times. These proposed requirements would apply to all affected facilities that commence construction, modification, or reconstruction after June 21, 2022.

The EPA has attempted to ensure that the general provisions we are proposing to override are inappropriate, unnecessary, or redundant in the absence of the SSM exemption. We are specifically seeking comment on whether we have successfully done so.

In proposing the standards in this rule, the EPA has taken into account startup and shutdown periods and, for the reasons explained below, has not proposed alternate standards for those periods. The primary means of controlling VOC emissions from surface coating of plastic parts for business machines is use of low-VOC-content coatings. This means of control is unaffected by startup and shutdown events.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. Malfunctions, in contrast, are neither predictable nor routine. Instead, they are, by definition, sudden, infrequent, and not reasonably preventable failures of emissions control, process, or monitoring equipment. (40 CFR 60.2). The EPA interprets CAA section 111 as not requiring emissions that occur during periods of malfunction to be factored into development of CAA section 111 standards. Nothing in CAA section 111 or in case law requires that the EPA consider malfunctions when determining what standards of performance reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated. While the EPA accounts for variability in setting emissions standards, nothing in CAA section 111 requires the Agency to consider malfunctions as part of that analysis. The EPA is not required to treat a malfunction in the same manner as the type of variation in performance that occurs during routine operations of a source. A malfunction is a failure of the source to perform in a ''normal or usual manner'' and no statutory language compels EPA to consider such events in setting CAA section 111 standards of performance. The EPA's approach to malfunctions in the analogous circumstances (setting ''achievable'' standards under CAA section 112) has been upheld as reasonable by the D.C. Circuit in *U.S. Sugar Corp.* v. *EPA,* 830 F.3d 579, 606–610 (D.C. Cir. 2016).

4. Definition of Business Machine

The EPA proposes to keep the definition of ''business machine'' that appears in subpart TTT, 40 CFR 60.721, except to make certain revisions to the list of example products included within the definition. Specifically, the EPA is proposing to delete the listed Standard Industrial Classification (SIC) codes, which are no longer in use, and replace the current list of example products that accompanied those SIC codes with a revised list of examples, as follows: ''such as products classified as: electronic computing devices; calculating and accounting machines; telephone equipment; office machines; and photocopy machines.'' Among example products that the EPA proposes to delete from the definition are typewriters and telegraph equipment, in light of the fact that these machines are far less commonly used than when this definition was first promulgated in 1988. The EPA's current view is that to provide examples is helpful to the general reader but we are also considering whether we could instead simply delete from the definition the ''such as'' list of example business machine products altogether, and we welcome comments on that.

The EPA considered revising the definition to substitute the outdated SIC codes with the latest NAICS codes. However, upon comparison, we found no crosswalk between those SIC codes and suggested NAICS codes that would be helpful toward updating the definition of ''business machine.'' The surface coating of plastic parts for business machines source category focuses on a process rather than on some clearly delineated industry making specific business machines. As was noted in the 1985 BID (pp. 9–1 to 9–2), it is difficult to analyze the surface coating of plastic parts for business machines as an industry unto itself. First, the surface coating of plastic parts for business machines represents an intermediate step in the production of business machines. Second, these surface coating operations are not classified within the representative industries. Third, it appears that individual existing markets are so small and specialized that publicly available data on them do not exist.

The EPA wishes to make clear that by changing the list of example business machine products, the EPA would not be changing the scope of the applicability of the current NSPS. The proposed revisions are intended to keep the meaning and intent of the definition as originally promulgated while allowing the definition to reflect changes in the business machines that are commonly used subsequent to the promulgation of subpart TTT in 1988. The same clarifications are being proposed in subpart TTTa. None of these amendments would increase the cost of the rule or result in a change in VOC emissions.

[25] *EPA's Final Plan for Periodic Retrospective Reviews,* August 2011. Available at: *https://www.regulations.gov/document?D=EPA-HQ-OA-2011-0156-0154.*

[26] *E-Reporting Policy Statement for EPA Regulations,* September 2013. Available at: *https://www.epa.gov/sites/default/files/2016-03/documents/epa-ereporting-policy-statement-2013-09-30.pdf.*

[27] *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.*

The EPA solicits comment on the proposed revisions to the definition of ''business machine,'' in particular on the proposed revised list of example business machine products. The EPA also solicits suggestions for additional examples to include in the definition. For example, in the 1994 ACT, plastic housings for medical equipment are among example surface-coated plastic parts for business machines.'' [28]

V. Summary of Cost, Environmental, and Economic Impacts

A. What are the air quality impacts?

Based on the EPA's expectation that there will be no new, modified, or reconstructed sources over the next 8 years, we estimate that there will be no reduction in VOC emissions from proposed NSPS subpart TTTa. If a new source were to be constructed, however, there would be a reduction in VOC emissions, because the subpart TTTa emission limits being proposed would be more stringent than the subpart TTT emission limits. There would be no emission control cost associated with that hypothetical emission reduction because compliance with the subpart TTTa emission limits can be achieved through use of low-VOC-content coatings that are commercially available. As described in section IV.D.3 of this preamble, as the baseline level of control for the BSER analysis, the EPA used an emission limit of 1.5 kg VOC/l (13 lb VOC/gal) coating solids applied as the representative coating limit. In the 1988 NSPS, the VOC emission limit both for prime coating and for color coating is 1.5 kg VOC/l (13 lb VOC/gal) coating solids applied. For two other coatings—texture coatings and touch-up coatings—the VOC emission limits in the 1988 NSPS are less stringent, at 2.3 kg VOC/l (19 lb VOC/gal) coating solids applied. Therefore, the potential reduction in VOC emissions to result from proposed NSPS subpart TTTa is even greater than was calculated using the representative coating limit for purposes of the BSER analysis in this NSPS review.

Because we do not anticipate that any source will operate a control device to meet proposed NSPS subpart TTTa, we anticipate no energy impacts (electricity, natural gas consumption, GHG emissions production) or air quality impacts from the proposed NSPS subpart TTTa.

B. What are the cost impacts?

Based on the EPA's expectation that there will be no new, modified, or reconstructed sources over the next 8 years, we estimate that there will be no capital or annual costs incurred to comply with the proposed NSPS subpart TTTa in the 8-year period after the rule is final.

We anticipate minimal cost impacts on sources subject to NSPS subpart TTT. The EPA estimates a total cost of $828 ($276 per source), for sources subject to subpart TTT to become familiar with the CDX and CEDRI systems used to comply with the requirement to submit reports electronically. The labor costs (2 hours per source) would occur only in the first year following promulgation of the amendments to NSPS subpart TTT.

C. What are the economic impacts?

The EPA conducted an economic impact analysis for this proposal, as detailed in the memorandum *Economic Impact Analysis for the Proposed New Source Performance Standards Review for Industrial Surface Coating of Plastic Parts for Business Machines,* which is available in the docket for this action.

The economic impacts of this proposed rule are expected to be minimal. The only incremental costs are associated with the proposed electronic report submission requirements for three existing facilities affected by subpart TTT. The EPA estimates total costs for this proposed rule of $828 in 2021 dollars, which will be incurred in the first year following promulgation of the rule. No other costs are expected in the 8 years following promulgation of this proposal other than these Year 1 costs. Since the estimated compliance costs are minimal, this proposed rule is not expected to result in market impacts, regardless of whether costs are passed on to consumers or absorbed by affected firms.

Two of the three facilities affected by this proposed rule are owned by small entities. However, neither small entity is expected to incur significant cost impacts based on a comparison of the Year 1 facility-level compliance costs to the annual sales revenues (*i.e.,* cost-to-sales ratios) of the two small parent companies. Thus, this proposed rule will not have a significant economic impact on a substantial number of small entities.

D. What are the benefits?

The proposed requirements in subpart TTT and new subpart TTTa to submit reports and test results electronically will improve monitoring, compliance, and implementation of the rule. Based on the EPA's expectation that there will be no new, modified, or reconstructed sources over the next 8 years, we estimate that there will be no reduction in VOC emissions from proposed NSPS subpart TTTa. If a new source were to be constructed, however, there would be a reduction in VOC emissions, because the subpart TTTa emission limits would be more stringent than the subpart TTT emission limits.

Reducing emissions of VOC is expected to help reduce ambient concentrations of ground level ozone and increase compliance with the National Ambient Air Quality Standards (NAAQS) for ozone. A quantitative analysis of the impacts on the NAAQS in the areas located near hypothetical new sources that perform surface coating of plastic parts for business machines would be technically complicated, resource intensive, and infeasible to perform in the time available, and would not represent the impacts for new, modified, and reconstructed affected facilities because the locations of those sources are currently unknown. For these reasons, we did not perform a quantitative analysis. However, currently available health effects evidence supporting the December 23, 2020, final decision for the ozone NAAQS continues to support the conclusion that ozone can cause difficulty breathing and other respiratory system effects. For people with asthma, these effects can lead to emergency room visits and hospital admissions. Exposure over the long term may lead to the development of asthma. People most at risk from breathing air containing ozone include people with asthma, children, the elderly, and outdoor workers. For children, exposure to ozone increases their risk of asthma attacks while playing, exercising, or engaging in strenuous activities outdoors.

VI. Request for Comments

We solicit comments on all aspects of this proposed action. Comments on the proposed emission limits, cost effectiveness estimates, and other impacts in this proposed action should be accompanied by data to support the comment. We are specifically interested in receiving information related to developments in practices, processes, and control technologies that reduce VOC emissions from owners or operators of facilities that perform surface coating of plastic parts for business machines and any other interested persons with such information.

VII. Incorporation by Reference

The EPA proposes to amend the 40 CFR 60.17 to incorporate by reference the following VCS:

[28] 1994 ACT, p. 2–1.

- ASTM D2369–20, ''Standard Test Method for Volatile Content of Coatings'' is a test method that allows for more accurate results for multi-component chemical resistant coatings and is proposed as an alternative to EPA Method 24.
- ASTM D2697–03 (Reapproved 2014), ''Standard Test Method for Volume Nonvolatile Matter in Clear or Pigmented Coatings'' is a test method that can be used to determine the volume of nonvolatile matter in clear and pigmented coatings and is proposed as an alternative to EPA Method 24.
- ASTM D6093–97 (Reapproved 2016) ''Standard Test Method for Percent Volume Nonvolatile Matter in Clear or Pigmented Coatings Using a Helium Gas Pycnometer'' is a test method that can be used to determine the percent volume of nonvolatile matter in clear and pigmented coatings and is proposed as an alternative to EPA Method 24.

We also identified VCS ASTM D2111–10 (2015), ''Standard Test Methods for Specific Gravity of Halogenated Organic Solvents and Their Admixtures'' as an acceptable alternative to EPA Method 24. This ASTM standard can be used to determine the density for the specific coatings (halogenated organic solvents) cited using Method B (pycnometer) only (as in ASTM 1217). We are not proposing this VCS because facilities that perform surface coating of plastic parts for business machines do not use halogenated organic solvents, based on our knowledge of the industry.

The ASTM standards are available from ASTM, International (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959. See *https://www.astm.org.*

VIII. Statutory and Executive Order Reviews

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

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

This action is a significant regulatory action that was submitted to OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an economic impact analysis (EIA) of the potential costs and benefits associated with this action. This analysis is available in the docket.

B. Paperwork Reduction Act (PRA)

The information collection activities in this proposed rule have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document, under OMB Control Number 2060–0162, has been assigned EPA ICR number 1093.14. You can find a copy of the ICR in the docket for this action (Docket ID No. EPA–HQ–OAR–2021–0200), and it is briefly summarized here. The ICR is specific to information collection associated with the source category referred to as surface coating of plastic parts for business machines, through 40 CFR part 60, subpart TTT and subpart TTTa.

As part of the NSPS review, the EPA is proposing emission limit requirements for new, modified, and reconstructed sources in 40 CFR part 60, subpart TTTa. We are also proposing testing, recordkeeping, and reporting requirements associated with 40 CFR part 60, subpart TTTa, that include the requirement for electronic submittal of reports. Further, we are proposing changes to the reporting requirements associated with 40 CFR part 60, subpart TTT, by including the requirement for electronic submittal of reports. This information is being collected to assure compliance with 40 CFR part 60, subpart TTT and subpart TTTa.

Respondents/affected entities: The respondents to the recordkeeping and reporting requirements are owners or operators of facilities performing surface coating of plastic parts for business machines subject to 40 CFR part 60, subpart TTT and subpart TTTa.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart TTT and subpart TTTa).

Estimated number of respondents: In the 3 years after the amendments are final, approximately 3 respondents per year will be subject to the NSPS at 40 CFR part 60, subpart TTT, and approximately 0 respondents per year will be subject to the NSPS as 40 CFR part 60, subpart TTTa.

Frequency of response: The frequency of responses varies depending on the burden item. Responses include onetime review of rule requirements, reports of performance tests, quarterly reports of noncompliance, and semiannual statements of compliance.

Total estimated burden: The annual recordkeeping and reporting burden for responding facilities to comply with all of the requirements in the NSPS subpart TTT and NSPS subpart TTTa over the 3 years after the rule is final is estimated to be 2 hours (per year). The average annual burden to the Agency over the 3 years after the rule is final is estimated to be 0 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: The average annual cost to facilities that perform surface coating of plastic parts for business machines is $276 in labor costs in the first 3 years after the rule is final. The average annual capital and operation and maintenance cost is $0. The total average annual Agency cost over the first 3 years after the amendments are final is estimated to be $0.

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

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to *OIRA_submission@omb.eop.gov,* Attention: Desk Officer for the EPA. Because OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than August 22, 2022. The EPA will respond to any ICR-related comments in the final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. Details of this analysis are presented in the memorandum *Economic Impact Analysis for the Proposed New Source Performance Standards Review for Industrial Surface Coating of Plastic Parts for Business Machines,* which is available in the docket for this action. The annualized costs associated with the requirements in this action for the affected small entities are described in section V.C. above.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. While this action creates an enforceable duty on the private sector, the cost does not exceed $100 million or more.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

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

This action does not have tribal implications as specified in Executive Order 13175. It will 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 Executive Order 13175 (65 FR 67249, November 9, 2000). No tribal facilities are known to be engaged in the industry that would be affected by this action nor are there any adverse health or environmental effects from this action. However, the EPA conducted a proximity analysis for this source category and found that one affected facility is located within 50 miles of Tribal lands. Consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA will offer 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 not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children.

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

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. Further, sources will be able to achieve the level of control in proposed NSPS subpart TTTa entirely through use of a variety of currently available coating formulations, without operation of a control device to meet the proposed standards.

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

This rulemaking involves technical standards. Therefore, the EPA conducted searches through the Enhanced NSSN Database managed by the American National Standards Institute (ANSI) to determine if there are VCS that are relevant to this action. The Agency also contacted VCS organizations and accessed and searched their databases. Searches were conducted for EPA Method 24.

During the search, if the title or abstract (if provided) of the VCS described technical sampling and analytical procedures that are similar to the EPA's reference method, the EPA considered it as a potential equivalent method. All potential standards were reviewed to determine the practicality of the VCS for this rule. This review requires significant method validation data which meets the requirements of the EPA Method 301 for accepting alternative methods or scientific, engineering and policy equivalence to procedures in the EPA reference methods. The EPA may reconsider determinations of impracticality when additional information is available for particular VCS. As a result, the EPA identified the following as acceptable VCS:

• ASTM D2369–20, ''Standard Test Method for Volatile Content of Coatings'' as an alternative to EPA Method 24.

• ASTM Method D2697–03 (Reapproved 2014), ''Standard Test Method for Volume Nonvolatile Matter in Clear or Pigmented Coatings'' as an alternative to EPA Method 24.

• ASTM Method D6093–97 (Reapproved 2016) ''Standard Test Method for Percent Volume Nonvolatile Matter in Clear or Pigmented Coatings Using a Helium Gas Pycnometer'' as an alternative to EPA Method 24.

• ASTM D2111–10 (2015), ''Standard Test Methods for Specific Gravity of Halogenated Organic Solvents and Their Admixtures'' as an acceptable alternative to EPA Method 24. This ASTM standard can be used to determine the density for the specific coatings (halogenated organic solvents) cited using Method B (pycnometer) only (as in ASTM 1217).

The ASTM standards (methods) are available for purchase individually through the American National Standards Institute (ANSI) Webstore, *https://webstore.ansi.org.* Telephone (212) 642–4980 for customer service.

Additional information for the VCS search and determinations can be found in the memorandum *Voluntary Consensus Standard Results for New Source Performance Standards Review for Industrial Surface Coating of Plastic Parts for Business Machines,* which is available in the docket for this action.

Under 40 CFR 60.8(b) and 60.13(i) of subpart A of the General Provisions, a source may apply to the EPA to use alternative test methods or alternative monitoring requirements in place of any required testing methods, performance specifications or procedures in the final rule or any amendments. The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially applicable VCS and to explain why such standards should be used in this regulation.

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

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).

We performed a demographic analysis for the surface coating of plastic parts for business machines source category, which is an assessment of the proximity of individual demographic groups living close to the facilities (within 50 km and within 5 km). Results of the demographic analysis indicate representation within 5 km of existing facilities of one group above the national average: People without a High School Diploma.

Following the directives set forth in multiple Executive Orders, the Agency has carefully analyzed the impacts of this action on communities with EJ concerns. For Surface Coating of Plastic Parts for Business Machines facilities, the proximity demographic analysis of the three existing sources subject to NSPS subpart TTT shows that key demographic indicators for the populations around these facilities (such as the proportion of residents who are low-income or people of color) are similar to or lower than the national average. Based on the EPA's determination that there will be no new, modified, or reconstructed sources over the next 8 years, we estimate that there will be no reduction in VOC emissions from proposed NSPS subpart TTTa and no EJ impacts. If a new source were to be constructed at a future date, the new emission limits proposed for NSPS subpart TTTa reflect the BSER demonstrated and establish a new more stringent standard of performance for the primary sources of VOC emissions from the source category. Thus, if a source were to be constructed, modified, or reconstructed, the EPA expects the proposed requirements in subpart TTT will result in VOC emission reductions for communities surrounding the affected subpart TTTa sources compared to the existing rule in subpart TTT and will result in lower VOC emissions for communities located in areas designated as ozone non-attainment areas. These areas are already overburdened by pollution.

Executive Order 12898 directs the EPA to identify the populations of concern who are most likely to experience unequal burdens from environmental harms; specifically, minority populations (*i.e.,* people of color), low-income populations, and indigenous peoples (59 FR 7629, February 16, 1994). Additionally, Executive Order 13985 is intended to advance racial equity and support underserved communities through federal government actions (86 FR 7009, January 20, 2021). The EPA defines 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.'' [29] The EPA further defines fair treatment to 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.'' 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.

This action proposes standards of performance for new, modified, and reconstructed sources that commence construction after the rule is proposed. Therefore, the future locations of the new sources at Surface Coating of Plastic Parts for Business Machines facilities are not known. In addition, it is not known which of the existing Surface Coating of Plastic Parts for Business Machines facilities will modify or reconstruct in the future. Therefore, the proximity demographic analysis was conducted for the three existing facilities to characterize the demographics in areas where the facilities are currently located.

To examine the potential for any EJ issues that might be associated with Surface Coating of Plastic Parts for Business Machines facilities, a demographic analysis assessed the individual demographic groups of the populations living within 5 kilometers (km) and 50 km of the three existing facilities. The EPA then compared the data from this analysis to the national average for each of the demographic groups.

The results of the demographic analysis (see Table 2) indicate that, for populations within 5 km of existing Surface Coating of Plastic Parts for Business Machines facilities, the percent of the population that are people of color (calculated as the total population minus the white population) is significantly lower than the national average (23 percent versus 40 percent). All demographic subgroups within people of color are also below the corresponding national averages. The percent of people living below the poverty level (10 percent) is below the national average (13 percent). The percent of the population that is over 25 without a high school diploma (13 percent) and those living in linguistic isolation (5 percent) were similar to the corresponding national averages (12 percent and 5 percent, respectively).

The results of the analysis of populations within 50 km of the three existing Surface Coating of Plastic Parts for Business Machines facilities are shown in Table 2. The percent of the population that are people of color (calculated as the total population minus the white population) is significantly lower than the national average (29 percent versus 40 percent). However, the percent of the population that is African American (17 percent) is higher than the national average (12 percent). All other demographic subgroups within people of color are below the corresponding national averages. The percent of people living below the poverty level (14 percent) is slightly above the national average (13 percent). The percent of the population that is over 25 without a high school diploma (10 percent) and those living in linguistic isolation (2 percent) were below the corresponding national averages (12 percent and 5 percent, respectively).

A summary of the proximity demographic assessment performed for the three existing Surface Coating of Plastic Parts for Business Machines facilities is included as Table 2. The methodology and the results of the demographic analysis are presented in a technical report, *Analysis of Demographic Factors for Populations Living Near Surface Coating of Plastic Parts for Business Machines,* available in this docket for this action (Docket EPA–HQ–OAR–2021–0200).

TABLE 2—PROXIMITY DEMOGRAPHIC ASSESSMENT RESULTS FOR SURFACE COATING OF PLASTIC PARTS FOR BUSINESS MACHINES NSPS SOURCE CATEGORY OPERATIONS *

Demographic group	Nationwide	Population within 50 km of 3 existing facilities	Population within 5 km of 3 existing facilities
Total Population	328,016,242	2,979,558	79,323
	White and People of Color by Percent		
White	60	71	77
People of Color	40	29	23
	People of Color by Percent		
African American	12	17	2
Native American	0.7	0.4	0.2
Hispanic or Latino (includes white and nonwhite)	19	6	14

[29] See *https://www.epa.gov/environmentaljustice.*

TABLE 2—PROXIMITY DEMOGRAPHIC ASSESSMENT RESULTS FOR SURFACE COATING OF PLASTIC PARTS FOR BUSINESS MACHINES NSPS SOURCE CATEGORY OPERATIONS *—Continued

Demographic group	Nationwide	Population within 50 km of 3 existing facilities	Population within 5 km of 3 existing facilities
Other and Multiracial	8	5	7
	Income by Percent		
Below Poverty Level	13	14	10
Above Poverty Level	87	86	90
	Education by Percent		
Over 25 and without a High School Diploma	12	10	13
Over 25 and with a High School Diploma	88	90	87
	Linguistically Isolated by Percent		
Linguistically Isolated	5	2	5

Notes:
- The nationwide population count and all demographic percentages are based on the Census' 2015–2019 American Community Survey five-year block group averages and include Puerto Rico. Demographic percentages based on different averages may differ. The total population counts within 5 km and 50 km of all facilities are based on the 2010 Decennial Census block populations.
- People of Color population is the total population minus the white population.
- To avoid double counting, the ''Hispanic or Latino'' category is treated as a distinct demographic category for these analyses. A person is identified as one of five racial/ethnic categories above: White, African American, Native American, Other and Multiracial, or Hispanic/Latino. A person who identifies as Hispanic or Latino is counted as Hispanic/Latino for this analysis, regardless of what race this person may have also identified as in the Census.

* This action proposes standards of performance for new, modified, and reconstructed sources that commence construction after the rule is proposed. Therefore, the locations of the construction of new Surface Coating of Plastic Parts for Business Machines facilities are not known. In addition, it is not known which of the existing Surface Coating of Plastic Parts for Business Machines facilities will be modified or reconstructed in the future. Therefore, the demographic analysis was conducted for the 3 existing facilities as a characterization of the demographics in areas where these facilities are now located.

Michael S. Regan,

Administrator.

[FR Doc. 2022–12250 Filed 6–17–22; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 1

[MD Docket No. 21–190; MD Docket No. 22–223; FCC 22–39; FR ID 91190]

Assessment and Collection of Regulatory Fees for Fiscal Year 2022

AGENCY: Federal Communications Commission.

ACTION: Notification of amendment.

SUMMARY: The Federal Communications Commission released a Report and Order and Notice of Proposed Rulemaking in June 2022. The Commission has corrected that document.

DATES: June 21, 2022.

ADDRESSES: The June document is available at *https://www.fcc.gov/document/fy-2022-regulatory-fees-notice-proposed-rulemaking.* To request materials in accessible formats for people with disabilities, email *FCC504@fcc.gov* or call the Consumer & Governmental Affairs Bureau at (202) 418–0530 (voice), (202) 418–0432 (TTY).

FOR FURTHER INFORMATION CONTACT: Roland Helvajian, Office of Managing Director at (202) 418–0444.

SUPPLEMENTARY INFORMATION: On June 2, 2022, the Federal Communications Commission released a Report and Order and Notice of Proposed Rulemaking (Report and Order), FCC 22–39, in the above captioned proceeding. The Report and Order has not been published in the **Federal Register** and is available at *https://www.fcc.gov/document/fy-2022-regulatory-fees-notice-proposed-rulemaking.* To request materials in accessible formats for people with disabilities, email *FCC504@fcc.gov* or call the Consumer & Governmental Affairs Bureau at (202) 418–0530 (voice), (202) 418–0432 (TTY). The Commission corrects the date ''August 31, 2022'' in paragraph 72 of the Ordering Clause to read ''September 1, 2022.''

Federal Communications Commission.

Marlene Dortch,

Secretary.

[FR Doc. 2022–12812 Filed 6–17–22; 8:45 am]

BILLING CODE 6712–01–P

Notices

Federal Register

Vol. 87, No. 118

Tuesday, June 21, 2022

DEPARTMENT OF AGRICULTURE

Farm Service Agency

[Docket ID FSA–2021–0013]

Notice of Funds Availability (NOFA) for the Food Safety Certification for Specialty Crops Program

AGENCY: Commodity Credit Corporation, Farm Service Agency, Department of Agriculture (USDA).

ACTION: Notification of fund availability.

SUMMARY: The Farm Service Agency (FSA) is announcing the availability of $200 million through the new Food Safety Certification for Specialty Crops Program (FSCSC) for specialty crop operations that incur eligible on-farm food safety program expenses to obtain or renew a food safety certification in calendar years 2022 or 2023. To be eligible for assistance with expenses related to a 2022 food safety certification, the certification must have been issued on or after June 21, 2022. Specialty crop operations incur significant costs to comply with regulatory requirements and market-driven food safety certification requirements each year with little opportunity to recover the increased costs. In this document, FSA is providing the eligibility requirements, application process, and payment calculation for FSCSC.

DATES:

Funding availability: Implementation will begin June 27, 2022.

Comments Due Date: We will consider comments on the information collection request discussed in the Paperwork Reduction Act section that we receive by: August 22, 2022.

ADDRESSES: We invite you to submit comments on the information collection request. You may submit comments using any of the following methods, although FSA prefers that you submit comments electronically through the Federal eRulemaking Portal:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov* and search for Docket ID FSA–2021–0013. Follow the online instructions for submitting comments.
- *Mail, Hand-Delivery, or Courier:* Director, Safety Net Division, FSA, USDA, 1400 Independence Avenue SW, Stop 0510, Washington, DC 20250–0522. In your comment, specify the docket ID FSA–2021–0013.

All comments received, including those received by mail, will be posted without change and will be publicly available on *http://www.regulations.gov.* Copies of the information collection may be requested by contacting the above address.

FOR FURTHER INFORMATION CONTACT: Tona Huggins: (202) 720–7641; or by email: *tona.huggins@usda.gov.* Persons with disabilities who require alternative means for communication should contact the USDA Target Center at (202) 720–2600 (voice).

SUPPLEMENTARY INFORMATION:

Background

FSA, on behalf of CCC, is establishing FSCSC to assist specialty crop operations that incurred eligible on-farm food safety certification and related expenses in order to obtain or renew a:

- 2022 food safety certification issued between June 21, 2022 and December 30, 2022; or
- 2023 food safety certification issued at any time during the 2023 calendar year.

For each year, FSCSC will cover a portion of the specialty crop operation's cost of obtaining or renewing their certification, as well as a portion of their related costs as described in this NOFA.

Specialty crops intended for human consumption are subject to concerns about safety, particularly since specialty crops sold as raw agricultural commodities do not undergo a ''kill step'' like cooking, canning, or pasteurizing used for other agricultural commodities such as meat or dairy products. As a result, specialty crop operations face increasing demand from grocery stores, schools, and other institutional buyers and retailers to obtain certification through programs that address the safe growing, harvesting, packing, and holding of their crops. The need to develop, implement, and maintain on-farm food safety programs has resulted in additional costs for many specialty crop operations that seek alternate markets for their products due to changes in demand from traditional markets such as restaurants and food service. As they identify new markets, many specialty crop operations also find they need to undergo food safety audits and absorb the additional costs to achieve food safety certification through a private or government-based certification program in order to meet buyers' requirements to sell their products.

FSCSC funding of $200 million is provided through the CCC Charter Act, which authorizes CCC to increase the domestic consumption of agricultural commodities (other than tobacco) by expanding or aiding in the expansion of domestic markets or by developing or aiding in the development of new and additional markets, marketing facilities, and uses for such commodities (15 U.S.C. 714c(e)). FSCSC will aid in the expansion of domestic markets and development of new and additional markets by assisting specialty crop operations with costs that they incur to obtain or renew food safety certifications in order to comply with government and retail buyers' demands for food safety certification, ultimately expanding the markets available to those operations and increasing domestic consumption of specialty crops. To that end, only producers that successfully obtain or renew a food safety certification after publication of this notice are eligible to be compensated for a portion of the cost of that certification, as explained further below.

Definitions

The following definitions apply to this notice:

Beginning farmer or rancher means a farmer or rancher who has not operated a farm or ranch for more than 10 years and who materially and substantially participates in the operation. For a legal entity to be considered a beginning farmer or rancher, at least 50 percent of the ownership interest must be held by individuals who are beginning farmers or ranchers.

Certification upload fee means the fee paid by a specialty crop operation to upload reports and other documentation to a commercial database.

Certifier means either a private entity accredited for the purpose of providing food safety certification or a government-based certifier.

Deputy Administrator means the FSA Deputy Administrator for Farm Programs.

Food safety certification means certification that a specialty crop operation meets regulatory or market-driven food safety standards.

Food safety management system means a documented system developed by a group of specialty crop operations to obtain food safety certification, also referred to as a ''quality management system.''

FSMA means the FDA Food Safety Modernization Act (Pub. L. 111–353).

Food safety plan means a documented plan implemented by a specialty crop operation to obtain food safety certification.

Historically underserved farmer or rancher means a beginning farmer or rancher, limited resource farmer or rancher, socially disadvantaged farmer or rancher, or veteran farmer or rancher.

Limited resource farmer or rancher means a farmer or rancher who is both of the following:

(1) A person whose direct or indirect gross farm sales did not exceed:

(a) For the 2022 program year, $189,200 in each of the 2019 and 2020 calendar years; or

(b) For the 2023 program year, the amount identified through the Limited Resource Farmer and Rancher Online Self Determination Tool in each of the 2020 and 2021 calendar years; and

(2) A person whose total household income was at or below the national poverty level for a family of four in each of the same two previous years referenced in paragraph (1) of this definition.

For an entity to be considered a limited resource farmer or rancher, all members who hold an ownership interest in the entity must meet the criteria in paragraphs (1) and (2) of this definition. Limited resource farmer or rancher status can be determined using a website available through the Limited Resource Farmer and Rancher Online Self Determination Tool, which is available through the Natural Resources Conservation Service at *https://lrftool.sc.egov.usda.gov.* Producers may also contact their FSA county office for assistance.

Produce Safety Rule means the final rule titled ''Standards for the Growing, Harvesting, Packing, and Holding of Produce for Human Consumption'' published on November 27, 2015 (80 FR 74354–74568).

Program year means the calendar year in which the applicant's food safety certification is issued (that is, 2022 or 2023).

Raw agricultural commodity means any food in its raw or natural state, including all fruits that are washed, colored, or otherwise treated in their unpeeled natural form prior to marketing.

Small business means an applicant that had an average annual monetary value of specialty crops the applicant sold during the 3-year period preceding the program year of more than $250,000 but not more than $500,000.

Socially disadvantaged farmer or rancher means a farmer or rancher who is a member of a group whose members have been subjected to racial, ethnic, or gender prejudice because of their identity as members of a group without regard to their individual qualities. For entities, at least 50 percent of the ownership interest must be held by individuals who are members of such a group. Socially disadvantaged groups include the following and no others unless approved in writing by the Deputy Administrator:

(1) American Indians or Alaskan Natives;

(2) Asians or Asian-Americans;

(3) Blacks or African Americans;

(4) Hispanics or Hispanic Americans;

(5) Native Hawaiians or other Pacific Islanders; and

(6) Women.

Specialty crop means any fruit or vegetable (including mixes of intact fruits and vegetables) and includes mushrooms, sprouts (irrespective of seed source), tree nuts, and herbs. A fruit is the edible reproductive body of a seed plant or tree nut (such as apple, orange, and almond) such that fruit means the harvestable or harvested part of a plant developed from a flower. A vegetable is the edible part of an herbaceous plant (such as cabbage or potato) or fleshy fruiting body of a fungus (such as white button or shiitake) grown for an edible part such that vegetable means the harvestable or harvested part of any plant or fungus whose fruit, fleshy fruiting bodies, seeds, roots, tubers, bulbs, stems, leaves, or flower parts are used as food and includes mushrooms, sprouts, and herbs (such as basil or cilantro). ''Specialty crop'' does not include peanuts or food grains, meaning the small, hard fruits or seeds of arable crops, or the crops bearing these fruits or seeds, which are primarily grown and processed for use as meal, flour, baked goods, cereals, and oils rather than for direct consumption as small, hard fruits or seeds (including cereal grains, pseudo cereals, oilseeds, and other plants used in the same fashion). Examples of food grains include barley, dent- or flint-corn, sorghum, oats, rice, rye, wheat, amaranth, quinoa, buckwheat, and oilseeds (for example, cotton seed, flax seed, rapeseed, soybean, and sunflower seed).

Specialty crop operation means a farming operation that produces specialty crops that are raw agricultural commodities. It includes both individuals and legal entities.

Very small business means an applicant that had an average annual monetary value of specialty crops the applicant sold during the 3-year period preceding the program year of no more than $250,000.

Veteran farmer or rancher means a farmer or rancher who has served in the Armed Forces (as defined in 38 U.S.C. 101(10)[1]) and:

(1) Has not operated a farm or ranch for more than 10 years; or

(2) Has obtained status as a veteran (as defined in 38 U.S.C. 101(2)[2]) during the most recent 10-year period.

For an entity to be considered a veteran farmer or rancher, at least 50 percent of the ownership interest must be held by members who have served in the Armed Forces and meet the criteria in paragraph (1) or (2) of this definition.

Eligible Applicants

To be eligible for FSCSC, the applicant must meet all of the following:

- Be a specialty crop operation;
- Be a small business or very small business;
- Have obtained or renewed a:
  - 2022 food safety certification that was issued between June 21, 2022 and December 31, 2022; or
  - 2023 food safety certification issued during the 2023 calendar year; and
- Have paid eligible expenses as described in this document.

FSCSC is available to specialty crop operations located in the 50 United States, the District of Columbia, the Commonwealth of Puerto Rico, Guam, American Samoa, the U.S. Virgin Islands, and the Commonwealth of the Northern Mariana Islands.

Eligible Expenses

FSCSC provides assistance for eligible expenses that the applicant both incurs and pays in order to obtain or renew a 2022 or 2023 food safety certification as described above. Expenses that have

[1] The term ''Armed Forces'' means the United States Army, Navy, Marine Corps, Air Force, Space Force, and Coast Guard, including the reserve components.

[2] The term ''veteran'' means a person who served in the active military, naval, air, or space service, and who was discharged or released under conditions other than dishonorable.

been incurred by an applicant who does not ultimately obtain a 2022 or 2023 food safety certification are not eligible for assistance through FSCSC.

Some specialty crop operations obtain food safety certification through a group model, which enables multiple producers to form a group that develops a food safety management system and is audited and certified as one unit. This approach enables group members to pool resources to implement food safety training programs and share the cost of certification. Specialty crop operations that obtain certification through a group model are eligible to apply for assistance for their share of eligible expenses paid by the group, in addition to any eligible expenses they incur individually.

Specialty crop operations may receive assistance for the costs described below, including any associated postage costs.

Developing a food safety plan for first-time food safety certification. A food safety plan is a requirement for any specialty crop operation or group undergoing formal food safety certification, and the majority of costs associated with food safety plan development occur the first year an operation undergoes food safety certification. There are 2 general approaches to plan development—the specialty crop operation may develop its own plan, hire a consultant, or a combination of both. FSCSC will cover a percentage of the costs of seminars and tools used by specialty crop operations to create a food safety plan. FSCSC will also cover a percentage of the consulting fees and other associated expenses incurred if the specialty crop operation hires a consultant to develop a food safety plan. For specialty crop operations certified through a group, this category of expenses will cover a percentage of their share of the cost for developing a food safety or quality management system for the group.

Maintaining or updating an existing food safety plan. Certification programs typically require an annual review of the food safety plan to ensure it is current and addresses any new audit or regulatory requirements, as well as incorporates any new hazards. FSCSC will cover a percentage of the costs of maintaining and updating existing food safety plans. For specialty crop operations certified through a group, this category of expenses will cover a percentage of their share of the cost for maintaining or updating an existing food safety management system for the group.

Food safety certification. FSCSC will cover a percentage of the cost of obtaining food safety certification issued by a certifier, including application fees, inspection costs, inspection fees (including travel costs and per diem for certifiers), and user fees or certifier sales assessments.

Certification upload fees. FSCSC will cover a percentage of the cost to upload audit reports and certification documentation into commercial audit databases, which may be required by buyers of specialty crops.

Microbiological testing. FSCSC will cover a percentage of the cost of microbiological testing for products, soil amendments, and water as specified by a food safety plan or food safety management system. The FSMA Produce Safety Rule requires covered farms to test their agricultural water, and commercial food safety standards may require additional testing to determine if water meets the microbial requirements of the Environmental Protection Agency's drinking water standard (40 CFR part 141). Retail, food service, and institutional buyers are also increasingly requiring microbiological testing of finished products. Testing of soil amendments, particularly amendments of animal origin (composting) is also required by many food safety audit programs.

Training. FSCSC will cover the cost of food safety training for the specialty crop operation. The FSMA requires all covered operations to take a training course annually. Additionally, most certification programs require training as well.

Ineligible Expenses

Any expenses not listed above, as determined by the Deputy Administrator, are not covered by FSCSC. The following expenses are examples of costs that are not eligible for cost share under FSCSC:

- Infrastructure improvements (such as improvements to buildings, cold storage, flooring, restrooms, and handwashing stations);
- Equipment (such as grading or packing lines and sanitation equipment);
- Supplies (such as sanitation and cleaning supplies and personal protective equipment);
- Salaries and benefits of employees or other costs for labor, except for expenses for consultants described above; and
- Fees or penalties for late payment.

Application Process

The application period for 2022 begins on June 27, 2022, and ends on January 31, 2023. The application period for 2023 will be announced at a later date. Applicants may apply for FSCSC at any USDA Service Center.[3] Each applicant must submit the following forms in person or by mail, email, facsimile, or other methods announced by FSA:

- Form FSA–888, Food Safety Certification for Specialty Crops Program (FSCSC);
- Form CCC–860, Socially Disadvantaged, Limited Resource, Beginning and Veteran Farmer or Rancher Certification, for the applicable program year if the applicant qualifies as a historically underserved farmer or rancher and this form is not already on file with FSA;[4]
- Form AD–2047, Customer Data Worksheet, if not already on file with FSA; and
- Form SF–3881, ACH Vendor/Miscellaneous Payment Enrollment Form, if not already on file with FSA.[5]

Eligible expenses are based on the applicant's certification and are subject to spot check.

Applicants may be required to provide additional documentation to FSA, if requested by FSA, to verify eligibility or issue payment. Specialty crop operations certified as part of a group under a food safety management system must provide documentation of the applicant's portion of the group's expenses from the entity responsible for maintaining the group's certification if requested by FSA. Additional documentation must be received within 30 days of the request or the application will not be processed.

Payments

FSCSC payments are calculated separately for each category of eligible costs based on the percentages and

[3] USDA Service Center locations and contact information are available at *https://offices.sc.egov.usda.gov/locator/app.*

[4] Form CCC–860 is not required for applicants meeting the definition of socially disadvantaged, limited resource, beginning, and veteran farmer or rancher to receive a payment; however, failure to submit form CCC–860 will result in an applicant's payment being calculated using the lower payment rate that applies to all other applicants. An applicant who has filed CCC–860 certifying their status as a socially disadvantaged, beginning, or veteran farmer or rancher for a prior program year is not required to submit a subsequent certification of their status for a later program year because their status as socially disadvantaged would not change in different years, and their certification as a beginning or veteran farmer or rancher includes the relevant date needed to determine for what programs years the status would apply. Because an applicant's status as a limited resource farmer or rancher may change annually depending on their direct and indirect gross farm sales, those applicants must submit CCC–860 for each applicable program year.

[5] Applicants who are unable to receive payment through direct deposit are still eligible to participate in FSCSC. Those applicants should contact their local FSA county office for further information.

maximum payment amounts in the following table. An applicant may receive the specified percentage of their eligible costs, up to the maximum per category, for each program year.

Category of eligible expenses	Payment amount of eligible costs	
	Historically underserved farmer or rancher	All other applicants
Development of a food safety plan for first-time certification	75 percent (no maximum)	50 percent (no maximum).
Maintaining or updating a food safety plan	75 percent, up to a maximum of $375	50 percent, up to a maximum of $250.
Food safety certification	75 percent, up to a maximum of $2,000	50 percent, up to a maximum of $2,000.
Certification upload fees	75 percent, up to a maximum of $375	50 percent, up to a maximum of $250.
Microbiological testing—products	75 percent, up to 5 tests	50 percent, up to 5 tests.
Microbiological testing—soil amendments	75 percent, up to 5 tests	50 percent, up to 5 tests.
Microbiological testing—water	75 percent, up to 5 tests	50 percent, up to 5 tests.
Training	100 percent, up to a maximum of $300	100 percent, up to a maximum of $200.

Payments will be equal to the applicant's eligible expenses multiplied by the percentage for the applicable category in the table above, not to exceed the maximum payment amount for the category, if applicable. An applicant must report any previous cost share assistance received from any source for the expenses included on their application. The amount of the applicant's FSCSC payment plus the reported additional cost share assistance cannot exceed the total amount of eligible expenses for each category. If the amount of the additional cost share plus the calculated FSCSC payment exceed the total amount of eligible expenses for a category, the FSCSC payment for that category will be equal to the total amount of eligible expenses minus the additional reported cost share assistance.

FSA will issue payments for the 2022 program year as applications are processed and approved. Due to the limited amount of funding, FSA will issue 2023 program year payments after the end of the application period. If calculated payments exceed the amount of available funding for 2023, payments will be prorated.

Other Provisions

Participants are required to retain documentation in support of their application for 3 years after the date of approval. Participants receiving FSCSC payments or any other person who furnishes such information to USDA must permit authorized representatives of USDA or the Government Accountability Office, during regular business hours, to enter the operation and to inspect, examine, and to allow representatives to make copies of books, records, or other items for the purpose of confirming the accuracy of the information provided by the participant.

Applicants have a right to a decision in response to their application. If an applicant files an application with an FSA county office after the application deadline, the application will be considered a request to waive the deadline.

Requests to waive or modify program provisions, including requests to waive the deadline, are at the discretion of the Deputy Administrator. The Deputy Administrator has the authority to waive or modify application deadlines and other requirements or program provisions not specified in law, in cases where the Deputy Administrator determines it is (1) equitable to do so and (2) where the lateness or failure to meet such other requirements or program provisions do not adversely affect the operation of FSCSC.

Applicants who request to waive or modify FSCSC provisions do not have a right to a decision on those requests, and the Deputy Administrator's refusal to exercise discretion on requests to waive or modify FSCSC provisions will not be considered an adverse decision and is, by itself, not appealable.

Equitable relief and finality provisions specified in 7 CFR part 718, subpart D, apply to determinations under FSCSC. Persons and legal entities who file an application with FSA have the right to an administrative review of any FSA adverse decision with respect to the application under the appeals procedures at 7 CFR parts 780 and 11. The determination of matters of general applicability that are not in response to, or do not result from, an individual set of facts in an individual participant's application for payment are not matters that can be appealed. Such matters of general applicability include, but are not limited to, the determination of eligible categories of expenses and payment rates.

Any payment under FSCSC will be made without regard to questions of title under State law and without regard to any claim or lien. The regulations governing offsets in 7 CFR part 3 apply to FSCSC payments.

If an FSCSC payment resulted from erroneous information provided by a participant, or any person acting on their behalf, the payment will be recalculated and the participant must refund any excess payment with interest calculated from the date of the disbursement of the payment. If FSA determines that the applicant intentionally misrepresented information provided on their application, the application will be disapproved and the applicant must refund the full payment to FSA with interest from the date of disbursement.

In either applying for or participating in FSCSC, or both, the applicant is subject to laws against perjury (including but not limited to 18 U.S.C. 1621). If the applicant willfully makes and represents as true any verbal or written declaration, certification, statement, or verification that the applicant knows or believes not to be true, in the course of either applying for or participating in FSCSC, or both, then the applicant may be found to be guilty of perjury. Except as otherwise provided by law, if guilty of perjury the applicant may be fined, imprisoned for not more than 5 years, or both, regardless of whether the applicant makes such verbal or written declaration, certification, statement, or verification within or outside the United States.

For the purposes of the effect of a lien on eligibility for Federal programs (28 U.S.C. 3201(e)), USDA waives the restriction on receipt of funds under FSCSC but only as to beneficiaries who, as a condition of the waiver, agree to apply the FSCSC payments to reduce the amount of the judgment lien.

In addition to any other Federal laws that apply to FSCSC, the following laws apply: 18 U.S.C. 286, 287, 371, and 1001.

Paperwork Reduction Act Requirements

In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35), FSA is requesting comments from interested individuals and organizations on the information collection request associated with FSCSC. The FSCSC information collection request is for the eligible specialty crop operations to provide FSA the information about their eligible expenses to qualify for the payments and to enable FSA to determine the amount of the payment. FSA has submitted the emergency approval request for the FSCSC information collection activities to OMB for a 6-month approval. After the 60-day comment ends the information collection request will be submitted to OMB for a 3-year OMB approval.

Title: Food Safety Certification for Specialty Crops (FSCSC) Program.

OMB Control Number: 0560-New.

Type of Request: New Collection.

Abstract: The information collection request is required to support specialty crop operations to provide their eligible expenses to get the FSCSC payments. The forms for the applicants, who are producers or farmers, to complete for the FSCSC payments and the payment calculations are described in this document.

For the following estimated total annual burden on respondents, the formula used to calculate the total burden hour is the estimated average time per response multiplied by the estimated total annual responses. Public reporting burden for this information collection is estimated 0.685 hours to include the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed and completing and reviewing the collections of information.

Type of Respondents: Farmer or producer.

Estimated Annual Number or Respondents: 22,000.

Estimated Number of Responses per Respondent: 1.7.

Estimated Total Annual Responses: 37,400.

Estimated Average Time per Response: 0.685.

Estimated Total Annual Burden on Respondents: 25,652 hours.

FSA is requesting comments on all aspects of this information collection to help us to:

(1) Evaluate whether the collection of information is necessary for the proper performance of the functions of FSA, including whether the information will have practical utility;

(2) Evaluate the accuracy of FSA's estimate of burden including the validity of the methodology and assumptions used;

(3) Enhance the quality, utility, and clarity of the information to be collected; and

(4) Minimize the burden of the information collection 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.

All comments received in response to this document, including names and addresses when provided, will be a matter of public record. Comments will be summarized and included in the submission for Office of Management and Budget approval.

Environmental Review

The environmental impacts of this notice have been considered in a manner consistent with the provisions of the National Environmental Policy Act (NEPA, 42 U.S.C. 4321–4347), the regulations of the Council on Environmental Quality (40 CFR parts 1500–1508), and the FSA regulations for compliance with NEPA (7 CFR part 799).

The purpose of FSCSC is to provide assistance to specialty crop operations for eligible costs related to food safety certification. The Categorical Exclusions in 7 CFR 799.31 apply, specifically 7 CFR 799.31(b)(6)(iii) (that is, financial assistance to supplement income). No Extraordinary Circumstances (7 CFR 799.33) exist. FSA has determined that this notice does not constitute a major Federal action that would significantly affect the quality of the human environment, individually or cumulatively. Therefore, FSA will not prepare an environmental assessment or environmental impact statement for this regulatory action.

Federal Assistance Programs

The title and number of the Federal assistance program in the Assistance Listing,[6] to which this NOFA applies is 10.142, Food Safety Certification for Specialty Crops (FSCSC) Program.

USDA Non-Discrimination Policy

In accordance with Federal civil rights law and U.S. Department of Agriculture (USDA) civil rights regulations and policies, USDA, its Agencies, offices, and employees, and institutions participating in or administering USDA programs are prohibited from discriminating based on race, color, national origin, religion, sex, gender identity (including gender expression), sexual orientation, disability, age, marital status, family or parental status, income derived from a public assistance program, political beliefs, or reprisal or retaliation for prior civil rights activity, in any program or activity conducted or funded by USDA (not all bases apply to all programs). Remedies and complaint filing deadlines vary by program or incident.

Persons with disabilities who require alternative means of communication for program information (for example, braille, large print, audiotape, American Sign Language, etc.) should contact the responsible Agency or USDA TARGET Center at (202) 720–2600 (voice and TTY) or (844) 433–2774. Additionally, program information may be made available in languages other than English.

To file a program discrimination complaint, complete the USDA Program Discrimination Complaint Form, AD–3027, found online at *https://www.usda.gov/oascr/how-to-file-a-program-discrimination-complaint* and at any USDA office or write a letter addressed to USDA and provide in the letter all the information requested in the form. To request a copy of the complaint form, call (866) 632–9992. Submit your completed form or letter to USDA by mail to: U.S. Department of Agriculture, Office of the Assistant Secretary for Civil Rights, 1400 Independence Avenue SW, Washington, DC 20250–9410 or email: *OAC@usda.gov.*

USDA is an equal opportunity provider, employer, and lender.

Zach Ducheneaux,

Administrator, Farm Service Agency, and Executive Vice President, Commodity Credit Corporation.

[FR Doc. 2022–13014 Filed 6–17–22; 8:45 am]

BILLING CODE 3410–05–P

[6] See *https://sam.gov/content/assistance-listings.*

DEPARTMENT OF COMMERCE

[Docket No. 210518–0109]

Privacy Act of 1974; System of Records

AGENCY: U.S. Census Bureau, U.S. Department of Commerce.

ACTION: Notice of amendment, Privacy Act System of Records; COMMERCE/CENSUS–8, Statistical Administrative Records System.

SUMMARY: In accordance with the Privacy Act of 1974, as amended and Office of Management and Budget (OMB) Circular A–108, ''Federal Agency

Responsibilities for Review, Reporting, and Publication under the Privacy Act,'' the Department of Commerce (Department) is issuing this notice of intent to modify a system of records, COMMERCE/CENSUS–8, Statistical Administrative Records System.

DATES: To be considered, written comments must be submitted on or before July 21, 2022. This modified system of records will become effective on June 21, 2022 with the exception of any newly proposed or modified routine uses set forth under the section heading, ''ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND PURPOSES OF SUCH USES,'' which are subject to a 30-day period during which interested persons may submit comments to the Department. A new or modified routine use will become effective on August 5, 2022, unless the new or modified routine use needs to be changed as a result of public comment.

If the modified system of records notice needs to be changed, the Department will publish a subsequent notice in the **Federal Register** by August 5, 2022, stating that the current system of records will remain in effect until a revised notice is published in the **Federal Register**.

ADDRESSES: Please address comments to: Byron Crenshaw, Privacy Compliance Branch, Room 8H021, U.S. Census Bureau, Washington, DC 20233–3700 or by email, *Byron.Crenshaw@census.gov.*

FOR FURTHER INFORMATION CONTACT: Byron Crenshaw, Privacy Compliance Branch, Room 8H021, U.S. Census Bureau, Washington, DC 20233–3700, 301–763–7997, or by email, *Byron.Crenshaw@census.gov.*

SUPPLEMENTARY INFORMATION: This update makes nine program-related changes to COMMERCE/CENSUS–8, Statistical Administrative Records System. The first of nine proposed changes to program-related provisions update the description of the system location to specify the name and address of the cloud service provider. The second proposed change updates the description of the system manager for this system of records to reflect a U.S. Census Bureau (Census Bureau) reorganization that places some of the administrative records maintained in this system of records under a new manager. Administrative records maintained by the Center for Optimization and Data Science, including unique data sets that are extracted or combined on an as-needed basis for approved projects, are maintained in this system of records and will remain with the Research and Methodology Directorate but will be managed by the Assistant Director rather than the Associate Director. For specific research activities, these records may contain names as the personal identifier for retrieval of these records. The remaining administrative records with personal identifiers will be managed by the Associate Director for Economic Programs. The third proposed change updates the description of the purposes of the system to clarify that some identifiers (*e.g.,* social security numbers) may be retained for special research projects, including projects to support evidence-based policymaking as specified in the Foundations for Evidence-Based Policymaking Act of 2018, and consist of evidence of program effectiveness to inform processes for making policy decisions. The fourth proposed change revises the description of categories of individuals covered by the system to clarify that the system of records may include data on individuals obtained from other government entities (*e.g.,* state, local, and tribal governments), other third-party entities, and websites (such as through web scraping). The fifth proposed change updates the description of categories of records in the system to provide new detail about the information in the categories, including the collection of social media screen name (such as through web scraping or the acquisition of contact information through commercial resellers), place of birth, mobility status, citizenship, immigration status, and disability status. The sixth proposed change clarifies the record source categories by specifying other Census Bureau systems of records from which records in this system are obtained and by providing additional details regarding non-federal sources, including other government entities and other third-party entities. The seventh proposed change is a non-substantive change to the description of routine uses of the records to clarify that certain individuals (designated as Special Sworn Status individuals) authorized by Title 13, U.S. Code have access to this system of records. Special Sworn Status individuals are subject to the same confidentiality requirements as regular Census Bureau employees. This notice does not propose any new or significantly modified routine uses to this system of records. The eighth proposed change updates the policies and practices for retrieval of records to show the linkage between systems of records covered by COMMERCE/CENSUS–3, Demographic Survey Collection (Census Bureau Sampling Frame) (name change from COMMERCE/CENSUS–3, Special Censuses, Surveys, and Other Studies pending publication in the **Federal Register**); COMMERCE/CENSUS–4, Economic Survey Collection; COMMERCE/CENSUS–5, Decennial Census Program; COMMERCE/CENSUS–7, Demographic Survey Collection (Non-Census Bureau Sampling Frame) (name change from COMMERCE/CENSUS–7, Special Censuses of Population Conducted for State and Local Government pending publication in the **Federal Register**); COMMERCE/CENSUS–9, Longitudinal Employer-Household Dynamics System; COMMERCE/CENSUS–12, Foreign Trade Statistics; and this system of records for approved special research projects with limited access. The ninth proposed change updates administrative, technical, and physical safeguards to include additional safeguard language regarding cloud service providers approved in the government-wide Federal Risk and Authorization Management Program (FedRAMP) that provides a standardized approach to security assessment, authorization, and continuous monitoring for cloud products and services. This update also makes minor administrative updates.

The proposed changes are in accordance with OMB Circular A–108, which requires agencies to periodically review systems of records notices for accuracy and completeness, paying special attention to changes in the manner in which records are organized, indexed or retrieved that result in a change in the nature or scope of these records; and the Privacy Act, which requires agencies to publish in the **Federal Register** a notice that describes the changes to the system of records.

The Privacy Act also requires each agency that proposes to establish or significantly modify a system of records to provide adequate advance notice of any such proposal to OMB, the Committee on Oversight and Reform of the House of Representatives, and the Committee on Homeland Security and Governmental Affairs of the Senate (5 U.S.C 552a(r)). The purpose of providing the advance notice to OMB and Congress is to permit an evaluation of the potential effect of the proposal on the privacy and other rights of individuals. The Department filed a report describing the modified system of records covered by this notice with the Chair of the Senate Committee on Homeland Security and Governmental Affairs, the Chair of the House

Committee on Oversight and Reform, and the Deputy Administrator of the Office of Information and Regulatory Affairs, OMB on [INSERT DATE OF LETTERS].

SYSTEM NAME AND NUMBER:

COMMERCE/CENSUS–8, Statistical Administrative Records System.

SECURITY CLASSIFICATION:

None.

SYSTEM LOCATION:

U.S. Census Bureau, Bowie Computer Center, 17101 Melford Boulevard, Bowie, Maryland 20715; and at a FedRAMP-approved cloud services facility, Amazon Web Services (AWS), located at 410 Terry Ave. N, Seattle, WA 98109.

SYSTEM MANAGER(S):

For Center for Optimization and Data Science: Assistant Director for Research and Methodology, U.S. Census Bureau, 4600 Silver Hill Road, Washington, DC 20233–8000.

For Economic Research Division (ERD) Records: Associate Director for Economic Programs, U.S. Census Bureau, 4600 Silver Hill Road, Washington, DC 20233–8000.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

13 U.S.C. 6.

PURPOSE(S) OF THE SYSTEM:

This system of records supports the Census Bureau's core mission of producing economic and demographic statistics. To accomplish this mission, the Census Bureau is directed to acquire information from public and third-party sources to ensure the efficient and economical conduct of its censuses and surveys by using that information instead of conducting direct inquiries. To provide the information on which the American public, businesses, policymakers, and analysts rely, the Statistical Administrative Records System efficiently re-uses data from external sources, thereby eliminating the need to collect information again. Therefore, the purpose of this system is to centralize and control the use of personally identifiable information by providing a secure repository that supports statistical operations. With the exception of special projects, the system removes Social Security Numbers (SSNs) contained in source files and replaces them with unique non-identifying codes called Protected Identification Keys (PIKs) prior to use by other Census Bureau operating units. Census Bureau staff use the PIK to merge files to conduct approved research projects. Through legal agreements documenting permitted uses of the external data, linked files may be created to produce statistics. By combining survey and census data with administrative record data obtained from other government entities, third-party entities (*e.g.,* commercial and private sources) and websites, the Census Bureau will improve the quality and usefulness of its statistics and reduce the respondent burden associated with direct data collection efforts. The system will also be used to plan, evaluate, and enhance survey and census operations; improve questionnaire design and selected survey data products; produce research and statistical products such as estimates of the demographic, social, and economic characteristics of the population. Additionally, this system of records includes records maintained for evidence-based policymaking. These records consist of evidence of program effectiveness to inform processes for making policy decisions.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

This system covers the population of the United States and territories. In order to approximate coverage of the population in support of its statistical programs, the Census Bureau will acquire administrative record files from federal agencies such as the Departments of Agriculture, Education, Health and Human Services, Homeland Security, Housing and Urban Development, Labor, Treasury, Veterans Affairs, the Office of Personnel Management, the Social Security Administration, the Selective Service System, and the U.S. Postal Service. Data on individuals may also be sought from other government entities (*e.g.,* state, local, and tribal governments), third-party entities (*e.g.,* commercial and private sources), and websites.

CATEGORIES OF RECORDS IN THE SYSTEM:

Records in this system of records are organized into three components: The first category contains records with personal identifiers (names and SSNs), with access restricted to a limited number of sworn Census Bureau staff. These records are only used for a brief period of time while the personal identifiers are replaced with unique non-identifying codes. In a controlled Information Technology (IT) environment, the identifying information SSN contained in source files is removed and replaced with unique non-identifying codes. Section 6 of Title 13, U.S. Code, authorizes the Census Bureau to acquire information from other federal departments and agencies and for the acquisition of reports of other governmental or private sources. Data acquired by the Census Bureau to meet this directive may include direct identifiers such as name, address, date of birth, driver's license number, and SSN. The direct identifiers are used to identify duplicate lists and link across multiple sources. The Census Bureau has developed software to standardize and validate incoming person records to assign a PIK, which is retained on file so that SSNs can be removed. This process occurs through the Person Identification Validation System (PVS). The PVS software processes direct identifiers from input files. Census Bureau staff use the person linkage keys to merge files when conducting approved research and operations activities. The software is also used to facilitate record linkage for Census Bureau research partners within the Federal Statistical System, the decentralized network of federal agencies that produce data about the people, economy, natural resources, and infrastructure of the United States. Through legal agreements, linkage keys may be created by the Census Bureau for other Federal Statistical System agencies to produce statistics. The PVS does not append additional identifying information, only a unique identifier to facilitate record linkage.

The second category contains records that are maintained on unique data sets that are extracted or combined on an as-needed basis in approved projects. Records are extracted or combined as needed using the unique non-identifying codes, not by name or SSN, to prepare numerous statistical products. These records may contain information such as: demographic information—date of birth, place of birth, sex, race, ethnicity, household and family characteristics, birth expectations, mobility status, education, citizenship, immigration status, marital status, tribal affiliation, veteran's status, and disability status, etc.; geographical information—address and geographic codes, etc.; mortality information—cause of death and hospitalization information, etc.; health information—type of provider, services provided, cost of services, and quality indicators, etc.; economic information—housing characteristics, income, occupation, employment and unemployment information, health insurance coverage, federal and state program participation, assets, and wealth, etc.; respondent contact information—name, telephone number, email address or equivalent (such as social media screen name). Additionally, the Census Bureau may retain some direct identifiers (*e.g.,* SSN) for projects per interagency agreements and for short-term projects.

The third category contains two types of records that use name data for specific research activities. The Census Bureau has policies and procedures to review and control name data from administrative records providers and third-party sources. This category refers to name data used to plan contact operations for surveys and censuses and for research on names. The first type of records includes: Respondent contact information—name (or username), address, telephone number (both landline and cell phone number), and email address or equivalent (such as social media screen name), etc. The second type of records includes name data used to set Demographic Characteristics Flags—names are compared to lookup tables and used in models to assign sex and ethnicity. Records in this category are maintained on unique data sets that are extracted or combined on an as-needed basis using the unique non-identifying codes that replaced the SSNs, but with some name information retained. Other demographic information in this second type of records includes: date of birth, place of birth, sex, race, ethnicity, household and family characteristics, mobility status, citizenship, immigration status, education, marital status, tribal affiliation, veteran status, and disability status.

RECORD SOURCE CATEGORIES:

In general the records in this system come indirectly from individuals and addresses obtained from other systems of records covered by COMMERCE/CENSUS–3, Demographic Survey Collection (Census Bureau Sampling Frame) (name change from COMMERCE/CENSUS–3, Special Censuses, Surveys, and Other Studies pending publication in the **Federal Register**); COMMERCE/CENSUS–4, Economic Survey Collection; COMMERCE/CENSUS–5, Decennial Census Programs; COMMERCE/CENSUS–7, Demographic Survey Collection (Non-Census Bureau Sampling Frame) (name change from COMMERCE/CENSUS–7, Special Censuses of Population Conducted for State and Local Government pending publication in the **Federal Register**); COMMERCE/CENSUS–9, Longitudinal Employer-Household Dynamics System; and COMMERCE/CENSUS–12, Foreign Trade Statistics. Additionally, the Census Bureau will acquire administrative record files on individuals and addresses from federal, state, local and tribal governments, third-party entities (*e.g.,* commercial or private sources), and websites. Federal agency sources include: Departments of Agriculture, Education, Health and Human Services, Homeland Security, Housing and Urban Development, Labor, Treasury, Veterans Affairs, the Office of Personnel Management, the Social Security Administration, the Selective Service System, and the U.S. Postal Service.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND PURPOSES OF SUCH USES:

There are no routine uses for this system of records. Access to records maintained in the system is restricted to Census Bureau employees and certain individuals authorized by Title 13, U.S. Code (designated as Special Sworn Status individuals). These individuals are subject to the same confidentiality requirements as regular Census Bureau employees.

POLICIES AND PRACTICES FOR STORAGE OF RECORDS:

Records will be stored in a secure computerized system and on magnetic media; output data will be electronic. Magnetic media will be stored in a secure area within a locked drawer or cabinet. Source data sets containing personal identifiers will be maintained in a secure restricted-access IT environment. Records may also be stored by or at a secure FedRAMP-approved cloud service provider or facility.

POLICIES AND PRACTICES FOR RETRIEVAL OF RECORDS:

Census Bureau staff producing statistical products will have access only to data sets from which SSNs have been deleted and replaced by a PIK. Records from this system of records may also be linked to records covered by COMMERCE/CENSUS–3, Demographic Survey Collection (Census Bureau Sampling Frame) (name change from COMMERCE/CENSUS–3, Special Censuses, Surveys, and Other Studies pending publication in the **Federal Register**); COMMERCE/CENSUS–4, Economic Survey Collection; COMMERCE/CENSUS–5, Decennial Census Programs; COMMERCE/CENSUS–7, Demographic Survey Collection (Non-Census Bureau Sampling Frame) (name change from COMMERCE/CENSUS–7, Special Censuses of Population Conducted for State and Local Government pending publication in the **Federal Register**), COMMERCE/CENSUS–9, Longitudinal Employer-Household Dynamics System; and, COMMERCE/CENSUS–12, Foreign Trade Statistics, where the records may be retrieved by the PIK or by a direct identifier (such as name or SSN) common to all seven systems of records (including this SORN) to conduct approved special research projects. Only a limited number of sworn Census Bureau staff and individuals with Special Sworn Status, who work within a secure restricted-access environment, will be permitted to retrieve records containing direct identifiers.

POLICIES AND PRACTICES FOR RETENTION AND DISPOSAL OF RECORDS:

Records are to be retained in accordance with General Records Schedule GRS 5.1, 5.2, and the Census Bureau's records control schedule DAA–0029–2014–0005, Records of the Center for Administrative Records Research and Applications, which are approved by the National Archives and Records Administration (NARA). Records are also retained in accordance with agreements developed in accordance with other agencies and source entities. Federal tax information administrative record data will be retained and disposed of in accordance with 26 U.S.C. 6103(p)(4)(F)(ii) and Internal Revenue Service (IRS) Publication 1075, Tax Information Security Guidelines for Federal, State and Local Agencies. The Census Bureau issues an Annual Safeguard Security Report that includes information on the retention and disposal of federal tax information. The Census Bureau does not transfer Federal tax information administrative record data to NARA.

ADMINISTRATIVE, TECHNICAL, AND PHYSICAL SAFEGUARDS:

The Census Bureau is committed to respecting respondent privacy and protecting confidentiality. Through the Data Stewardship Program, we have implemented management, operational, and technical controls and practices to ensure high-level data protection to respondents of our censuses and surveys.

(1) A policy against unauthorized browsing protects respondent information from casual or inappropriate use by any person with access to Census Bureau protected data. Unauthorized browsing is defined as the act of searching or looking through, for other than work-related purposes, protected personal or business-related information that directly or indirectly identifies individual persons or businesses. Unauthorized browsing is prohibited.

(2) All Census Bureau employees and persons with Special Sworn Status are subject to the restrictions, penalties, and prohibitions of 13 U.S.C. 9 and 214 as

modified by 18 U.S.C. 3551, *et. seq.*; provisions of the Privacy Act, as applicable; 18 U.S.C. 1905; 26 U.S.C. 7213, 7213A, and 7431; and 42 U.S.C. 1306.

(3) All Census Bureau employees and persons with Special Sworn Status will be regularly advised of regulations governing the confidentiality of the data and will be required to complete an annual Data Stewardship Awareness training, and those who have access to Federal Tax Information data will be regularly advised of regulations governing the confidentiality of the data and will be required to complete an annual Title 26, U.S. Code awareness program. Employees of FedRAMP-approved cloud service providers do not have access to Census Bureau protected data maintained in this system of records.

(4) The restricted-access IT environment has been established to limit the number of Census Bureau staff with direct access to the personal identifiers in this system to protect the confidentiality of the data and to prevent unauthorized use or access.

(5) All Census Bureau and FedRAMP-approved computer systems that maintain sensitive information are in compliance with the Federal Information Security Management Act, as amended (44 U.S.C. 3551–3559), which includes auditing and controls over access to restricted data.

(6) The use of unsecured telecommunications to transmit individually identifiable information is prohibited.

(7) Paper copies that contain sensitive information are stored in secure facilities in a locked drawer or file cabinet.

(8) Each requested use of the data maintained in this system of records will be reviewed by an in-house Project Review Board to ensure that data relating to the project will be used only for authorized purposes. All uses of the data are solely for statistical purposes, which by definition means that uses will not directly affect benefits or enforcement actions for any individual. Only when the Project Review Board has approved a project will access to information from one or more of the source data sets be granted. Data from external sources in approved projects will not be made publicly available. Any publications based on the Statistical Administrative Records System will be cleared for release under the direction of the Census Bureau's Disclosure Review Board, which will confirm that all the required disclosure protection procedures have been implemented. No information will be released that identifies any individual.

RECORD ACCESS PROCEDURES:

None.

CONTESTING RECORD PROCEDURES:

None.

NOTIFICATION PROCEDURES:

None.

EXEMPTIONS PROMULGATED FOR THE SYSTEM:

Pursuant to 5 U.S.C. 552a(k)(4), this system of records is exempted from subsections (c)(3); (d); (e)(1); (e)(4)(G), (H), and (I); and (f) of the Privacy Act. These subsections include, but are not limited to, certain requirements concerning notification, access, and contest procedures. This exemption is applicable as the data are maintained by the Census Bureau solely as statistical records, as required under Title 13, U.S. Code, and are not used in whole or in part in making any determination about an identifiable individual. This exemption is made in accordance with the Department's rules which appear in 15 CFR part 4 Subpart B.

HISTORY:

81 FR 776554, November 3, 2016, Notice of Proposed Amendment.

Jennifer Goode,

Deputy Director and Acting Director of the Office of Privacy and Open Government.

[FR Doc. 2022–12598 Filed 6–17–22; 8:45 am]

BILLING CODE 3510–07–P

DEPARTMENT OF COMMERCE

International Trade Administration

[C–533–907]

Sodium Nitrite From India: Preliminary Affirmative Countervailing Duty Determination and Alignment of Final Determination With the Final Antidumping Duty Determination

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The U.S. Department of Commerce (Commerce) preliminarily determines that countervailable subsidies are being provided to producers and exporters of sodium nitrite from India for the period of investigation (POI) January 1, 2021, through December 31, 2021. Interested parties are invited to comment on this preliminary determination.

DATES: Applicable June 21, 2022.

FOR FURTHER INFORMATION CONTACT: Eva Kim, AD/CVD Operations, Office IV, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–8283.

SUPPLEMENTARY INFORMATION:

Background

This preliminary determination is made in accordance with section 703(b) of the Tariff Act of 1930, as amended (the Act). Commerce published the notice of initiation of this countervailing duty (CVD) investigation on February 8, 2022.[1] On March 18, 2022, Commerce postponed the preliminary determination of this investigation until June 13, 2022.[2] For a complete description of events that followed the initiation of this investigation, *see* the Preliminary Decision Memorandum.[3] A list of topics discussed in the Preliminary Decision Memorandum is included as Appendix II to this notice. The Preliminary 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 Preliminary Decision Memorandum can be accessed directly at *https://access.trade.gov/public/FRNoticesListLayout.aspx.*

Scope of the Investigation

The product covered by this investigation is sodium nitrite from India. For a complete description of the scope of the investigation, *see* Appendix I.

Scope Comments

In accordance with the preamble to Commerce's regulations,[4] the *Initiation Notice* set aside a period of time for parties to raise issues regarding product coverage, (*i.e.,* scope).[5] No interested party commented on the scope of the investigation as it appeared in the *Initiation Notice.*

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[1] *See Sodium Nitrite from India and the Russian Federation: Initiation of Countervailing Duty Investigations,* 87 FR 7108 (February 8, 2022) (*Initiation Notice*).

[2] *See Sodium Nitrite from India: Postponement of Preliminary Determination in the Countervailing Duty Investigation,* 87 FR 15373 (March 18, 2022).

[3] *See* Memorandum, ''Decision Memorandum for the Preliminary Affirmative Determination in the Countervailing Duty Investigation of Sodium Nitrite from India,'' dated concurrently with, and hereby adopted by, this notice (Preliminary Decision Memorandum).

[4] *See Antidumping Duties; Countervailing Duties, Final Rule,* 62 FR 27296, 27323 (May 19, 1997).

[5] *See Initiation Notice,* 87 FR at 7109.

Methodology

Commerce is conducting this investigation in accordance with section 701 of the Act. For each of the subsidy programs found to be countervailable, Commerce preliminarily determines that there is a subsidy, *i.e.,* a financial contribution by an ''authority'' that gives rise to a benefit to the recipient, and that the subsidy is specific.[6]

Commerce notes that, in making these findings, it relied, in part, on facts available and, because it finds that the Government of India did not act to the best of its ability to respond to Commerce's requests for information, it drew an adverse inference where appropriate in selecting from among the facts otherwise available.[7] For further information, *see* the ''Use of Facts Otherwise Available and Adverse Inferences'' section in the Preliminary Decision Memorandum.

Alignment

As noted in the Preliminary Decision Memorandum, in accordance with section 705(a)(1) of the Act and 19 CFR 351.210(b)(4), Commerce is aligning the final CVD determination in this investigation with the final determination in the companion antidumping duty investigation of sodium nitrite from India based on a request made by the petitioner.[8] Consequently, the final CVD determination will be issued on the same date as the final AD determination, which is currently scheduled to be issued no later than October 25, 2022, unless postponed.

All-Others Rate

Sections 703(d) and 705(c)(5)(A) of the Act provide that in the preliminary determination, Commerce shall determine an estimated all-others rate for companies not individually examined. This rate shall be an amount equal to the weighted average of the estimated subsidy rates established for those companies individually examined, excluding any zero and *de minimis* rates and any rates based entirely under section 776 of the Act.

Commerce calculated an individual estimated countervailable subsidy rate for Deepak Nitrite Limited (Deepak), the only individually examined exporter/producer in this investigation. Because the only individually calculated rate is not zero, *de minimis,* or based entirely on facts otherwise available, the estimated weighted-average rate calculated for Deepak is the rate assigned to all other producers and exporters, pursuant to section 735(c)(5)(A)(i) of the Act.

Preliminary Determination

Commerce preliminarily determines that the following estimated countervailable subsidy rates exist:

Company	Subsidy rate (percent *ad valorem*)
Deepak Nitrite Limited[9]	12.88
All Others	12.88

Suspension of Liquidation

In accordance with section 703(d)(1)(B) and (d)(2) of the Act, Commerce will direct U.S. Customs and Border Protection (CBP) to suspend liquidation of entries of subject merchandise as described in the scope of the investigation section entered, or withdrawn from warehouse, for consumption on or after the date of the publication of this notice in the **Federal Register**. Further, pursuant to 19 CFR 351.205(d), Commerce will instruct CBP to require a cash deposit equal to the rates indicated above.

Disclosure

Commerce intends to disclose its calculations and analysis performed to interested parties in this preliminary determination within five days of its public announcement, or if there is no public announcement, within five days of the date of this notice in accordance with 19 CFR 351.244(b).

Verification

As provided in section 782(i)(1) of the Act, Commerce intends to verify the information relied upon in making its final determination.[10]

Public Comment

Case briefs or other written comments may be submitted to the Assistant Secretary for Enforcement and Compliance no later than seven days after the deadline for the verification questionnaire response in this investigation. Rebuttal briefs, limited to issues raised in case briefs, may be submitted no later than seven days after the deadline for case briefs.[11] Note that Commerce has temporarily modified certain of its requirements for serving documents containing business proprietary information, until further notice.[12] Pursuant to 19 CFR 351.309(c)(2) and (d)(2), parties who submit case briefs or rebuttal briefs in this investigation are encouraged to submit with each argument: (1) a statement of the issue; (2) a brief summary of the argument; and (3) a table of authorities.

Pursuant to 19 CFR 351.310(c), interested parties who wish to request a hearing, limited to issues raised in the case and rebuttal briefs, must submit a written request to the Assistant Secretary for Enforcement and Compliance, U.S. Department of Commerce within 30 days after the date of publication of this notice. Requests should contain the party's name, address, and telephone number, the number of participants, whether any participant is a foreign national, and a list of the issues to be discussed. If a request for a hearing is made, Commerce intends to hold the hearing at a time and date to be determined. Parties should confirm by telephone the date, time, and location of the hearing two days before the scheduled date.

International Trade Commission Notification

In accordance with section 703(f) of the Act, Commerce will notify the U.S. International Trade Commission (ITC) of its determination. If the final determination is affirmative, the ITC will determine before the later of 120 days after the date of this preliminary determination or 45 days after the final determination whether imports of sodium nitrite from India are materially injuring, or threaten material injury to, the U.S. industry.

Notification to Interested Parties

This determination is issued and published pursuant to sections 703(f) and 777(i) of the Act, and 19 CFR 351.205(c).

[6] *See* sections 771(5)(B) and (D) of the Act regarding financial contribution; section 771(5)(E) of the Act regarding benefit; and section 771(5A) of the Act regarding specificity.

[7] *See* sections 776(a) and (b) of the Act.

[8] The petitioner is Chemtrade Chemicals US LLC. *See* Petitioner's Letter, ''Sodium Nitrite from India: Request to Align Final Countervailing Duty Determination with Companion Antidumping Duty Final Determination,'' dated May 27, 2022.

[9] Deepak Nitrite Limited includes Deepak Nitrite Limited Nandesari Division.

[10] *See* Commerce's Letter, ''Countervailing Duty Investigation of Sodium Nitrite from India: Verification Preparedness Questionnaire,'' dated June 6, 2022.

[11] *See* 19 CFR 351.309; *see also* 19 CFR 351.303 (for general filing requirements).

[12] *See Temporary Rule Modifying AD/CVD Service Requirements Due to COVID–19; Extension of Effective Period,* 85 FR 41363 (July 10, 2020).

Dated: June 13, 2022.

Lisa W. Wang,

Assistant Secretary for Enforcement and Compliance.

Appendix I

Scope of the Investigation

The product covered by this investigation is sodium nitrite in any form, at any purity level. In addition, the sodium nitrite covered by this investigation may or may not contain an anticaking agent. Examples of names commonly used to reference sodium nitrite are nitrous acid, sodium salt, anti-rust, diazotizing salts, erinitrit, and filmerine. Sodium nitrite's chemical composition is NaNO2, and it is generally classified under subheading 2834.10.1000 of the Harmonized Tariff Schedule of the United States (HTSUS). The American Chemical Society Chemical Abstract Service (CAS) has assigned the name ''sodium nitrite'' to sodium nitrite. The CAS registry number is 7632–00–0. For purposes of the scope of this investigation, the narrative description is dispositive, not the tariff heading, CAS registry number or CAS name, which are provided for convenience and customs purposes.

Appendix II

List of Topics Discussed in the Preliminary Decision Memorandum

I. Summary
II. Background
III. Scope Comments
IV. Subsidies Valuation
V. Use of Facts Otherwise Available and Adverse Inferences
VI. Benchmarks and Interest Rates
VII. Analysis of Programs
VIII. Recommendation

[FR Doc. 2022–13184 Filed 6–17–22; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

Agency Information Collection Activities; Submission to the Office of Management and Budget (OMB) for Review and Approval; Comment Request; Domestic and International Client Export Services and Customized Forms Revision

AGENCY: International Trade Administration, U.S. Commercial Service, Commerce.

ACTION: Notice of information collection, request for comment.

SUMMARY: The Department of Commerce, in accordance with the Paperwork Reduction Act of 1995 (PRA), invites the general public and other Federal agencies to comment on proposed, and continuing information collections, which helps us assess the impact of our information collection requirements and minimize the public's reporting burden. The purpose of this notice is to allow for 60 days of public comment preceding submission of the collection to OMB.

DATES: To ensure consideration, comments regarding this proposed information collection must be received on or before August 22, 2022.

ADDRESSES: Direct all written comments to John Seo, Senior Economist, International Trade Administration, 1401 Constitution Ave. NW, Washington, DC 20230, (202) 482–7497 or *john.seo@trade.gov.*

FOR FURTHER INFORMATION CONTACT: Requests for additional information or specific questions related to collection activities should be directed to John Seo, Senior Economist, International Trade Administration, 1401 Constitution Ave. NW, Washington, DC 20230, (202) 482–7497 or *john.seo@trade.gov.*

SUPPLEMENTARY INFORMATION:

I. Abstract

The International Trade Administration's (ITA) Global Markets/ U.S. Commercial Service (CS) is mandated by Congress to broaden and deepen the U.S. exporter base. The CS accomplishes this by providing counseling, programs, and services to help U.S. organizations export and conduct business in overseas markets. This information collection package enables the CS to provide appropriate export services to U.S. exporters and international buyers.

The CS offers a variety of services to enable clients to begin exporting/ importing or to expand existing exporting/importing efforts. Clients may learn about our services from business related entities such as the National Association of Manufacturers, Federal Express, State Economic Development offices, the internet, or word of mouth. The CS provides a standard set of services to assist clients with identifying potential overseas partners, establishing meeting programs with appropriate overseas business contacts, and providing due diligence reports on potential overseas business partners. The CS also provides other export-related services considered to be of a ''customized nature'' because they do not fit into the standard set of the CS' export services, but are driven by unique business needs of individual clients.

The dissemination of international market information and potential business opportunities for U.S. exporters are critical components of the Commercial Service's export assistance programs and services. U.S. companies conveniently access and indicate their interest in these services by completing the appropriate forms via ITA and the CS U.S. Export Assistance Center websites.

The CS works closely with clients to educate them about the exporting/ importing process and to help prepare them for exporting/importing. When a client is ready to begin the exporting/ importing process our field staff provide counseling to assist in the development of an exporting strategy. We provide fee-based, export-related services designed to help client export/import. The type of export-related service that is proposed to a client depends upon a client's business goals and where they are in the export/import process. Some clients are at the beginning of the export process and require assistance with identifying potential distributors, whereas other clients may be ready to sign a contract with a potential distributor and require due diligence assistance.

Before the CS can provide export-related services to clients, such as assistance with identifying potential partners or providing due diligence, specific information is required to determine the client's business objectives and needs. For example, before we can provide a service to identify potential business partners we need to know whether the client would like a potential partner to have specific technical qualifications, coverage in a specific market, English or foreign language ability or warehousing requirements. This information collection is designed to elicit such data so that appropriate services can be proposed and conducted to most effectively meet the client's exporting goals. Without these forms the CS is unable to provide services when requested by clients.

The forms ask U.S. exporters standard questions about their company details, demographic information, export experience, information about the products or services they wish to export, and exporting goals. In addition, the CS is seeking approval to collect demographic information to help meet the Executive Order (E.O.) On Advancing Racial Equity and Support for Underserved Communities Through the Federal Government. In order to better assist underserved communities as defined by the E.O., the CS plans to ask questions related to equity and underserved communities. CS staff will use this information to gain a better understanding of client's needs and objectives so that they can provide appropriate and effective export assistance tailored to an exporter's requirements.

II. Method of Collection

Clients will be asked to provide their information on our website (*trade.gov*), web-based survey or form links, or paper-based forms.

III. Data

OMB Control Number: 0625–0143.

Form Number(s): ITA–4096P.

Type of Review: Regular submission [revision of a current information collection].

Affected Public: Business or other for-profit organizations; Not-for-profit institutions; State, Local, or Tribal government; and Federal government.

Estimated Number of Respondents: 200,000.

Estimated Time per Response: 10 minutes.

Estimated Total Annual Burden Hours: 33,333 hours.

Respondent's Obligation: Voluntary.

IV. Request for Comments

We are soliciting public comments to permit the Department/Bureau to: (a) Evaluate whether the proposed information collection is necessary for the proper functions of the Department, including whether the information will have practical utility; (b) 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; (c) Evaluate ways to enhance the quality, utility, and clarity of the information to be collected; and (d) Minimize the reporting burden on those who are to respond, including the use of automated collection techniques or other forms of information technology.

Comments that you submit in response to this notice are a matter of public record. We will include or summarize each comment in our request to OMB to approve this ICR. Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you may 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.

Sheleen Dumas,

Department PRA Clearance Officer, Office of the Chief Information Officer, Commerce Department.

[FR Doc. 2022–13247 Filed 6–17–22; 8:45 am]

BILLING CODE 3510–FP–P

DEPARTMENT OF COMMERCE

National Institute of Standards and Technology

Information Collection Activities; Submission to the Office of Management and Budget (OMB) for Review and Approval; Comment Request; Generic Clearance for Community Resilience Data Collections

The Department of Commerce will submit the following information collection request to the Office of Management and Budget (OMB) for review and clearance in accordance with the Paperwork Reduction Act of 1995, on or after the date of publication of this notice. We invite the general public and other Federal agencies to comment on proposed, and continuing information collections, which helps us assess the impact of our information collection requirements and minimize the public's reporting burden. Public comments were previously requested via the **Federal Register** on March 15, 2022 during a 60-day comment period. This notice allows for an additional 30 days for public comments.

Agency: National Institute of Standards and Technology (NIST), Commerce.

Title: Generic Clearance for Community Resilience Data Collections.

OMB Control Number: 0693–0078.

Form Number(s): None.

Type of Request: Regular submission (revision and extension of a currently approved information collection).

Number of Respondents: 25,000.

Average Hours per Response: Varied, dependent upon the data collection method used. The possible response time to complete a questionnaire may be 15 minutes or 2 hours to participate in an interview.

Burden Hours: 18,000.

Needs and Uses: Through acts such as the National Construction Safety Team Act (NCSTA), the National Windstorm Impact Reduction Act (NWIRA) and the NIST Organic Act, among others, as well as the President's Climate Action Plan (2013), NIST conducts research and develops guidance and other related tools to promote and enhance the safety and well-being of people in the face of a hazard event. With this in mind, NIST proposes to conduct a number of data collection efforts within the topic areas of disaster and failure studies and community resilience and sustainability, including studies of specific disaster events (*e.g.,* wildfire, urban fire, structure collapse, hurricane, earthquake, tornado, and flood events), assessments of community resilience and sustainability, and evaluations of the usability and utility of NIST resilience guidance or other products. NIST is requesting an increase in both number of respondents and burden hours through this renewal.

Affected Public: Federal government; households and individuals; the private sector; and state and local governments.

Frequency: On occasion.

Respondent's Obligation: Voluntary.

This information collection request may be viewed at *www.reginfo.gov.* Follow the instructions to view the Department of Commerce collections currently under review by OMB.

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 and entering either the title of the collection or the OMB Control Number 0693–0078.

Sheleen Dumas,

Department PRA Clearance Officer, Office of the Chief Information Officer, Commerce Department.

[FR Doc. 2022–13146 Filed 6–17–22; 8:45 am]

BILLING CODE 3510–13–P

DEPARTMENT OF COMMERCE

National Telecommunications and Information Administration

Commerce Spectrum Management Advisory Committee Meeting

AGENCY: National Telecommunications and Information Administration, U.S. Department of Commerce.

ACTION: Notice of open meeting.

SUMMARY: This notice announces a public meeting of the Commerce Spectrum Management Advisory Committee (Committee). The Committee provides advice to the Assistant Secretary of Commerce for Communications and Information and the National Telecommunications and Information Administration (NTIA) on spectrum management policy matters.

DATES: The meeting will be held June 30, 2022, from 11:00 a.m. to 1:00 p.m., Eastern Daylight Time (EDT).

ADDRESSES: This meeting will be conducted in an electronic format and open to the public via audio teleconference (866–880–0098 participant code 48261650). Public comments may be emailed to *arichardson@ntia.gov* or mailed to Commerce Spectrum Management Advisory Committee, National Telecommunications and Information Administration, 1401 Constitution Avenue NW, Room 4600, Washington, DC 20230.

FOR FURTHER INFORMATION CONTACT: Antonio Richardson, Designated Federal Officer, at (202) 482–4156 or *arichardson@ntia.gov*; and/or visit NTIA's website at *https://www.ntia.gov/category/csmac*.

SUPPLEMENTARY INFORMATION:

Background: The Committee provides advice to the Assistant Secretary of Commerce for Communications and Information on needed reforms to domestic spectrum policies and management in order to: license radio frequencies in a way that maximizes public benefits; keep wireless networks as open to innovation as possible; and make wireless services available to all Americans. *See* Charter at *https://www.ntia.doc.gov/files/ntia/publications/csmac-charter-2021.pdf*.

This Committee is subject to the Federal Advisory Committee Act (FACA), 5 U.S.C. App. 2, and is consistent with the National Telecommunications and Information Administration Act, 47 U.S.C. 904(b). The Committee functions solely as an advisory body in compliance with the FACA. For more information about the Committee visit: *http://www.ntia.gov/category/csmac*.

Matters to Be Considered: The Committee provides advice to the Assistant Secretary to assist in developing and maintaining spectrum management policies that enable the United States to maintain or strengthen its global leadership role in the introduction of communications technology, services, and innovation; thus expanding the economy, adding jobs, and increasing international trade, while at the same time providing for the expansion of existing technologies and supporting the country's homeland security, national defense, and other critical needs of government missions. NTIA will post an agenda on its website, *http://www.ntia.gov/category/csmac,* prior to the meeting. To the extent that the meeting time and agenda permit, any member of the public may address the Committee regarding the agenda items. *See Open Meeting and Public Participation Policy,* available at *http://www.ntia.gov/category/csmac*.

Time and Date: The meeting will be held on June 30, 2022, from 11:00 a.m. to 1:00 p.m. EDT. The meeting time and the agenda topics are subject to change. Please refer to NTIA's website, *http://www.ntia.gov/category/csmac,* for the most up-to-date meeting agenda and access information.

Place: This meeting will be conducted in an electronic format and open to the public via audio teleconference. Individuals requiring accommodations are asked to notify Mr. Richardson at (202) 482–4156 or *arichardson@ntia.gov* at least ten (10) business days before the meeting.

Status: Interested parties are invited to join the teleconference and to submit written comments to the Committee at any time before or after the meeting. Parties wishing to submit written comments for consideration by the Committee in advance of the meeting are strongly encouraged to submit their comments in Microsoft Word and/or PDF format via electronic mail to *arichardson@ntia.gov*. Comments may also be sent via postal mail to Commerce Spectrum Management Advisory Committee, National Telecommunications and Information Administration, 1401 Constitution Avenue NW, Room 4600, Washington, DC 20230. It would be helpful if paper submissions also include a compact disc (CD) that contains the comments in one or both of the file formats specified above. CDs should be labeled with the name and organizational affiliation of the filer. Comments must be received five (5) business days before the scheduled meeting date to provide sufficient time for review. Comments received after this date will be distributed to the Committee but may not be reviewed prior to the meeting. Additionally, please note that there may be a delay in the distribution of comments submitted via postal mail to Committee members.

Records: NTIA maintains records of all Committee proceedings. Committee records are available for public inspection at NTIA's Washington, DC office at the address above.

Documents including the Committee's charter, member list, agendas, minutes, and reports are available on NTIA's website at *http://www.ntia.gov/category/csmac*.

Josephine Arnold,

Acting Chief Counsel, National Telecommunications and Information Administration.

[FR Doc. 2022–13155 Filed 6–17–22; 8:45 am]

BILLING CODE 3510–60–P

BUREAU OF CONSUMER FINANCIAL PROTECTION

[Docket No. CFPB–2022–0040]

Request for Information Regarding Relationship Banking and Customer Service

AGENCY: Bureau of Consumer Financial Protection.

ACTION: Request for information.

SUMMARY: The Consumer Financial Protection Bureau (Bureau or CFPB) is seeking comments from the public related to relationship banking and how consumers can assert the right to obtain timely responses to requests for information about their accounts from banks and credit unions with more than $10 billion in assets, as well as from their affiliates.

DATES: Comments must be received by July 21, 2022.

ADDRESSES: You may submit comments, identified by Docket No. CFPB–2022–0040, by any of the following methods:

• *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.

• *Email: RelationshipBankingAndCustomerService@cfpb.gov.* Include Docket No. CFPB–2022–0040 in the subject line of the message.

• *Mail/Hand Delivery/Courier:* Comment Intake—Relationship Banking, Consumer Financial Protection Bureau, 1700 G Street NW, Washington, DC 20552. Please note that due to circumstances associated with the COVID–19 pandemic, the CFPB discourages the submission of comments by hand delivery, mail, or courier.

Instructions: The CFPB encourages the early submission of comments. All submissions should include document title and docket number. Because paper mail in the Washington, DC, area and at the CFPB is subject to delay, commenters are encouraged to submit comments electronically. In general, all comments received will be posted without change to *https://www.regulations.gov.* In addition, once the CFPB's headquarters reopens, comments will be available for public inspection and copying at 1700 G Street NW, Washington, DC 20552, on official business days between the hours of 10 a.m. and 5 p.m. Eastern Time. At that time, you can make an appointment to inspect the documents by telephoning 202–435–7275.

All comments, including attachments and other supporting materials, will become part of the public record and subject to public disclosure. Proprietary information or sensitive personal information, such as account numbers or Social Security numbers, or names of other individuals, should not be included. Comments will not be edited to remove any identifying or contact information.

FOR FURTHER INFORMATION CONTACT: Leslie Parrish, Deputy Assistant Director, Consumer Credit, Payments, and Deposits Markets, or Ted Wegner, Policy Analyst, Office of Consumer Education, at 202–435–7700. If you require this document in an alternative electronic format, please contact *CFPB_Accessibility@cfpb.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

Under section 1034(c) of the Consumer Financial Protection Act (CFPA), consumers have a legal right to obtain information from the approximately 175 largest banks and credit unions in the country with more than $10 billion in assets, as well as from their affiliates.[1] Through this statutory authority, consumers are able to gain valuable insight into their accounts by requesting certain account information from their depository institution.

In the modern banking environment, consumers reasonably expect financial institutions to provide responses to their requests for information and high levels of customer service. Some banks may not be offering the baseline level of customer service that consumers reasonably expect to receive from companies that have control over their money.

Relationship banking is an aspirational model of banking that meets its customers' needs through strong customer service, responsiveness, and care. Relationship banking can play a critical role in helping to foster fair, transparent, and competitive marketplaces.

The CFPB endeavors to help institutions of all sizes foster an inclusive relationship banking model that meets consumers' reasonable expectations of high levels of customer service and enables consumers to hold financial institutions accountable when they encounter problems. This model is especially critical during a time when consumers report wanting and valuing high-quality human interactions in their financial lives, as well as more helpful digital channels to better facilitate self-help.[2]

Increasing market concentration in the financial services industry may present challenges in implementing an inclusive relationship banking model.[3] The number of banking institutions has decreased ''from nearly 18,000 in 1984 to fewer than 5,000 in 2021.'' [4] Bank consolidation has had mixed results for consumers and customer service experiences.[5]

Of particular note is the loss of local banks in rural communities. Rural customers are more likely to visit smaller banks or credit unions, but face decreased banking access due to ''[t]rends in banking consolidation[, which] may be a contributing factor to the prevalence of rural banking deserts.'' [6] Rural customers rely on smaller banks and the relationship banking they offer, with local knowledge and long-standing relationships, to help maintain the ''civic fabric of rural communities.'' [7]

Federal consumer financial law has long been concerned with consumers' ability to access information. For example, consumers have the right to send a request for information to their mortgage servicer in order to obtain information with respect to their mortgage loan.[8] In addition, the Fair Credit Reporting Act gives consumers the right to annually request a free copy of their consumer report from each of the nationwide consumer reporting agencies and mandates that consumers receive notice when a user of a consumer report takes any adverse actions on a consumer on the basis, in whole or in part, of information contained in a consumer report.[9]

The CFPA's section 1034(c) right also provides an ability for consumers to access information, as Congress made a determination that consumers need additional rights to demand information from large depository institutions.

II. Request for Comment

This request for information seeks information from the public on what customer service obstacles consumers face in the banking market, and specifically, what information would be helpful for consumers to obtain from depository institutions pursuant to section 1034(c) of the CFPA.

The CFPB welcomes the public to submit stories, data, and information related to this request. To assist commenters in developing responses, the CFPB has crafted the below questions that commenters may answer.

1. What types of information do consumers request from their depository institution? How are consumers using the information?

2. What types of information do consumers request from their depository institution, but are often unable to obtain?

3. How does the channel (phone, in-writing, online, in-person) through which consumers request information impact their ability to obtain information?

4. How do consumers' customer service experiences differ depending on the channel through which they interact with their depository institution (phone, in-writing, online, in-person)?

5. How are customer service representatives evaluated and

[1] ''A covered person subject to supervision and primary enforcement by the Bureau pursuant to section 1025 shall, in a timely manner, comply with a consumer request for information in the control or possession of such covered person concerning the consumer financial product or service that the consumer obtained from such covered person, including supporting written documentation, concerning the account of the consumer.'' 12 U.S.C. 5534(c)(1). There are certain exceptions. *See* 12 U.S.C. 5534(c)(2); CFPB Depository Institutions (Dec. 2021), *https://files.consumerfinance.gov/f/documents/cfpb_depository-institutions-list_2021-12.pdf.*

[2] *The Human + Digital Challenge in Banking: Consumers Want Both,* Cornerstone Advisors (2021), *https://go.backbase.com/rs/987-MGR-655/images/Backbase_Cornerstone_Human_Digital.pdf.*

[3] *Best & Worst Banks According to Consumer Reports Members: Smaller institutions get higher ratings in our latest survey of more than 72,000 members,* Consumer Reports (Mar. 23, 2018), *https://www.consumerreports.org/banks/best-and-worst-banks-and-credit-unions-a5170659592/.*

[4] *The Great Consolidation of Banks and Acceleration of Branch Closures Across America,* National Community Reinvestment Coalition (Feb. 16, 2022), *https://ncrc.org/the-great-consolidation-of-banks-and-acceleration-of-branch-closures-across-america/.*

[5] *U.S. Retail Banks Struggle to Differentiate, Deliver Meaningful Customer Experience as Economy Sours, J.D. Power Finds,* J.D. Power (Apr. 7, 2022), *https://www.jdpower.com/business/press-releases/2022-us-retail-banking-satisfaction-study; The Human + Digital Challenge in Banking: Consumers Want Both* at 12, 30, Cornerstone Advisors (2021), *https://go.backbase.com/rs/987-MGR-655/images/Backbase_Cornerstone_Human_Digital.pdf* (Consumers report that it takes too long to get what they need done, that they have to repeat information to multiple sources, that employees aren't knowledgeable about their situation, and that it's difficult to find the information they need online.); *Consumer Response Annual Report* at 30–31, Consumer Financial Protection Bureau (Mar. 2022), *https://files.consumerfinance.gov/f/documents/cfpb_2021-consumer-response-annual-report_2022-03.pdf* (The CFPB received approximately 37,400 checking or savings account complaints in 2021. Of the complaints where the company confirmed a commercial relationship with the consumer and responded with an explanation or relief, in 94% of those complaints, consumers reported that they attempted to resolve their issue with the company before submitting a complaint to the CFPB, indicating that many consumers are unable to resolve their issues through direct contact with their bank.).

[6] *Data Spotlight: Challenges in Rural Banking Access* at 9, Consumer Financial Protection Bureau (Apr. 2022), *https://files.consumerfinance.gov/f/documents/cfpb_data-spotlight_challenges-in-rural-banking_2022-04.pdf.*

[7] *Id* at 10.

[8] 12 CFR 1024.36.

[9] 15 U.S.C. 1681j(a); 15 U.S.C. 1681m(a).

compensated, and how might compensation structure and incentives impact the service provided?

6. What customer service obstacles have consumers experienced that have adversely affected their ability to bank?

7. What unique customer service obstacles do immigrants, rural communities, or older consumers experience?

8. What are typical call wait times?

9. How often are calls dropped or disconnected? How often do companies use automated and digital communication channels such as interactive voice response (IVR) systems and online chat functions?

10. Are there any fees associated with customer service or requests for information?

11. What are the most important customer service features or experiences that help produce satisfactory banking relationships between financial institutions and consumers?

12. Please explain the value of consumers having access to the following information pertaining to their accounts:

a. Internal or external communications about an account.

b. A listing of all companies that are provided with information about an account.

c. The purposes for which information about a consumer's account are shared.

d. Any compensation that a depository institution receives for sharing information about an account.

e. Any conditions placed on the use of information about an account.

f. A listing of all companies with authorization to receive automatic or reoccurring payments from an account.

g. Information reviewed or used in investigating a consumer's dispute about an account.

h. Any third-party information used to make account decisions about consumers, including but not limited to consumer reports and credit or other risk scores.

13. What information would be helpful for consumers to obtain from depository institutions in order to improve their banking experience?

14. How have methods of customer engagement changed as a result of the COVID–19 pandemic?

Rohit Chopra,

Director, Consumer Financial Protection Bureau.

[FR Doc. 2022–13207 Filed 6–17–22; 8:45 am]

BILLING CODE 4810–AM–P

COUNCIL ON ENVIRONMENTAL QUALITY

[CEQ–2022–0003]

Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery

AGENCY: Council on Environmental Quality.

ACTION: Notice of information collection; request for comments.

SUMMARY: Consistent with the Paperwork Reduction Act of 1995 (PRA), this notice announces that the Council on Environmental Quality (CEQ) will submit an Information Collection Request (ICR) to the Office of Management and Budget (OMB) for review and approval. This notice describes a collection of information on generic clearance for qualitative feedback on agency service delivery. 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.

DATES: Interested persons are invited to submit comments on or before July 21, 2022.

ADDRESSES: You may submit comments, identified by docket number CEQ–2022–0003, by any of the following methods:

• *Federal eRulemaking Portal: https://www.regulations.gov.* Follow the instructions for submitting comments.

• *Fax:* 202–456–6546.

• *Mail:* Council on Environmental Quality, 730 Jackson Place NW, Washington, DC 20503.

All submissions received must include the agency name, ''Council on Environmental Quality,'' and the docket number, CEQ–2022–0003. All comments received will be posted without change to *https://www.regulations.gov,* including any personal information provided. Do not submit electronically any information you consider to be private, Confidential Business Information (CBI), or other information, the disclosure of which is restricted by statute.

FOR FURTHER INFORMATION CONTACT: To request additional information about this Information Collection Request, please contact Sharmila L. Murthy at 202–395–5750 or *Sharmila.L.Murthy@ceq.eop.gov.*

SUPPLEMENTARY INFORMATION:

CEQ previously published this proposed information collection in the **Federal Register** on March 16, 2022, and allowed 60 days for public comment. 87 FR 14842. CEQ did not receive any public comments. CEQ notes that the total burden hours have changed since the 60-day notice due to a clerical error. The purpose of this notice is to allow an additional 30 days for public comment.

Pursuant to the Paperwork Reduction Act, 44 U.S.C. 3506(c)(2)(A), CEQ is soliciting 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 CEQ, including whether the information will have practical utility; (2) evaluate the accuracy of CEQ's estimate 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; and (4) minimize the burden of the collection of information on those who are to respond, including through the use of automated collection techniques or other forms of information technology.

Abstract: The information collection activity provides a means to garner qualitative stakeholder feedback in an efficient, timely manner. CEQ envisions using surveys and focus groups to enhance customer service, improve product development, target messaging, ensure quality control, engage with stakeholders, and spur innovation. Information gathered will yield qualitative information; the collections will not be designed or expected to yield statistically representative results, but rather to provide insight about the challenges that subsets of stakeholders face. This feedback will provide insights into stakeholder perceptions, experiences and expectations, provide an understanding of issues with service, or focus attention on areas where communication, training or changes in operations might improve delivery of products or services. These collections will allow for ongoing, collaborative, and actionable communications between CEQ and its stakeholders. It also will allow feedback to contribute directly to the improvement of program management and services. The solicitation of feedback will target areas such as timeliness, appropriateness, accuracy of information, courtesy, efficiency of service delivery, and resolution of issues with service delivery. CEQ will assess responses to plan and inform efforts to improve or maintain the quality of service offered to the public. If this information is not collected, vital feedback from stakeholders on CEQ's services will be unavailable.

CEQ will only submit a collection for approval by OMB under this generic clearance if the collections are voluntary; the collections are low burden for respondents and are low- or no-cost for both the respondents and the Federal Government; the collections are noncontroversial and do not raise issues of concern to other Federal agencies; the collections are targeted to the solicitation of opinions from respondents who have experience with a program or may have experience with a program in the near future; personally identifiable information is collected only to the extent necessary and is not retained; information gathered will be used only internally for general service improvement and program management purposes; information gathered will not be used for the purpose of substantially informing influential policy decisions; and information gathered will yield qualitative information.

Title of Collection: CEQ Stakeholder Engagement.

Form Numbers: None.

Respondents/affected entities: Individuals and households; businesses, academic institutions, non-profit groups, and other organizations; or state, Tribal, local, or foreign governments.

Respondent's obligation to respond: Voluntary.

Estimated number of respondents: 125,000 (over three years).

Frequency of response: Once.

Total estimated burden: 9,000 hours (over three years). Burden is defined at 5 CFR 1320.03(b).

Total estimated cost: There are no annualized capital or operation and maintenance costs.

Amy B. Coyle,

Deputy General Counsel.

[FR Doc. 2022–13200 Filed 6–17–22; 8:45 am]

BILLING CODE 3325–F2–P

DEPARTMENT OF DEFENSE

Defense Acquisition Regulations System

[Docket Number DARS–2022–0016; OMB Control Number 0704–0478]

Information Collection Requirements; Defense Federal Acquisition Regulation Supplement (DFARS); Cyber Incident Reporting and Cloud Computing

AGENCY: Defense Acquisition Regulations System, Department of Defense (DoD).

ACTION: Notice and request for comments regarding a proposed extension of an approved information collection requirement.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995, DoD announces the proposed extension of a public information collection requirement and seeks public comment on the provisions thereof. *DoD invites comments on:* whether the proposed collection of information is necessary for the proper performance of the functions of DoD, including whether the information will have practical utility; the accuracy of the 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 the use of automated collection techniques or other forms of information technology. The Office of Management and Budget (OMB) has approved this information collection for use through September 30, 2022. DoD proposes that OMB extend its approval for use for three additional years beyond the current expiration date.

DATES: DoD will consider all comments received by August 22, 2022.

ADDRESSES: You may submit comments, identified by OMB Control Number 0704–0478, using any of the following methods:

○ *Federal eRulemaking Portal: https://www.regulations.gov.* Follow the instructions for submitting comments.

○ *Email: osd.dfars@mail.mil.* Include OMB Control Number 0704–0478 in the subject line of the message.

Comments received generally will be posted without change to *https://www.regulations.gov,* including any personal information provided.

FOR FURTHER INFORMATION CONTACT: Ms. Heather Kitchens, telephone 571–296–7152.

SUPPLEMENTARY INFORMATION:

Title and OMB Number: Safeguarding Covered Defense Information, Cyber Incident Reporting, and Cloud Computing; OMB Control Number 0704–0478.

Affected Public: Businesses or other for-profit and not-for-profit institutions.

Respondent's Obligation: Required to obtain or retain benefits.

Type of Request: Extension of a currently approved collection.

Number of Respondents: 2,017.

Responses per Respondent: 17.35, approximately.

Annual Responses: 34,974.

Average Burden per Response: 0.29 hour.

Annual Burden Hours: 10,071.

Reporting Frequency: On occasion.

Needs and Uses: Offerors and contractors must report cyber incidents on unclassified networks or information systems, within cloud computing services, and when they affect contractors designated as providing operationally critical support, as required by statute.

a. The clause at DFARS 252.204–7012, Safeguarding Covered Defense Information and Cyber Incident Reporting, covers cyber incident reporting requirements for incidents that affect a covered contractor information system or the covered defense information residing therein, or that affects the contractor's ability to perform the requirements of the contract that are designated as operationally critical support and identified in the contract.

b. DFARS provision 252.204–7008, Compliance with Safeguarding Covered Defense Information Controls, requires an offeror that proposes to vary from any of the security controls of National Institute of Standards and Technology (NIST) Special Publication (SP) 800–171 in effect at the time the solicitation is issued to submit to the contracting officer a written explanation of how the specified security control is not applicable or an alternative control or protective measure is used to achieve equivalent protection.

c. DFARS provision 252.239–7009, Representation of Use of Cloud Computing, requires contractors to report that they "anticipate" or do not anticipate" utilizing cloud computing service in performance of the resultant contract. The representation will notify contracting officers of the applicability of the cloud computing requirements at DFARS clause 252.239–7010 of the contract.

d. DFARS clause 252.239–7010, Cloud Computing Services, requires reporting of cyber incidents that occur when DoD is purchasing cloud computing services.

These DFARS provisions and clauses facilitate mandatory cyber incident reporting requirements in accordance with statutory regulations. When reports are submitted, DoD will analyze the reported information for cyber threats and vulnerabilities in order to develop response measures as well as improve U.S. Government understanding of advanced cyber threat activity. In addition, the security requirements in NIST SP 800–171 are specifically tailored for use in protecting sensitive information residing in contractor information systems and generally reduce the burden placed on contractors by eliminating Federal-centric processes and requirements. The information provided will inform the Department in assessing the overall risk to DoD covered defense information on unclassified contractor systems and networks.

Jennifer D. Johnson,

Editor/Publisher, Defense Acquisition Regulations System.

[FR Doc. 2022–13233 Filed 6–17–22; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Defense Acquisition Regulations System

[Docket Number DARS–2022–0015; OMB Control Number 0704–0216]

Information Collection Requirements; Defense Federal Acquisition Regulation Supplement; Bonds and Insurance

AGENCY: Defense Acquisition Regulations System, Department of Defense (DoD).

ACTION: Notice and request for comments regarding a proposed extension of an approved information collection requirement.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995, DoD announces the proposed extension of a public information collection requirement and seeks public comment on the provisions thereof. *DoD invites comments on:* whether the proposed collection of information is necessary for the proper performance of the functions of DoD, including whether the information will have practical utility; the accuracy of the 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 the use of automated collection techniques or other forms of information technology. The Office of Management and Budget (OMB) has approved this information collection for use through September 30, 2022. DoD proposes that OMB extend its approval for use for three additional years beyond the current expiration date.

DATES: DoD will consider all comments received by August 22, 2022.

ADDRESSES: You may submit comments, identified by OMB Control Number 0704–0216, using any of the following methods:

○ *Federal eRulemaking Portal: https://www.regulations.gov.* Follow the instructions for submitting comments.

○ *Email: osd.dfars@mail.mil.* Include OMB Control Number 0704–0216 in the subject line of the message.

Comments received generally will be posted without change to *https://www.regulations.gov,* including any personal information provided.

FOR FURTHER INFORMATION CONTACT: Mr. David E. Johnson, telephone 202–913–5764.

SUPPLEMENTARY INFORMATION:

Title and OMB Number: Defense Federal Acquisition Regulation Supplement (DFARS) Part 228, Bonds and Insurance, and related clauses at 252.228; OMB Control Number 0704–0216.

Affected Public: Businesses or other for-profit and not-for-profit institutions.

Respondent's Obligation: Required to obtain or retain benefits.

Type of Request: Extension of a currently approved collection.

Number of Respondents: 274.

Responses per Respondent: 1.

Annual Responses: 274.

Average Burden per Response: 2 hours, approximately.

Annual Burden Hours: 548.

Reporting Frequency: On occasion.

Needs and Uses: DoD uses the information obtained through this collection to determine (1) the allowability of a contractor's costs of providing war-hazard benefits to its employees; (2) the need for an investigation regarding an accident that occurs in connection with a contract; and (3) whether a non-Spanish contractor performing a service or construction contract in Spain has adequate insurance coverage. DFARS 252.228–7000, Reimbursement for War-Hazard Losses, requires the contractor to provide notice and supporting documentation to the contracting officer regarding potential claims, open claims, and settlements providing war-hazard benefits to contractor employees. DFARS 252.228–7005, Accident Reporting and Investigation Involving Aircraft, Missiles, and Space Launch Vehicles, requires the contractor to report promptly to the administrative contracting officer all pertinent facts relating to each accident involving an aircraft, missile, or space launch vehicle being manufactured, modified, repaired, or overhauled in connection with the contract. DFARS 252.228–7006, Compliance with Spanish Laws and Insurance, requires the contractor to provide the contracting officer with a written representation that the contractor has obtained the required types of insurance in the minimum amounts specified in the clause, when performing a service or construction contract in Spain.

Jennifer D. Johnson,

Editor/Publisher, Defense Acquisition Regulations System.

[FR Doc. 2022–13232 Filed 6–17–22; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

[Docket ID: DoD–2022–OS–0032]

Submission for OMB Review; Comment Request

AGENCY: The Office of the Under Secretary of Defense for Personnel and Readiness (OUSD(P&R)), Department of Defense (DoD).

ACTION: 30-Day information collection notice.

SUMMARY: The Department of Defense 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 July 21, 2022.

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, *whs.mc-alex.esd.mbx.dd-dod-information-collections@mail.mil.*

SUPPLEMENTARY INFORMATION:

Title; Associated Form; and OMB Number: Family Member Travel Screening; DD Form 3040, DD Form 3040–1, DD Form 3040–2, DD Form 3040–3; OMB Control Number 0704–0560.

Type of Request: Extension.

Number of Respondents: 267,032.

Responses per Respondent: 1.

Annual Responses: 267,032.

Average Burden per Response: 19 minutes.

Annual Burden Hours: 84,560.13.

Needs and Uses: The DD Forms 3040, 3040–1, 3040–2, and 3040–3, are used during the Family Member Travel Screening process when active duty Service members with Permanent Change of Station order request Command sponsorship for accompanied travel to remote or outside continental U.S. installations. These forms document any special medical, dental, and/or educational needs of dependents accompanying the Service member to assist in determining the availability of care at a gaining installation. This standardized collection of information is required by the National Defense Authorization Act of 2010 (NDAA), 10 U.S.C. 136 and the DoD Instruction (DoDI) 1315.19, ''The Exceptional Family Member Program (EFMP).'' The NDAA 2010 established the Office of Special Needs (OSN) and tasked the office with developing, implementing, and overseeing comprehensive policies surrounding assignment and support for these military families. Additionally, per DoDI 1315.19, military departments are required to screen family members of active duty Service members for special needs and to coordinate assignments for Service members enrolled in the EFMP to verify if necessary medical and/or educational services are available at the next assignment.

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: June 15, 2022.

Aaron T. Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2022–13242 Filed 6–17–22; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

[Docket ID DoD–2022–OS–0037]

Submission for OMB Review; Comment Request

AGENCY: Office of the General Counsel (OGC), Department of Defense (DoD).

ACTION: 30-Day information collection notice.

SUMMARY: The Department of Defense 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 July 21, 2022.

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, *whs.mc-alex.esd.mbx.dd-dod-information-collections@mail.mil.*

SUPPLEMENTARY INFORMATION:

Title; Associated Form; and OMB Number: Post Government Employment Advice Opinion Request; DD Form 2945; OMB Control Number 0704–0467.

Type of Request: Extension.

Number of Respondents: 250.

Responses per Respondent: 1.

Annual Responses: 250.

Average Burden per Response: 1 hour.

Annual Burden Hours: 250.

Needs and Uses: The information collection requirement is necessary to obtain information about post Government employment of select former and departing DoD employees who are seeking to work for Defense Contractors within two years after leaving DoD. The departing or former DoD employees use the form to organize and provide employment-related information to an ethics official who uses the information to render an advisory opinion to the employee requesting the opinion. The National Defense Authorization Act for Fiscal Year 2008, Public Law 110–181, section 847, requires that select DoD officials and former DoD officials who, within two years after leaving DoD, expect to receive compensation from a DoD Contractor, shall, before accepting such compensation, request a written opinion regarding the applicability of post-employment restrictions to activities that the official or former official may undertake on behalf of a contractor.

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: June 15, 2022.

Aaron T. Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2022–13239 Filed 6–17–22; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

[Docket ID: DoD–2022–OS–0026]

Submission for OMB Review; Comment Request

AGENCY: Office of the Under Secretary of Defense for Personnel and Readiness (OUSD(P&R)), Department of Defense (DoD).

ACTION: 30-Day information collection notice.

SUMMARY: The Department of Defense 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 July 21, 2022.

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, *whs.mc-alex.esd.mbx.dd-dod-information-collections@mail.mil.*

SUPPLEMENTARY INFORMATION:

Title; Associated Form; and OMB Number: Job Challenge Participant Focus Groups; OMB Control Number 0704–JCFG.

Type of Request: New.

Number of Respondents: 60.

Responses per Respondent: 1.

Annual Responses: 60.

Average Burden per Response: 75 minutes.

Annual Burden Hours: 75 hours.

Needs and Uses: 32 U.S. Code 509, ''National Guard Youth Challenge Program of Opportunities for Civilian Youth'' seeks to ''improve life skills and employment potential of participants by providing military-based training and supervised work experience, together with the core program components of assisting participants, to receive a high school diploma or its equivalent, leadership development, etc.'' Job Challenge is an extension of Youth Challenge and provides technical and career training to graduates of Youth Challenge.

This collection is part of a study examining the implementation of the Job Challenge program across its six operating sites. This program focuses on underserved populations and communities and brings them into alignment with Executive Order (E.O.) 13985, which directs the Federal Government to work to advance equity, with a focus on historically underserved communities. The E.O. also directs resources to be allocated to advance fairness and opportunity. The results of this collection will help inform site operations and continuous program improvement. This information is being collected to better understand program participants' experiences and perceptions. This information will be used to help inform site operations, program policy decisions, and drive continuous program improvement.

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: June 15, 2022.

Aaron T. Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2022–13240 Filed 6–17–22; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

[Docket ID: DoD–2022–OS–0025]

Submission for OMB Review; Comment Request

AGENCY: The Office of the Under Secretary of Defense for Personnel and Readiness (OUSD(P&R)), Department of Defense (DoD).

ACTION: 30-Day information collection notice.

SUMMARY: The Department of Defense 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 July 21, 2022.

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, *whs.mc-alex.esd.mbx.dd-dod-information-collections@mail.mil.*

SUPPLEMENTARY INFORMATION:

Title; Associated Form; and OMB Number: Disposition of Remains-Reimbursable Basis Request for Payment of Funeral and/or Interment Expenses; DD Form 2065, DD Form 1375; OMB Control Number 0704–0030.

Type of Request: Extension.

Number of Respondents: 2,450.

Responses per Respondent: 1.

Annual Responses: 2,450.

Average Burden per Response: 30 minutes.

Annual Burden Hours: 1,225 hours.

Needs and Uses: This collection is needed to support service members and other federal agencies by providing mortuary services, transportation, funeral and interment, support for deceased dependents of service members; and transportation and mortuary service support requested by other federal agencies. This allows the person authorized to direct disposition of our service members remains to be reimbursed for authorized expenses incident to death.

DD Forms 2065 and 1375 are initially prepared by military authorities and presented to the next-of-kin or sponsor to fill-in the reimbursable costs or desired disposition of remains. Without the information on these forms, the U.S. government would not be able to respond to the survivor's wishes or justify its expenses in handling the deceased.

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: June 15, 2022.

Aaron T. Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2022–13244 Filed 6–17–22; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Department of the Navy

Certificate of Alternate Compliance for USS LENAH H. SUTCLIFFE (DDG 123)

AGENCY: Department of the Navy (DON), Department of Defense (DOD).

ACTION: Notice of issuance of Certificate of Alternate Compliance.

SUMMARY: The U.S. Navy hereby announces that a Certificate of Alternate Compliance has been issued for USS LENAH H. SUTCLIFFE (DDG 123). Due to the special construction and purpose of this vessel, the Admiralty Counsel of the Navy has determined it is a vessel of the Navy which, due to its special construction and purpose, cannot comply fully with the navigation lights provisions of the International Regulations for Preventing Collisions at Sea, 1972 (72 COLREGS) without interfering with its special function as a naval ship. The intended effect of this notice is to warn mariners in waters where 72 COLREGS apply.

DATES: This Certificate of Alternate Compliance is effective June 21, 2022 and is applicable beginning May 25, 2022.

FOR FURTHER INFORMATION CONTACT: Lieutenant Commander J. Martin Bunt, JAGC, U.S. Navy, Admiralty Attorney, Office of the Judge Advocate General, Admiralty and Maritime Law Division (Code 11), 1322 Patterson Ave. SE, Suite 3000, Washington Navy Yard, DC 20374–5066, 202–685–5040, or *admiralty@navy.mil.*

SUPPLEMENTARY INFORMATION:

Background and Purpose

Executive Order 11964 of January 19, 1977 and 33 U.S.C. 1605 provide that the requirements of the 72 COLREGS, as to the number, position, range, or arc of visibility of lights or shapes, as well as to the disposition and characteristics of sound-signaling appliances, shall not apply to a vessel or class of vessels of the Navy where the Secretary of the Navy shall find and certify that, by reason of special construction or purpose, it is not possible for such vessel(s) to comply fully with the provisions without interfering with the special function of the vessel(s). Notice of issuance of a Certificate of Alternate Compliance must be made in the **Federal Register**.

In accordance with 33 U.S.C. 1605, the Deputy Assistant Judge Advocate General (DAJAG) (Admiralty and Maritime Law)/Admiralty Counsel of the Navy, under authority delegated by the Secretary of the Navy, hereby finds and certifies that USS LENAH H. SUTCLIFFE (DDG 123) is a vessel of special construction or purpose, and that, with respect to the position of the following navigational lights, it is not possible to comply fully with the requirements of the provisions enumerated in the 72 COLREGS without interfering with the special function of the vessel:

Annex I, paragraph 3(a), pertaining to the position of the forward masthead light; Annex I, paragraph 2(f)(i) pertaining to the vertical position of the aft masthead light; Annex I, paragraph 3(a), pertaining to the horizontal distance between the masthead lights; Annex I, paragraph 3(c), pertaining to the horizontal distance of the ‘‘task lights’’ below the masthead lights; Annex I, paragraph 2(f)(ii), pertaining to the horizontal position of the task lights above the aft masthead light(s) and vertical position of the task lights between the forward masthead light(s) and aft masthead light(s).

The DAJAG (Admiralty and Maritime Law)/Admiralty Counsel of the Navy further finds and certifies that these navigational lights are in closest possible compliance with the applicable provision of the 72 COLREGS.

(Authority: 33 U.S.C. 1605(c), E.O. 11964)

Dated: June 15, 2022.

J.M. Pike,

Commander, Judge Advocate General's Corps, U.S. Navy, Federal Register Liaison Officer.

[FR Doc. 2022–13243 Filed 6–17–22; 8:45 am]

BILLING CODE 3810–FF–P

DEPARTMENT OF EDUCATION

[Docket No.: ED–2022–SCC–0037]

Agency Information Collection Activities; Submission to the Office of Management and Budget for Review and approval; Comment Request; William D. Ford Federal Direct Loan Program (Direct Loan Program) Promissory Notes and Related Forms

AGENCY: Federal Student Aid (FSA), 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 July 21, 2022.

ADDRESSES: Written comments and recommendations for proposed information collection requests should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this information collection request by selecting ‘‘Department of Education’’ under ‘‘Currently Under Review,’’ then check ‘‘Only Show ICR for Public Comment’’ checkbox. Comments may also be sent to *ICDocketmgr@ed.gov.*

FOR FURTHER INFORMATION CONTACT: For specific questions related to collection activities, please contact Jon Utz, (202) 377–4040.

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: William D. Ford Federal Direct Loan Program (Direct Loan Program) Promissory Notes and related forms.

OMB Control Number: 1845–0007.

Type of Review: Revision of a currently approved collection.

Respondents/Affected Public: Individuals or Households *Total Estimated Number of Annual Responses:* 9,862,685.

Total Estimated Number of Annual Burden Hours: 4,021,665.

Abstract: The Direct Subsidized Loan and Direct Unsubsidized Loan Master Promissory Note (Subsidized/Unsubsidized MPN) serves as the means by which an individual agrees to repay a Direct Subsidized Loan and/or Direct Unsubsidized Loan.

The Direct PLUS Loan Master Promissory Note (PLUS Loan MPN) serves as the means by which an individual applies for and agrees to repay a Direct PLUS Loan. If a Direct PLUS Loan applicant is determined to have an adverse credit history, the applicant may qualify for a Direct PLUS Loan by obtaining an endorser who does not have an adverse credit history. The Endorser Addendum serves as the means by which an endorser agrees to repay the Direct PLUS Loan if the borrower does not repay it.

An MPN is a promissory note under which a borrower may receive loans for a single or multiple academic years. The MPN explains the terms and conditions of the loans that are made under the MPN.

The Direct Consolidation Loan Application and Promissory Note (Consolidation Note) serves as the means by which a borrower applies for a Direct Consolidation Loan and promises to repay the loan. It also explains the terms and conditions of the Direct Consolidation Loan. The Consolidation Note Instructions explain to the borrower how to complete the Consolidation Note. The Consolidation Additional Loan Listing Sheet provides additional space for a borrower to list loans that he or she wishes to consolidate. The Consolidation Request to Add Loans serves as the means by which a borrower may add other loans to an existing Direct Consolidation Loan within a specified time period. The Consolidation Loan Verification Certificate serves as the means by which the U.S. Department of Education obtains the information needed to pay off the holders of the loans that the borrower wants to consolidate.

This revision updates the Subsidized/Unsubsidized MPN and the Consolidation Note by removing information related to the 150% Subsidized Usage Limit requirements. This previous statutory provision was repealed by the Free Application for Federal Student Aid (FAFSA) Simplification Act, part of the part of the Consolidated Appropriations Act, 2021 (Public Law 116–260), and no longer applies to borrowers of Direct Subsidized Loans and Direct Consolidation Loans. There are no proposed changes to the PLUS MPN or to any of the other forms included in this submission.

Dated: June 14, 2022.

Kun Mullan,

PRA Coordinator, Strategic Collections and Clearance Governance and Strategy Division, Office of Chief Data Officer, Office of Planning, Evaluation and Policy Development.

[FR Doc. 2022–13168 Filed 6–17–22; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF EDUCATION

[Docket No. ED–2022–SCC–0047]

Agency Information Collection Activities; Submission to the Office of Management and Budget for Review and Approval; Comment Request; Loan Cancellation in the Federal Perkins Loan Program

AGENCY: Federal Student Aid (FSA), Department of Education (ED).

ACTION: Notice.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, ED is proposing an extension without change of a currently approved collection.

DATES: Interested persons are invited to submit comments on or before July 21, 2022.

ADDRESSES: Written comments and recommendations for proposed information collection requests should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this information collection request by selecting ''Department of Education'' under ''Currently Under Review,'' then check ''Only Show ICR for Public Comment'' checkbox. Comments may also be sent to *ICDocketmgr@ed.gov.*

FOR FURTHER INFORMATION CONTACT: For specific questions related to collection activities, please contact Beth Grebeldinger, (202) 377–4018.

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: Loan Cancellation in the Federal Perkins Loan Program.

OMB Control Number: 1845–0100.

Type of Review: Extension without change of a currently approved collection.

Respondents/Affected Public: Private Sector; Individuals or Households; State, Local, and Tribal Governments.

Total Estimated Number of Annual Responses: 116,872.

Total Estimated Number of Annual Burden Hours: 43,832.

Abstract: This is a request for an extension of the current OMB approval for the recordkeeping requirements contained in 34 CFR 674.53, 674.56, 674.57, 674.58 and 674.59. The information collections in these regulations are necessary to determine Federal Perkins Loan (Perkins Loan) Program borrower's eligibility to receive program benefits and to prevent fraud and abuse of program funds. There has been no change to the regulatory requirements. Due to the effects of the COVID–19 pandemic and the suspension of the collection of loans, the Department lacks sufficient data to allow for more accurate updates to the usage of the regulations.

Dated: June 14, 2022.

Kun Mullan,

PRA Coordinator, Strategic Collections and Clearance, Governance and Strategy Division, Office of Chief Data Officer. Office of Planning, Evaluation and Policy Development.

[FR Doc. 2022–13165 Filed 6–17–22; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF EDUCATION

[Docket No. ED–2022–SCC–0048]

Agency Information Collection Activities; Submission to the Office of Management and Budget for Review and Approval; Comment Request; Part 601 Preferred Lender Arrangements

AGENCY: Federal Student Aid (FSA), Department of Education (ED).

ACTION: Notice.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, ED is proposing an extension without change of a currently approved collection.

DATES: Interested persons are invited to submit comments on or before July 21, 2022.

ADDRESSES: Written comments and recommendations for proposed information collection requests should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this information collection request by selecting ''Department of Education'' under ''Currently Under Review,'' then check ''Only Show ICR for Public Comment'' checkbox. Comments may also be sent to *ICDocketmgr@ed.gov.*

FOR FURTHER INFORMATION CONTACT: For specific questions related to collection activities, please contact Beth Grebeldinger, (202) 377–4018.

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: Part 601 Preferred Lender Arrangements.

OMB Control Number: 1845–0101.

Type of Review: Extension without change of a currently approved collection.

Respondents/Affected Public: Private Sector; Individuals or Households; State, Local, and Tribal Governments.

Total Estimated Number of Annual Responses: 18,623,389.

Total Estimated Number of Annual Burden Hours: 3,801,989.

Abstract: 34 CFR part 601—Institution and Lender Requirements Relating to Education Loans is a section of the regulations governing private education loans offered at covered institutions. These regulations assure the Secretary that the integrity of the program is protected from fraud and misuse of program funds and places requirements on institutions and lenders to ensure that borrowers receive additional disclosures about Title IV, HEA program assistance prior to obtaining a private education loan. The Department is submitting the unchanged Private Education Loan Applicant Self-Certification for OMB's continued approval. While information about the applicant's cost of attendance and estimated financial assistance must be provided to the student, if available, the student will provide the data to the private loan lender who must collect and maintain the self-certification form prior to disbursement of a Private Education Loan. The Department will not receive the Private Education Loan Applicant Self-Certification form and therefore will not be collecting and maintaining the form or its data.

Dated: June 14, 2022.

Kun Mullan,

PRA Coordinator, Strategic Collections and Clearance, Governance and Strategy Division, Office of Chief Data Officer, Office of Planning, Evaluation and Policy Development.

[FR Doc. 2022–13166 Filed 6–17–22; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF ENERGY

Environmental Management Advisory Board; Meeting

AGENCY: Office of Environmental Management, Department of Energy.

ACTION: Notice of open meeting.

SUMMARY: This notice announces an online virtual open 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, July 18, 2022; 2:00 p.m.–5:00 p.m. EDT.

ADDRESSES: This meeting will be held virtually via Zoom. To attend, please contact Alyssa Petit by email, *Alyssa.Petit@em.doe.gov,* no later than 5:00 p.m. EDT on Wednesday, July 13, 2022.

FOR FURTHER INFORMATION CONTACT: Alyssa Petit, EMAB Federal Coordinator. U.S. Department of Energy, 1000 Independence Avenue SW, Washington, DC 20585. Phone (202) 430–9624 or Email: *Alyssa.Petit@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

- Remarks from EM leadership
- Charge Discussion
- Reading of Public Comment
- Ethics Briefing for EMAB Members
- Board Business

Public Participation: The online virtual meeting is open to the public. 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. If you require special accommodations due to a disability, please contact Alyssa Petit at least seven days in advance of the meeting at the email address listed above.

Public comments will be accepted via email prior to and after the meeting. Comments received no later than 5:00 p.m. EDT on Wednesday, July 13, 2022, 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, July 25, 2022. Please email comments to Alyssa Petit at: *Alyssa.Petit@em.doe.gov.*

Minutes: Minutes will be available by writing or calling Alyssa Petit 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 June 14, 2022.

LaTanya Butler,

Deputy Committee Management Officer.

[FR Doc. 2022–13181 Filed 6–17–22; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

[Docket Nos. 13–04–LNG and 16–109–LNG]

Lake Charles LNG Export Company, LLC; Application To Amend Export Term Through December 31, 2050, for Existing Non-Free Trade Agreement Authorizations

AGENCY: Office of Fossil Energy and Carbon Management, Department of Energy.

ACTION: Notice of application.

SUMMARY: The Office of Fossil Energy and Carbon Management (FECM) (formerly the Office of Fossil Energy) of the Department of Energy (DOE) gives notice (Notice) of receipt of an application (Application), filed on May 24, 2022, by Lake Charles LNG Export Company, LLC (Lake Charles LNG Export). Lake Charles LNG Export seeks to amend the export term set forth in its current authorizations to export liquefied natural gas (LNG) to non-free trade agreement countries, DOE/FE Order Nos. 3868 and 4010 (both as amended), to a term ending on December 31, 2050. Lake Charles LNG Export filed the Application under the Natural Gas Act (NGA) and DOE's policy statement entitled, ''Extending Natural Gas Export Authorizations to Non-Free Trade Agreement Countries Through the Year 2050'' (Policy Statement). Protests, motions to intervene, notices of intervention, and written comments on the requested term extension are invited.

DATES: Protests, motions to intervene, or notices of intervention, as applicable, and written comments are to be filed electronically as detailed in the Public Comment Procedures section no later than 4:30 p.m., Eastern time, July 6, 2022.

ADDRESSES:

Electronic Filing by email: fergas@hq.doe.gov.

Although DOE has routinely accepted public comment submissions through a variety of mechanisms, including postal mail and hand delivery/courier, DOE has found it necessary to make temporary modifications to the comment submission process in light of the ongoing Covid-19 pandemic. DOE is currently accepting only electronic submissions at this time. If a commenter finds that this change poses an undue hardship, please contact Office of Resource Sustainability staff at (202) 586–4749 or (202) 586–7893 to discuss the need for alternative arrangements. Once the Covid-19 pandemic health emergency is resolved, DOE anticipates resuming all of its regular options for public comment submission, including postal mail and hand delivery/courier.

FOR FURTHER INFORMATION CONTACT:

Jennifer Wade or Peri Ulrey, U.S. Department of Energy (FE–34), Office of Regulation, Analysis, and Engagement, Office of Resource Sustainability, Office of Fossil Energy and Carbon Management, Forrestal Building, Room 3E–042, 1000 Independence Avenue SW, Washington, DC 20585, (202) 586–4749 or (202) 586–7893, *jennifer.wade@hq.doe.gov* or *peri.ulrey@hq.doe.gov.*

Cassandra Bernstein, U.S. Department of Energy (GC–76), Office of the Assistant General Counsel for Energy Delivery and Resilience, Forrestal Building, Room 6D–033, 1000 Independence Avenue SW, Washington, DC 20585, (202) 586–9793, *cassandra.bernstein@hq.doe.gov.*

SUPPLEMENTARY INFORMATION: Lake Charles LNG Export is authorized to export domestically produced LNG by vessel from the Lake Charles Terminal, located in Lake Charles, Louisiana, to any country with which the United States has not entered into a free trade agreement (FTA) requiring national treatment for trade in natural gas, and with which trade is not prohibited by U.S. law or policy (non-FTA countries), pursuant to NGA section 3(a),[1] under the following orders and their amendments:

- DOE/FE Order No. 3868 (Docket No. 13–04–LNG), in a volume equivalent to 730 billion cubic per year (Bcf/yr) of natural gas.[2]
- In DOE/FE Order No. 4010 (Docket No. 16–109–LNG), in a volume equivalent to 121 Bcf/yr of natural gas.[3]

In the Application,[4] Lake Charles LNG Export asks DOE to extend the 20-year export term set forth in both Order No. 3868 and the non-FTA portion of Order No. 4010 to a term ending on December 31, 2050, as provided in the Policy Statement.[5] Additional details can be found in the Application, posted on the DOE website at: *www.energy.gov/sites/default/files/2022-06/Lake%20Charles%20LNG%20Export%20Company%20LLC%20DOE%20Application%20Re%202050.pdf.*

DOE Evaluation

In the Policy Statement, DOE adopted a term through December 31, 2050 (inclusive of any make-up period), as the standard export term for long-term non-FTA authorizations.[6] As the basis for its decision, DOE considered its obligations under NGA section 3(a), the public comments supporting and opposing the proposed Policy Statement, and a wide range of information bearing on the public interest.[7] DOE explained that, upon receipt of an application under the Policy Statement, it would conduct a public interest analysis of the application under NGA section 3(a). DOE further stated that ''the public interest analysis will be limited to the application for the term extension—meaning an intervenor or protestor may challenge the requested extension but not the existing non-FTA order.'' [8]

Accordingly, in reviewing Lake Charles LNG Export's Application, DOE will consider any issues required by law or policy under NGA section 3(a), as informed by the Policy Statement. To the extent appropriate, DOE will consider the study entitled, *Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports* (2018 LNG Export Study),[9] DOE's

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[1] 15 U.S.C. 717b(a).

[2] *Lake Charles LNG Export Co., LLC,* DOE/FE Order No. 3868, Docket No. 13–04–LNG, Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Lake Charles Terminal in Calcasieu Parish, Louisiana, to Non-Free Trade Agreement Nations (July 29, 2016), *amended by* Order No. 3868–A (Oct. 6, 2020) (amending the commencement of operations deadline).

[3] *Lake Charles LNG Export Co., LLC,* DOE/FE Order No. 4010, Docket No. 16–109–LNG, Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Lake Charles Terminal in Lake Charles, Louisiana, to Free Trade and Non-Free Trade Agreement Nations (June 29, 2017), *amended by* Order No. 4010–A (Oct. 6, 2020) (amending the commencement of operations deadline). The portion of this order authorizing Lake Charles LNG Export to export LNG to FTA countries is not subject to this Notice. *See* 15 U.S.C. 717b(c).

[4] Lake Charles LNG Export Co., LLC, Application to Amend Export Term for Existing Long-Term Authorizations Through December 31, 2050, Docket Nos. 13–04–LNG and 16–109–LNG (May 24, 2022). Lake Charles LNG Export's request regarding its FTA authorization, Order No. 3252 (Docket No. 13–04–LNG), is not subject to this notice. *See* 15 U.S.C. 717b(c).

[5] U.S. Dep't of Energy, Extending Natural Gas Export Authorizations to Non-Free Trade Agreement Countries Through the Year 2050; Notice of Final Policy Statement and Response to Comments, 85 FR 52237 (Aug. 25, 2020) [hereinafter Policy Statement].

[6] *See id.,* 85 FR 52247.

[7] *See id.,* 85 FR 52247.

[8] *Id.,* 85 FR 52247.

[9] *See* NERA Economic Consulting, Macroeconomic Outcomes of Market Determined

response to public comments received on that Study,[10] and the following environmental documents:

- *Addendum to Environmental Review Documents Concerning Exports of Natural Gas From the United States,* 79 FR 48132 (Aug. 15, 2014); [11]
- *Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas From the United States,* 79 FR 32260 (June 4, 2014); [12] and
- *Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas From the United States: 2019 Update,* 84 FR 49278 (Sept. 19, 2019), and DOE's response to public comments received on that study.[13]

Parties that may oppose the Application should address these issues and documents in their comments and/or protests, as well as other issues deemed relevant to the Application.

The National Environmental Policy Act (NEPA), 42 U.S.C. 4321 *et seq.,* requires DOE to give appropriate consideration to the environmental effects of its proposed decisions. No final decision will be issued in this proceeding until DOE has met its environmental responsibilities.

Public Comment Procedures

In response to this Notice, any person may file a protest, comments, or a motion to intervene or notice of intervention, as applicable, addressing the Application. Interested parties will be provided 15 days from the date of publication of this Notice in which to submit comments, protests, motions to intervene, or notices of intervention. The public previously was given an opportunity to intervene in, protest, and comment on Lake Charles LNG Export's long-term non-FTA applications. Therefore, DOE will not consider comments or protests that do not bear directly on the requested term extension.

Any person wishing to become a party to the proceeding must file a motion to intervene or notice of intervention. The filing of comments or a protest with respect to the Application will not serve to make the commenter or protestant a party to the proceeding, although protests and comments received from persons who are not parties will be considered in determining the appropriate action to be taken on the Application. All protests, comments, motions to intervene, or notices of intervention must meet the requirements specified by the regulations in 10 CFR part 590, including the service requirements.

As noted, DOE is only accepting electronic submissions at this time. Please email the filing to *fergas.hq.doe.gov.* All filings must include a reference to ''Docket Nos. 13–04–LNG and 16–09–LNG'' or ''Lake Charles LNG Export Company, LLC Term Extension'' in the title line.

Please Note: Please include all related documents and attachments (*e.g.,* exhibits) in the original email correspondence. Please do not include any active hyperlinks or password protection in any of the documents or attachments related to the filing. All electronic filings submitted to DOE must follow these guidelines to ensure that all documents are filed in a timely manner. Any hardcopy filing submitted greater in length than 50 pages must also include, at the time of the filing, a digital copy on disk of the entire submission.

The Application and any filed protests, motions to intervene, notices of interventions, and comments will also be available electronically by going to the following DOE Web address: *www.energy.gov/fecm/regulation.*

A decisional record on the Application will be developed through responses to this Notice by parties, including the parties' written comments and replies thereto. Additional procedures will be used as necessary to achieve a complete understanding of the facts and issues. If an additional procedure is scheduled, notice will be provided to all parties. If no party requests additional procedures, a final Opinion and Order may be issued based on the official record, including the Application and responses filed by parties pursuant to this Notice, in accordance with 10 CFR 590.316.

Signed in Washington, DC, on June 14, 2022.

Amy Sweeney,

Director, Office of Regulation, Analysis, and Engagement, Office of Resource Sustainability.

[FR Doc. 2022–13193 Filed 6–17–22; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

DOE/NSF Nuclear Science Advisory Committee

AGENCY: Office of Science, Department of Energy.

ACTION: Notice of open meeting.

SUMMARY: This notice announces an open virtual meeting of the DOE/NSF Nuclear Science Advisory Committee (NSAC). Due to the COVID–19 pandemic, this meeting will be held virtually for members of the public. The Federal Advisory Committee Act requires that public notice of these meetings be announced in the **Federal Register**.

DATES: Wednesday, July 13, 2022; 9:00 a.m.–3:30 p.m. (eastern time).

ADDRESSES: Information to participate virtually can be found on the NSAC website closer to the meeting at *https://science.osti.gov/np/nsac/meetings.*

FOR FURTHER INFORMATION CONTACT: Brenda L. May, Committee Manager, NSAC, Email: *Brenda.May@science.doe.gov* or Telephone: (301) 903–0536.

SUPPLEMENTARY INFORMATION:

Purpose of the Board: The purpose of the Board is to provide advice and guidance on a continuing basis to the Department of Energy and the National Science Foundation on scientific priorities within the field of basic nuclear science research.

Tentative Agenda

- Call to Order, Introductions, Review of the Agenda
- Perspectives from the Department of Energy and National Science Foundation
- Update from the Department of Energy and National Science Foundation's Nuclear Physics Office
- Presentation of new Charge for the Long-Range Plan
- Discussion of the Long-Range Plan Charge
- Update on DNP planning for Community Workshops
- NSAC Business/Discussions
- Public Comment

Public Participation: The meeting is open to the public. Please check the website below for updates and

Levels of U.S. LNG Exports (June 7, 2018), *available at: www.energy.gov/sites/prod/files/2018/06/f52/Macroeconomic%20LNG%20Export%20Study%202018.pdf.*

[10] U.S. Dep't of Energy, Study on Macroeconomic Outcomes of LNG Exports: Response to Comments Received on Study; Notice of Response to Comments, 83 FR 67251 (Dec. 28, 2018).

[11] The Addendum and related documents are available at: *https://energy.gov/fe/draft-addendum-environmental-review-documents-concerning-exports-natural-gas-united-states.*

[12] The 2014 Life Cycle Greenhouse Gas Report is available at: *https://energy.gov/fe/life-cycle-greenhouse-gas-perspective-exporting-liquefied-natural-gas-united-states.*

[13] U.S. Dep't of Energy, Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas From the United States: 2019 Update—Response to Comments, 85 FR 72 (Jan. 2, 2020). The 2019 Update and related documents are available at: *https://fossil.energy.gov/app/docketindex/docket/index/21.*

information on how to view the meeting. If you would like to file a written statement with the Committee, you may do so either before or after the meeting. If you would like to make oral statements regarding any of these items on the agenda, you should contact Brenda L. May at *Brenda.May@science.doe.gov.* You must make your request for an oral statement at least five business days before the meeting. Reasonable provisions will be made to include the scheduled oral statements on the agenda. The Chairperson of the Committee will conduct the meeting to facilitate the orderly conduct of business. Public comment will follow the 10-minute rule.

Minutes: The minutes of the meeting will be available for review on the U.S. Department of Energy's Office of Nuclear Physics website at *https://science.osti.gov/np/nsac/meetings.*

Signed in Washington, DC, on June 14, 2022.

LaTanya Butler,

Deputy Committee Management Officer.

[FR Doc. 2022–13189 Filed 6–17–22; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Agency Information Collection Extension

AGENCY: Bonneville Power Administration, Department of Energy.

ACTION: Submission for Office of Management and Budget (OMB) review; comment request.

SUMMARY: The Department of Energy (DOE), Bonneville Power Administration (BPA), has submitted an information collection request to the OMB for extension under the provisions of the Paperwork Reduction Act of 1995. The information collection requests a three-year extension of its collection, titled Bonneville Power Administration (BPA) Security, OMB Control Number 1910–5188. The proposed collection will be used to determine access to BPA facilities and report incidents of damage or loss. This information is used to manage and oversee personnel and physical security programs.

DATES: Comments regarding this proposed information collection must be received on or before July 21, 2022. If you anticipate that you will be submitting comments but find it difficult to do so within the period allowed by this notice, please advise the OMB Desk Officer of your intention to make a submission as soon as possible. The Desk Officer may be telephoned at (202) 881–8585.

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. Written comments may be sent to Bonneville Power Administration, Attn: Stephanie Noell, Privacy Program, CGI–7, P.O. Box 3621, Portland, OR 97208–3621, or by email at *privacy@bpa.gov.*

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the information collection instrument and instructions should be directed to Attn: Stephanie Noell, Privacy Program, by email at *privacy@bpa.gov,* or by phone at 503–230–3881.

SUPPLEMENTARY INFORMATION: This information collection request contains: (1) *OMB No.:* 1910–5188; (2) *Information Collection Request Title:* Security; (3) *Type of Request:* Extension; (4) *Purpose:* This information collection is associated with BPA's management and oversight of access to BPA offices and facilities in order to provide measures to safeguard personnel; to prevent unauthorized access to equipment, facilities, material and documents; to safeguard against espionage, sabotage, and theft; the likely respondents include BPA employees, contractors, and the public: BPA F 1400.22a—Other Utility/Contractor/Vendor Worker Access Request, BPA F 1400.22e—Non-Government Employee Data in HRMIS, BPA F 5630.04e—Security Privilege Request—for BPA Control Centers, BPA F 5632.01e—Security Incident Report, BPA F 5632.08e—Unclassified Visits and Assignments—Foreign Nationals Registration (Short Form), BPA F 5632.09e—Personal Identity Verification (PIV) Request for LSSO/Smart Credential, BPA F 5632.11a—BPA Visitor(s) Access Request—with continuation page, BPA F 5632.11e—BPA Visitor(s) Access Request, BPA F 5632.12e—Evidence/Chain of Custody Document, BPA F 5632.18e—Crime Witness Telephone Report, BPA F 5632.27e—Badge Replacement Request, BPA F 5632.30e—PIN Code Request, BPA F 5632.32e—Card Key Access Request; (5) *Estimated Number of Respondents:* 8,033; (6) *Annual Estimated Number of Respondents:* 8,033; (7) *Annual Estimated Number of Burden Hours:* 1,509; (8) *Annual Estimated Reporting and Recordkeeping Cost Burden:* $0.

Statutory Authority: The Bonneville Project Act of 1937, 16 U.S.C. 832a; and the following additional authorities: 5 U.S.C. 1302, 2951, 3301, 3372, 4118, & 8347; 42 U.S.C. 2165 & 7101, *et seq.;* 5 CFR Chapter I parts 5 & 736, E.O. 10450, E.O. 12107, E.O. 12333, E.O. 13284, E.O. 13467, E.O. 13470, E.O. 13488, E.O. 13764, FERC Order No. 706, FIPS 201–2, and HSPD 12.

Signing Authority: This document of the Department of Energy was signed on June 10, 2022, by Candice D. Palen, Information Collection Clearance Manager, Bonneville Power Administration, pursuant to delegated authority from the Secretary of Energy. That document with the original signature and date is maintained by DOE. For administrative purposes only, and in compliance with requirements of the Office of the Federal Register, the undersigned DOE Federal Register Liaison Officer has been authorized to sign and submit the document in electronic format for publication, as an official document of the Department of Energy. This administrative process in no way alters the legal effect of this document upon publication in the **Federal Register**.

Signed in Washington, DC, on June 15, 2022.

Treena V. Garrett,

Federal Register Liaison Officer, U.S. Department of Energy.

[FR Doc. 2022–13185 Filed 6–17–22; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Environmental Management Site-Specific Advisory Board, Nevada; Meeting

AGENCY: Office of Environmental Management, Department of Energy.

ACTION: Notice of open meeting.

SUMMARY: This notice announces an in-person/virtual hybrid meeting of the Environmental Management Site-Specific Advisory Board (EM SSAB), Nevada. The Federal Advisory Committee Act requires that public notice of this meeting be announced in the **Federal Register**.

DATES: Wednesday, July 20, 2022; 4:00 p.m.–8:30 p.m.

The opportunity for public comment is at 4:10 p.m. PT.

This time is subject to change; please contact the Nevada Site Specific Advisory Board (NSSAB) Administrator (below) for confirmation of time prior to the meeting.

ADDRESSES: This meeting will be open to the public in-person at the Beatty

Community Center (address below) or virtually via Microsoft Teams. To attend virtually, please contact Barbara Ulmer, NSSAB Administrator, by email *nssab@emcbc.doe.gov* or phone (702) 523–0894, no later than 4:00 p.m. PT on Monday, July 18, 2022.

Beatty Community Center, 100 A Avenue South, Beatty, NV 89003.

FOR FURTHER INFORMATION CONTACT: Barbara Ulmer, NSSAB Administrator, by phone: (702) 523–0894 or email: *nssab@emcbc.doe.gov* or visit the Board's internet homepage at *www.nnss.gov/NSSAB/.*

SUPPLEMENTARY INFORMATION:

Purpose of the Board: The purpose of the Board is to make recommendations to DOE–EM and site management in the areas of environmental restoration, waste management, and related activities.

Tentative Agenda

1. Follow-up to Post Closure Inspection Observation and Evaluation (Work Plan Item #4)
2. Follow-up to Optimization of Hybrid Meeting Approach (Work Plan Item #2)
3. Briefing for Radioactive Waste Acceptance Program Annual Report (Work Plan Item #5)

Public Participation: The in-person/virtual hybrid meeting is open to the public either in-person at the Beatty Community Center or via Microsoft Teams. To sign-up for public comment, please contact the NSSAB Administrator (above) no later than 4:00 p.m. PT on Monday, July 18, 2022. In addition to participation in the live public comment session identified above, written statements may be filed with the Board either before or within seven days after the meeting by sending them to the NSSAB Administrator at the aforementioned email address. Written public comment received prior to the meeting will be read into the record. The Deputy Designated Federal Officer is empowered to conduct the meeting in a fashion that will facilitate the orderly conduct of business. Individuals wishing to make public comments can do so in 2-minute segments for the 15 minutes allotted for public comments.

Minutes: Minutes will be available by writing or calling Barbara Ulmer, NSSAB Administrator, U.S. Department of Energy, EM Nevada Program, 100 North City Parkway, Suite 1750, Las Vegas, NV 89106; Phone: (702) 523–0894. Minutes will also be available at the following website: *http://www.nnss.gov/nssab/pages/MM_FY22.html.*

Signed in Washington, DC, on June 14, 2022.

LaTanya Butler,

Deputy Committee Management Officer.

[FR Doc. 2022–13182 Filed 6–17–22; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Agency Information Collection Extension

AGENCY: U.S. Department of Energy.

ACTION: Submission for Office of Management and Budget (OMB) review; comment request.

SUMMARY: The Department of Energy (DOE) has submitted an information collection request to the OMB for extension under the provisions of the Paperwork Reduction Act of 1995. The information collection requests a three-year extension of its collection, titled Certification of Vaccination—DOE Onsite Support Service Contractor Employees,

OMB Control Number 1910–5194. The proposed collection will collect vaccination status information from DOE Onsite Support Service Contractor Employees. This information is being collected and maintained in order to promote the safety of Federal buildings, the Federal workforce, and others on site at agency facilities consistent with the COVID–19 Workplace Safety: Agency Model Safety Principles established by the Safer Federal Workforce Task Force and guidance from the Centers for Disease Control and Prevention and the Occupational Safety and Health Administration. Specifically, this information is being used by DOE staff charged with implementing and enforcing workplace safety protocols.

DATES: Comments regarding this collection must be received on or before July 21, 2022. If you anticipate that you will be submitting comments but find it difficult to do so within the period allowed by this notice, please advise the OMB Desk Officer of your intention to make a submission as soon as possible. The Desk Officer may be telephoned at 202–881–8585.

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: John Harris, (202) 287–1471, *John.Harris@hq.doe.gov*.

SUPPLEMENTARY INFORMATION:

This information collection request contains:

(1) *OMB No.:* 1910–5194;

(2) *Information Collection Request Title:* Certification of Vaccination—DOE Onsite Support Service Contractor Employees;

(3) *Type of Request:* Extension;

(4) *Purpose:* This information is being collected, and maintained in order to promote the safety of Federal buildings, the Federal workforce, and others on site at agency facilities consistent with the COVID–19 Workplace Safety: Agency Model Safety Principles established by the Safer Federal Workforce Task Force, and guidance from the Centers for Disease Control and Prevention, and the Occupational Safety and Health Administration. Specifically, this information will be used by DOE staff charged with implementing and enforcing workplace safety protocols.

(5) *Annual Estimated Number of Respondents:* 15,000;

(6) *Annual Estimated Number of Total Responses:* 15,000;

(7) *Annual Estimated Number of Burden Hours:* 2,505;

(8) *Annual Estimated Reporting and Recordkeeping Cost Burden:* $232,057.

Statutory Authority: Executive Order 13991, Protecting the Federal Workforce and Requiring Mask-Wearing (Jan. 20, 2021); Occupational Safety and Health Program for Federal Employees (Feb. 26, 1980); 5 U.S.C. chapters 11, and 79.; the COVID–19 Workplace Safety: Agency Model Safety Principles established by the Safer Federal Workforce Task Force, and guidance from Centers for Disease Control and Prevention, and the Occupational Safety and Health Administration.

Signing Authority

This document of the Department of Energy was signed on June 14, 2022, by John R. Bashista, Director, Office of Acquisition Management and Senior Procurement Executive, pursuant to delegated authority from the Secretary of Energy. That document with the original signature and date is maintained by DOE. For administrative purposes only, and in compliance with requirements of the Office of the Federal Register, the undersigned DOE Federal Register Liaison Officer has been authorized to sign and submit the document in electronic format for publication, as an official document of the Department of Energy. This administrative process in no way alters the legal effect of this document upon publication in the **Federal Register**.

Signed in Washington, DC, on June 15, 2022.

Treena V. Garrett,

Federal Register Liaison Officer, U.S. Department of Energy.

[FR Doc. 2022–13194 Filed 6–17–22; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Environmental Management Site-Specific Advisory Board, Northern New Mexico; Meeting

AGENCY: Office of Environmental Management, Department of Energy.

ACTION: Notice of open meeting.

SUMMARY: This notice announces an in-person/virtual hybrid meeting of the Environmental Management Site-Specific Advisory Board (EM SSAB), Northern New Mexico. The Federal Advisory Committee Act requires that public notice of this meeting be announced in the **Federal Register**.

DATES: Wednesday, July 20, 2022; 1:00 p.m.–5:00 p.m.

ADDRESSES: This hybrid meeting will be open to the public virtually via WebEx only. To attend virtually, please contact the Northern New Mexico Citizens Advisory Board (NNMCAB) Executive Director (below) no later than 5:00 p.m. MDT on Friday, July 15, 2022.

Board members, Department of Energy (DOE) representatives, agency liaisons, and Board support staff will participate in-person, strictly following COVID–19 precautionary measures, at: Cottonwood on the Greens, 4244 Diamond Drive, Los Alamos, NM 87544.

FOR FURTHER INFORMATION CONTACT: Menice B. Santistevan, NNMCAB Executive Director, by Phone: (505) 699–0631 or Email: *menice.santistevan@em.doe.gov.*

SUPPLEMENTARY INFORMATION:

Purpose of the Board: The purpose of the Board is to make recommendations to DOE–EM and site management in the areas of environmental restoration, waste management, and related activities.

Tentative Agenda

1. Update on Waste Isolation Pilot Plant
2. Various program updates

Public Participation: The in-person/online virtual hybrid meeting is open to the public virtually via WebEx only. Written statements may be filed with the Board no later than 5:00 p.m. MDT on Friday, July 15, 2022 or within seven days after the meeting by sending them to the NNMCAB Executive Director at the aforementioned email address. Written public comments received prior to the meeting will be read into the record. The Deputy Designated Federal Officer is empowered to conduct the meeting in a fashion that will facilitate the orderly conduct of business. Individuals wishing to submit public comments should follow as directed above.

Minutes: Minutes will be available by emailing or calling Menice Santistevan, NNMCAB Executive Director, at *menice.santistevan@em.doe.gov* or at (505) 699–0631.

Signed in Washington, DC, on June 14, 2022.

LaTanya Butler,

Deputy Committee Management Officer.

[FR Doc. 2022–13183 Filed 6–17–22; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

[Docket Nos. 11–59–LNG and 16–110–LNG]

Lake Charles Exports, LLC; Application To Amend Export Term Through December 31, 2050, for Existing Non-Free Trade Agreement Authorizations

AGENCY: Office of Fossil Energy and Carbon Management, Department of Energy.

ACTION: Notice of application.

SUMMARY: The Office of Fossil Energy and Carbon Management (FECM) (formerly the Office of Fossil Energy) of the Department of Energy (DOE) gives notice (Notice) of receipt of an application (Application), filed on May 24, 2022, by Lake Charles Exports, LLC (LCE). LCE seeks to amend the export term set forth in its current authorizations to export liquefied natural gas (LNG) to non-free trade agreement countries, DOE/FE Order Nos. 3324–A and 4011 (both as amended), to a term ending on December 31, 2050. LCE filed the Application under the Natural Gas Act (NGA) and DOE's policy statement entitled, ''Extending Natural Gas Export Authorizations to Non-Free Trade Agreement Countries Through the Year 2050'' (Policy Statement). Protests, motions to intervene, notices of intervention, and written comments on the requested term extension are invited.

DATES: Protests, motions to intervene, or notices of intervention, as applicable, and written comments are to be filed electronically as detailed in the Public Comment Procedures section no later than 4:30 p.m., Eastern time, July 6, 2022.

ADDRESSES:

Electronic Filing by email: fergas@hq.doe.gov.

Although DOE has routinely accepted public comment submissions through a variety of mechanisms, including postal mail and hand delivery/courier, DOE has found it necessary to make temporary modifications to the comment submission process in light of the ongoing Covid-19 pandemic. DOE is currently accepting only electronic submissions at this time. If a commenter finds that this change poses an undue hardship, please contact Office of Resource Sustainability staff at (202) 586–4749 or (202) 586–7893 to discuss the need for alternative arrangements. Once the Covid-19 pandemic health emergency is resolved, DOE anticipates resuming all of its regular options for public comment submission, including postal mail and hand delivery/courier.

FOR FURTHER INFORMATION CONTACT:

Jennifer Wade or Peri Ulrey, U.S. Department of Energy (FE–34), Office of Regulation, Analysis, and Engagement, Office of Resource Sustainability, Office of Fossil Energy and Carbon Management, Forrestal Building, Room 3E–042, 1000 Independence Avenue SW, Washington, DC 20585, (202) 586–4749 or (202) 586–7893, *jennifer.wade@hq.doe.gov* or *peri.ulrey@hq.doe.gov.*

Cassandra Bernstein, U.S. Department of Energy (GC–76), Office of the Assistant General Counsel for Energy Delivery and Resilience, Forrestal Building, Room 6D–033, 1000 Independence Avenue SW, Washington, DC 20585, (202) 586–9793, *cassandra.bernstein@hq.doe.gov.*

SUPPLEMENTARY INFORMATION:

LCE is authorized to export domestically produced LNG by vessel from the Lake Charles Terminal, located in Lake Charles, Louisiana, to any country with which the United States has not entered into a free trade agreement (FTA) requiring national treatment for trade in natural gas, and with which trade is not prohibited by U.S. law or policy (non-FTA countries), pursuant to NGA section 3(a),[1] under the following orders and their amendments:

- DOE/FE Order No. 3324–A (Docket No. 11–59–LNG), in a volume

[1] 15 U.S.C. 717b(a).

equivalent to 730 billion cubic per year (Bcf/yr) of natural gas; [2] and

- DOE/FE Order No. 4011 (Docket No. 16–110–LNG), in a volume equivalent to 121 Bcf/yr of natural gas.[3]

In the Application,[4] LCE asks DOE to extend the 20-year export term set forth in both Order No. 3324–A and the non-FTA portion of Order No. 4011 to a term ending on December 31, 2050, as provided in the Policy Statement.[5] Additional details can be found in the Application, posted on the DOE website at: *www.energy.gov/sites/default/files/2022-06/Lake%20Charles%20LNG%20Export%20Company%20LLC%20DOE%20Application%20Re%202050.pdf.*

DOE Evaluation

In the Policy Statement, DOE adopted a term through December 31, 2050 (inclusive of any make-up period), as the standard export term for long-term non-FTA authorizations.[6] As the basis for its decision, DOE considered its obligations under NGA section 3(a), the public comments supporting and opposing the proposed Policy Statement, and a wide range of information bearing on the public interest.[7] DOE explained that, upon receipt of an application under the Policy Statement, it would conduct a public interest analysis of the application under NGA section 3(a). DOE further stated that ''the public interest analysis will be limited to the application for the term extension—meaning an intervenor or protestor may challenge the requested extension but not the existing non-FTA order.'' [8]

Accordingly, in reviewing LCE's Application, DOE will consider any issues required by law or policy under NGA section 3(a), as informed by the Policy Statement. To the extent appropriate, DOE will consider the study entitled, *Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports* (2018 LNG Export Study),[9] DOE's response to public comments received on that Study,[10] and the following environmental documents:

- *Addendum to Environmental Review Documents Concerning Exports of Natural Gas From the United States,* 79 FR 48132 (Aug. 15, 2014); [11]
- *Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas From the United States,* 79 FR 32260 (June 4, 2014); [12] and
- *Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas From the United States: 2019 Update,* 84 FR 49278 (Sept. 19, 2019), and DOE's response to public comments received on that study.[13]

Parties that may oppose the Application should address these issues and documents in their comments and/or protests, as well as other issues deemed relevant to the Application.

The National Environmental Policy Act (NEPA), 42 U.S.C. 4321 *et seq.,* requires DOE to give appropriate consideration to the environmental effects of its proposed decisions. No final decision will be issued in this proceeding until DOE has met its environmental responsibilities.

Public Comment Procedures

In response to this Notice, any person may file a protest, comments, or a motion to intervene or notice of intervention, as applicable, addressing the Application. Interested parties will be provided 15 days from the date of publication of this Notice in which to submit comments, protests, motions to intervene, or notices of intervention. The public previously was given an opportunity to intervene in, protest, and comment on LCE's long-term non-FTA applications. Therefore, DOE will not consider comments or protests that do not bear directly on the requested term extension.

Any person wishing to become a party to the proceeding must file a motion to intervene or notice of intervention. The filing of comments or a protest with respect to the Application will not serve to make the commenter or protestant a party to the proceeding, although protests and comments received from persons who are not parties will be considered in determining the appropriate action to be taken on the Application. All protests, comments, motions to intervene, or notices of intervention must meet the requirements specified by the regulations in 10 CFR part 590, including the service requirements.

As noted, DOE is only accepting electronic submissions at this time. Please email the filing to *fergas.hq.doe.gov.* All filings must include a reference to ''Docket Nos. 11–59–LNG and 16–110–LNG'' or ''Lake Charles Exports, LLC Term Extension'' in the title line.

Please Note: Please include all related documents and attachments (*e.g.,* exhibits) in the original email correspondence. Please do not include any active hyperlinks or password protection in any of the documents or attachments related to the filing. All electronic filings submitted to DOE must follow these guidelines to ensure that all documents are filed in a timely manner. Any hardcopy filing submitted greater in length than 50 pages must also include, at the time of the filing, a digital copy on disk of the entire submission.

The Application and any filed protests, motions to intervene, notices of interventions, and comments will also be available electronically by going to the following DOE Web address: *www.energy.gov/fecm/division-natural-gas-regulation.*

A decisional record on the Application will be developed through responses to this Notice by parties, including the parties' written comments

[2] *Lake Charles Exports, LLC,* DOE/FE Order No. 3324–A, Docket No. 11–59–LNG, Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Lake Charles Terminal in Calcasieu Parish, Louisiana to Non-Free Trade Agreement Nations (July 29, 2016), *amended by* DOE/FE Order No. 3324–B (Oct. 6, 2020) (amending the commencement of operations deadline).

[3] *Lake Charles Exports, LLC,* DOE/FE Order No. 4011, Docket No. 16–110–LNG, Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Lake Charles Terminal in Lake Charles, Louisiana, to Free Trade Agreement and Non-Free Trade Agreement Nations (June 29, 2017), *amended by* DOE/FE Order No. 4011–A (Oct. 6, 2020) (amending the commencement of operations deadline). The portion of this order authorizing LCE to export LNG to FTA countries is not subject to this Notice. *See* 15 U.S.C. 717b(c).

[4] Lake Charles Exports, LLC, Application to Amend Export Term for Existing Long-Term Authorizations Through December 31, 2050, Docket Nos. 11–59–LNG and 16–110–LNG (May 24, 2022). LCE's request regarding its FTA authorization, Order No. 2987 (Docket No. 11–59–LNG), is not subject to this Notice. *See* 15 U.S.C. 717b(c).

[5] U.S. Dep't of Energy, Extending Natural Gas Export Authorizations to Non-Free Trade Agreement Countries Through the Year 2050; Notice of Final Policy Statement and Response to Comments, 85 FR 52237 (Aug. 25, 2020) [hereinafter Policy Statement].

[6] *See id.,* 85 FR 52247.

[7] *See id.,* 85 FR 52247.

[8] *Id.,* 85 FR 52247.

[9] *See* NERA Economic Consulting, Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports (June 7, 2018), *available at: www.energy.gov/sites/prod/files/2018/06/f52/Macroeconomic%20LNG%20Export%20Study%202018.pdf.*

[10] U.S. Dep't of Energy, Study on Macroeconomic Outcomes of LNG Exports: Response to Comments Received on Study; Notice of Response to Comments, 83 FR 67251 (Dec. 28, 2018).

[11] The Addendum and related documents are available at: *https://energy.gov/fe/draft-addendum-environmental-review-documents-concerning-exports-natural-gas-united-states.*

[12] The 2014 Life Cycle Greenhouse Gas Report is available at: *https://energy.gov/fe/life-cycle-greenhouse-gas-perspective-exporting-liquefied-natural-gas-united-states.*

[13] U.S. Dep't of Energy, Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas From the United States: 2019 Update—Response to Comments, 85 FR 72 (Jan. 2, 2020). The 2019 Update and related documents are available at: *https://fossil.energy.gov/app/docketindex/docket/index/21.*

and replies thereto. Additional procedures will be used as necessary to achieve a complete understanding of the facts and issues. If an additional procedure is scheduled, notice will be provided to all parties. If no party requests additional procedures, a final Opinion and Order may be issued based on the official record, including the Application and responses filed by parties pursuant to this Notice, in accordance with 10 CFR 590.316.

Signed in Washington, DC, on June 15, 2022.

Amy Sweeney,

Director, Office of Regulation, Analysis, and Engagement, Office of Resource Sustainability.

[FR Doc. 2022–13208 Filed 6–17–22; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

[Docket Nos. 11–59–LNG, 16–110–LNG]

Change in Control; Lake Charles Exports, LLC

AGENCY: Office of Fossil Energy and Carbon Management, Department of Energy.

ACTION: Notice of change in control.

SUMMARY: The Office of Fossil Energy and Carbon Management (FECM) (formerly the Office of Fossil Energy) of the Department of Energy (DOE) gives notice of receipt of a Notice of Change in Control (Notice) filed by Lake Charles Exports, LLC (LCE) on May 17, 2022. The Notice describes a change in LCE's upstream ownership. The Notice was filed under the Natural Gas Act (NGA).

DATES: Protests, motions to intervene, or notices of intervention, as applicable, and written comments are to be filed electronically as detailed in the Public Comment Procedures section no later than 4:30 p.m., Eastern time, July 6, 2022.

ADDRESSES:

Electronic Filing by email: fergas@hq.doe.gov.

Although DOE has routinely accepted public comment submissions through a variety of mechanisms, including postal mail and hand delivery/courier, the Department has found it necessary to make temporary modifications to the comment submission process in light of the ongoing Covid-19 pandemic. DOE is currently accepting only electronic submissions at this time. If a commenter finds that this change poses an undue hardship, please contact Office of Resource Sustainability staff at (202) 586–4749 or (202) 586–7893 to discuss the need for alternative arrangements. Once the Covid-19 pandemic health emergency is resolved, DOE anticipates resuming all of its regular options for public comment submission, including postal mail and hand delivery/courier.

FOR FURTHER INFORMATION CONTACT:

Jennifer Wade or Peri Ulrey, U.S. Department of Energy (FE–34), Office of Regulation, Analysis, and Engagement, Office of Resource Sustainability, Office of Fossil Energy and Carbon Management, Forrestal Building, Room 3E–042, 1000 Independence Avenue SW, Washington, DC 20585, (202) 586–4749 or (202) 586–7893, *jennifer.wade@hq.doe.gov* or *peri.ulrey@hq.doe.gov.*

Cassandra Bernstein, U.S. Department of Energy (GC–76), Office of the Assistant General Counsel for Energy Delivery and Resilience, Forrestal Building, Room 6D–033, 1000 Independence Avenue SW, Washington, DC 20585, (202) 586–9793, *cassandra.bernstein@hq.doe.gov.*

SUPPLEMENTARY INFORMATION:

Summary of Change in Control

In the Notice, LCE states that, by means of a transaction (Transaction) that closed on April 1, 2020, its ownership has changed. LCE states that, prior to the Transaction, LCE was a joint venture between Energy Transfer Equity, L.P. (Energy Transfer) and Royal Dutch Shell plc (Shell). LCE states that, on April 1, 2020, Energy Transfer acquired Shell's membership interests in LCE. Accordingly, LCE is now a wholly owned subsidiary of Energy Transfer.

Additional details can be found in the Notice, posted on the DOE website at: *www.energy.gov/sites/default/files/2022-06/Notice%20of%20change%20in%20control%20Lake%20Charles%20Exports%20LLC.pdf.*

DOE Evaluation

DOE will review the Notice in accordance with its Procedures for Changes in Control Affecting Applications and Authorizations to Import or Export Natural Gas (CIC Procedures).[1] Consistent with the CIC Procedures, this notice addresses LCE's existing authorizations to export LNG to non-free trade agreement (non-FTA) countries, as identified in the Notice.[2] If no interested person protests the change in control and DOE takes no action on its own motion, the proposed change in control will be deemed granted 30 days after publication in the **Federal Register**. If one or more protests are submitted, DOE will review any motions to intervene, protests, and answers, and will issue a determination as to whether the proposed change in control has been demonstrated to render the underlying authorizations inconsistent with the public interest.

Public Comment Procedures

Interested persons will be provided 15 days from the date of publication of this notice in the **Federal Register** to move to intervene, protest, and answer the Notice.[3] Protests, motions to intervene, notices of intervention, and written comments are invited in response to this notice only as to the change in control described in the Notice. All protests, comments, motions to intervene, or notices of intervention must meet the requirements specified by DOE's regulations in 10 CFR part 590, including the service requirements.

As noted, DOE is only accepting electronic submissions at this time. Please email the filing to *fergas@hq.doe.gov.* All filings must include a reference to ''Docket Nos. 11–59–LNG, *et al.*'' in the title line, or ''Lake Charles Exports, LLC Change in Control'' in the title line.

Please Note: Please include all related documents and attachments (*e.g.,* exhibits) in the original email correspondence. Please do not include any active hyperlinks or password protection in any of the documents or attachments related to the filing. All electronic filings submitted to DOE must follow these guidelines to ensure that all documents are filed in a timely manner. Any hardcopy filing submitted greater in length than 50 pages must also include, at the time of the filing, a digital copy on disk of the entire submission.

The Notice, and any filed protests, motions to intervene, notices of intervention, and comments will be available electronically by going to the following DOE Web address: *www.energy.gov/fecm/regulation.*

Signed in Washington, DC, on June 14, 2022.

Amy R. Sweeney,

Director, Office of Regulation, Analysis, and Engagement, Office of Resource Sustainability.

[FR Doc. 2022–13192 Filed 6–17–22; 8:45 am]

BILLING CODE 6450–01–P

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[1] 79 FR 65541 (Nov. 5, 2014).

[2] LCE's Notice also applies to its existing authorizations to export LNG to FTA countries, but DOE will respond to that portion of the filing separately pursuant to the CIC Procedures, 79 FR 65542.

[3] Intervention, if granted, would constitute intervention only in the change in control portion of these proceedings, as described herein.

DEPARTMENT OF ENERGY

Industrial Technology Innovation Advisory Committee

AGENCY: Office of Energy Efficiency and Renewable Energy, Department of Energy.

ACTION: Notice of solicitation of nominations.

SUMMARY: In accordance with the Federal Advisory Committee Act, the U.S. Department of Energy (DOE) is soliciting nomination for candidates to the Industrial Technology Innovation Advisory Committee (Committee).

DATES: Deadline for Advisory Committee member nominations is August 1, 2022.

ADDRESSES: The nominee's name, resume, biography, and any letters of support must be submitted via one of the following methods:

(1) Email to: *ITIAC@ee.doe.gov.*

(2) Overnight delivery service to: Antonio M. Bouza, Designated Federal Officer, Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, Mail Stop EE–5B, 1000 Independence Avenue SW, Washington, DC 20585–0121.

FOR FURTHER INFORMATION CONTACT: Antonio M. Bouza, Designated Federal Officer, Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, 1000 Independence Avenue SW, Washington, DC 20585; telephone at (202) 586–4563, or email: *ITIAC@ ee.doe.gov.*

SUPPLEMENTARY INFORMATION: The Committee is established pursuant to section 455 of the Energy Independence and Security Act of 2007, Public Law 110–140 (hereafter, ''EISA'') as added by Public Law 116–260, div. Z, section 6004 and in accordance with the Federal Advisory Committee Act (FACA), as amended, 5 U.S.C., App. 2, and the rules and regulations in implementation of that Act. The Committee is established under the authority of DOE. The Committee will advise the Secretary of Energy (Secretary) with respect to the Industrial Emissions Reductions Technology Development Program (the program) by identifying and evaluating any technologies being developed by the private sector relating to the focus areas described in section 454(c) of the EISA; identifying technology gaps in the private sector or other Federal agencies in those focus areas, and making recommendations on how to address those gaps; surveying and analyzing factors that prevent the adoption of emissions reduction technologies by the private sector; and recommending technology screening criteria for technology developed under the program to encourage adoption of the technology by the private sector. The Committee shall also develop a strategic plan on how to achieve the program's goals and, in consultation with the Secretary and the Director of the Office of Science and Technology Policy (Director), propose missions and goals for the program consistent with the purposes of the program described in section 454(b)(1) of the EISA.

The Committee shall be comprised of not fewer than 16 members and not more than 20 members, who shall be appointed by the Secretary, in consultation with the Director. The members shall be appointed by the Secretary, in consultation with the Director, to serve as representatives, Federal Government employees, and special Government employees (SGEs) in accordance with the following membership requirements articulated in the EISA:

- Not less than 1 representative of each relevant Federal agency, as determined by the Secretary;
- Chair of the Secretary of Energy Advisory Board, if that position is filled;
- Not less than 2 representatives of labor groups;
- Not less than 3 representatives of the research community, which shall include academia and National Laboratories;
- Not less than 2 representatives of nongovernmental organizations;
- Not less than 6 representatives of small- and large-scale industry, the collective expertise of which shall cover every focus area described in section 454(c) of EISA;
- Not less than 1 representative of a State government; and
- Any other individuals the Secretary, in coordination with the Director, determines to be necessary to ensure that the Committee is comprised of a diverse group of representatives of industry, academia, independent researchers, and public and private entities.

The Committee members will serve for a term of up to two years, and may be reappointed for up to two successive terms. Appointments may be made in a manner that allows the terms of the members serving at any time to expire at spaced intervals to ensure continuity in the functioning of the Committee. Committee members will serve at the discretion of the Secretary. The Chairperson of the Committee will be selected by the Secretary. The Chairperson will serve a two-year term and may be reappointed for an additional term. Committee members will meet periodically, approximately twice a year. When vacancies occur, the Secretary will, in consultation with the Director, identify appointment nominees who can address the Committee's needs pursuant to EISA. Subcommittee membership is drawn from that of the full Committee and thus reflects much of the balance described previously. Additionally, technical experts may be appointed to the subcommittee in order to provide additional expertise and fulfill any lacking points of view relative to the subcommittee's mission/function.

Members must be able to actively participate in the tasks of the Committee including, but not limited to, attending, and participating in in-person meetings, reviewing materials, and regularly participating in conference calls, working groups, and formal subcommittees. The Secretary will consider nominees who can best support, in an advisory capacity.

Members of the Committee serve without compensation; however, members may be reimbursed in accordance with the Federal Travel Regulations for authorized travel and per diem expenses.

Nominations are open to all individuals without regard to race, color, religion, sex, national origin, age, mental or physical handicap, marital status, or sexual orientation. Members will be selected based on their individual qualifications as detailed in their nomination package, as well as the overall need to achieve a balanced representation of viewpoints, subject matter expertise, and regional knowledge. As part of achieving a balanced representation of viewpoints, the Secretary and the Director will strive for the Committee to reflect the principles of inclusion, equity, and diversity, and to ensure that the Committee's recommendations strive for equitable distribution of benefits for all Americans, including people of color and others who have been historically underserved, marginalized, and adversely affected by persistent poverty and inequality. The Secretary and the Director also will strive for geographic diversity in the composition of the Committee.

The Secretary will, in consultation with the Director, consider nominations of all qualified individuals to ensure that the Committee includes the areas of experience noted previously. Individuals may nominate themselves or other individuals, and professional associations and organizations may nominate one or more qualified persons for consideration. Nominations shall state that the nominee is willing to serve as a member and carry out the duties of the Committee. A nomination package should include the following information for each nominee: A letter of nomination (1) stating the name, affiliation, position title, and contact information for the nominee; (2) the basis for the nomination (*i.e.,* what specific attributes recommend him/her for service in this capacity), and (3) the nominee's field(s) of experience within the focus areas listed in section 454(c) of the EISA, as codified at 42 U.S.C. 17113(c), and (4) the name, return address, email address, and daytime telephone number at which the nominator can be contacted. A nomination package should provide an adequate description of the nominee's qualifications, including information that will enable DOE to make an informed decision regarding meeting the membership requirements and objectives.

DOE expressly values diversity, equity, inclusion, and accessibility, and encourages nominations of appropriately qualified candidates from diverse backgrounds.

All nomination information should be provided in a single, complete package by August 1, 2022. Interested applicants should send their nomination package to *ITIAC@ee.doe.gov.*

Signed in Washington, DC, on June 14, 2022.

LaTanya Butler,

Deputy Committee Management Officer.

[FR Doc. 2022–13186 Filed 6–17–22; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #1

Take notice that the Commission received the following electric corporate filings:

Docket Numbers: EC22–74–000.
Applicants: Wisconsin Power and Light Company, Wisconsin Public Service Corporation, Madison Gas and Electric Company.
Description: Joint Application for Authorization Under Section 203 of the Federal Power Act of Wisconsin Power and Light Company, et al.
Filed Date: 6/13/22.
Accession Number: 20220613–5175.
Comment Date: 5 p.m. ET 7/5/22.

Take notice that the Commission received the following exempt wholesale generator filings:

Docket Numbers: EG22–144–000.
Applicants: Timber Road Solar Park LLC.
Description: Timber Road Solar Park LLC submits Notice of Self-Certification of Exempt Wholesale Generator Status.
Filed Date: 6/13/22.
Accession Number: 20220613–5161.
Comment Date: 5 p.m. ET 7/5/22.

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER10–3079–019.
Applicants: Tyr Energy LLC.
Description: Supplement to December 22, 2021 Updated Market Power Analysis for Southwest Power Pool Inc. Region of Tyr Energy LLC.
Filed Date: 6/13/22.
Accession Number: 20220613–5158.
Comment Date: 5 p.m. ET 6/23/22.

Docket Numbers: ER20–1068–005; ER20–2100–004.
Applicants: The Dayton Power and Light Company, PJM Interconnection, L.L.C., The Dayton Power and Light Company.
Description: Compliance Filing of The Dayton Power & Light Company respect to the South Charleston (Madison) Substation 345 kV planned transmission project.
Filed Date: 6/10/22.
Accession Number: 20220610–5253.
Comment Date: 5 p.m. ET 7/1/22.

Docket Numbers: ER22–1200–001.
Applicants: PJM Interconnection, L.L.C.
Description: Compliance filing: Response to 5/13/2022 Deficiency Notice in Docket No. ER22–1200 to be effective 9/1/2022.
Filed Date: 6/13/22.
Accession Number: 20220613–5131.
Comment Date: 5 p.m. ET 7/5/22.

Docket Numbers: ER22–1882–001.
Applicants: VESI 10 LLC.
Description: Tariff Amendment: Amendment to be effective 5/17/2022.
Filed Date: 6/14/22.
Accession Number: 20220614–5095.
Comment Date: 5 p.m. ET 7/5/22.

Docket Numbers: ER22–2102–000.
Applicants: Deerfield Wind Energy 2, LLC.
Description: Baseline eTariff Filing: Shared Facilities Agreement and Request for Waivers to be effective 6/14/2022.
Filed Date: 6/13/22.
Accession Number: 20220613–5136.
Comment Date: 5 p.m. ET 7/5/22.

Docket Numbers: ER22–2103–000.
Applicants: Deerfield Wind Energy 2, LLC.
Description: § 205(d) Rate Filing: Certificate of Concurrence and Request for Waiver and Blanket Approval to be effective 6/14/2022.
Filed Date: 6/13/22.
Accession Number: 20220613–5139.
Comment Date: 5 p.m. ET 7/5/22.

Docket Numbers: ER22–2104–000.
Applicants: Logan Generating Company, L.P.
Description: Tariff Amendment: MBR Cancellation to be effective 6/14/2022.
Filed Date: 6/13/22.
Accession Number: 20220613–5147.
Comment Date: 5 p.m. ET 7/5/22.

Docket Numbers: ER22–2105–000.
Applicants: Logan Generating Company, L.P.
Description: Tariff Amendment: Tariff Cancellation to be effective 12/31/9998.
Filed Date: 6/14/22.
Accession Number: 20220614–5000.
Comment Date: 5 p.m. ET 7/5/22.

Docket Numbers: ER22–2106–000.
Applicants: Chambers Cogeneration, Limited Partnership
Description: Tariff Amendment: Reactive Power Tariff Cancellation to be effective 12/31/9998.
Filed Date: 6/14/22.
Accession Number: 20220614–5001.
Comment Date: 5 p.m. ET 7/5/22.

Docket Numbers: ER22–2108–000.
Applicants: Cheyenne Light, Fuel and Power Company.
Description: § 205(d) Rate Filing: Amended Engineering and Procurement Agreement to be effective 6/15/2022.
Filed Date: 6/14/22.
Accession Number: 20220614–5048.
Comment Date: 5 p.m. ET 7/5/22.

Docket Numbers: ER22–2109–000.
Applicants: Ohio Power Company, PJM Interconnection, L.L.C.
Description: § 205(d) Rate Filing: Ohio Power Company submits tariff filing per 35.13(a)(2)(iii: AEP submits OPCo and AMP Transmission IA SA No. 6451 to be effective 5/1/2022.
Filed Date: 6/14/22.
Accession Number: 20220614–5076.
Comment Date: 5 p.m. ET 7/5/22.

Docket Numbers: ER22–2110–000.
Applicants: PJM Interconnection, L.L.C.
Description: § 205(d) Rate Filing: Interconnection Reform, Request Action by October 3, 2022 and 30-day Comments to be effective 10/3/2022.
Filed Date: 6/14/22.
Accession Number: 20220614–5081.
Comment Date: 5 p.m. ET 7/5/22.

Docket Numbers: ER22–2111–000.
Applicants: Chambers Cogeneration, Limited Partnership.
Description: Tariff Amendment: MBR Cancellation to be effective 6/15/2022.
Filed Date: 6/14/22.
Accession Number: 20220614–5088.

Comment Date: 5 p.m. ET 7/5/22.

Docket Numbers: ER22–2112–000.

Applicants: PJM Interconnection, L.L.C.

Description: § 205(d) Rate Filing: Original ISA, Service Agreement No. 6475; Queue No. AE1–079 to be effective 5/13/2022.

Filed Date: 6/14/22.

Accession Number: 20220614–5090.

Comment Date: 5 p.m. ET 7/5/22.

Docket Numbers: ER22–2114–000.

Applicants: PPL Electric Utilities Corporation, PJM Interconnection, L.L.C.

Description: § 205(d) Rate Filing: PPL Electric Utilities Corporation submits tariff filing per 35.13(a)(2)(iii: Revision to OATT re: Fund Network Upgrades and pro forma NUFA to be effective 1/3/2023.

Filed Date: 6/14/22.

*Accession Number:*20220614–5111.

Comment Date: 5 p.m. ET 7/5/22.

Docket Numbers: ER22–2115–000.

Applicants: Timber Road Solar Park LLC.

Description: Baseline eTariff Filing: Market-Based Rate Application to be effective 8/14/2022.

Filed Date: 6/14/22.

Accession Number: 20220614–5156.

Comment Date: 5 p.m. ET 7/5/22.

Docket Numbers: ER22–2116–000.

Applicants: Blue Harvest Solar Park LLC.

Description: Baseline eTariff Filing: Market-Based Rate Application to be effective 8/14/2022.

Filed Date: 6/14/22.

Accession Number: 20220614–5157.

Comment Date: 5 p.m. ET 7/5/22.

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: June 14, 2022.

Debbie-Anne A. Reese,

Deputy Secretary.

[FR Doc. 2022–13222 Filed 6–17–22; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. IC22–10–000]

Commission Information Collection Activities (FERC–606 and FERC–607) Comment Request; Extension

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

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 (FERC)–606 and 607 FERC–606, Notification of Request for Federal Authorization and Requests for Further Information; FERC–607, Report on Decision or Action on Request for Federal Authorization, which will be submitted to the Office of Management and Budget (OMB) for review. No comments were received for the 60-day notice published on April 12, 2022.

DATES: Comments on the collection of information are due July 21, 2022.

ADDRESSES: Send written comments on FERC–606 and 607 to OMB through *www.reginfo.gov/public/do/PRAMain.* Attention: Federal Energy Regulatory Commission Desk Officer. Please identify the OMB Control Number (1902–0241) in the subject line of your comments. Comments should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.*

Please submit copies of your comments to the Commission. You may submit copies of your comments (identified by Docket No. IC22–10–000) by one of the following methods:

Electronic filing through *https://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: OMB submissions must be formatted and filed in accordance with submission guidelines at *www.reginfo.gov/public/do/PRAMain.* Using the search function under the ''Currently Under Review'' field, select Federal Energy Regulatory Commission; click ''submit,'' and select ''comment'' to the right of the subject collection.

FERC submissions must be formatted and filed in accordance with submission guidelines at: *https://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 *https://www.ferc.gov/ferc-online/overview.*

FOR FURTHER INFORMATION CONTACT: Ellen Brown may be reached by email at *DataClearance@FERC.gov,* telephone at (202) 502–8663.

SUPPLEMENTARY INFORMATION:

Title: FERC–606, Notification of Request for Federal Authorization and Requests for Further Information; FERC–607, Report on Decision or Action on Request for Federal Authorization.

OMB Control No.: 1902–0241.

Type of Request: Three-year extension of these information collection requirements for all collections described below with no changes to the current reporting requirements. Please note that each collection is distinct from the other.

Abstract: Under 18 CFR 385.2013 (FERC–606) requires agencies and officials responsible for issuing, conditioning, or denying requests for federal authorizations necessary for a proposed natural gas project to report to the Commission regarding the status of an authorization request. This reporting requirement is intended to allow agencies to assist the Commission to make better informed decisions in establishing due dates for agencies' decisions.

18 CFR 385.2014 (FERC–607) requires agencies or officials to submit to the Commission a copy of a decision or action on a request for federal authorization and an accompanying index to the documents and materials relied on in reaching a conclusion.

The information collections can neither be discontinued nor collected less frequently because of statutory requirements. The consequences of not collecting this information are that the Commission would be unable to fulfill its statutory mandate under the Energy Policy Act of 2005 to:

• Establish a schedule for agencies to review requests for federal authorizations required for a project, and

• Compile a record of each agency's decision, together with the record of the Commission's decision, to serve as a consolidated record for the purpose of appeal or review, including judicial review.

Type of Respondent: Agencies with federal authorization responsibilities.

Estimate of Annual Burden: [1] The Commission estimates the annual public reporting burden [2] and cost [3] (rounded) for the information collection as follows:

FERC–606 (NOTIFICATION OF REQUEST FOR FEDERAL AUTHORIZATION AND REQUESTS FOR FURTHER INFORMATION), AND FERC–607 (REPORT ON DECISION OR ACTION ON REQUEST FOR FEDERAL AUTHORIZATION)

	Number of respondents (1)	Annual number of responses per respondent (2)	Total number of responses (1) * (2) = (3)	Average burden hours & cost per response (4)	Total annual burden hours & total annual cost (3) * (4) = (5)	Cost per respondent ($) (5) ÷ (1)
FERC–606	1	1	1	4 hrs.; $348	4 hrs.; $348	$348
FERC–607	1	1	1	1 hr.; $87	1 hr.; $87	87
Total	2		2		5 hrs.; $435	

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; 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: June 14, 2022.

Debbie-Anne A. Reese,

Deputy Secretary.

[FR Doc. 2022–13220 Filed 6–17–22; 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: RP22–979–000.

Applicants: WBI Energy Transmission, Inc.

Description: § 4(d) Rate Filing: 2022 Negotiated and Non-Conforming SA Blue Flint to be effective 7/15/2022.

Filed Date: 6/14/22.

Accession Number: 20220614–5030.

Comment Date: 5 p.m. ET 6/27/22.

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.

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: June 14, 2022.

Debbie-Anne A. Reese,

Deputy Secretary.

[FR Doc. 2022–13221 Filed 6–17–22; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL 9855–01–OW]

Lifetime Drinking Water Health Advisories for Four Perfluoroalkyl Substances

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of availability.

SUMMARY: The Environmental Protection Agency (EPA) announces the release of health advisories for four perfluoroalkyl substances (PFAS), including interim updated lifetime drinking water health advisories for perfluorooctanoic acid (PFOA) and perfluorooctane sulfonic acid (PFOS), and final health advisories for hexafluoropropylene oxide (HFPO) dimer acid and its ammonium salt (together referred to as ''GenX chemicals'') and perfluorobutane sulfonic acid and its related compound potassium perfluorobutane sulfonate (together referred to as ''PFBS''). EPA's health advisories, which identify the concentration of chemicals in drinking water at or below which adverse health effects are not anticipated to occur, are: 0.004 parts per trillion (ppt) for PFOA, 0.02 ppt for PFOS, 10 ppt for GenX chemicals, and 2,000 ppt for PFBS. Health advisories are non-regulatory and reflect EPA's assessment of the best available peer-reviewed science. The interim updated health advisories for PFOA and PFOS supersede EPA's 2016 health advisories for PFOA and PFOS.

[1] 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.

[2] Annual public reporting burden based on respondents over the last three-year period.

[3] The estimates for cost per response are derived using the formula: Average Burden Hours per Response * 87.00 per hour = Average Cost per Response. The hourly cost figure comes from the FERC average salary plus benefits of $180,703 per year (or $87.00/hour). These estimates were updated in May 2021. This figure is being used because the staff thinks industry is similarly situated in terms of average hourly cost.

FOR FURTHER INFORMATION CONTACT: Susan Euling, Health and Ecological Criteria Division, Office of Water (Mail Code 4304T), Environmental Protection Agency, 1200 Pennsylvania Avenue NW, Washington, DC 20460; telephone: (202) 566–2717; or email: *euling.susan@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. What are PFAS, and specifically, what are PFOA, PFOS, GenX chemicals, and PFBS?

PFAS are a large and diverse structural family of compounds used in myriad commercial applications due to their unique properties, such as resistance to high and low temperatures, resistance to degradation, and nonstick characteristics. Although PFAS have been manufactured and used broadly in commerce since the 1940s, particular concern over potential adverse effects on human health grew in the early 2000s with the discovery of PFOA and PFOS in human blood. Since that time, hundreds of PFAS have been identified in water, soil, and air. Many PFAS are environmentally persistent, bioaccumulative, and have long half-lives in humans, particularly the longer-chained carbon species such as PFOA and PFOS. Most uses of PFOA and PFOS were phased out by U.S. manufacturers in the mid-2000s although there are a limited number of ongoing uses. In addition, some currently used PFAS break down into PFOA and PFOS in the environment. PFAS with fewer carbon atoms, such as GenX chemicals and PFBS, were subsequently developed to replace PFOA and PFOS, respectively, and integrated into various consumer products and industrial applications because they have the desired properties and characteristics associated with this class of compounds but are more quickly eliminated from the human body than PFOA and PFOS.

II. What health effects are associated with exposure to PFOA, PFOS, GenX chemicals, and PFBS?

The interim updated health advisories for PFOA and PFOS are based on human epidemiology studies in populations exposed to these chemicals. Human studies have found associations between PFOA and/or PFOS exposure and effects on the immune system, the cardiovascular system, human development (*e.g.,* decreased birth weight), and cancer. The most sensitive non-cancer effect and the basis for the interim updated health advisories for PFOA and PFOS is suppression of vaccine response (decreased serum antibody concentrations) in children. While there is evidence that PFOA is likely to be carcinogenic to humans, EPA has not derived a cancer risk concentration in water for PFOA at this time. There is suggestive evidence of carcinogenic potential of PFOS in humans. Cancer analyses are ongoing for both PFOA and PFOS.

EPA's final health advisories for GenX chemicals and PFBS are based on animal toxicity studies following oral exposure to these chemicals. GenX chemicals have been linked to health effects on the liver, the kidney, the immune system, and developmental effects, as well as cancer. The most sensitive non-cancer effect and the basis for the final health advisories for GenX chemicals is a liver effect (constellation of liver lesions). There is suggestive evidence of carcinogenic potential of oral exposure to GenX chemicals in humans, but data are insufficient to derive a cancer risk concentration in water for GenX chemicals at this time. Animal studies following oral exposure to PFBS have shown health effects on the thyroid, reproductive organs and tissues, developing fetus, and kidney following oral exposure. The most sensitive non-cancer effect and the basis for the final health advisory for PFBS is a thyroid effect (decreased serum total thyroxine). There are no known studies evaluating potential cancer effects of PFBS and so the potential for cancer effects after PFBS exposure could not be evaluated.

III. What are drinking water health advisories?

Under the Safe Drinking Water Act, EPA may publish health advisories for contaminants that are not subject to any national primary drinking water regulation. 42 U.S.C. 300g–1(b)(1)(F)). EPA develops health advisories to provide information on the chemical and physical properties, occurrence and exposure, health effects, quantification of toxicological effects, other regulatory standards, analytical methods, and treatment technology for drinking water contaminants. Health advisories describe concentrations of drinking water contaminants at which adverse health effects are not anticipated to occur over specific exposure durations (*e.g.,* one-day, ten-days, and a lifetime). Health advisories serve as technical information to assist Federal, state and local officials, as well as managers of public or community water systems in protecting public health. They are not regulations and should not be construed as legally enforceable Federal standards. Health advisories may change as new information becomes available.

IV. What are EPA's interim health advisories for PFOA and PFOS?

EPA is releasing interim updated health advisories for PFOA and PFOS based on data and draft analyses that indicate that the levels at which negative health effects could occur are much lower than previously understood when the agency issued its 2016 health advisories for PFOA and PFOS (70 parts per trillion or ppt). Human studies have found associations between PFOA and/or PFOS exposure and effects on the immune system, the cardiovascular system, development (*e.g.,* decreased birth weight), and cancer. These data and draft analyses, which were released publicly in November 2021, are currently undergoing EPA Science Advisory Board (SAB) review. EPA is concerned about the public health implications of these preliminary findings and is therefore issuing interim updated health advisories for PFOA and PFOS. The interim updated health advisories for PFOA and PFOS are 0.004 ppt and 0.02 ppt, respectively. The interim updated health advisories replace the 2016 final health advisories for PFOA and PFOS which were both set at 70 ppt. EPA is reviewing and will respond to the SAB comments as the Agency moves forward to develop Maximum Contaminant Level Goals (MCLGs) to support the Safe Drinking Water Act National Primary Drinking Water Regulation for PFOA and PFOS, which is expected to be proposed later this year.

V. What are EPA's final health advisories for GenX chemicals and PFBS?

EPA is also releasing final health advisories for GenX chemicals and PFBS for the first time, based on EPA's 2021 final toxicity assessments for these PFAS. In chemical and product manufacturing, GenX chemicals are considered a replacement for PFOA, and PFBS is considered a replacement for PFOS. Animal toxicity studies following oral exposure to GenX chemicals have reported health effects in the liver, kidney, immune system, development, as well as cancer. For PFBS, animal studies have reported health effects on the thyroid, reproductive system, development, and kidney following oral exposure. The final health advisories for GenX chemicals and PFBS are 10 ppt and 2,000 ppt, respectively.

Radhika Fox,

Assistant Administrator.

[FR Doc. 2022–13158 Filed 6–17–22; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPP–2022–0160; FRL–9409–02–OCSPP]

Pesticide Product Registration; Receipt of Applications for New Active Ingredients—May 2022

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: EPA has received applications to register pesticide products containing active ingredients not included in any currently registered pesticide products. Pursuant to the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA), EPA is hereby providing notice of receipt and opportunity to comment on these applications.

DATES: Comments must be received on or before July 21, 2022.

ADDRESSES: Submit your comments, identified by docket identification (ID) number EPA–HQ–OPP–2022–0160, through the Federal eRulemaking Portal at *https://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. For the latest information on EPA/DC docket access, services and submitting comments, visit *https://www.epa.gov/dockets.*

FOR FURTHER INFORMATION CONTACT: Marietta Echeverria, Registration Division (RD) (7505P), main telephone number: (202) 566–2659, email address: *RDFRNotices@epa.gov*; The mailing address for each contact person is: Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460–0001. As part of the mailing address, include the contact person's name, division, and mail code. The division to contact is listed at the end of each pesticide petition summary.

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).

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

1. *Submitting CBI.* Do not submit this information to EPA through regulations.gov or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for preparing your comments.* When preparing and submitting your comments, see the commenting tips at *https://www.epa.gov/dockets/commenting-epa-dockets.*

II. Registration Applications

EPA has received applications to register pesticide products containing active ingredients not included in any currently registered pesticide products. Pursuant to the provisions of FIFRA section 3(c)(4) (7 U.S.C. 136a(c)(4)), EPA is hereby providing notice of receipt and opportunity to comment on these applications. Notice of receipt of these applications does not imply a decision by the Agency on these applications. For actions being evaluated under EPA's public participation process for registration actions, there will be an additional opportunity for public comment on the proposed decisions. Please see EPA's public participation website for additional information on this process (*https://www2.epa.gov/pesticide-registration/public-participation-process-registration-actions*).

Notice of Receipt—New Active Ingredients

1. *File Symbol:* 100–RTEE. *Docket ID number:* EPA–HQ–OPP–2022–0003. *Applicant:* Syngenta Crop Protection, LLC, 410 Swing Road, P.O. Box 18300, Greensboro, NC 27410. *Product name:* A22011 T&O. *Active ingredient:* Nematocide—Cyclobutrifluram at 38.5%. *Proposed use:* Ornamentals and turf. *Contact:* RD.

2. *File Symbol:* 100–RTEG. *Docket ID number:* EPA–HQ–OPP–2022–0003. *Applicant:* Syngenta Crop Protection, LLC, 410 Swing Road, P.O. Box 18300, Greensboro, NC 27410. *Product name:* A22011 Crop. *Active ingredient:* Nematocide—Cyclobutrifluram at 38.5%. *Proposed use:* Lettuce, romaine. *Contact:* RD.

3. *File Symbol:* 100–RTEL. *Docket ID number:* EPA–HQ–OPP–2022–0003. *Applicant:* Syngenta Crop Protection, LLC, 410 Swing Road, P.O. Box 18300, Greensboro, NC 27410. *Product name:* A23156 Crop. *Active ingredient:* Nematocide—Cyclobutrifluram at 25.6%. *Proposed use:* Lettuce, romaine. *Contact:* RD.

4. *File Symbol:* 100–RTER. *Docket ID number:* EPA–HQ–OPP–2022–0003. *Applicant:* Syngenta Crop Protection, LLC, 410 Swing Road, P.O. Box 18300, Greensboro, NC 27410. *Product name:* Cyclobutrifluram Technical. *Active ingredient:* Nematocide—Cyclobutrifluram at 85.0%. *Proposed use:* Lettuce, romaine, seed treatment use on cotton, seed treatment use on soybean, ornamentals, and turf. *Contact:* RD.

5. *File Symbol:* 100–RTEU. *Docket ID number:* EPA–HQ–OPP–2022–0003. *Applicant:* Syngenta Crop Protection, LLC, 410 Swing Road, P.O. Box 18300, Greensboro, NC 27410. *Product name:* A22417 ST. *Active ingredient:* Nematocide—Cyclobutrifluram at 41.7%. *Proposed use:* Seed treatment use on cotton and soybean. *Contact:* RD.

6. *File Symbol:* 10163–GIO and 10163–GOR. *Docket ID number:* EPA–HQ–OPP–2022–0452. *Applicant:* Gowan Company, LLC., 370 South Main Street, Yuma, AZ 85364. *Product name:* Acynonapyr Technical and GWN–10409, respectively. *Active ingredient:* Miticide—Acynonapyr at 99.5% and 20.09%, respectively. *Proposed uses:* Almonds; citrus fruit (group 10–10); grapes; hops; pome fruit (group 11–10); ornamental plants and nonbearing fruit trees; vines growing in nurseries, greenhouses, and shadehouses; christmas tree plantations; established ornamental landscape plantings (including those in interiorscapes, residences, public areas, commercial areas, institutional areas, rights of way and other easements, and recreational sites such as campgrounds, golf courses, parks, and athletic fields); ornamental lawns and turf (including residential); non-residential turfgrass; residential pome fruit trees; residential almond trees; residential citrus trees. *Contact:* RD.

(Authority: 7 U.S.C. 136 *et seq.*)

Dated: June 10, 2022.

Delores Barber,

Director, Information Technology and Resources Management Division, Office of Program Support.

[FR Doc. 2022–13235 Filed 6–17–22; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPP–2022–0163; FRL–9408–05–OCSPP]

Pesticide Product Registration; Receipt of Applications for New Uses—May 2022

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: EPA has received applications to register new uses for pesticide products containing currently registered active ingredients. Pursuant to the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA), EPA is hereby providing notice of receipt and opportunity to comment on these applications.

DATES: Comments must be received on or before July 21, 2022.

ADDRESSES: Submit your comments, identified by docket identification (ID) number EPA–HQ–OPP–2022–0163, through the Federal eRulemaking Portal at *https://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. For the latest information on EPA/DC docket access, services and submitting comments, visit *https://www.epa.gov/dockets.*

FOR FURTHER INFORMATION CONTACT: Marietta Echeverria, Registration Division (RD) (7505P), main telephone number: (202) 566–2659, email address: *RDFRNotices@epa.gov.* The mailing address for each contact person is: Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460–0001. As part of the mailing address, include the contact person's name, division, and mail code. The division to contact is listed at the end of each application summary.

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).

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

1. *Submitting CBI.* Do not submit this information to EPA through regulations.gov or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for preparing your comments.* When preparing and submitting your comments, see the commenting tips at *https://www.epa.gov/dockets/commenting-epa-dockets.*

II. Registration Applications

EPA has received applications to register new uses for pesticide products containing currently registered active ingredients. Pursuant to the provisions of FIFRA section 3(c)(4) (7 U.S.C. 136a(c)(4)), EPA is hereby providing notice of receipt and opportunity to comment on these applications. Notice of receipt of these applications does not imply a decision by the Agency on these applications.

Notice of Receipt—New Uses

1. *EPA File Symbol:* 432–RAEE. *Docket ID number:* EPA–HQ–OPP–2022–0444. *Applicant:* Bayer Environmental Science, A Division of Bayer CropScience, 5000 Centregreen Way Suite 400, Cary, NC 27513. *Active ingredient:* Flupyradifurone. *Product type:* Insecticide. *Proposed use:* Indoor non-food & Indoor residential. *Contact:* RD.

2. *EPA Registration Number:* 7969–446,7969–445, 7969–474, and 7969–448. *Docket ID number:* EPA–HQ–OPP–2022–0424. *Applicant:* BASF Corporation, Agricultural Solutions, 26 Davis Drive, Research Triangle Park, North Carolina 27709. *Active ingredient:* Glufosinate ammonium. *Product type:* Herbicide. *Proposed use:* Tropical and subtropical, medium to large fruit, edible peel, subgroup 23B; tropical and subtropical, small fruit, inedible peel, subgroup 24A; tropical and subtropical, medium to large fruit, smooth, inedible peel, subgroup 24B; grass, forage and grass, hay. *Contact:* RD.

3. *EPA Registration Numbers:* 59639–230, 59639–233. *Docket ID number:* EPA–HQ–OPP–2021–0433. *Applicant:* Valent U.S.A. LLC, 4600 Norris Canyon Road, San Ramon, CA 94583. *Active ingredient:* Inpyrfluxam. *Product type:* Fungicide. *Proposed use:* Wheat (foliar). *Contact:* RD.

4. *EPA Registration Numbers:* 59639–231, 59639–233. *Docket ID number:* EPA–HQ–OPP–2021–0433. *Applicant:* Valent U.S.A. LLC, 4600 Norris Canyon Road, San Ramon, CA 94583. *Active ingredient:* Inpyrfluxam. *Product type:* Fungicide. *Proposed Use:* Cotton (seed treatment). *Contact:* RD.

5. *EPA Registration Numbers:* 59639–231, 59639–233. *Docket ID number:* EPA–HQ–OPP–2021–0833. *Applicant:* Valent U.S.A. LLC, 4600 Norris Canyon Road, San Ramon, CA 94583. *Active ingredient:* Inpyrfluxam. *Product type:* Fungicide. *Proposed use:* Seed treatment on rapeseed (crop subgroup 20A). *Contact:* RD.

6. *EPA Registration Numbers:* 67690–6, 67690–78. *Docket ID number:* EPA–HQ–OPP–2021–0787. *Applicant:* SePRO Corporation, 11550 North Meridian Street, Suite 600, Carmel, IN 46032. *Active ingredient:* Fluridone. *Product type:* Herbicide. *Proposed use:* Peanut. *Contact:* RD.

(Authority: 7 U.S.C. 136 *et seq.*)

Dated: June 10, 2022.

Delores Barber,

Director, Information Technology and Resources Management Division, Office of Program Support.

[FR Doc. 2022–13236 Filed 6–17–22; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

[OMB 3060–1092; FR ID 91891]

Information Collection Being Reviewed by the Federal Communications Commission

AGENCY: Federal Communications Commission.

ACTION: Notice and request for comments.

SUMMARY: As part of its continuing effort to reduce paperwork burdens, and as required by the Paperwork Reduction Act of 1995 (PRA), the Federal Communications Commission (FCC or Commission) invites the general public and other Federal agencies to take this opportunity to comment on the following information collection. Comments are requested concerning: whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; the accuracy of the Commission's burden estimate; ways to enhance the quality, utility, and clarity of the information collected; ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology; and ways to further reduce the information collection burden on small business concerns with fewer than 25 employees. The FCC may not conduct or sponsor a collection of information unless it displays a currently valid Office of Management and Budget (OMB) control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the PRA that does not display a valid OMB control number.

DATES: Written PRA comments should be submitted on or before August 22, 2022. If you anticipate that you will be submitting comments but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: Direct all PRA comments to Cathy Williams, FCC, via email to *PRA@fcc.gov* and to *Cathy.Williams@fcc.gov.*

FOR FURTHER INFORMATION CONTACT: For additional information about the information collection, contact Cathy Williams at (202) 418–2918.

SUPPLEMENTARY INFORMATION:

OMB Control Number: 3060–1092.

Title: Interim Procedures for Filing Applications Seeking Approval for Designated Entity Reportable Eligibility Events and Annual Reports.

Form Numbers: FCC Forms 609–T and 611–T.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for-profit entities; Not-for profit institutions; and State, Local and Tribal Governments.

Number of Respondents: 1,100 respondents; 2,750 responses.

Estimated Time per Response: .50 hours to 6 hours.

Frequency of Response: On occasion and annual reporting requirements.

Obligation to Respond: Required to obtain or retain benefits. Statutory authority for this information collection is contained in 47 U.S.C. 4(i), 308(b), 309(j)(3) and 309(j)(4).

Total Annual Burden: 7,288 hours.

Total Annual Cost: $2,223,375.

Needs and Uses: The Commission will submit this expiring information collection to the Office of Management and Budget (OMB) after this comment period to obtain the three year clearance from them. FCC Form 609–T is used by Designated Entities (DEs) to request prior Commission approval pursuant to Section 1.2114 of the Commission's rules for any reportable eligibility event. The data collected on the form is used by the FCC to determine whether the public interest would be served by the approval of the reportable eligibility event.

FCC Form 611–T is used by DE licensees to file an annual report, pursuant to Section 1.2110(n) of the Commission's rules, related to eligibility for designated entity benefits.

The information collected will be used to ensure that only legitimate small businesses reap the benefits of the Commission's designated entity program. Further, this information will assist the Commission in preventing companies from circumventing the objectives of the designated entity eligibility rules by allowing us to review: (1) The FCC 609–T applications seeking approval for ''reportable eligibility events'' and (2) the FCC Form 611–T annual reports to ensure that licensees receiving designated entity benefits are in compliance with the Commission's policies and rules.

Federal Communications Commission.

Marlene Dortch,

Secretary, Office of the Secretary.

[FR Doc. 2022–13234 Filed 6–17–22; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

[OMB 3060–0484, OMB 3060–1003, OMB 3060–1271; FR ID 91859]

Information Collections Being Submitted for Review and Approval to Office of Management and Budget

AGENCY: Federal Communications Commission.

ACTION: Notice and request for comments.

SUMMARY: As part of its continuing effort to reduce paperwork burdens, as required by the Paperwork Reduction Act (PRA) of 1995, the Federal Communications Commission (FCC or the Commission) invites the general public and other Federal Agencies to take this opportunity to comment on the following information collection. Pursuant to the Small Business Paperwork Relief Act of 2002, the FCC seeks specific comment on how it might ''further reduce the information collection burden for small business concerns with fewer than 25 employees.'' The Commission may not conduct or sponsor a collection of information unless it displays a currently valid Office of Management and Budget (OMB) control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the PRA that does not display a valid OMB control number.

DATES: Written comments and recommendations for the proposed information collection should be submitted on or before July 21, 2022.

ADDRESSES: Comments should be sent 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. Your comment must be submitted into *www.reginfo.gov* per the above instructions for it to be considered. In addition to submitting in *www.reginfo.gov* also send a copy of your comment on the proposed information collection to Nicole Ongele, FCC, via email to *PRA@fcc.gov* and to *Nicole.Ongele@fcc.gov.* Include in the comments the OMB control number as shown in the **SUPPLEMENTARY INFORMATION** below.

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collection, contact Nicole Ongele at (202) 418–2991. To view a copy of this information collection request (ICR) submitted to OMB: (1) go to the web page *http://www.reginfo.gov/public/do/PRAMain,* (2) look for the section of the web page called ''Currently Under Review,'' (3) click on the downward-pointing arrow in the ''Select Agency'' box below the ''Currently Under Review'' heading, (4) select ''Federal Communications Commission'' from the list of agencies presented in the ''Select Agency'' box, (5) click the ''Submit'' button to the right of the ''Select Agency'' box, (6) when the list of FCC ICRs currently under review appears, look for the Title of this ICR and then click on the ICR Reference Number. A copy of the FCC submission to OMB will be displayed.

SUPPLEMENTARY INFORMATION: As part of its continuing effort to reduce paperwork burdens, as required by the Paperwork Reduction Act (PRA) of 1995 (44 U.S.C. 3501–3520), the FCC invited the general public and other Federal Agencies to take this opportunity to comment on the following information collection. Comments are requested concerning: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (b) the accuracy of the Commission's burden estimates; (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 the respondents, including the use of automated collection techniques or other forms of information technology. Pursuant to the Small Business Paperwork Relief Act of 2002, Public Law 107–198, see 44 U.S.C. 3506(c)(4), the FCC seeks specific comment on how it might ''further reduce the information collection burden for small business concerns with fewer than 25 employees.''

OMB Control Number: 3060–0484.

Title: Amendments to Part 4 of the Commission's Rules Concerning Disruptions to Communications.

Form Number: N/A.

Type of Review: Revision of a currently approved collection.

Respondents: Business or other for-profit; Not-for-profit institutions; State, Local or Tribal Government.

Number of Respondents and Responses: 1,065 respondents; 27,395 responses.

Estimated Time per Response: 1 hour–2 hours (average per response).

Frequency of Response: On occasion and annual reporting requirements and recordkeeping requirement.

Obligation to Respond: Mandatory and Voluntary. Statutory authority for this collection is contained in sections 1, 4(i), 4(j), 4(o), 251(e)(3), 254, 301, 303(b), 303(g), 303(r), 307, 309(a), 309(j), 316, 332, and 403 of the Communications Act of 1934, as amended, and section 706 of the Telecommunications Act of 1996, 47 U.S.C. 151, 154(i)–(j) & (o), 251(e)(3), 254, 301, 303(b), 303(g), 303(r), 332, 403, and 1302.

Total Annual Burden: 54,215 hours.

Total Annual Cost: No Cost.

Privacy Act Impact Assessment: No impact(s).

Nature and Extent of Confidentiality: In accordance with 47 CFR 4.2, reports and information contained in the underlying NORS filings are presumed confidential. The filings are shared with the Department of Homeland Security through password-protected real time access to NORS. Other persons seeking disclosure must follow the procedure delineated in 47 CFR 0.457 and 0.459 of the Commission's Rules for requests for and disclosure of information. The modified collection proposed here will allow ''need to know'' agencies acting on behalf of the federal government, the 50 states, the District of Columbia, Tribal Nations, and the U.S. territories access to confidential information derived from NORS filings based on events occurring within an agency's jurisdiction, provided those agencies maintain the confidentiality of the information and report any breach of that confidentiality.

The Commission has adopted procedures allowing state, federal, local, and Tribal agencies with a demonstrated ''need to know'' to apply for ''read-only'' access to NORS reports impacting locations where the agency has jurisdiction. To protect the confidentiality of the NORS and DIRS information disclosed to these Participating Agencies, the Commission limited the access to only those agencies who complete the registration process and then limits by geographic area the reports available to each Participating Agency. The Commission also adopted safeguards to protect the data accessed by Participating Agencies from manipulation and from distribution to unauthorized recipients.

Needs and Uses: The general purpose of the Commission's Part 4 rules is to gather sufficient information regarding disruptions to telecommunications to facilitate FCC monitoring, analysis, and investigation of the reliability and security of voice, paging, and interconnected Voice over internet Protocol (interconnected VoIP) communications services, and to identify and act on potential threats to our Nation's telecommunications infrastructure. The Commission uses this information collection to identify the duration, magnitude, root causes, and contributing factors with respect to significant outages, and to identify outage trends; support service restoration efforts; and help coordinate with public safety officials during times of crisis. The Commission also maintains an ongoing dialogue with reporting entities, as well as with the communications industry at large, generally regarding lessons learned from the information collection in order to foster a better understanding of the root causes of significant outages and to explore preventive measures in the future so as to mitigate the potential scale and impact of such outages.

In a Second Report and Order adopted on March 18, 2021, as FCC 21–34, the Commission adopted rules allowing certain federal, state, and Tribal Nation agencies 10 (Participating Agencies) to access to certain geographically relevant outage reports filed in the Commission's Network Outage Reporting System (NORS). The information collections and record keeping provisions adopted will allow federal, state and Tribal Nation agencies (Participating Agencies) to apply for, and receive access to, NORS report in the areas where they have jurisdiction. The collection will further enable these Participating Agencies, at their election, to share NORS reports with qualified local agencies whose jurisdiction is affected by an outage, while still maintaining the confidentiality of the substantive data. The changes to the data collections fields in the NORS filings made by service providers will further facilitate the ability of Participating Agencies to access those reports relevant to their specific geographies. Finally, the changes to the information collection and associated recordkeeping requirements, including retention by participating agencies of qualification forms submitted by local agency seeking access to NORS data, as well as a list of which local agencies receive information from the Participating Agency, training materials setting clear parameters for the use of NORS data, and a list of those persons granted NORS account access, will enable auditing functions to ensure accountability in the use of NORS information and immediate reporting of breaches of access or confidentiality protocols.

OMB Control Number: 3060–1003.

Title: Communications Disaster Information Reporting System (DIRS).

Form Number: N/A.

Type of Review: Revision of a currently approved collection.

Respondents: Business or other for-profit; Not-for-profit institutions; State, Local or Tribal Government.

Number of Respondents and Responses: 400 respondents; 104,000 responses.

Estimated Time per Response: 1 hour–1.5 hours (average per response).

Frequency of Response: On occasion and annual reporting requirements and recordkeeping requirements.

Obligation to Respond: Voluntary. Statutory authority for this collection is contained in sections 1, 4(i), 4(j), 4(o), 251(e)(3), 254, 301, 303(b), 303(g), 303(r), 307, 309(a), 309(j), 316, 332, and 403 of the Communications Act of 1934, as amended, and section 706 of the Telecommunications Act of 1996, 47 U.S.C. 151, 154(i)–(j) & (o), 251(e)(3), 254, 301, 303(b), 303(g), 303(r), 332, 403, and 1302.

Total Annual Burden: 16,320 hours.

Total Annual Costs: No Cost.

Privacy Act Impact Assessment: No impact(s).

Nature and Extent of Confidentiality: The Commission provides respondents with assurances that their collected filings reports will be treated with a presumption of confidentiality. As noted in the DIRS User Manual, ''[b]ecause the information that communications companies input to [their collected filings] is sensitive for national security and/or commercial reasons, [the collected filings] shall be treated as presumptively confidential upon filing.''

In accordance with 47 CFR 4.2, reports and information contained in the underlying DIRS filings are presumed confidential. The filings are shared with the Department of Homeland Security through password-protected real time access to NORS. Other persons seeking disclosure must follow the procedure delineated in 47 CFR 0.457 and 0.459 of the Commission's Rules for requests for and disclosure of information. The modified collection proposed here will allow ''need to know'' agencies acting on behalf of the federal government, the 50 states, the District of Columbia, Tribal Nations, and the U.S. territories access to confidential information derived from DIRS filings based on events occurring within an agency's jurisdiction, provided those agencies maintain the confidentiality of the information and report any breach of that confidentiality.

The Commission has adopted procedures allowing state, federal, local, and Tribal agencies with a demonstrated ''need to know'' to apply for ''read-only'' access to DIRS reports impacting locations where the agency has jurisdiction. To protect the confidentiality of the NORS and DIRS information disclosed to these Participating Agencies, the Commission limited the access to only those agencies who complete the registration process and then limits by geographic area the reports available to each Participating Agency. The Commission also adopted safeguards to protect the data accessed by Participating Agencies from manipulation and from distribution to unauthorized recipients.

Needs and Uses: The Commission launched the Disaster Information Reporting System (DIRS) in 2007 pursuant to its mandate to promote the safety of life and property through the use of wire and radio communication as required by the Communications Act of 1934, as amended. DIRS is a voluntary, efficient, and web-based system that communications companies may use to report their infrastructure status during times of crisis (*e.g.,* related to a disaster). DIRS uses a number of template forms tailored to different communications sectors (*i.e.,* wireless, wireline, broadcast, and cable) to facilitate the entry of this information. To use DIRS, a company first inputs its emergency contact information. After this, they submit information using the template form appropriate for their communications sector. In a *Second Report and Order* adopted on March 18, 2021, as FCC 21–34, the Commission adopted rules allowing certain federal, state, and Tribal Nation agencies (Participating Agencies) to access to certain geographically relevant reports filed in the Commission's Disaster Information Reporting System (DIRS). The information collections and record keeping provisions adopted will allow Participating Agencies to apply for, and receive access to, DIRS report in the areas where they have jurisdiction. The collection will further enable these Participating Agencies, at their election, to share DIRS reports with qualified local agencies whose jurisdiction is affected by a disaster, while still maintaining the confidentiality of the substantive data. The changes to the data collections fields in the DIRS filings made by service providers will further facilitate the ability of Participating Agencies to access those reports relevant to their specific geographies. Finally, the changes to the information collection and associated recordkeeping requirements, including retention by participating agencies of qualification forms submitted by local agency seeking access to DIRS data, as well as a list of which local agencies receive information from the Participating Agency, training materials setting clear parameters for the use of DIRS data, and a list of those persons granted DIRS account access, will enable auditing functions to ensure accountability in the use of DIRS information and immediate reporting of breaches of access or confidentiality protocols.

The Commission notes that the information sharing framework established in the Second Report and Order allows for access to be granted not only for DIRS, but also to the Commission's Network Outage Reporting System (NORS). We note that the process and requirements for Participating Agencies under this framework is identical, regardless of whether they seek access to NORS, DIRS, or both. Because the Commission anticipates that NORS and DIRS access will be requested together in most cases, it believes that the estimated burden hours and costs for Participating Agencies associated with DIRS access are fully included in the estimates that it has separately submitted as part of its collection on Part 4 of the Commission's Rules Concerning Disruptions to Communications, OMB Control No. 3060–0484. To avoid double-counting the estimated burden hours and costs associated with both collections, the Commission estimates the marginal cost of the Participating Agency aspect of this collection to be zero.

OMB Control Number: 3060–1271.

Title: Promoting Telehealth for Low-Income Consumers, COVID–19 Telehealth Program.

Form Numbers: FCC Forms 460, 461, 462, and 463.

Type of Review: Revision of a currently approved collection.

Respondents: Business or other for-profit; Not-for-profit institutions; Federal Government; and State, Local, or Tribal governments.

Number of Respondents and Responses: 7,210 respondents; 34,553 responses.

Estimated Time per Response: 0.30–25 hours.

Frequency of Response: One-time, annual, and on occasion reporting requirements; recordkeeping requirement.

Obligation to Respond: Required to obtain or retain benefits. Statutory authority for this collection of information is contained in sections 1–4, 201–205, 214, 254, 303(r), and 403 of the Communications Act of 1934, as amended, 47 U.S.C. 151–154, 201–205, 214, 254, 303(r), and 403, and DIVISION B of the Coronavirus Aid, Relief, and Economic Security Act, Public Law 116–136, 134 Stat. 281.

Total Annual Burden: 197,787 hours.

Total Annual Cost: No cost.

Privacy Act Impact Assessment: No Impact(s).

Nature and Extent of Confidentiality: The Name, Address, DUNS Number and Business Type will be disclosed in accordance with the FFATA/DATA Act reporting requirements as part of the COVID–19 Telehealth Program. Also, the COVID–19 Telehealth Program award and disbursement amounts will be made public. We intend to keep other information submitted under the COVID–19 Telehealth Program confidential to the extent permitted by law. There is no assurance of confidentiality provided to respondents as part of the Connected Care Pilot Program, the selected applicants and estimated funding will be made public. Respondents under both programs may request materials or information submitted to the Commission to be withheld from public inspection under 47 CFR 0.459 of the Commission's rules.

Needs and Uses: On March 31, 2020, the Commission adopted a Report and Order entitled *Promoting Telehealth for Low-Income Consumers; COVID–19 Telehealth Program,* WC Docket No. 18–213, WC Docket No. 20–89 (FCC 20–44), establishing two programs designed to assist health care providers in providing connected care services to consumers—the COVID–19 Telehealth Program and the Connected Care Pilot Program (collectively, Programs). June 2021, the Commission adopted a Second Report and Order, WC Docket No. 18–213 (FCC 21–74), that provided guidance on eligible services, competitive bidding, invoicing, and data reporting for Pilot Program participants. The information collected herein is necessary to meet the specific requirements for information that must be submitted as part of the annual and final reports to the Commission as outlined in the *Second Connected Care Report and Order,* and for the Commission to receive and evaluate data for the selected projects and ensure compliance with the Commission's rules and procedures applicable to the Connected Care Pilot Program. This submission does not make any changes to the previously approved information collections for the COVID–19 Telehealth Program and some of the previously approved requirements for the Pilot Program.

Federal Communications Commission.

Marlene Dortch,

Secretary, Office of the Secretary.

[FR Doc. 2022–13237 Filed 6–17–22; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL DEPOSIT INSURANCE CORPORATION

[OMB No. 3064–0092; –0113; –0174]

Agency Information Collection Activities: Proposed Collection Renewal; Comment Request

AGENCY: Federal Deposit Insurance Corporation (FDIC).

ACTION: Notice and request for comment.

SUMMARY: The FDIC, as part of its obligations under the Paperwork Reduction Act of 1995 (PRA), invites the general public and other Federal agencies to take this opportunity to comment on the renewal of the existing information collections described below (OMB Control No. 3064–0092; –0113 and –0174).

DATES: Comments must be submitted on or before August 22, 2022.

ADDRESSES: Interested parties are invited to submit written comments to the FDIC by any of the following methods:

- *Agency website: https://www.fdic.gov/resources/regulations/federal-register-publications/.*
- *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 NW building (located on F Street NW), on business days between 7:00 a.m. and 5:00 p.m.

All comments should refer to the relevant OMB control number. A copy of the comments may also be submitted to the OMB desk officer for the FDIC: Office of Information and Regulatory Affairs, Office of Management and Budget, New Executive Office Building, Washington, DC 20503.

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:* Community Reinvestment Act.

OMB Number: 3064–0092.

Form Number: None.

Affected Public: Insured state nonmember banks and state savings associations.

Burden Estimate:

SUMMARY OF ANNUAL BURDEN AND INTERNAL COST
[OMB 3064–0092]

Information collection description	Type of burden (obligation to respond)	Estimated number of respondents	Estimated number of responses per respondent	Estimated average time per response (hours)	Total estimated annual burden
Request for designation as a wholesale or limited purpose bank—Banks requesting this designation shall file a request in writing with the FDIC at least 3 months prior to the proposed effective date of the designation.	Reporting (Mandatory)	1	1	4	4
Strategic plan—Applies to banks electing to submit strategic plans to the FDIC for approval.	Reporting (Voluntary) ..	11	1	400	4,400
Small business/small farm loan data—Large banks shall and Small banks may report annually in machine readable form the aggregate number and amount of certain loans.	Reporting (Mandatory)	274	1	8	2,192
Community development loan data—Large banks shall and Small banks may report annually, in machine readable form, the aggregate number and aggregate amount of community development loans originated or purchased.	Reporting (Mandatory)	274	1	13	3,562
Home mortgage loans—Large banks, if subject to reporting under part 203 (Home Mortgage Disclosure (HMDA)), shall, and Small banks may report the location of each home mortgage loan application, origination, or purchase outside the MSA in which the bank has a home/branch office.	Reporting (Mandatory)	350	1	253	88,550

SUMMARY OF ANNUAL BURDEN AND INTERNAL COST—Continued
[OMB 3064–0092]

Information collection description	Type of burden (obligation to respond)	Estimated number of respondents	Estimated number of responses per respondent	Estimated average time per response (hours)	Total estimated annual burden
Data on affiliate lending—Banks that elect to have the FDIC consider loans by an affiliate, for purposes of the lending or community development test or an approved strategic plan, shall collect, maintain and report the data that the bank would have collected, maintained, and reported pursuant to § 345.42(a), (b), and (c) had the loans been originated or purchased by the bank. For home mortgage loans, the bank shall also be prepared to identify the home mortgage loans reported under HMDA.	Reporting (Mandatory)	307	1	38	11,666
Data on lending by a consortium or a third party—Banks that elect to have the FDIC consider community development loans by a consortium or a third party, for purposes of the lending or community development tests or an approved strategic plan, shall report for those loans the data that the bank would have reported under § 345.42(b)(2) had the loans been originated or purchased by the bank.	Reporting (Mandatory)	118	1	17	2,006
Assessment area data –Large banks shall and Small banks may collect and report to the FDIC a list for each assessment area showing the geographies within the area.	Reporting (Mandatory)	372	1	2	744
		....	....	....	113,124
Small business/small farm loan register—Large banks shall and Small banks may collect and maintain certain data in machine-readable form.	Recordkeeping (Mandatory).	372	1	219	81,468
Optional consumer loan data—All banks may collect and maintain in machine readable form certain data for consumer loans originated or purchased by a bank for consideration under the lending test.	Recordkeeping (Mandatory).	10	1	326	3,260
Other loan data –All banks optionally may provide other information concerning their lending performance, including additional loan distribution data.	Recordkeeping (Voluntary).	98	1	25	2,450
		....	....	....	87,178
Content and availability of public file—All banks shall maintain a public file that contains certain required information.	Disclosure (Mandatory)	3,128	1	10	31,280
		....	....	....	31,280
Total Estimated Annual Burden	....	....	....	231,582	

General Description of Collection: The Community Reinvestment Act regulation requires the FDIC to assess the record of banks and thrifts in helping meet the credit needs of their entire communities, including low- and moderate-income neighborhoods, consistent with safe and sound operations; and to take this record into account in evaluating applications for mergers, branches, and certain other corporate activities. There is no change in the method or substance of the collection. The overall decrease in burden hours is a result of decreases in the estimated number of respondents. On June 3, 2022, the Office of the Comptroller of the Currency, the Board of Governors of the Federal Reserve System and the FDIC (the ''Agencies'') published a proposal to amend the Agencies' Community Reinvestment Act regulations.[1] The agencies are expecting comments from the industry and other concerned parties which will be considered and addressed when a final rule is issued. The FDIC does not wish to discontinue this information collection while the proposed revisions are considered and a new rule is issued and is, therefore, extending its Community Reinvestment Act information collection as-is, without revision, to preserve its validity.

2. *Title:* External Audits.

OMB Number: 3064–0113.

Form Number: None.

Affected Public: All insured financial institutions with total assets of $500 million or more and other insured financial institutions with total assets of less than $500 million that voluntarily choose to comply.

Burden Estimate:

SUMMARY OF ESTIMATED ANNUAL BURDENS
[OMB No. 3064–0013]

Information collection description	Type of burden (obligation to respond)	Frequency of response	Number of respondents	Number of responses per respondent	Hours per response	Annual burden (hours)
FDIC-Supervised Institutions with $10 Billion or More in Consolidated Total Assets						
Annual Report (Recordkeeping)	Recordkeeping (Mandatory).	Annually	59	1	150	8,850
Annual Report (Reporting)	Reporting (Mandatory) ..	Annually	59	1	150	8,850

[1] 87 FR 33884, June 3, 2022

SUMMARY OF ESTIMATED ANNUAL BURDENS—Continued
[OMB No. 3064–0013]

Information collection description	Type of burden (obligation to respond)	Frequency of response	Number of respondents	Number of responses per respondent	Hours per response	Annual burden (hours)
Audit Committee Composition (Recordkeeping)	Recordkeeping (Mandatory).	Annually	59	1	3	177
Audit Committee Composition (Reporting)	Reporting (Mandatory)	Annually	59	1	3	177
Filing of Other Reports (Recordkeeping)	Recordkeeping (Mandatory).	Annually	59	1	0.13	7.38
Filing of Other Reports (Reporting)	Reporting (Mandatory)	Annually	59	1	0.13	7.38
Notice of Change in Accountants (Recordkeeping).	Recordkeeping (Mandatory).	Annually	15	1	0.25	3.75
Notice of Change in Accountants (Reporting)	Reporting (Mandatory)	Annually	15	1	0.25	3.75
FDIC-Supervised Institutions with $3 billion to less than $10 billion in Consolidated Total Assets						
Annual Report (Recordkeeping)	Recordkeeping (Mandatory).	Annually	128	1	125	16,000
Annual Report (Reporting)	Reporting (Mandatory)	Annually	128	1	125	16,000
Audit Committee Composition (Recordkeeping)	Recordkeeping (Mandatory).	Annually	128	1	3	384
Audit Committee Composition (Reporting)	Reporting (Mandatory)	Annually	128	1	3	384
Filing of Other Reports (Recordkeeping)	Recordkeeping (Mandatory).	Annually	128	1	0.13	16
Filing of Other Reports (Reporting)	Reporting (Mandatory)	Annually	128	1	0.13	16
Notice of Change in Accountants (Recordkeeping).	Recordkeeping (Mandatory).	Annually	32	1	0.25	8
Notice of Change in Accountants (Reporting)	Reporting (Mandatory)	Annually	32	1	0.25	8
FDIC-Supervised Institutions with $1 billion to less than $3 billion in Consolidated Total Assets						
Annual Report (Recordkeeping)	Recordkeeping (Mandatory).	Annually	342	1	100	34,200
Annual Report (Reporting)	Reporting (Mandatory)	Annually	342	1	100	34,200
Audit Committee Composition (Recordkeeping)	Recordkeeping (Mandatory).	Annually	342	1	2	684
Audit Committee Composition (Reporting)	Reporting (Mandatory)	Annually	342	1	2	684
Filing of Other Reports (Recordkeeping)	Recordkeeping (Mandatory).	Annually	342	1	0.13	42.75
Filing of Other Reports (Reporting)	Reporting (Mandatory)	Annually	342	1	0.13	42.75
Notice of Change in Accountants (Recordkeeping).	Recordkeeping (Mandatory).	Annually	86	1	0.25	21.5
Notice of Change in Accountants (Reporting)	Reporting (Mandatory)	Annually	86	1	0.25	21.5
FDIC-Supervised Institutions with $500 million to less than $1 billion in Consolidated Total Assets						
Annual Report (Recordkeeping)	Recordkeeping (Mandatory).	Annually	483	1	12.5	6,037.5
Annual Report (Reporting)	Reporting (Mandatory)	Annually	483	1	12.5	6,037.5
Audit Committee Composition (Recordkeeping)	Recordkeeping (Mandatory).	Annually	483	1	1	483
Audit Committee Composition (Reporting)	Reporting (Mandatory)	Annually	483	1	1	483
Filing of Other Reports (Recordkeeping)	Recordkeeping (Mandatory).	Annually	483	1	0.13	60.38
Filing of Other Reports (Reporting)	Reporting (Mandatory)	Annually	483	1	0.13	60.38
Notice of Change in Accountants (Recordkeeping).	Recordkeeping (Mandatory).	Annually	121	1	0.25	30.25
Notice of Change in Accountants (Reporting)	Reporting (Mandatory)	Annually	121	1	0.25	30.25
FDIC-Supervised Institutions with less than $500 million in Consolidated Total Assets						
Filing of Other Reports (Recordkeeping)	Recordkeeping (Voluntary).	Annually	2,116	1	0.25	529
Filing of Other Reports (Reporting)	Reporting (Voluntary)	Annually	2,116	2	0.25	1,058
Total Annual Burden Hours						135,598

Source: FDIC.

General Description of Collection: FDIC's regulations at 12 CFR part 363 establish annual independent audit and reporting requirements for financial institutions with total assets of $500 million or more. The requirements include the submission of an annual report on their financial statements, recordkeeping about management deliberations regarding external auditing and reports about changes in auditors. The information collected is used to facilitate early identification of problems in financial management at financial institutions. There is no change in the substance or methodology of this information collection. The overall increase in burden hours is a result of the increase in the estimated number of respondents with consolidated total assets greater than $500 million.

3. *Title:* Funding and Liquidity Risk Management.

OMB Number: 3064–0174.

Form Number: None.

Affected Public: Businesses or other for-profits.

Burden Estimate:

Information collection description	Type of burden	Estimated number of respondents	Estimated number of responses per respondent	Estimated time per response (hours)	Estimated annual burden (hours)
Paragraph 14—Strategies, policies, procedures, and risk tolerances.	Recordkeeping (Voluntary).	3,128	1	83.94	262,564
Paragraph 20—Liquidity risk management measurement, monitoring, and reporting.	Reporting (Voluntary) ...	3,128	12	4	150,144
Total Annual Burden	....	....	....	....	412,708

General Description of Collection: The information collection includes reporting and recordkeeping burdens related to sound risk management principles applicable to insured depository institutions. To enable an institution and its supervisor to evaluate the liquidity risk exposure of an institution's individual business lines and for the institution as a whole, the Interagency Policy Statement on Funding and Liquidity Risk Management (Interagency Statement) summarizes principles of sound liquidity risk management and advocates the establishment of policies and procedures that consider liquidity costs, benefits, and risks in strategic planning. In addition, the Interagency Statement encourages the use of liquidity risk reports that provide detailed and aggregate information on items such as cash flow gaps, cash flow projections, assumptions used in cash flow projections, asset and funding concentrations, funding availability, and early warning or risk indicators. This is intended to enable management to assess an institution's sensitivity to changes in market conditions, the institution's financial performance, and other important risk factors. There is no change in the method or substance of the collection. The overall reduction in burden hours is the result of economic fluctuation. In particular, the number of respondents.

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 June 14, 2022.

James P. Sheesley,

Assistant Executive Secretary.

[FR Doc. 2022–13156 Filed 6–17–22; 8:45 am]

BILLING CODE 6714–01–P

DEPARTMENT OF DEFENSE

GENERAL SERVICES ADMINISTRATION

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

[OMB Control No. 9000–0082; Docket No. 2022–0053; Sequence No. 11]

Submission for OMB Review; Information Collection; Federal Acquisition Regulation Part 7 Requirements

AGENCY: Department of Defense (DOD), General Services Administration (GSA), and National Aeronautics and Space Administration (NASA).

ACTION: Notice.

SUMMARY: Under the provisions of the Paperwork Reduction Act, the Regulatory Secretariat Division has submitted to the Office of Management and Budget (OMB) a request to review and approve a revision of a previously approved information collection requirement regarding Federal Acquisition Regulation Part 7 Requirements.

DATES: Submit comments on or before July 21, 2022.

ADDRESSES: Written comments and recommendations for this 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" or by using the search function.

Additionally, submit a copy to GSA through *https://www.regulations.gov* and follow the instructions on the site. This website provides the ability to type short comments directly into the comment field or attach a file for lengthier comments.

Instructions: All items submitted must cite OMB Control No. 9000–0082, Federal Acquisition Regulation Part 7 Requirements. Comments received generally will be posted without change to *https://www.regulations.gov,* including any personal and/or business confidential information provided. To confirm receipt of your comment(s), please check *www.regulations.gov,* approximately two-to-three days after submission to verify posting. If there are difficulties submitting comments, contact the GSA Regulatory Secretariat Division at 202–501–4755 or *GSARegSec@gsa.gov.*

FOR FURTHER INFORMATION CONTACT: Carrie Moore, Procurement Analyst, at telephone 571.300–5917, or *carrie.moore@gsa.gov.*

SUPPLEMENTARY INFORMATION:

A. OMB Control Number, Title, and Any Associated Form(s)

9000–0082, Federal Acquisition Regulation Part 7 Requirements.

B. Needs and Uses

DoD, GSA, and NASA are combining OMB Control Nos. for the Federal Acquisition Regulation (FAR) by FAR part. This consolidation is expected to improve industry's ability to easily and efficiently identify burdens associated with a given FAR part. The review of the information collections by FAR part allows improved oversight to ensure there is no redundant or unaccounted for burden placed on industry. Lastly, combining information collections in a given FAR part is also expected to reduce the administrative burden associated with processing multiple information collections.

This justification supports the revision of OMB Control No. 9000–0082 and combines it with the previously approved information collection under OMB Control No. 9000–0114, with the new title "Federal Acquisition Regulation Part 7 Requirements". Upon approval of this consolidated information collection, OMB Control No. 9000–0114 will be discontinued. The burden requirements previously approved under the discontinued number will be covered under OMB Control No. 9000–0082.

This clearance covers the information that offerors or contractors must submit to comply with the following FAR requirements:

FAR clause 52.207–3, Right of First Refusal of Employment, requires contractors to provide the contracting officer, within 120 days of beginning contract performance, the names of personnel who were: Adversely affected or separated from Government employment as a result of the contract award; and subsequently hired by the contractor to perform under the contract within 90 days after contract performance began. The information provided under this clause is used by the Government to ensure: Contractor compliance with providing the right of first refusal to such affected personnel; and certain obligations to displaced employees are met by the Government.

FAR provision 52.207–4, Economic Purchase Quantity—Supplies, permits offerors, who believe that acquisition of supplies in quantity different from what is being solicited would be more advantageous to the Government, to recommend with their offer a more economic purchase quantity for the required supplies. The information provided under this provision is used by the Government to acquire supplies at the total and unit costs most advantageous to the Government and to develop a database for future acquisitions of such items of supply.

C. Annual Burden

Respondents: 14,510.

Total Annual Responses: 14,510.

Total Burden Hours: 14,530.

D. Public Comment

A 60-day notice was published in the **Federal Register** at 87 FR 19515, on April 4, 2022. No comments were received.

Obtaining Copies: Requesters may obtain a copy of the information collection documents from the GSA Regulatory Secretariat Division, by calling 202–501–4755 or emailing *GSARegSec@gsa.gov.* Please cite OMB Control No. 9000–0082, Federal Acquisition Regulation Part 7 Requirements.

Janet Fry,

Director, Federal Acquisition Policy Division, Office of Governmentwide Acquisition Policy, Office of Acquisition Policy, Office of Governmentwide Policy.

[FR Doc. 2022–13218 Filed 6–17–22; 8:45 am]

BILLING CODE 6820–EP–P

GENERAL SERVICES ADMINISTRATION

[Notice–MRB–2022–02; Docket No. 2022–0002; Sequence No. 6]

Notice of Establishment of a Federal Advisory Committee

AGENCY: Office of Government-wide Policy (OGP), General Services Administration (GSA).

ACTION: Notice.

SUMMARY: The U.S. General Services Administration (GSA) is announcing the establishment of the GSA Acquisition Policy Federal Advisory Committee (hereinafter ''the Committee'' or ''the GAP FAC'') in accordance with the provisions of the Federal Advisory Committee Act (FACA).

DATES: June 21, 2022.

FOR FURTHER INFORMATION CONTACT: Boris Arratia, OGP, 703–795–0816, or Stephanie Hardison, OGP, 202–258–6823, or email: *gapfac@gsa.gov.*

SUPPLEMENTARY INFORMATION: The Administrator of GSA established the GSA Acquisition Policy Federal Advisory Committee (GAP FAC) as a discretionary advisory committee under agency authority in accordance with the provisions of FACA (5 U.S.C. App 2). GSA has determined that the establishment of GAP FAC is necessary and in the public interest.

As America's buyer, GSA is uniquely positioned to enable a modern, accessible, and streamlined acquisition ecosystem and a robust marketplace connecting buyers to the suppliers and businesses that meet their mission needs. The GAP FAC will assist GSA in this endeavor through expert advice on a broad range of innovative solutions to acquisition policy, workforce and industry partnership challenges.

The GAP FAC will serve as an advisory body to GSA's Administrator on how GSA can use its acquisition tools and authorities to target the highest priority Federal acquisition challenges. The GAP FAC will advise GSA's Administrator on emerging acquisition issues, challenges, and opportunities to support its role as America's buyer. The initial focus for the GAP FAC will be on driving regulatory, policy, and process changes required to embed climate and sustainability considerations in Federal acquisition. This includes examining and recommending steps GSA can take to support its workforce and industry partners in ensuring climate and sustainability issues are fully considered in the acquisition process. In accordance with FACA, the charter for the Committee will be filed with the appropriate entities no earlier than 15 calendar days following the date of publication of this notice.

Krystal Brumfield,

Associate Administrator, Office of Government-wide Policy, General Services Administration.

[FR Doc. 2022–13223 Filed 6–17–22; 8:45 am]

BILLING CODE 6820–61–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2022–D–0737]

Non-Clinical Performance Assessment of Tissue Containment Systems Used During Power Morcellation Procedures; Draft Guidance for Industry and Food and Drug Administration Staff; Availability

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice of availability.

SUMMARY: The Food and Drug Administration (FDA or Agency) is announcing the availability of the draft guidance entitled ''Non-Clinical Performance Assessment of Tissue Containment Systems Used During Power Morcellation Procedures.'' This draft guidance document provides recommendations that may help manufacturers comply with the special controls related to non-clinical performance data for gynecologic and general laparoscopic power morcellation containment systems. This draft guidance is not final nor is it for implementation at this time.

DATES: Submit either electronic or written comments on the draft guidance by August 22, 2022 to ensure that the Agency considers your comment on this draft guidance before it begins work on the final version of the guidance.

ADDRESSES: You may submit comments on any guidance at any time as follows:

Electronic Submissions

Submit electronic comments in the following way:

• *Federal eRulemaking Portal: https://www.regulations.gov.* Follow the instructions for submitting comments. Comments submitted electronically, including attachments, to *https://www.regulations.gov* will be posted to the docket unchanged. Because your comment will be made public, you are solely responsible for ensuring that your comment does not include any confidential information that you or a third party may not wish to be posted, such as medical information, your or anyone else's Social Security number, or confidential business information, such as a manufacturing process. Please note that if you include your name, contact information, or other information that identifies you in the body of your comments, that information will be posted on *https://www.regulations.gov.*

• If you want to submit a comment with confidential information that you do not wish to be made available to the public, submit the comment as a written/paper submission and in the manner detailed (see ''Written/Paper Submissions'' and ''Instructions'').

Written/Paper Submissions

Submit written/paper submissions as follows:

• *Mail/Hand Delivery/Courier (for written/paper submissions):* Dockets Management Staff (HFA–305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.

• For written/paper comments submitted to the Dockets Management Staff, FDA will post your comment, as well as any attachments, except for information submitted, marked and identified, as confidential, if submitted as detailed in ''Instructions.''

Instructions: All submissions received must include the Docket No. FDA–2022–D–0737 for ''Non-Clinical Performance Assessment of Tissue Containment Systems Used During Power Morcellation Procedures.'' Received comments will be placed in the docket and, except for those submitted as ''Confidential Submissions,'' publicly viewable at *https://www.regulations.gov* or at the Dockets Management Staff between 9 a.m. and 4 p.m., Monday through Friday, 240–402–7500.

• Confidential Submissions—To submit a comment with confidential information that you do not wish to be made publicly available, submit your comments only as a written/paper submission. You should submit two copies total. One copy will include the information you claim to be confidential with a heading or cover note that states ''THIS DOCUMENT CONTAINS CONFIDENTIAL INFORMATION.'' The Agency will review this copy, including the claimed confidential information, in its consideration of comments. The second copy, which will have the claimed confidential information redacted/blacked out, will be available for public viewing and posted on *https://www.regulations.gov.* Submit both copies to the Dockets Management Staff. If you do not wish your name and contact information to be made publicly available, you can provide this information on the cover sheet and not in the body of your comments and you must identify this information as ''confidential.'' Any information marked as ''confidential'' will not be disclosed except in accordance with 21 CFR 10.20 and other applicable disclosure law. For more information about FDA's posting of comments to public dockets, see 80 FR 56469, September 18, 2015, or access the information at: *https://www.govinfo.gov/content/pkg/FR-2015-09-18/pdf/2015-23389.pdf.*

Docket: For access to the docket to read background documents or the electronic and written/paper comments received, go to *https://www.regulations.gov* and insert the docket number, found in brackets in the heading of this document, into the ''Search'' box and follow the prompts and/or go to the Dockets Management Staff, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852, 240–402–7500.

You may submit comments on any guidance at any time (see 21 CFR 10.115(g)(5)).

An electronic copy of the guidance document is available for download from the internet. See the **SUPPLEMENTARY INFORMATION** section for information on electronic access to the guidance. Submit written requests for a single hard copy of the draft guidance document entitled ''Non-Clinical Performance Assessment of Tissue Containment Systems Used During Power Morcellation Procedures'' to the Office of Policy, Center for Devices and Radiological Health, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 66, Rm. 5431, Silver Spring, MD 20993–0002. Send one self-addressed adhesive label to assist that office in processing your request.

FOR FURTHER INFORMATION CONTACT: Prasanna Hariharan, Center for Devices and Radiological Health, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 62, Rm. 2222, Silver Spring, MD 20993–0002, 301–796–2689.

SUPPLEMENTARY INFORMATION:

I. Background

FDA is issuing this draft guidance to provide recommendations that may help manufacturers comply with the special controls related to non-clinical performance data for gynecologic and general laparoscopic power morcellation containment systems. These devices are class II (special controls) devices and subject to premarket notification (510(k)) requirements. These tissue containment systems are prescription devices consisting of an instrument port and tissue containment method that create a working space allowing for direct visualization during a power morcellation procedure following a laparoscopic procedure for the excision of benign tissue that is not suspected to contain malignancy.

This draft guidance is being issued consistent with FDA's good guidance practices regulation (21 CFR 10.115). The draft guidance, when finalized, will represent the current thinking of FDA on the topic of the guidance. It does not establish any rights for any person and is not binding on FDA or the public. You can use an alternative approach if it satisfies the requirements of the applicable statutes and regulations.

II. Electronic Access

Persons interested in obtaining a copy of the draft guidance may do so by downloading an electronic copy from the internet. A search capability for all Center for Devices and Radiological Health guidance documents is available at *https://www.fda.gov/medical-devices/device-advice-comprehensive-regulatory-assistance/guidance-documents-medical-devices-and-radiation-emitting-products.* This guidance document is also available at *https://www.regulations.gov* or *https://www.fda.gov/regulatory-information/search-fda-guidance-documents.* Persons unable to download an electronic copy of ''Non-Clinical Performance Assessment of Tissue Containment Systems Used During Power Morcellation Procedures'' may send an email request to *CDRH-Guidance@fda.hhs.gov* to receive an electronic copy of the document. Please use the document number 19015 and complete title to identify the guidance you are requesting.

III. Paperwork Reduction Act of 1995

While this guidance contains no new collection of information, it does refer to previously approved FDA collections of information. Therefore, clearance by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3501–3521) is not required for this guidance. The previously approved collections of information are subject to review by

OMB under the PRA. The collections of information in the following FDA regulation and guidance have been approved by OMB as listed in the following table:

21 CFR part or guidance	Topic	OMB control No.
807, subpart E	Premarket notification	0910–0120
"Requests for Feedback and Meetings for Medical Device Submissions: The Q-Submission Program".	Q-submissions	0910–0756

Dated: June 14, 2022.

Lauren K. Roth,

Associate Commissioner for Policy.

[FR Doc. 2022–13212 Filed 6–17–22; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2022–N–0799]

Improving 510(k) Submission Preparation and Review: Center for Biologics Evaluation and Research; Voluntary Electronic Submission Template and Resource Pilot Program; Request for Comments

AGENCY: Food and Drug Administration, Department of Health and Human Services (HHS).

ACTION: Notice; request for comments.

SUMMARY: The Food and Drug Administration's (FDA or Agency) Center for Biologics Evaluation and Research (CBER) is announcing a pilot program for sponsors of CBER premarket notification (510(k)) submissions that wish to use the voluntary Electronic Submission Template and Resource (eSTAR) Pilot Program. CBER's voluntary eSTAR Pilot Program is intended to improve consistency and efficiency in both industry's preparation and FDA's review of premarket notification (510(k)) submissions. During CBER's voluntary eSTAR Pilot Program, participants will have the opportunity to provide input to FDA on the eSTAR Pilot Program for submissions to CBER.

DATES: FDA is seeking participation in CBER's voluntary eSTAR Pilot Program beginning June 21, 2022. See section I.A. for instructions on how to submit a request to participate. The CBER voluntary eSTAR Pilot Program will select up to nine participants who best match the selection criteria. This pilot program will begin June 21, 2022. Submit either electronic or written comments on the notice by August 22, 2022.

ADDRESSES: You may submit comments as follows. Please note that late, untimely filed comments will not be considered. The *https://www.regulations.gov* electronic filing system will accept comments until 11:59 p.m. Eastern Time at the end of August 22, 2022. Comments received by mail/hand delivery/courier (for written/paper submissions) will be considered timely if they are postmarked or the delivery service acceptance receipt is on or before that date.

Electronic Submissions

Submit electronic comments in the following way:

- *Federal eRulemaking Portal: https://www.regulations.gov.* Follow the instructions for submitting comments. Comments submitted electronically, including attachments, to *https://www.regulations.gov* will be posted to the docket unchanged. Because your comment will be made public, you are solely responsible for ensuring that your comment does not include any confidential information that you or a third party may not wish to be posted, such as medical information, your or anyone else's Social Security number, or confidential business information, such as a manufacturing process. Please note that if you include your name, contact information, or other information that identifies you in the body of your comments, that information will be posted on *https://www.regulations.gov.*
- If you want to submit a comment with confidential information that you do not wish to be made available to the public, submit the comment as a written/paper submission and in the manner detailed (see "Written/Paper Submissions" and "Instructions").

Written/Paper Submissions

Submit written/paper submissions as follows:

- *Mail/Hand Delivery/Courier (for written/paper submissions):* Dockets Management Staff (HFA–305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.
- For written/paper comments submitted to the Dockets Management Staff, FDA will post your comment, as well as any attachments, except for information submitted, marked and identified, as confidential, if submitted as detailed in "Instructions."

Instructions: All submissions received must include the Docket No. FDA–2022–N–0799 for "Improving 510(k) Submission Preparation and Review: Center for Biologics Evaluation and Research; Voluntary Electronic Submission Template and Resource Pilot Program." Received comments, those filed in a timely manner (see **ADDRESSES**), will be placed in the docket and, except for those submitted as "Confidential Submissions," publicly viewable at *https://www.regulations.gov* or at the Dockets Management Staff between 9 a.m. and 4 p.m., Monday through Friday, 240–402–7500.

- Confidential Submissions—To submit a comment with confidential information that you do not wish to be made publicly available, submit your comments only as a written/paper submission. You should submit two copies total. One copy will include the information you claim to be confidential with a heading or cover note that states "THIS DOCUMENT CONTAINS CONFIDENTIAL INFORMATION." The Agency will review this copy, including the claimed confidential information, in its consideration of comments. The second copy, which will have the claimed confidential information redacted/blacked out, will be available for public viewing and posted on *https://www.regulations.gov.* Submit both copies to the Dockets Management Staff. If you do not wish your name and contact information to be made publicly available, you can provide this information on the cover sheet and not in the body of your comments and you must identify this information as "confidential." Any information marked as "confidential" will not be disclosed except in accordance with 21 CFR 10.20 and other applicable disclosure law. For more information about FDA's posting of comments to public dockets, see 80 FR 56469, September 18, 2015, or access the information at: *https://www.govinfo.gov/content/pkg/FR-2015-09-18/pdf/2015-23389.pdf.*

Docket: For access to the docket to read background documents or the electronic and written/paper comments received, go to *https://www.regulations.gov* and insert the docket number, found in brackets in the heading of this document, into the ''Search'' box and follow the prompts and/or go to the Dockets Management Staff, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852, 240–402–7500.

FOR FURTHER INFORMATION CONTACT:

Myrna Hanna, Center for Biologics Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 71, Rm. 7301, Silver Spring, MD 20993–0002, 240–402–7911.

SUPPLEMENTARY INFORMATION:

I. Background

In the Medical Device User Fee Amendments of 2012 (MDUFA III) Commitment Letter from the Secretary of Health and Human Services to Congress, FDA committed to streamlining review processes by moving beyond paper-based review (Ref. 1). Under section 745A(b) of the Federal Food, Drug, and Cosmetic Act (FD&C Act) (21 U.S.C. 379k–1), added by section 1136 of the Food and Drug Administration Safety and Innovation Act (Pub. L. 112–144), an electronic copy (eCopy) is required for certain premarket submission types, including 510(k) submissions. FDA provided additional information about the submissions subject to the eCopy requirements in section 745A(b) of the FD&C Act and recommendations about the use of eCopy generally in a guidance initially issued in 2013 (Ref. 2). FDA subsequently published a final rule in the **Federal Register** of December 16, 2019 (84 FR 68334), amending FDA's regulations, where appropriate, to reflect the requirement of a single submission in electronic format, including the use of eCopy requirements.

In the Medical Device User Fee Amendments of 2017 (MDUFA IV) Commitment Letter from the Secretary of Health and Human Services to Congress (Ref. 3), FDA committed to developing ''electronic submission templates that will serve as guided submission preparation tools for industry to improve submission consistency and enhance efficiency in the review process.'' In addition, section 745A(b) of the FD&C Act, as amended by section 207 of the FDA Reauthorization Act of 2017 (Pub. L. 115–52), requires that certain presubmissions and submissions for devices, including 510(k) submissions, be submitted in such electronic format as specified in guidance by FDA.

FDA considers both eCopies and eSubmissions to be submissions in electronic format. eSubmissions are submission packages produced by an electronic submission template that contains the data of a ''complete'' (see Ref. 4) submission. To support the next step in transition to 510(k) submissions solely in electronic format, FDA has developed eSTAR, an electronic submission template built within a structured dynamic PDF that guides a user through construction of an eSubmission. eSTAR includes the following benefits:

- automation (*e.g.,* form construction, autofilling);
- content and structure that is complementary to FDA internal review templates;
- integration of multiple resources (*e.g.,* guidances, databases);
- guided construction for each submission section;
- automatic verification (*i.e.,* FDA does not intend to conduct a Refuse to Accept (RTA) review (Ref. 4)); and
- it is free to use.

eSTAR contains the following additional benefits:

- intuitive interface;
- no special software installation (if the user has Adobe Acrobat or similar software already installed);
- support for images and dynamic pop-up messages;
- mobile device and Apple iOS support;
- ability to comment when converted to a static PDF;
- ability to share (*e.g.,* email) an eSTAR file that is in the process of being constructed; and
- no packaging process.

In February 2020, CDRH piloted the use of the eSTAR electronic submission template (85 FR 11371). FDA then issued a draft guidance in September 2021 describing the technical standards associated with preparation of the electronic submission template for 510(k)s (Ref. 5) that, when the guidance is finalized, will enable submission of 510(k) electronic submissions solely in electronic format. In the draft guidance, FDA noted that CBER also intended to pilot eSTAR. FDA is now announcing CBER's voluntary eSTAR Pilot Program and soliciting participation from 510(k) submitters for this program. This pilot will provide an opportunity for CBER staff to gain experience with review of and internal processes for 510(k) submissions using the eSTAR template. It will also provide experience with use of the FDA Electronic Submissions Gateway for 510(k) submissions using the eSTAR template. Information collected through the pilot program will help inform FDA on how to improve eSTAR and identify any additional considerations specific to submissions for CBER-regulated devices.

A. CBER Voluntary eSTAR Pilot Program Participation

FDA seeks participation from 510(k) submitters in CBER's voluntary eSTAR Pilot Program beginning June 21, 2022. The CBER voluntary eSTAR Pilot Program will select up to nine participants whose submissions to CBER meet the selection criteria.

Companies that may be eligible to participate in CBER's voluntary eSTAR Pilot Program are limited to those firms following the procedures set out in section I.B. of this document and that also meet all the selection criteria that follow:

1. intent to submit a traditional, special, or abbreviated 510(k) for a medical device regulated by CBER (Ref. 6) using eSTAR within 1 month of acceptance to the CBER voluntary eSTAR Pilot Program; and
2. willingness to provide feedback on eSTAR as outlined in section I.C. of this document.

At its discretion, FDA may withdraw a manufacturer from the CBER voluntary eSTAR Pilot Program for not carrying out any of the commitments mentioned previously.

B. CBER Voluntary eSTAR Pilot Program Procedure

To be considered for CBER's voluntary eSTAR Pilot Program, a company should submit a statement of interest for participation to *Industry.biologics@fda.hhs.gov.* The statement of interest should include ''CBER Voluntary eSTAR Pilot Program'' in the subject line and agreement to the selection criteria listed in section I.A. of this document, as well as a description of the device in enough detail to allow verification that it is a CBER regulated device.

The following captures the process for the CBER voluntary eSTAR Pilot Program:

1. FDA will collect statements of interest for participation in the pilot program beginning June 21, 2022.

The statement of interest should include:

- agreement to the selection criteria listed in section I.A. of this document
- the device(s) that is/are likely to be submitted during the pilot program using eSTAR

2. FDA will select no more than nine participants, who best meet the

selection criteria and who reflect the broad spectrum of device manufacturers, including companies that develop a range of products. Enrollment in the pilot program will be ongoing throughout the duration of the program. FDA will apply lessons learned from the initial participants in the pilot program to refine eSTAR with participants, as appropriate.

3. FDA intends to notify the manufacturer via email if the manufacturer is enrolled as a participant in the CBER's voluntary eSTAR Pilot Program.

4. The enrolled manufacturer should navigate to the FDA ''Voluntary eSTAR Program'' web page at: *https://www.fda.gov/medical-devices/how-study-and-market-your-device/premarket-submissions* and download eSTAR from the ''Voluntary eSTAR Program'' web page (Ref. 7). *Note:* eSTAR should not be submitted to CBER unless the sponsor is a pilot participant.

5. Directions for preparing and submitting a 510(k) using eSTAR to FDA are in the final section of the eSTAR pdf. We recommend that all eSTAR elements including the cover letter be submitted through the FDA Electronic Submissions Gateway (refer to ''Electronic Submissions Gateway'') (Ref. 8) or on physical media through CBER's Document Control Center in accordance with the ''Regulatory Submissions in Electronic and Paper Format for CBER-Regulated Products'' web page (Ref. 9). We recommend that you use Adobe Acrobat Pro with eSTAR. Be aware that eSTARs should not be submitted to CDRH via the Electronic Submission Gateway, as CDRH does not use the Electronic Submission Gateway to receive submissions.

6. If eligible and enrolled as a participant, the manufacturer should submit a 510(k) submission prepared and verified using eSTAR within the timeframe identified in the selection criteria in section I.A. of this document.

7. Once the eSTAR prepared 510(k) is received by FDA, FDA does not intend to conduct the RTA process. However, FDA intends to employ a technical screening process for the eSTAR like the one described in FDA draft guidance ''Electronic Submission Template for Medical Device 510(k) Submissions'' (Ref. 5). The technical screening process is a process for verifying that eSTAR responses accurately describe the device(s) (*e.g.,* there are, in fact, no tissue contacting components if indicated as such) and that there is at least one relevant attachment per each applicable attachment-type question (*e.g.,* a Software Description attachment is included in response to the Software Description question if software is applicable to the submission). The technical screening process is anticipated to occur within 15 calendar days of FDA receiving the 510(k) eSTAR. FDA intends to only begin the technical screening for 510(k) electronic submissions where the appropriate user fee has been paid. If the eSTAR is not complete when submitted, FDA intends to notify the submitter via email and identify the missing information, and the 510(k) may be placed on hold until a complete replacement eSTAR is submitted to FDA. The remainder of the review will be conducted according to the FDA guidance ''The 510(k) Program: Evaluating Substantial Equivalence in Premarket Notifications'' (Ref. 10), and the procedures identified in part 807, subpart E (21 CFR part 807, subpart E).

8. Following completion of the review of 510(k)s in the CBER voluntary eSTAR Pilot Program, participating manufacturers will have the opportunity to provide individual feedback on the CBER voluntary eSTAR Pilot Program through the procedures outlined on the ''Voluntary eSTAR Program'' web page (Ref. 7). Non-pilot participants are welcome to submit feedback to the Docket (see **ADDRESSES**).

During the CBER voluntary eSTAR Pilot Program, CBER staff intends to be available to answer questions from or concerns of pilot participants that may arise.

C. Targeted Questions for the CBER Voluntary eSTAR Pilot Program

FDA requests responses to the following questions about eSTAR from pilot program participants and stakeholders outside the pilot who want to submit comments to the docket.

(1) Is eSTAR able to integrate into your organization's business process?

(2) Are you able to open eSTAR, and are you able to add values to the structured data fields, as well as add attachments? Once entered and added, are the data retained after closing and reopening eSTAR?

(3) If you use Assistive Technology, are you able to navigate through and complete eSTAR?

(4) If eSTAR is not intuitive to use, why?

(5) Is the organization and content in eSTAR as expected?

(6) If applicable, did you experience any difficulties using the Electronic Submission Gateway to submit eSTAR?

(7) Is eSTAR able to accommodate PDF attachments that are of the size you typically would provide in a submission?

(8) If all the required questions (indicated by red or green indicators) are provided values, and all the required attachments are added, does eSTAR properly indicate it is complete on the first page, and are all the sections listed in the ''Completed'' column in the final section?

(9) Do you have any suggestions to improve the effectiveness of eSTAR in its purpose, or suggestions to improve the usability?

II. Paperwork Reduction Act of 1995

This notice refers to previously approved FDA collections of information. These collections of information are subject to review by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3521). The collections of information in part 807, subpart E have been approved under OMB control number 0910–0120.

III. References

The following references are on display at the Dockets Management Staff (see **ADDRESSES**), and are available for viewing by interested persons between 9 a.m. and 4 p.m., Monday through Friday; they are also available electronically at *https://www.regulations.gov.* FDA has verified the website addresses, as of the date this document publishes in the **Federal Register**, but websites are subject to change over time.

1. MDUFA III Commitment Letter, available at: *https://www.fda.gov/media/83244/download.*
2. ''eCopy Program for Medical Device Submissions: Guidance for Industry and Food and Drug Administration Staff,'' dated April 27, 2020; available at: *https://www.fda.gov/media/83522/download.*
3. MDUFA IV Commitment Letter, available at: *https://www.fda.gov/media/102699/download.*
4. ''Refuse to Accept Policy for 510(k)s: Guidance for Industry and Food and Drug Administration Staff,'' dated September 13, 2019; available at: *https://www.fda.gov/media/83888/download.*
5. ''Electronic Submission Template for Medical Device 510(k) Submissions: Draft Guidance for Industry and Food and Drug Administration Staff,'' dated September 29, 2021; available at: *https://www.fda.gov/media/152429/download.*
6. Premarket Notification 510(k) Process for CBER-Regulated Products at: *https://www.fda.gov/vaccines-blood-biologics/development-approval-process-cber/premarket-notification-510k-process-cber-regulated-products.*
7. Voluntary eSTAR Program, available at: *https://www.fda.gov/medical-devices/how-study-and-market-your-device/voluntary-estar-program.*
8. Electronic Submission Gateway, available

at: *https://www.fda.gov/industry/electronic-submissions-gateway.*

9. Regulatory Submissions in Electronic and Paper Format for CBER-Regulated Products; available at: *https://www.fda.gov/about-fda/center-biologics-evaluation-and-research-cber/regulatory-submissions-electronic-and-paper-format-cber-regulated-products.*
10. ''The 510(k) Program: Evaluating Substantial Equivalence in Premarket Notifications [510(k)]: Guidance for Industry and Food and Drug Administration Staff,'' dated July 28, 2014; available at: *https://www.fda.gov/media/82395/download.*

Dated: June 14, 2022.

Lauren K. Roth,

Associate Commissioner for Policy.

[FR Doc. 2022–13210 Filed 6–17–22; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2019–D–1997]

Food and Drug Administration Oversight of Food Covered by Systems Recognition Arrangements; Guidance for Food and Drug Administration Staff; Availability

AGENCY: Food and Drug Administration, Department of Health and Human Services (HHS).

ACTION: Notice of availability.

SUMMARY: The Food and Drug Administration (FDA or Agency) is announcing the availability of a final guidance for FDA staff entitled ''FDA Oversight of Food Covered by Systems Recognition Arrangements.'' This guidance provides recommendations related to FDA's regulatory oversight activities for food covered by a Systems Recognition Arrangement (SRA) and imported from countries whose food safety systems FDA has recognized in SRAs.

DATES: The announcement of the guidance is published in the **Federal Register** on June 21, 2022.

ADDRESSES: You may submit comments on any guidance at any time as follows:

Electronic Submissions

Submit electronic comments in the following way:

• *Federal eRulemaking Portal: https://www.regulations.gov.* Follow the instructions for submitting comments. Comments submitted electronically, including attachments, to *https://www.regulations.gov* will be posted to the docket unchanged. Because your comment will be made public, you are solely responsible for ensuring that your comment does not include any confidential information that you or a third party may not wish to be posted, such as medical information, your or anyone else's Social Security number, or confidential business information, such as a manufacturing process. Please note that if you include your name, contact information, or other information that identifies you in the body of your comments, that information will be posted on *https://www.regulations.gov.*

• If you want to submit a comment with confidential information that you do not wish to be made available to the public, submit the comment as a written/paper submission and in the manner detailed (see ''Written/Paper Submissions'' and ''Instructions'').

Written/Paper Submissions

Submit written/paper submissions as follows:

• *Mail/Hand Delivery/Courier (for written/paper submissions):* Dockets Management Staff (HFA–305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.

• For written/paper comments submitted to the Dockets Management Staff, FDA will post your comment, as well as any attachments, except for information submitted, marked and identified, as confidential, if submitted as detailed in ''Instructions.''

Instructions: All submissions received must include the Docket No. FDA–2019–D–1997 for ''FDA Oversight of Food Covered by Systems Recognition Arrangements; Guidance for FDA Staff.'' Received comments will be placed in the docket and, except for those submitted as ''Confidential Submissions,'' publicly viewable at *https://www.regulations.gov* or at the Dockets Management Staff between 9 a.m. and 4 p.m., Monday through Friday, 240–402–7500.

• Confidential Submissions—To submit a comment with confidential information that you do not wish to be made publicly available, submit your comments only as a written/paper submission. You should submit two copies total. One copy will include the information you claim to be confidential with a heading or cover note that states ''THIS DOCUMENT CONTAINS CONFIDENTIAL INFORMATION.'' The Agency will review this copy, including the claimed confidential information, in its consideration of comments. The second copy, which will have the claimed confidential information redacted/blacked out, will be available for public viewing and posted on *https://www.regulations.gov.* Submit both copies to the Dockets Management Staff. If you do not wish your name and contact information to be made publicly available, you can provide this information on the cover sheet and not in the body of your comments and you must identify this information as ''confidential.'' Any information marked as ''confidential'' will not be disclosed except in accordance with 21 CFR 10.20 and other applicable disclosure law. For more information about FDA's posting of comments to public dockets, see 80 FR 56469, September 18, 2015, or access the information at: *https://www.govinfo.gov/content/pkg/FR-2015-09-18/pdf/2015-23389.pdf.*

Docket: For access to the docket to read background documents or the electronic and written/paper comments received, go to *https://www.regulations.gov* and insert the docket number, found in brackets in the heading of this document, into the ''Search'' box and follow the prompts and/or go to the Dockets Management Staff, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852, 240–402–7500.

You may submit comments on any guidance at any time (see 21 CFR 10.115(g)(5)). Submit written requests for a single hard copy of the guidance entitled ''FDA Oversight of Food Covered by Systems Recognition Arrangements'' to the Office of Strategic Planning and Operational Policy, Office of Regulatory Affairs, Food and Drug Administration, 12420 Parklawn Dr., Element Building, Rm. 4148, Rockville, MD 20857. Send one self-addressed adhesive label to assist that office in processing your request. See the **SUPPLEMENTARY INFORMATION** section for electronic access to the guidance.

FOR FURTHER INFORMATION CONTACT: Marla Hallacy, Office of Regulatory Affairs, Division of Operational Policy, Food and Drug Administration, 12420 Parklawn Dr., Rockville, MD 20857, 240–402–6674.

SUPPLEMENTARY INFORMATION:

I. Background

FDA is announcing the availability of a guidance for FDA staff entitled ''FDA Oversight of Food Covered by Systems Recognition Arrangements; Guidance for FDA Staff.'' The guidance is part of FDA's larger effort to take a risk-based approach to food safety to include ensuring the safety of imported food, consistent with the FDA Food Safety Modernization Act. The guidance covers FDA's regulatory oversight activities for food covered by SRAs between FDA and its foreign regulatory counterparts. Currently, FDA has signed SRAs with food safety agencies in Australia, Canada, and New Zealand.

On July 12, 2021, FDA made available the draft guidance entitled ''FDA Oversight of Food Products Covered by Systems Recognition Arrangements; Draft Guidance for Food and Drug Administration Staff'' in the **Federal Register** (86 FR 36559). The comment period closed on September 10, 2021. FDA received no comments on the draft guidance. The Agency made minor editorial changes to the guidance to improve clarity. The guidance announced in this notice finalizes the draft guidance.

This guidance is being issued consistent with FDA's good guidance practices regulation (21 CFR 10.115). The guidance represents the current thinking of FDA on the topic of SRA implementation. It does not establish any rights for any person and is not binding on FDA or the public. You can use an alternate approach if it satisfies the requirements of the applicable statutes and regulations.

II. Paperwork Reduction Act of 1995

While this guidance contains no collection of information, it does refer to previously approved FDA collections of information. Therefore, clearance by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3501–3521) is not required for this guidance. The previously approved collections of information are subject to review by OMB under the PRA. The collections of information regarding the Foreign Supplier Verification Program have been approved under OMB control number 0910–0752, the collections of information regarding the Hazard Analysis and Critical Control Point Procedures for the Safe and Sanitary Processing and Importing of Juice have been approved under OMB control number 0910–0466, and the collections of information regarding the Hazard Analysis and Critical Control Point Procedures for the Safe and Sanitary Processing and Importing of Fish and Fishery Products have been approved under OMB control number 0910–0354.

III. Electronic Access

Persons with access to the internet may obtain the guidance at either *https://www.fda.gov/regulatory-information/search-fda-guidance-documents* or *https://www.regulations.gov.*

Dated: June 15, 2022.

Lauren K. Roth,

Associate Commissioner for Policy.

[FR Doc. 2022–13211 Filed 6–17–22; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Minority Health and Health Disparities; 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 on Minority Health and Health Disparities Special Emphasis Panel; NIH Support for Conferences and Scientific Meetings (R13).

Date: July 8, 2022.

Time: 1:00 p.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Gateway Plaza, 7201 Wisconsin Ave., Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Ivan K. Navarro, Ph.D., Scientific Review Officer, Office of Extramural Research Administration, National Institute on Minority Health and Health Disparities, National Institutes of Health, Gateway Building, 7201 Wisconsin Avenue, Bethesda, MD 20892, 301–827–2061, *ivan.navarro@nih.gov*.

Name of Committee: National Institute on Minority Health and Health Disparities Special Emphasis Panel; Rapid Acceleration of Diagnostics Tribal Data Repository (RADx TDR) (U24).

Date: July 12, 2022.

Time: 2:00 p.m. to 4:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Gateway Plaza, 7201 Wisconsin Ave., Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Maryline Laude-Sharp, Ph.D., Scientific Review Officer, Office of Extramural Research Administration, National Institute on Minority Health and Health Disparities, National Institutes of Health, Gateway Building, 7201 Wisconsin Avenue, Ste. 525, MSC. 9206, Bethesda, MD 20892, 301–451–9536, *mlaudesharp@mail.nih.gov*.

Name of Committee: National Institute on Minority Health and Health Disparities Special Emphasis Panel; Research Centers in Minority Institutions Clinical Research Network for Health Equity (RCMI–CRNHE).

Date: July 27, 2022.

Time: 1:00 p.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Gateway Plaza, 7201 Wisconsin Ave., Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Xinli Nan, M.D., Ph.D., Scientific Review Officer, Office of Extramural Research Activities, National Institute on Minority Health and Health Disparities, National Institutes of Health, Gateway Building, 7201 Wisconsin Avenue, Bethesda, MD 20892, 301–594–7784, *Xinli.Nan@nih.gov*.

Name of Committee: National Institute on Minority Health and Health Disparities Special Emphasis Panel; Misinformation among Populations that Experience Health Disparities (R01—Clinical Trials Optional).

Date: July 28, 2022.

Time: 10:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Gateway Plaza, 7201 Wisconsin Ave., Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Karen Nieves-Lugo, M.P.H., Ph.D., Scientific Review Officer, Office of Extramural Research Activities, National Institute on Minority Health and Health Disparities, National Institutes of Health, Gateway Building, 7201 Wisconsin Avenue, Bethesda, MD 20892, (301) 480–4727, *karen.nieveslugo@nih.gov*.

Dated: June 14, 2022.

David W. Freeman,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2022–13147 Filed 6–17–22; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Proposed Collection; 60-Day Comment Request: NIH Extramural Harassment Web Form (Office of the Director, Office of Extramural Research)

AGENCY: National Institutes of Health, HHS.

ACTION: Notice.

SUMMARY: In compliance with the requirement of the Paperwork Reduction Act of 1995 to provide opportunity for public comment on proposed data collection projects, the National Institutes of Health (NIH) Office of the Director (OD) Office of Extramural Research (OER) will publish periodic summaries of proposed projects to be submitted to the Office of Management and Budget (OMB) for review and approval.

DATES: Comments regarding this information collection are best assured of having their full effect if received within 60 days of the date of this publication.

FOR FURTHER INFORMATION CONTACT: To obtain a copy of the data collection plans and instruments, submit comments in writing, or request more information on the proposed project, contact: Dr. Patricia Valdez, Chief Extramural Research Integrity Officer, Office of Extramural Research, National Institutes of Health, 6705 Rockledge Dr., Room 811–G MSC 7963, Bethesda, Maryland 20892 or call non-toll-free number (301) 451–2160 or email your request, including your address to: *patricia.valdez@nih.gov.* Formal requests for additional plans and instruments must be requested in writing.

SUPPLEMENTARY INFORMATION: Section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995 requires: written comments and/or suggestions from the public and affected agencies are invited to address one or more of the following points: (1) Whether the proposed collection of information is necessary for the proper performance of the function 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) 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 those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology.

Proposed Collection Title: NIH Extramural Harassment Web Form, 0925–NEW, exp., date, XX/XX/XXXX, National Institutes of Health (NIH) Office of the Director (OD), Office of Extramural Research (OER).

Need and Use of Information Collection: The purpose of this web form is to assist extramural institutions with complying with Section 239 of the Consolidated Appropriations Act, 2022 (Pub. L. 117–103), Division H, Title II, which requires that ''institutions that receive funds through a grant or cooperative agreement during fiscal year 2022 and in future years to notify the Director when individuals identified as a principal investigator or as key personnel in an NIH notice of award are removed from their position or are otherwise disciplined due to concerns about harassment, bullying, retaliation, or hostile working conditions.'' The Harassment Web Form will be used as a secure and confidential portal by which recipient institutions notify NIH when individuals identified as a Program Director/Principal Investigator (PD/PI) or other Senior/Key personnel in an NIH notice of award are removed from their position or are otherwise disciplined by the recipient institution due to concerns about harassment, bullying, retaliation, or hostile working conditions, as specified in NOT–OD–22–129. Notification must be provided by the Authorized Organization Representative within 30 days of the removal or disciplinary action and must be submitted to NIH through the Harassment Web Form. All required notifications must include, at a minimum, the name of the Authorized Organization Representative submitting the notification, the name of the individual of concern, a description of the concerns, the action(s) taken, and any anticipated impact on the NIH-funded award(s).

OMB approval is requested for 3 years. There are no costs to respondents other than their time. The total estimated annualized burden hours are 60.

ESTIMATED ANNUALIZED BURDEN HOURS

Type of respondents	Number of respondents	Number of responses per respondent	Average burden per response (in hours)	Total annual burden hours
Private Sector (grant recipients)	140	1	15/60	35
Individuals (general public not in administrative role)	100	1	15/60	25
Total		240		60

Dated: June 10, 2022.

Tara A. Schwetz,

Acting Principal Deputy Director, National Institutes of Health.

[FR Doc. 2022–13142 Filed 6–17–22; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Biomedical Imaging and Bioengineering; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of a meeting of the National Institute of Biomedical Imaging and Bioengineering Special Emphasis Panel.

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 Biomedical Imaging and Bioengineering Special Emphasis Panel; Career Development (Ks) and Conference Support (R13) Review.

Date: July 19, 2022.

Time: 10:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Democracy II, 6707 Democracy Blvd., Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Ruixia Zhou, Ph.D., Scientific Review Officer, National Institute of Biomedical Imaging and Bioengineering, National Institutes of Health, 6707 Democracy Blvd., Bethesda, MD 20892, (301) 496–4773, *zhour@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.866, National Institute of Biomedical Imaging and Bioengineering, National Institutes of Health, HHS)

Dated: June 15, 2022.

Victoria E. Townsend,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2022–13238 Filed 6–17–22; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HOMELAND SECURITY

U.S. Customs and Border Protection

[1651–0081]

Delivery Ticket

AGENCY: U.S. Customs and Border Protection (CBP), Department of Homeland Security.

ACTION: 60-Day notice and request for comments; extension 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 August 22, 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 1651–0081 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: Delivery Ticket.

OMB Number: 1651–0081.

Form Number: CBP Form 6043.

Current Actions: CBP proposes to extend the expiration date of this information collection with no change to the burden hours or to the information collected.

Type of Review: Extension (without change).

Affected Public: Businesses.

Abstract: CBP Form 6043, *Delivery Ticket,* is used to document transfers of imported merchandise between parties. This form collects information such as the name and address of the consignee; the name of the importing carrier; lien information; the location of where the goods originated and where they were delivered; and information about the imported merchandise. CBP Form 6043 is completed by warehouse proprietors, carriers, Foreign Trade Zone operators and other trade entities involved in transfers of imported merchandise. This form is authorized by 19 U.S.C. 1551a and 1565, and provided for by 19 CFR 4.34, 4.37 and 19.9. It is accessible at: *https://www.cbp.gov/newsroom/publications/forms.*

The respondents to this information collection are members of the trade community who are familiar with CBP regulations.

Type of Information Collection: Delivery Ticket (Form 6043).

Estimated Number of Respondents: 1,156.

Estimated Number of Annual Responses per Respondent: 200.

Estimated Number of Total Annual Responses: 231,200.

Estimated Time per Response: 15 minutes.

Estimated Total Annual Burden Hours: 57,800.

Dated: June 15, 2022.

Seth D. Renkema,

Branch Chief, Economic Impact Analysis Branch, U.S. Customs and Border Protection.

[FR Doc. 2022–13206 Filed 6–17–22; 8:45 am]

BILLING CODE P

DEPARTMENT OF HOMELAND SECURITY

U.S. Customs and Border Protection

[1651–0061]

Application to Establish a Centralized Examination Station

AGENCY: U.S. Customs and Border Protection (CBP), Department of Homeland Security.

ACTION: 60-Day notice and request for comments; extension 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 August 22, 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 1651–0061 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: U.S. Customs and Border Protection (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 Establish a Centralized Examination Station.

OMB Number: 1651–0061.

Form Number: N/A.

Current Actions: CBP proposes to extend the expiration date of this information collection with no change to the burden hours or to the information collected.

Type of Review: Extension (without change).

Affected Public: Businesses.

Abstract: A Centralized Examination Station (CES) is a privately operated facility where merchandise is made available to CBP officers for physical examination. If a port director decides that a CES is needed, he or she solicits applications to operate a CES. The information contained in the application is used to determine the suitability of the applicant's facility; the fairness of fee structure; and the knowledge of cargo handling operations and of CBP procedures and regulations. The names of all principals or corporate officers and all employees who will come in contact with uncleared cargo are also to be provided so that CBP may perform background investigations. The CES application is provided for by 19 CFR 118.11 and is authorized by 19 U.S.C. 1499, Tariff Act of 1930.

CBP port directors solicit these applications by using port information bulletins, local newspapers, and/or the internet. This collection of information applies to the importing and trade community, which is familiar with import procedures and with the CBP regulations.

Type of Information Collection: Application for CES.

Estimated Number of Respondents: 50.

Estimated Number of Annual Responses per Respondent: 1.

Estimated Number of Total Annual Responses: 50.

Estimated Time per Response: 2 hours.

Estimated Total Annual Burden Hours: 100.

Dated: June 15, 2022.

Seth D. Renkema,

Branch Chief, Economic Impact Analysis Branch, U.S. Customs and Border Protection.

[FR Doc. 2022–13204 Filed 6–17–22; 8:45 am]

BILLING CODE 9111–14–P

DEPARTMENT OF HOMELAND SECURITY

Transportation Security Administration

Intent To Request Extension From OMB of One Current Public Collection of Information: TSA Reimbursable Screening Services Program (RSSP) Request

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 1652–0073, 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 of information involves an application completed by public and private entities requesting participation in TSA's Reimbursable Screening Services Program (RSSP), currently a pilot program for up to eight locations to obtain TSA security screening services outside of an existing primary passenger airport terminal screening area where screening services are currently provided or would be eligible to be provided under TSA's annually appropriated passenger screening program.

DATES: Send your comments by August 22, 2022.

ADDRESSES: Comments may be emailed to *TSAPRA@tsa.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

The RSSP is authorized by the Consolidated Appropriations Act, 2019, Section 225, Division A (Pub. L. 116–6, Div. A) and amended in the Consolidated Appropriations Act, 2021, Section 223, Division F (Pub. L. 116–

260, Div. F). Under this provision, TSA established a pilot for public or private entities regulated by TSA to request reimbursable screening services outside of an existing primary passenger terminal screening area where screening services are currently provided or eligible to be provided under TSA's annually appropriated passenger screening program. The authority available under this section is effective for fiscal years 2022 through 2023 and currently may be used at not more than eight locations for transportation security purposes. TSA collects this information to establish an application process for public and private entities regulated by TSA to request screening services under the RSSP. For purposes of RSSP, ''screening services'' means ''the screening of passengers, flight crews, and their carry-on baggage and personal articles, and may include checked baggage screening if that type of screening is performed at an offsite location that is not part of a passenger terminal of a commercial airport.

Public or private entities regulated by TSA interested in participating in the RSSP may submit an application to the TSA Administrator requesting that TSA provide screening services outside of an existing primary passenger terminal screening area where screening services are currently provided or eligible to be provided under TSA's annually appropriated passenger screening program as a primary passenger terminal screening area. The request may only be submitted to TSA after consultation with the relevant local airport authority. The application is used to identify basic information to grant approval or denial.

The respondents to this information collection request are public or private entities regulated by TSA requesting the screening services at an airport that is a commercial service airport (as defined by 49 U.S.C. 47107(7)). TSA estimates the annual respondents for fiscal year 2022 to be no more than 15. The annual burden for the information collection related to providing screening services is estimated to be 492 hours.

Dated: June 14, 2022.

Christina A. Walsh,

TSA Paperwork Reduction Act Officer, Information Technology.

[FR Doc. 2022–13164 Filed 6–17–22; 8:45 am]

BILLING CODE 9110–05–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–6316–N–01]

Waivers and Alternative Requirements for Community Development Block Grant Disaster Recovery (CDBG–DR) and Community Development Block Grant Mitigation (CDBG–MIT) Grantees

AGENCY: Office of the Assistant Secretary for Community Planning and Development, HUD.

ACTION: Notice.

SUMMARY: This notice governs Community Development Block Grant disaster recovery (CDBG–DR) and Community Development Block Grant mitigation (CDBG–MIT) funds awarded under several appropriations acts identified in the Table of Contents. Specifically, this notice provides waivers and establishes alternative requirements for certain CDBG–DR grantees that have submitted waiver requests for grants provided under the public laws cited in this notice.

DATES: Applicability Date: June 27, 2022.

FOR FURTHER INFORMATION CONTACT: Jessie Handforth Kome, Director, Office of Block Grant Assistance, U.S. Department of Housing and Urban Development, 451 7th Street SW, Room 7282, Washington, DC 20410, telephone number 202–708–3587. Persons with hearing or speech impairments may access this number via TTY by calling the toll-free Federal Relay Service at 800–877– 8339. Facsimile inquiries may be sent to Ms. Kome at 202–708–0033. (Except for the''800'' number, these telephone numbers are not toll-free.) Email inquiries may be sent to *disaster_recovery@hud.gov.*

SUPPLEMENTARY INFORMATION:

Table of Contents

I. Authority To Grant Waivers

Each of the appropriations acts cited in the Table of Contents authorize the Secretary to waive, or specify alternative requirements for, any provision of any statute or regulation that the Secretary administers in connection with the obligation by the Secretary or use by the recipient of grant funds, except for requirements related to fair housing, nondiscrimination, labor standards, and the environment. HUD may also exercise its regulatory waiver authority under 24 CFR 5.110, 91.600, and 570.5.

All waivers and alternative requirements authorized in this notice are based upon a determination by the Secretary that good cause exists, and that the waiver or alternative requirement is not inconsistent with the overall purposes of title I of the Housing and Community Development Act of 1974 (42 U.S.C. 5301 *et seq.*) (HCDA). The good cause for each waiver and alternative requirement is summarized in this notice.

II. Public Law 107–38, 107–73, 107–117, 107–206 Waivers and Alternative Requirements

Waiver to Allow the Lower Manhattan Development Corporation (LMDC) To Transfer Remaining Property Acquired and Cleared With CDBG–DR Funds in Exchange for Other Property Interests.

Provisions of four public laws (the 9/11 Appropriations Acts) govern the CDBG–DR funds provided in response to the terrorist attacks of September 11, 2001: Public Law 107–38, 107–73, 107–117, and 107–206. These 9/11 Appropriations Acts have funded three CDBG–DR grants: $700 million awarded to the New York State Development Corporation d/b/a Empire State Development (ESD); and two grants of $2.0 billion and $783 million, respectively, awarded to LMDC. ESD is a political subdivision and public benefit corporation of the State of New York and LMDC is a subsidiary of ESD. LMDC administers CDBG–DR funds allocated to the organization for emergency expenses and economic revitalization in response to the September 11, 2001, terrorist attacks in New York City. LMDC is charged with assisting New York City in recovering from the terrorist attacks on the World Trade Center (WTC), in part by working with the Port Authority of New York and New Jersey (Port Authority).

Previously, in the January 17, 2017 **Federal Register** notice (82 FR 4911), the Department granted a waiver of 24 CFR 570.489(j) for good cause and established an alternative requirement ''to the extent necessary to allow LMDC to transfer the portions of 130 and 140 Liberty Street necessary to finalize the WTC Vehicle Security Center, Liberty Park, and the St. Nicholas National Shrine at the World Trade Center to the Port Authority without reimbursing the CDBG–DR program for the fair market value of the properties . . . [and] to permit LMDC to acquire from the Port Authority property on the World Trade Center site, via long-term lease and purchase, sufficient to carry out the memorial and cultural facilities on the World Trade Center site that are contemplated in the GPP and LMDC's applicable Action Plan, as amended.'' (82 FR 4913).

The January 2017 waiver and alternative requirement contemplated several property exchanges that were consistent with LMDC's approved CDBG–DR action plan and amendments. LMDC used CDBG–DR funds to acquire and clear real property identified in the World Trade Center Memorial and Cultural Program General Project Plan (GPP) as 130 Liberty Street and 140 Liberty Street. Specifically, to enable LMDC to fully implement its Memorial Program and to enable the Port Authority to pursue its Redevelopment Program, LMDC and the Port Authority would exchange real property interests. The Port Authority would provide LMDC or its designee with a lease (up to 99 years) and purchase option for Port Authority-owned property that would be used for memorial and cultural facilities that are part of LMDC's Memorial Program. The overall exchange would allow the LMDC to facilitate use of what was originally Port Authority property for the Memorial Museum and a performing arts center.

The January 2017 waiver and alternative requirement permitted an exchange for the portion of the 130 and 140 Liberty Street necessary for the WTC Vehicle Security Center, and it also contemplated that HUD would need to extend the waiver for additional activities. It provided that ''HUD must waive certain regulations applicable to the reuse of 130 and 140 Liberty Street to facilitate the current exchange between LMDC and the Port Authority *and future development of the rest of the 130 Liberty Street site.* The current transfer of property to the Port Authority explicitly excludes that portion of 130 Liberty Street that is labeled as ''Tower 5'' on Attachment 1 to the GPP as LMDC will retain the Tower 5 site for future transfer and redevelopment.'' (82 FR 4912).

Since January 2017, LMDC and the Port Authority have solidified their plans for the second phase of the property transfer. Therefore, for the reasons described in this notice and in the January 2017 notice, the Department has determined that good cause exists to extend the January 2017 waiver and alternative requirement modifying 24 CFR 570.489(j) to encompass the second phase of the proposed property exchanges between LMDC and the Port Authority for the remainder of 130 and 140 Liberty Street (the Tower 5 site). LMDC and its designees will receive the Port Authority-owned properties to be used for memorial and cultural facilities that are part of LMDC's Memorial Program (as described in the January 2017 waiver and alternative requirement). Specifically, LMDC's designee, the National September 11 Memorial & Museum (further known as The World Trade Center Memorial Foundation, Inc.) will obtain a lease and purchase option for the Memorial Museum site and a different LMDC designee received a similar lease (up to 99 years) and purchase option for the site of a performing arts center.

To complete the property transfer, LMDC will transfer fee title of the Tower 5 site to the ESD, and ESD will facilitate payment of compensation to the Port Authority for land that the Port Authority provided for the memorial and cultural facilities. ESD will lease the Tower 5 site to a developer. The Port Authority will receive compensation in the form of rent paid under a 99-year ground lease for the Tower 5 site by a developer (equal to the value of the originally planned commercial use of the Tower 5 site plus 25 percent of any rent paid in excess of that amount) and the remainder interest at the end of the lease term.

As outlined in the January 2017 waiver and alternative requirement, the Department finds that the properties involved in this transfer present unique valuation difficulties. A restricted appraisal report and opinion letter by an appraiser engaged by LMDC estimates that the parcels subject to the exchange are of proximate value. The restricted appraisal report and opinion letter nonetheless also notes the difficulties in establishing current fair market valuations of the various parts of this transaction. In addition, the strong desire of all parties (including HUD) to facilitate and conclude redevelopment progress on and adjacent to the World Trade Center site more than twenty years after the events of September 11, 2001, creates a situation in which this waiver and alternative requirement represent the most practical and feasible path forward.

For the reasons described in this notice and in the January 2017 notice, HUD finds that good cause exists to waive 24 CFR 570.489(j) and to expand the alternative requirement previously given to the extent necessary to permit LMDC to transfer fee title to the Tower 5 site to ESD and to permit ESD to compensate the Port Authority as described above. As a condition of this waiver and alternative requirement, if the rental income from the Tower 5 site's development exceeds the value of the originally planned commercial use of the Tower 5 site, 75 percent of the excess will be paid to LMDC and designated as program income and 25 percent of the excess will be paid to the Port Authority. Following closeout of LMDC's grant, LMDC's share will be paid to the City in accordance with 67 FR 36017. For purposes of this waiver and alternative requirement, HUD has determined that amounts paid to the Port Authority do not constitute program income to the CDBG–DR grant.

Additionally, the property acquired by LMDC or its designees on the World Trade Center site will be subject to CDBG–DR programmatic requirements upon transfer to LMDC or its designee. HUD recognizes the phased nature of the transactions contemplated by various parties pursuant to this alternative requirement. However, as part of this alternative requirement, if LMDC does not acquire property that is sufficient to carry out the memorial and cultural facilities on the World Trade Center site as contemplated in the GPP and LMDC's applicable action plan, as amended, before LMDC closes out its grants, HUD may pursue appropriate remedial actions. This expanded waiver and alternative requirement are necessary to facilitate and conclude LMDC's use of CDBG–DR funds for its Memorial Program.

III. Public Law 113–2 Waivers and Alternative Requirements

Clarification on Citizen participation waiver and alternative requirement (CDBG–DR grantees only).

This waiver applies to certain grantees that received an allocation of funds appropriated under the Disaster Relief Appropriations Act, 2013 (Pub. L. 113–2), which ultimately made available $15.2 billion in CDBG–DR funds for necessary expenses related to disaster relief, long-term recovery, restoration of infrastructure and housing, and economic revitalization due to Hurricane Sandy and other eligible events in calendar years 2011, 2012, and 2013. The Department's **Federal Register** notices for Public Law 113–2 included requirements for CDBG–

DR grantees that must be followed for substantial amendments to a CDBG–DR action plan. Section VI.4. of the November 18, 2013 notice (78 FR 69104) and Section V.5 of the June 3, 2014 notice (79 FR 31964) require grantees to hold a public hearing on a substantial action plan amendment and to also publish the substantial action plan amendment for public comment for 30 days prior to submission to HUD. For recent allocations, HUD has not required grantees to hold public hearings for substantial action plan amendments, and this additional requirement adds administrative burden on grantees that have expended most of the funds allocated under Pub. L. 113–2. For these reasons, HUD has determined there is good cause to remove the requirement from both Section VI.4. of the November 18, 2013 notice and Section V.5. of the June 3, 2014 notice that requires public hearings on substantial action plan amendments. Grantees are still required to follow the remaining requirements for citizen participation and public comment for substantial action plan amendments in Section VI.4. of the November 18, 2013 notice, and Section V.5. of the June 3, 2014 notice, including posting the amendments for 30 days for public comment.

IV. Public Law 115–254 and 116–20 Waivers and Alternative Requirements

IV.A. *Base Flood Elevation Requirement and Reimbursement in the ''Homeowner Reimbursement Program'' (State of Texas only).*

The Department has awarded the State of Texas $46,400,000 of CDBG–DR funds under Public Law 115–254 and $26,513,000 of CDBG–DR funds under Public Law 116–20, for recovery from disasters occurring in 2018; and $227,510,000 of CDBG–DR funds under Public Law 116–20 for recovery from disasters occurring in 2019. These funds have been provided for necessary expenses related to disaster relief, long term recovery, restoration of infrastructure and housing, economic revitalization, and mitigation due to a qualified disaster. This waiver and alternative requirement modifies the requirements for CDBG–DR funds awarded to the State of Texas under Public Laws 115–254 and 116–20. The State of Texas has submitted a request and justification for the waiver and alternative requirements provided herein to facilitate the use of the funds.

The state is implementing a Homeowner Reimbursement Program designed to assist homeowners in recovering up to $50,000 in out-of-pocket expenses paid by the homeowner for residential rehabilitation due to the disasters occurring in 2018 and 2019. To be eligible for this program, the state's rules require the home be the owner's primary residence and the eligible rehabilitation must have been completed prior to the program's application launch date of April 24, 2021. Because the state's response and recovery efforts commenced on the dates of the disasters and before CDBG–DR assistance was available, some homeowners participating in the state's Homeowner Reimbursement Program may have rehabilitated their homes to meet FEMA program requirements and local elevation requirements, rather than the CDBG–DR program requirements.

Some homeowners seeking assistance from the state's Homeowner Reimbursement Program elevated their homes to meet the requirements of their municipalities but did not elevate their homes to meet HUD's requirement that residential structures be elevated to at least two feet above base flood elevation . Because these homeowners did not anticipate receiving CDBG–DR assistance, the state is requesting a waiver to reimburse homeowners that are otherwise eligible for assistance but elevated their homes to comply with FEMA program requirements and the local jurisdiction's elevation requirements, which may be lower than the HUD-mandated standard to elevate to base flood elevation plus two feet.

HUD's February 9, 2018 **Federal Register** notice provides that: ''All structures, defined at 44 CFR 59.1, designed principally for residential use and located in the 100-year (or 1 percent annual chance) floodplain that receive assistance for new construction, repair of substantial damage, or substantial improvement, as defined at 24 CFR 55.2(b)(10), must be elevated with the lowest floor, including the basement, at least two feet above the base flood elevation.'' (83 FR 5861).

Based on the reasons stated above, HUD finds that good cause exists to waive the provision of the **Federal Register** notice requiring the two feet above base flood elevation for homeowners seeking reimbursement in the state's Homeowner Reimbursement Program, and to establish an alternative requirement to permit the state to reimburse those homeowners for costs of rehabilitation completed before the program's application launch date, subject to the following requirements:

- The homeowner complied with applicable FEMA requirements and the elevation requirement of the local jurisdiction.
- The activity is eligible under title I of the HCDA or by waiver and is consistent with all other requirements of CPD notice 15–07: Guidance for Charging Pre-Application Costs of Homeowners, Businesses, and Other Qualifying Entities to CDBG Disaster Recovery Grants.
- The activity meets a CDBG–DR national objective and otherwise complies with CDBG–DR requirements not waived by this section.
- For each grant, the state uses not less than 70 percent of the aggregate CDBG–DR grant for activities that benefit low- and moderate-income persons.

The state must ensure that all costs charged to this program and to the CDBG–DR grants are necessary and reasonable expenses related to disaster recovery.

IV.B. *Requirement to Primarily Consider and Address Unmet Housing Recovery Needs (The Northern Mariana Islands only).*

The Department has awarded $188,652,000 of CDBG–DR funds under Public Law 115–254 and $65,672,000 under Public Law 116–20, for a combined allocation of $254,324,000 to the Commonwealth of the Northern Mariana Islands (CNMI) for recovery from 2018 disasters.

The CNMI has requested that HUD ease restrictions in existing notices to allow for the use of CDBG–DR funds for the rehabilitation and reconstruction of the Northern Marianas College (NMC) by modifying the requirements in the February 9, 2018 notice at 83 FR 5844, August 14, 2018 notice at 83 FR 40314, and then re-stated in the January 27, 2020 notice at 85 FR 4682, that each grantee primarily consider and address its unmet housing recovery needs. Specifically, the January 27, 2020, notice states that, ''Pursuant to the Prior Notices, each grantee receiving an allocation for a 2018 or 2019 disaster is required to primarily consider and address its unmet housing recovery needs. These grantees may, however, propose the use of funds for unmet economic revitalization and infrastructure needs unrelated to the grantee's unmet housing needs if the grantee demonstrates in its needs assessment that there is no remaining unmet housing need or that the remaining unmet housing need will be addressed by other sources of funds.''

NMC lost 37 out of its 39 classrooms as a result of Super Typhoon Yutu in 2018. The college offers a number of degrees, as well as Adult Basic Education, Workforce Development and Certificate Training. A number of other federal agencies are also providing funding for NMC campus projects, including a Student Center funded through the U.S. Department of Education, a Workforce Development and Training Center and a Center for Research Extension and Development funded through the Economic Development Authority, and a Gymnasium and Collateral Equipment/Content funded by FEMA. The construction of NMC's classrooms, as a public college, would otherwise be CDBG–DR eligible and is critical to the CNMI and its residents for many reasons. As the only public college on the island, the improvements will encourage enrollment growth, prevent outmigration, improve access to quality education on the island, and strengthen the position of the college for purposes of accreditation. CNMI also indicates any loss of NMC students would adversely impact the CNMI economy and community.

Based on these reasons, HUD has determined that good cause exists to modify the provisions in the February 9, 2018 notice (83 FR 5849), the August 14, 2018 notice (83 FR 40314), and re-stated in the January 27, 2020 notice at 85 FR 4682, that require a grantee to primarily consider and address its unmet housing recovery needs with its CDBG–DR funds or demonstrate there is no remaining unmet housing need or that the remaining unmet housing need will be addressed by other sources of funds. HUD is modifying those provisions for CNMI only, so that the grantee is subject to the following requirements: without regard to the housing priority identified in the notices cited above, CNMI may use amounts consistent with the amount in the CNMI's action plan and substantial amendments submitted to and approved by HUD to rehabilitate and reconstruct buildings for classrooms at NMC and complement the already significant other Federal investments in the reconstruction of the college. These amounts are subject to other applicable requirements, including the requirement that CDBG–DR funds may not be used for activities reimbursable by or for which funds are made available by FEMA or the US Army Corps of Engineers (USACE). As with other activities, the grantee must verify whether FEMA or USACE funds are available prior to awarding CDBG–DR funds to this activity. The housing priority remains in place for all other activities carried out by CNMI.

IV.C. *Extension of Waiver and Alternative Requirement Related to Tourism and Business Marketing (The Northern Marianas only).*

The Commonwealth of the Northern Marianas (CNMI) has submitted a request for an extension of HUD's previously granted waiver and alternative requirement authorizing activities related to tourism and business marketing, to revise the expiration date for the waiver and alternative requirement to December 31, 2023. The previously granted waiver and alternative requirement would expire January 11, 2023. Accordingly, HUD hereby grants the waiver and alternative requirement described in this notice for a revised expiration date of December 31, 2023.

In section VIII.A. of the **Federal Register** notice published on September 28, 2020 (85 FR 60821), the Department granted CNMI a waiver of 42 U.S.C. 5305(a) to the extent necessary to create a new eligible activity and use up to $10,000,000 of CDBG–DR funds for tourism and marketing activities to promote travel and to attract new businesses to disaster-impacted areas (without regard to housing need), consistent with the amount in CNMI's action plan and substantial amendments submitted to and approved by HUD. HUD required the waiver and alternative requirement to expire two years after CNMI's first draw of its CDBG–DR funds allocated in the **Federal Register** notice published on January 27, 2020 (85 FR 4681).

Tourism is a significant part of CNMI's economy and was severely impacted by Super Typhoon Yutu and further impacted by the COVID–19 pandemic. The current expiration date of the waiver and alternative requirements limits the ability of CNMI to use the CDBG–DR funds during its peak tourism season in 2023, interrupting economic development gains made by CNMI in its use of CDBG–DR funds for disaster recovery. As a result, the Secretary has determined that good cause exists to extend the waiver and alternative requirement described above, so that CNMI may continue to carry out tourism and marketing activities permitted by the waiver and alternative requirement until December 31, 2023. The cap on the activity costs remains unchanged. The grantee can expend no more than $10,000,000 on activities authorized by the extended waiver and alternative requirement. HUD may further extend the waiver and alternative requirements administratively, if requested by CNMI, for good cause.

V. Public Law 115–123 and 116–20 Waivers and Alternative Requirements

Amendment to the One-for-One Replacement Housing Alternative Requirements for CDBG–MIT Grants.

The Department's August 30, 2019 **Federal Register** notice (84 FR 45838) and its January 6, 2021 notice (86 FR 561) included waivers and alternative requirements for grantees that received a CDBG–MIT allocation under Public Laws 115–123 or 116–20. The August 30, 2019 notice included a one-for-one replacement housing waiver and alternative requirement for CDBG–MIT grantees and this notice modifies that requirement. Section V.A.22.a. of the notice (84 FR 45859) waives the one-for-one replacement requirements at section 104(d)(2)(A)(i) and (ii) and (d)(3) of the HCDA and 24 CFR 42.375 in connection with CDBG–MIT funds for lower income dwelling units that are damaged by the disaster and not suitable for rehabilitation, as defined by the grantee. This waiver and alternative requirement was limited to only disaster-damaged lower-income units that are demolished or converted and not suitable for rehabilitation. The Department, however, recognizes that the purposes of the CDBG–MIT grants are forward looking and are generally not for purposes of recovery from a previous disaster. CDBG–MIT funds are instead to be used to address current and future risks to lessen the impact of future disasters. With that purpose in mind, grantees are not required to demonstrate that their CDBG–MIT activities "tie-back" to the specific disaster and address a specific unmet recovery need for which funds were allocated. CDBG–MIT grantees therefore may be undertaking activities that remove housing units that are not damaged by a previous disaster but still constitute an eligible use of CDBG–MIT funds, because those activities must meet the requirement that they are moving people or property out of harm's way or otherwise lessening the impact of future disasters on residents of those units.

CDBG–MIT grantees are required to document how all activities funded by their CDBG–MIT grant meet the definition of mitigation activities, which as stated in the August 30, 2019 notice means those activities that increase resilience to disasters and reduce or eliminate the long-term risk of loss of life, injury, damage to and loss of property, and suffering and hardship, by lessening the impact of future disasters. Grantees are prohibited from funding activities with CDBG–MIT funds that fail to meet the definition of mitigation activities in the August 30, 2019 notice. Based on the goals and requirements of the CDBG–MIT funds and articulated in the August 30, 2019 notice, there is good cause to amend the one-for-one replacement alternative requirements for CDBG–MIT grants. Accordingly, HUD is deleting the provisions of the previous waiver and alternative requirement and replacing the paragraph at V.A.22.a. in its entirety. This new language will not apply retroactively and will only apply to the eligible CDBG–MIT activities identified below, as of the applicability date of this notice.

V.A.22.a. Section 104(d) one-for-one replacement.

One-for-one replacement housing requirements at section 104(d)(2)(A)(i) and (ii) and (d)(3) of the Housing and Community Development Act of 1974 (HCDA) and 24 CFR 42.375 are waived for all demolished or converted lower-income dwelling units that are CDBG–MIT eligible to permanently move people and/or property out of harm's way as part of a housing mitigation activity, such as a buyout, that addresses a risk identified in a grantee's risk-based Mitigation Needs Assessment. This waiver exempts lower-income dwelling units that meet the grantee's definition of ''not suitable for replacement'' from the one-for-one replacement requirements, since CDBG–MIT grantees may be undertaking activities that remove housing units that are not damaged by a previous disaster but still are necessary to address mitigation risk. Before carrying out activities that may be subject to the one-for-one replacement requirements, the grantee must define ''not suitable for replacement'' in its action plan or in policies and procedures governing these activities. When working to move people and/or property out of harm's way, requiring replacement housing units to be located within the same neighborhood can be inconsistent with the purposes of the CDBG–MIT grants and is not always feasible because these areas have been identified to have current and future disaster risks, as described in the grantee's Mitigation Needs Assessment. HUD is providing this waiver in recognition that grantees are using CDBG–MIT funds for mitigation needs based on a Mitigation Needs Assessment that identifies and analyzes all significant current and future disaster risks as the basis for undertaking the proposed demolition or conversion activities consistent with the goals of the CDBG–MIT funds.

Even when using CDBG–MIT funds, grantees must reassess post-disaster population and housing needs relative to the Mitigation Needs Assessment to determine the appropriate type and amount of lower-income dwelling units to rehabilitate or reconstruct. Grantees must include this analysis in their program files with a description of how CDBG–MIT funds or other sources, including CDBG–DR funds, will be used to address housing and mitigation needs for residents of lower-income dwelling units. Grantees should note that the demolition and/or disposition of public housing units continue to be subject to section 18 of the United States Housing Act of 1937, as amended, and 24 CFR part 970.

VI. Public Law 115–56, 115–123, 115–254, and 116–20 Grant Requirements

Certification and Supporting Documentation for CDBG–DR and CDBG–MIT Grants for Disasters Occurring in 2015 through 2019.

Typically, appropriations acts require the Secretary to certify, in advance of signing a grant agreement, that the grantee has in place proficient financial controls and procurement processes and has established adequate procedures to prevent any duplication of benefits as defined by section 312 of the Stafford Act, 42 U.S.C. 5155, to ensure timely expenditure of funds, maintain a comprehensive website regarding all disaster recovery activities assisted with these funds, and detect and prevent waste, fraud, and abuse of funds. To enable the Secretary to make this certification, each grantee must submit to HUD the certification documentation described in the applicable **Federal Register** notice governing the funds.

Over the life of a grant, HUD expects a grantee to modify and update its policies and procedures to implement effective recovery programs. In **Federal Register** notices published on February 9, 2018 at 83 FR 5844, August 14, 2018 at 83 FR 40314, August 30, 2019 at 84 FR 47528, January 27, 2020 at 85 FR 4681, and January 6, 2021 at 86 FR 561 and 86 FR 569, HUD describes the necessary steps each grantee must complete for the Secretary's certification for CDBG–DR and CDBG–MIT funds provided in response to qualifying disasters occurring in 2015 through 2019. For all CDBG–DR funds subject to the February 9, 2018 notice, HUD requires grantees to ''adhere to the controls, processes, and procedures described in the grantee's financial controls and procurement processes documentation submitted in response to the certification, unless amended with HUD's approval'' (83 FR 5846). Additionally, the January 27, 2020 notice requires grantees to ''implement the CDBG–DR grant consistent with the controls, processes, and procedures as certified by HUD'' (85 FR 4686). For all CDBG–MIT funds subject to the August 30, 2019 notice, HUD states that ''failure to implement a CDBG–MIT grant in accordance with a grantee's approved financial certification . . . shall constitute a performance deficiency'' (84 FR 45863).

HUD has determined that it is not necessary nor prudent for the agency to approve every change made to the supporting documentation submitted to support the Secretary's certification during the life of the grant or to require the grantee to implement funds per the initial submission. Instead, HUD is now establishing a modified requirement for all CDBG–DR and CDBG–MIT grantees subject to the notices cited in the previous paragraph. In lieu of submitting all changes for approval, a grantee must notify HUD of any substantial changes made to the supporting documentation submitted to support the Secretary's certification after the grant agreement has been signed by HUD and the grantee. Over the life of the grant, HUD will monitor the grantee for compliance with its submission and any updates made by the grantee. All updates must be retained and identified in the grantee's files, together with dates of applicability, so that HUD can determine which policies and procedures the grantee was following at any point in time. The grantee is required to adhere to its supporting documentation, as amended, until the closeout of the grant. HUD finds this change to be necessary to expedite recovery once the Secretary has completed a certification based on the grantee's supporting documentation, and a grant agreement has been signed by both parties.

VII. Public Law 115–56 and 115–123 Waivers and Alternative Requirements

Base Flood Elevation Requirement and Reimbursement in the ''*Homeowner Reimbursement Program*'' *(State of Texas—Harris County and City of Houston Only).*

The Department awarded $5,024,215,000 under Public Law 115–56 and $652,175,000 under Public Law 115–123 to the State of Texas for recovery from Hurricane Harvey for necessary expenses related to disaster relief, long term recovery, restoration of infrastructure and housing, economic revitalization, and mitigation. This section of the notice specifies waivers and alternative requirements and modifies requirements for CDBG–DR funds awarded to the State of Texas under Public Laws 115–56 and 115–123. In the **Federal Register** notice published on September 28, 2020 at 85 FR 60825, the Department provided a waiver and alternative requirement permitting the State of Texas to reimburse homeowners that are otherwise eligible for assistance but who elevated their homes to comply with the local jurisdiction's freeboard requirements, which may be lower than the HUD-mandated standard to elevate to base flood elevation plus 2 feet (the ''September 2020 waiver''). The State of Texas has submitted a request to extend the September 2020 waiver to also include two local governments awarded funds by the state: Harris County and the City of Houston, as described below.

The state awarded funds to Harris County and the City of Houston to develop their own disaster recovery programs. Both Harris County and the City of Houston are implementing homeowner reimbursement programs: Harris County's Homeowner Reimbursement Program and the City of Houston's Reimbursement Option in their Harvey Homeowner Assistance Program. These programs are designed to assist homeowners in recovering out-of-pocket expenses paid by the homeowner for residential rehabilitation due to Hurricane Harvey. Both programs' eligibility requirements require that the home be the owner's primary residence and the eligible rehabilitation costs must have been incurred prior to the owner's application to the program or December 31, 2020, whichever is earlier. Because the state, county, and city's Hurricane Harvey response and recovery efforts commenced on the date of the disaster and before CDBG–DR assistance was available, some homeowners participating in these homeowner reimbursement programs may have repaired their homes to meet FEMA's program requirements and the local jurisdiction's elevation requirements, rather than HUD's **Federal Register** notice requirements. The elevation requirements in the **Federal Register** notice require that residential structures be elevated to at least 2 feet above base flood elevation. Because the homeowners did not anticipate receiving CDBG–DR assistance, the state is requesting that HUD extend the September 28, 2020 waiver to include its subrecipients' reimbursement programs.

Based on the reasons cited above, HUD finds that good cause exists to modify the September 2020 waiver to include homeowners seeking reimbursement in the Harris County and City of Houston's homeowner reimbursement programs and permit the city and county to reimburse those homeowners for costs of rehabilitation incurred before application of the homeowner to the program or December 31, 2020, whichever is earlier, subject to the following requirements:

- The homeowner's reimbursed rehabilitation costs complied with the elevation requirement of the local jurisdiction.
- The activity is eligible under title I of the HCDA or by waiver and is consistent with CPD–15–07: Guidance for Charging Pre-Application Costs of Homeowners, Businesses, and Other Qualifying Entities to CDBG Disaster Recovery Grants.
- The activity meets a CDBG–DR national objective and otherwise complies with CDBG–DR requirements not waived by this section.
- The state uses not less than 70 percent of the aggregate CDBG–DR grant for activities that benefit low- and moderate-income persons.

The state must ensure that all costs charged to this program and to the CDBG–DR grant are necessary and reasonable expenses related to disaster recovery.

VIII. Public Law 115–56, 115–123, and 116–20 Waivers and Alternative Requirements

Buildings for the General Conduct of Government Waiver and Alternative Requirement (Commonwealth of Puerto Rico only).

The Department awarded $1,507,179,000 of CDBG–DR funds under Public Law 115–56, $8,220,783,000 of CDBG–DR funds and $8,285,284,000 of CDBG–MIT funds under Public Law 115–123, and $277,853,230 of CDBG–DR funds under Public Law 116–20 to the Commonwealth of Puerto Rico for recovery from Hurricanes Irma and Maria for necessary expenses related to disaster relief, long term recovery, restoration of infrastructure and housing, economic revitalization, and mitigation.

With these funds, Puerto Rico is implementing its Non-Federal Match Program (NFMP) designed to assist in the local non-Federal cost share of infrastructure projects across all 78 municipalities that are eligible under FEMA Public Assistance Category of Work E (buildings). Puerto Rico is also implementing a Community Revitalization Program (CRP) to reinvigorate its urban centers and key community programs. Included in both programs is a group of projects that are considered buildings for the general conduct of government, as defined in 42 U.S.C. 5302(a)(21). The subject buildings often function as both city halls and government centers, which provide important recovery-related services, such as permit evaluation and coordination and may also include facilities that are designed to detect public health threats and support local and regional emergency response that primarily serves low- and moderate-income areas.

To implement the above programs and to assist in the recovery of its 78 municipalities, Puerto Rico has requested a waiver of 42 U.S.C. 5305(a)(2), which prohibits acquisition, construction, reconstruction, or installation of buildings for the general conduct of government as eligible public facilities activities. The Secretary has determined that there is good cause to grant this waiver as these buildings are necessary for these municipalities to adequately address critical infrastructure needs created by the disaster, help disaster recovery by reinvigorating its urban centers and key community programs, and help coordinate resilience and mitigation efforts across Puerto Rico. Therefore, HUD is waiving the prohibition on buildings for the general conduct of government at 42 U.S.C. 5305(a)(2) and associated regulations at 24 CFR 570.207(a) to permit the Commonwealth of Puerto Rico to carry out the construction, reconstruction, and rehabilitation of public improvements or facilities on buildings for the general conduct of government within the NFMP or CRP programs, subject to the following requirements. All CDBG–DR funded activities must address a direct or indirect impact from the major disaster in a most impacted and distressed area resulting from the major disaster. The grantee is prohibited from using CDBG–DR or CDBG–MIT funds for buildings that do not provide services all year around and is prohibited from using funds for buildings that are used exclusively as emergency operations centers.

IX. Public Law 116–20 Waivers and Alternative Requirements for the Commonwealth of Puerto Rico

Aligning requirements for the Commonwealth of Puerto Rico's 2019 CDBG–DR allocation with the requirements of its 2020 CDBG–DR allocation (Commonwealth of Puerto Rico only).

The Department allocated the Commonwealth of Puerto Rico $36,424,000 under Public Law 116–20 for recovery from earthquakes (''2019 CDBG–DR Grant'') and $184,626,000 under Public Law 117–43 for recovery from earthquakes and Tropical Storm Isaias (''2020 CDBG–DR Grant'') for necessary expenses related to disaster relief, long term recovery, restoration of infrastructure and housing, economic revitalization, and mitigation.

HUD has described the relevant statutory and regulatory requirements, including all applicable waivers and alternative requirements, that apply to Puerto Rico's 2019 CDBG–DR Grant in the following **Federal Register** notices (''PR's Prior Notices''): February 9, 2018 at 83 FR 5844, August 14, 2018 at 83 FR 40314, February 19, 2019 at 84 FR 4836, June 20, 2019 at 84 FR 28848, January 27, 2020 at 85 FR 4681,1 August 17, 2020 at 85 FR 50041, and September 28, 2020 at 85 FR 60821, and January 6, 2021 at 86 FR 569.

Though HUD allocated some of the 2020 CDBG–DR funds for the same major disaster assisted by the 2019 CDBG–DR Grant, HUD established different requirements for the use of the 2020 CDBG–DR Grant in the February 3, 2022 **Federal Register** notice at 87 FR 6364, which includes a CDBG–DR Consolidated Notice as Appendix B (the ''Consolidated Notice''). The February 3, 2022 notice (including the Consolidated Notice) describes the waivers and alternative requirements, applicable statutory and regulatory requirements, the grant award process, criteria for action plan approval, and eligible disaster recovery activities for the use of the 2020 CDBG–DR Grant funds.

To ease the administrative burden of managing two grants that are tied to the same disaster, HUD has determined that there is good cause to allow Puerto Rico to manage these grants under a single action plan and a single set of requirements (to the extent permitted by governing appropriations acts). Implementing this change will allow the grantee to follow a single set of requirements and submit a single action plan for the uses of both the existing 2019 CDBG–DR Grant under Public Law 116–20 and the new 2020 CDBG–DR Grant under Public Law 117–43, while each grant remains separate, with separate financial controls, and some other distinctions.

To do this, HUD is imposing the following modifications of the requirements of PR's Prior Notices for the 2019 CDBG–DR grant:

1. Puerto Rico must submit its action plan for the 2020 CDBG–DR Grant in accordance with the Consolidated Notice at section III.C.1. (87 FR 6379) using the Public Action Plan in the Disaster Recovery Grant Reporting (DRGR) system. Even though section III.C.1. is written for the 2020 CDBG–DR grant, under the terms of the waiver and alternative requirement, the Grantee's Public Action Plan shall also describe the use of all grant funds for the 2019 CDBG–DR grant in its Public Action Plan required by section III.C.1. of the Consolidated Notice. Together, the description of the use of funds allocated for 2020 disasters and the use of funds under the 2019 CDBG–DR Grant shall be described in a single action plan (the Public Action Plan) that substantially amends the 2019 CDBG–DR action plan. Puerto Rico will then be able to download the single action plan and post it for public comment on its disaster recovery website to meet the public comment requirements for 2019 and 2020 disasters. The deadline for that submission is 120 days after the applicability date of the February 3, 2022 notice. Based on the requirements in the February 3, 2022 notice, Puerto Rico may submit its Public Action Plan (a single document that describes the use of 2020 CDBG–DR Grant and 2019 CDBG–DR Grant), earlier than that date or may request an extension of the submission deadline to submit at a later date, if HUD approves the request.

2. Once the Public Action Plan that contains a description of all 2019 and 2020 CDBG–DR funds is approved, Puerto Rico's use of all grant funds must be consistent with the Public Action Plan. Upon HUD's approval of the Public Action Plan, the action plan that described the use of the 2019 CDBG–DR grant shall only be relevant to costs charged to the 2019 CDBG grant before the date of approval of the Public Action Plan.

3. Once the Public Action Plan is approved, except as identified below, Puerto Rico's 2019 CDBG–DR grant will no longer be subject to any provisions in PR's Prior Notices and the use of 2019 and 2020 CDBG–DR Grants shall be subject to the requirements of February 3, 2022 notice (including the Consolidated Notice) provisions, as may be amended from time to time. The exceptions are as follows:

a. The 2019 CDBG–DR Grant is not subject to the following provisions of the February 3, 2022 Notice (including the Consolidated Notice) that implement statutory authorities specific to Public Law 117–43 or are related to requirements that were previously met: Section I (Allocations), requirements in section II (Use of Funds) related to the CDBG–DR mitigation set-aside, III. (Requirements Related to Administrative Funds), IV.A.2. (CDBG–DR mitigation set-aside), IV.A.3. (Interchangeability of Disaster Funds), and the provisions of the Consolidated Notice that direct grantees to make pre-award submissions (section III.A. ''Pre-Award Evaluation of Management and Oversight of Funds'' of the Consolidated Notice (87 FR 6376).

b. PR's Prior Notices (as modified by section VII of this notice) continue to govern all requirements for the 2017 Unmet Infrastructure Needs Grant and the following requirements for the 2019 CDBG–DR grant: HUD's allocations for 2019 disasters and allocation methodology, the requirements that governed the grantee's pre-grant submissions to support the Secretary's certifications, the grantee's submissions describing its implementation plan and capacity assessment, the identified major disasters and MID areas for the 2019 CDBG–DR Grant, and the use of administrative funds across multiple grants (section IV.B.3. of the notice published Jan. 27, 2020).

X. Flexibilities for Grants Under Recent Appropriations Acts (Affects Multiple Grantees)

Recent appropriations acts have provided CDBG–DR grantees with additional flexibilities. This section notifies grantees, the public, and oversight entities of these flexibilities. The new statutory authorities supersede any requirements to the contrary in **Federal Register** notices or grant agreements governing awards that are subject to the new statutory provisions.

Public Law 117–43 authorizes the Secretary to permit grantees that received funds under Public Law 117–43 and under prior or future appropriations for activities related to unmet recovery needs in the MID areas resulting from a major disaster to use those funds interchangeably and without limitation for the same activities related to unmet recovery needs in the MID areas resulting from another major disaster in Public Law 117–43 or in prior or future appropriation acts, when the MID areas overlap and when the use of the funds will address unmet recovery needs of both major disasters. The Secretary authorized this use of funds and implemented this requirement for all grantees that received a grant under Public Law 117–43. This authorization is published in section IV.A.3. of the **Federal Register** notice published on February 3, 2022 at 87 FR 6368 and in section IV.A.3. of the **Federal Register** notice published on May 24, 2022 at 87 FR 31643.

Under these authorizations, grantees may use CDBG–DR funds that they were awarded under Public Law 117–43 and under prior and future appropriations acts interchangeably and without limitation for eligible activities authorized by title I of the HCDA, as modified by applicable waivers and alternative requirements, if:

(a) The activities support recovery in the overlapping portions of MID areas resulting from major disasters assisted under both appropriations (if applicable **Federal Register** notices do not specify MID areas for a major disaster, the MID areas are those areas covered by the President's major disaster declaration); and

(b) The use of the funds will address unmet recovery needs of both major disasters. Consistent with Congressional intent to increase the speed of recovery and ease administrative burdens, HUD will evaluate whether the use of funds in the overlapping MID areas will address unmet recovery needs of both major disasters at the highest reasonable level. For CDBG–DR grants, this will be evaluated at the action plan level (not by evaluating unmet needs of individual beneficiaries). Accordingly, before using funds for a disaster other than the major disaster for which the funds were awarded, a CDBG–DR grantee must describe in its action plan that governs the use of the funds how the combined use of all funds under both appropriations will address unmet recovery needs of both major disasters.

Public Law 117–43 also provides flexibility for grantees receiving funds under Public Law 117–43 and under prior or future acts to use grant funds for administrative costs across multiple grants. HUD implemented this requirement for all grantees affected by the provision in section III.A.2. of the **Federal Register** notice published on February 3, 2022, at 87 FR 6367 and in section III.A.2. of the **Federal Register** notice published on May 24, 2022, at 87 FR 31642.

Public Law 116–20 authorized grantees that received grants under Public Laws 114–113, 114–223, 114–254, 115–31, 115–56, 115–123, 115–254, and 116–20 or any future act to use eligible administrative funds (up to 5 percent of each grant plus up to 5 percent of program income generated by the grant) appropriated by these acts for the cost of administering any of these grants without regard to the particular disaster appropriation from which such funds originated. HUD implemented this requirement for all affected grantees in section IV.B.3. of the **Federal Register** notice published on January 27, 2020, at 85 FR 4686. This flexibility is also codified at 42 U.S.C. 5122 note.

Section 432 of the Transportation, Housing and Urban Development, and Related Agencies Appropriations Act, 2022 (Pub. L. 117–103) extended the expenditure deadline to September 30, 2025, for grants made available under Public Law 113–2.

XI. Finding of No Significant Impact

A Finding of No Significant Impact (FONSI) with respect to the environment has been made in accordance with HUD regulations at 24 CFR part 50, which implement section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)). The FONSI is available online on HUD's CDBG–DR website. Due to security measures at the HUD Headquarters building, an advance appointment to review the docket file must be scheduled by calling the Regulations Division at 202–708–3055 (this is not a toll-free number).

Adrianne Todman,

Deputy Secretary.

[FR Doc. 2022–13179 Filed 6–17–22; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[Docket No. FWS–R8–ES–2022–0019; FF08ESMF00–FXES11140800000–223]

Maricopa Sun Solar Complex Habitat Conservation Plan, Kern County, California; Environmental Assessment

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of availability of documents; request for public comment.

SUMMARY: We, the U.S. Fish and Wildlife Service, announce receipt of an application from Maricopa Sun, LLC to amend their existing incidental take permit for the Maricopa Sun Solar Complex. Under the Endangered Species Act and National Environmental Policy Act, we are making available the applicant's draft amended habitat conservation plan and our draft environmental assessment. We invite the public and local, State, Tribal, and Federal agencies to comment on the documents. Before issuing a requested amended permit, we will take into consideration any information that we receive during the public comment period.

DATES: We must receive your written comments on or before July 21, 2022.

ADDRESSES:

Obtaining Documents: The incidental take permit application, draft environmental assessment (EA), draft amended habitat conservation plan (HCP), and any comments and other materials that we receive are available for public inspection at *https://www.regulations.gov* in Docket No. FWS–R8–ES–2022–0019.

Submitting Comments: To send written comments, please use one of the following methods, and note that your information requests or comments are in reference to the draft EA, draft HCP, or both.

- *Internet:* Submit comments at *https://www.regulations.gov* under Docket No. FWS–R8–ES–2022–0019.
- *U.S. Mail:* Public Comments Processing, Attn: Docket No. FWS–R8–ES–2022–0019; U.S. Fish and Wildlife Service Headquarters, MS: PERMA; 5275 Leesburg Pike; Falls Church, VA 22041–3803.

For more information, see Public Comments under **SUPPLEMENTARY INFORMATION**.

FOR FURTHER INFORMATION CONTACT: Justin Sloan, Senior Wildlife Biologist, or Patricia Cole, Supervisor, San Joaquin Valley Division, Sacramento Fish and Wildlife Office, by phone at 916–414–6600. Individuals in the United States who are deaf, deafblind, hard of hearing, or have a speech disability may dial 711 (TTY, TDD, or TeleBraille) to access telecommunications relay services. Individuals outside the United States should use the relay services offered within their country to make international calls to the point-of-contact in the United States.

SUPPLEMENTARY INFORMATION: We, the U.S. Fish and Wildlife Service (Service), announce receipt of an application from Maricopa Sun, LLC to amend their existing incidental take permit (TE54164B–0) for the Maricopa Sun Solar Complex. Maricopa Sun, LLC is requesting an amendment to extend the permit term from 35 to 50 years, add Kern mallow (*Eremalche kernensis*) as a covered species, reduce the habitat conservation plan (HCP) area by removing 489.9 acres (ac) of potential solar development, and add the installation and operation of battery energy storage systems as covered activities. The amended HCP would encompass 5,318.4 ac.

We also make available the draft environmental assessment (EA), prepared pursuant to the National Environmental Policy Act of 1969, as amended (NEPA; 42 U.S.C. 4321 *et seq.*), and its implementing regulations in the Code of Federal Regulations (CFR) at 40 CFR 1506.6. The draft EA evaluates the impacts of the proposed action and the no-action alternative. The draft EA tiers from the analysis within the final environmental impact statement issued by the Service and announced via a **Federal Register** notice to the public on December 8, 2014 (79 FR 72696).

Background Information

Section 9 of the ESA (16 U.S.C. 1531–1544 *et seq.*) and Federal regulations (50 CFR 17) prohibit the taking of fish and wildlife species listed as endangered or threatened under section 4 of the ESA. The definition of ''take'' under the ESA does not apply to plant species; however, plant species can be listed on the Federal permit as covered species in recognition of the conservation measures provided for them under the HCP, and in order to receive ''No Surprises'' regulatory assurances under the Federal permit. Regulations governing permits for endangered and threatened species are at 50 CFR 17.22 and 17.32, respectively. For more about the Federal habitat conservation plan (HCP) program, go to *https://www.fws.gov/service/habitat-conservation-plans*

National Environmental Policy Act Compliance

The proposed issuance of a permit amendment triggers the need for compliance with the National Environmental Policy Act of 1969, as amended (NEPA; 42 U.S.C. 4321 *et seq.*). The draft EA was prepared to analyze the impacts of issuing an amended ITP based on the draft amended HCP; to inform the public of the proposed action, any alternatives, and associated impacts; and to disclose any irreversible commitments of resources. The draft EA tiers from the analysis within the final environmental impact statement issued by the Service and noticed to the public on December 8, 2014 (79 FR 72696).

Proposed Action

The proposed action includes amendments to the existing permit and HCP to include:

1. The addition of Kern mallow to the five species that are covered by the HCP and permit, and inclusion of additional species-specific minimization measures.

2. An extension of the permit term from 35 years to 50 years.

3. The removal of 489.9 ac of potential solar site development area that would reduce the permit area to 5,318.4 ac.

4. The inclusion of the installation and operation of battery energy storage systems as part of the project.

Public Comments

We request data, comments, new information, or suggestions from the public, other concerned governmental agencies, the scientific community, Tribes, industry, or any other interested party on this notice, the draft EA, and the draft amended HCP. We particularly seek comments on the following:

1. Biological information concerning the species;

2. Relevant data concerning the species;

3. Additional information concerning the range, distribution, population size, and population trends of the species;

4. Current or planned activities in the area and their possible impacts on the species;

5. The presence of archeological sites, buildings and structures, historic events, sacred and traditional areas, and other historic preservation concerns, which are required to be considered in project planning by the National Historic Preservation Act; and

6. Any other environmental issues that should be considered with regard to the proposed development and permit action.

Public Availability of Comments

Before including your address, phone number, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—might 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

We publish this notice under the National Environmental Policy Act of 1969, as amended (42 U.S.C. 4321–4347 *et seq.*), and its implementing regulations at 40 CFR 1500–1508, as well as in compliance with section 10(c) of the Endangered Species Act (16 U.S.C. 1531–1544 *et seq.*) and its implementing regulations at 50 CFR 17.22.

Michael Fris,

Field Supervisor, Sacramento Fish and Wildlife Office.

[FR Doc. 2022–13205 Filed 6–17–22; 8:45 am]

BILLING CODE 4333–15–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[LLOR957000.L1440000.BJ0000.212.HAG 22–0019]

Filing of Plats of Survey: Oregon/Washington

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), Oregon State Office, Portland, Oregon, 30 calendar days from the date of this publication.

DATES: Protests must be received by the BLM prior to the scheduled date of official filing, July 21, 2022.

ADDRESSES: A copy of the plats may be obtained from the Public Room at the Bureau of Land Management, Oregon State Office, 1220 SW 3rd Avenue, Portland, Oregon 97204, upon required payment. The plats may be viewed at this location at no cost.

FOR FURTHER INFORMATION CONTACT: Mary Hartel, telephone: (503) 808–6131, email: *mhartel@blm.gov,* Branch of Geographic Sciences, Bureau of Land Management, 1220 SW 3rd Avenue, Portland, Oregon 97204. Persons who use a telecommunications device for the deaf (TDD) may call the Federal Relay Service at 1–800–877–8339 to contact Ms. Hartel 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 plats of survey of the following described lands are scheduled to be officially filed in the Bureau of Land Management, Oregon State Office, Portland, Oregon:

Willamette Meridian, Oregon

T. 23 S., R. 5 W., accepted April 26, 2022
T. 23 S., R. 6 W., accepted April 26, 2022
T. 21 S., R. 4 W., accepted April 26, 2022
T. 34 S., R. 2 W., accepted April 26, 2022
T. 33 S., R. 2 W., accepted April 26, 2022
T. 33 S., R. 2 E., accepted April 26, 2022
T. 37 S., R. 1 E., accepted April 26, 2022
T. 24 S., R. 28 E., accepted April 26, 2022
T. 26 S., R. 2 W., accepted April 26, 2022
T. 32 S., R. 1 W., accepted April 26, 2022

A person or party who wishes to protest one or more plats of survey identified above must file a written notice of protest with the Chief Cadastral Surveyor for Oregon/Washington, Bureau of Land Management. The notice of protest must identify the plat(s) of survey that the person or party wishes to protest. The notice of protest must be filed before the scheduled date of official filing for the plat(s) of survey being protested. Any notice of protest filed after the scheduled date of official filing will be untimely and will not be considered. A notice of protest is considered filed on the date it is received by the Chief Cadastral Surveyor for Oregon/Washington during regular business hours; if received after regular business hours, a notice of protest will be considered filed the next business day. A written statement of reasons in support of a protest, if not filed with the notice of protest, must be filed with the Chief Cadastral Surveyor for Oregon/Washington within 30 calendar days after the notice of protest is filed. If a notice of protest against a plat of survey is received prior to the scheduled date of official filing, the official filing of the plat of survey identified in the notice of protest will be stayed pending consideration of the protest. A plat of survey will not be officially filed until the next business day following dismissal or resolution of all protests of the plat.

Before including your address, phone number, email address, or other personal identifying information in a notice of protest or statement of reasons, you should be aware that the documents you submit—including your personal identifying information—may be made publicly available in their entirety at any time. While you can ask us 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., Chapter 3)

Mary J.M. Hartel,

Chief Cadastral Surveyor of Oregon/ Washington.

[FR Doc. 2022–13196 Filed 6–17–22; 8:45 am]

BILLING CODE 4310–33–P

DEPARTMENT OF THE INTERIOR

National Indian Gaming Commission

Renewals of Information Collections Under the Paperwork Reduction Act

AGENCY: National Indian Gaming Commission, Interior.

ACTION: Second notice of request for comments.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995, the National Indian Gaming Commission (NIGC or Commission) is announcing its submission, concurrently with the publication of this notice or soon thereafter, of the following information collection requests to the Office of Management and Budget (OMB) for review and approval. The Commission is seeking comments on the renewal of information collections for the following activities: (i) Indian gaming management contract-related submissions, as authorized by Office of Management and Budget (OMB) Control Number 3141–0004 (expires on June 30, 2022); (ii) Indian gaming fee payments-related submissions, as authorized by OMB Control Number 3141–0007 (expires on June 30, 2022); (iii) minimum internal control standards for class II gaming submission and recordkeeping requirements, as authorized by OMB Control Number 3141–0009 (expires on June 30, 2022); (iv) facility license-related submission and recordkeeping requirements, as authorized by OMB Control Number 3141–0012 (expires on June 30, 2022); and (v) minimum technical standards for class II gaming systems and equipment submission and recordkeeping requirements, as authorized by OMB Control Number 3141–0014 (expires on June 30, 2022).

DATES: The OMB has up to 60 days to approve or disapprove the information collection requests, but may respond after 30 days. Therefore, public comments should be submitted to OMB by July 21, 2022 in order to be assured of consideration.

ADDRESSES: Submit comments directly to OMB's Office of Information and Regulatory Affairs, Attn: Policy Analyst/ Desk Officer for the National Indian Gaming Commission. Comments can also be emailed to *OIRA_Submission@omb.eop.gov*, include reference to ''NIGC PRA Renewals'' in the subject line.

FOR FURTHER INFORMATION CONTACT: For further information, including copies of the proposed information collection requests and supporting documentation, contact Tim Osumi at (202) 632–7003; fax (202) 632–7066 (not toll-free numbers). You may also review these information collection requests by going to *http://www.reginfo.gov* (Information Collection Review, Currently Under Review, Agency: National Indian Gaming Commission).

SUPPLEMENTARY INFORMATION:

I. Abstract

The gathering of this information is in keeping with the purposes of the Indian Gaming Regulatory Act of 1988 (IGRA or the Act), Public Law 100–497, 25 U.S.C. 2701, *et seq.,* which include: providing a statutory basis for the operation of gaming by Indian tribes as a means of promoting tribal economic development, self-sufficiency, and strong tribal governments; ensuring that the Indian tribe is the primary beneficiary of the gaming operation; and declaring that the establishment of independent federal regulatory authority for gaming on Indian lands, the establishment of federal standards for gaming on Indian lands, and the establishment of the Commission are necessary to meet congressional concerns regarding gaming and to protect such gaming as a means of generating tribal revenue. 25 U.S.C. 2702. The Act established the Commission and laid out a comprehensive framework for the regulation of gaming on Indian lands.

II. Data

Title: Management Contract Provisions.

OMB Control Number: 3141–0004.

Brief Description of Collection: The Indian Gaming Regulatory Act (IGRA or the Act), Public Law 100–497, 25 U.S.C. 2701, *et seq.,* established the National Indian Gaming Commission (NIGC or Commission) and laid out a comprehensive framework for the regulation of gaming on Indian lands. Amongst other actions necessary to carry out the Commission's statutory duties, the Act requires the NIGC Chairman to review and approve all management contracts for the operation and management of class II and/or class III gaming activities, and to conduct background investigations of persons with direct or indirect financial interests in, and management responsibility for, management contracts. 25 U.S.C. 2710, 2711. The Commission is authorized to ''promulgate such regulations and guidelines as it deems appropriate to implement'' IGRA. 25 U.S.C. 2706(b)(10). The Commission has promulgated parts 533, 535, and 537 of title 25, Code of Federal Regulations, to implement these statutory requirements.

Section 533.2 requires a tribe or management contractor to submit a management contract for review within 60 days of execution, and to submit all of the items specified in § 533.3. Section 535.1 requires a tribe to submit an amendment to a management contract within 30 days of execution, and to submit all of the items specified in § 535.1(c). Section 535.2 requires a tribe or a management contractor, upon execution, to submit the assignment by a management contractor of its rights under a previously approved management contract. Section 537.1 requires a management contractor to submit all of the items specified in § 537.1(b),(c) in order for the Commission to conduct background investigations on: each person with management responsibility for a management contract; each person who is a director of a corporation that is a party to a management contract; the ten persons who have the greatest direct or indirect financial interest in a management contract; any entity with a financial interest in a management contract; and any other person with a direct or indirect financial interest in a management contract, as otherwise designated by the Commission. This collection is mandatory, and the benefit to the respondents is the approval of Indian gaming management contracts, and any amendments thereto.

Respondents: Tribal governing bodies and management contractors.

Estimated Number of Respondents: 29.

Estimated Annual Responses: 41 (submissions of contracts, contract amendments, contract assignments, and background investigation material).

Estimated Time per Response: Depending on the type of submission, the range of time can vary from 1.0 burden hours to 16.0 burden hours for one item.

Frequency of Response: Usually no more than once per year.

Estimated Total Annual Burden Hours on Respondents: 401.

Estimated Total Non-hour Cost Burden: $19,729.

Title: Fees.

OMB Control Number: 3141–0007.

Brief Description of Collection: The Indian Gaming Regulatory Act (IGRA or the Act), 25 U.S.C. 2701, *et seq.,* laid out a comprehensive framework for the regulation of gaming on Indian lands. Amongst other actions necessary to carry out the Commission's statutory duties, the Act requires Indian tribes that conduct a class II and/or class III gaming activity to pay annual fees to the Commission on the basis of the assessable gross revenues of each gaming operation using rates established by the Commission. 25 U.S.C. 2717. The Commission is authorized to ''promulgate such regulations and guidelines as it deems appropriate to implement'' IGRA. 25 U.S.C. 2706(b)(10). The Commission has promulgated part 514 of title 25, Code of Federal Regulations, to implement these statutory requirements.

Section 514.6 requires a tribe to submit, along with its fee payments, quarterly fee statements (worksheets) showing its assessable gross revenues for the previous fiscal year in order to support the computation of fees paid by each gaming operation. Section 514.7 requires a tribe to submit a notice within 30 days after a gaming operation changes its fiscal year. Section 514.15 allows a tribe to submit fingerprint cards to the Commission for processing by the Federal Bureau of Investigation (FBI), along with a fee to cover the NIGC's and FBI's cost to process the fingerprint cards on behalf of the tribes. Part of this collection is mandatory and the other part is voluntary. The required submission of the fee worksheets allows the Commission to both set and adjust fee rates, and to support the computation of fees paid by each gaming operation. In addition, the voluntary submission of fingerprint cards allows a tribe to conduct statutorily mandated background investigations on applicants for key employee and primary management official positions.

Respondents: Indian gaming operations.

Estimated Number of Respondents: 698.

Estimated Annual Responses: 60,826.

Estimated Time per Response: Depending on the type of submission, the range of time can vary from 0.5 burden hours to 2.3 burden hours for one item.

Frequency of Response: Quarterly (for fee worksheets); varies (for fingerprint cards and fiscal year change notices).

Estimated Total Annual Burden on Respondents: 33,885.

Estimated Total Non-hour Cost Burden: $ 1,649,004.

Title: Minimum Internal Control Standards for Class II Gaming.

OMB Control Number: 3141–0009.

Brief Description of Collection: The Indian Gaming Regulatory Act (IGRA or the Act), 25 U.S.C. 2701, *et seq.,* laid out a comprehensive framework for the regulation of gaming on Indian lands. Amongst other actions necessary to carry out the Commission's statutory duties, the Act directs the Commission to monitor class II gaming conducted on Indian lands on a continuing basis in order to adequately shield Indian gaming from organized crime and other corrupting influences, to ensure that the Indian tribe is the primary beneficiary of the gaming operation, and to assure that gaming is conducted fairly and honestly by both the operator and players. 25 U.S.C. 2702(2), 2706(b)(1). The Commission is also authorized to ''promulgate such regulations and guidelines as it deems appropriate to implement'' IGRA. 25 U.S.C. 2706(b)(10). The Commission has promulgated part 543 of title 25, Code of Federal Regulations, to aid it in monitoring class II gaming on a continuing basis.

Section 543.3 requires a tribal gaming regulatory authority (TGRA) to submit to the Commission a notice requesting an extension to the deadline (by an additional six months) to achieve compliance with the requirements of the new tier after a gaming operation has moved from one tier to another. Section 543.5 requires a TGRA to submit a detailed report after the TGRA has approved an alternate standard to any of the NIGC's minimum internal control standards, and the report must contain all of the items specified in § 543.5(a)(2). Section 543.23(c) requires a tribe to maintain internal audit reports and to make such reports available to the Commission upon request. Section 543.23(d) requires a tribe to submit two copies of the agreed-upon procedures (AUP) report within 120 days of the gaming operation's fiscal year end. This collection is mandatory and allows the NIGC to confirm tribal compliance with the minimum internal control standards in the AUP reports.

Respondents: Tribal governing bodies.

Estimated Number of Respondents: 398.

Estimated Annual Responses: 842.

Estimated Time per Response: Depending on the tier level of the gaming facility, the range of time can vary from 1.0 burden hour to 10.0 burden hours for one AUP audit report.

Frequency of Response: Annually.

Estimated Total Annual Hourly Burden to Respondents: 1,199.

Estimated Total Non-hour Cost Burden: $ 3,296,800.

Title: Facility License Notifications and Submissions.

OMB Control Number: 3141–0012.

Brief Description of Collection: The Indian Gaming Regulatory Act (IGRA or the Act), 25 U.S.C. 2701, *et seq.,* laid out a comprehensive framework for the regulation of gaming on Indian lands. Amongst other actions necessary to carry out the Commission's statutory duties, the Act requires Indian tribes that conduct class II and/or class III gaming to issue ''a separate license . . . for each place, facility, or location on Indian lands at which class II [and class III] gaming is conducted,'' 25 U.S.C. 2710(b)(1), (d)(1), and to ensure that ''the construction and maintenance of the gaming facilities, and the operation of that gaming is conducted in a manner which adequately protects the environment and public health and safety.'' 25 U.S.C. 2710(b)(2)(E). The Commission is authorized to ''promulgate such regulations and guidelines as it deems appropriate to implement'' IGRA. 25 U.S.C. 2706(b)(10). The Commission has promulgated part 559 of title 25, Code of Federal Regulations, to implement these requirements.

Section 559.2 requires a tribe to submit a notice (that a facility license is under consideration for issuance) at least 120 days before opening any new facility on Indian lands where class II and/or class III gaming will occur, with the notice containing all of the items specified in § 559.2(b). Section 559.3 requires a tribe to submit a copy of each newly issued or renewed facility license within 30 days of issuance. Section 559.4 requires a tribe to submit an attestation certifying that by issuing the facility license, the tribe has determined that the construction, maintenance, and operation of that gaming facility is conducted in a manner that adequately protects the environment and the public health and safety. Section 559.5 requires a tribe to submit a notice within 30 days if a facility license is terminated or expires or if a gaming operation closes or reopens. Section 559.6 requires a tribe to maintain and provide applicable and available Indian lands or environmental and public health and safety documentation, if requested by the NIGC. This collection is mandatory and enables the Commission to perform its statutory duty by ensuring that tribal gaming facilities on Indian lands are properly licensed by the tribes.

Respondents: Indian tribal gaming operations.

Estimated Number of Respondents: 462.

Estimated Annual Responses: 500.

Estimated Time per Response: Depending on the type of submission, the range of time can vary from 1.0 burden hours to 3.0 burden hours for one item.

Frequency of Response: Varies.

Estimated Total Annual Hourly Burden to Respondents: 966.

Estimated Total Non-hour Cost Burden: $0.

Title: Minimum Technical Standards for Class II Gaming Systems and Equipment.

OMB Control Number: 3141–0014.

Brief Description of Collection: The Indian Gaming Regulatory Act (IGRA or the Act), 25 U.S.C. 2701, *et seq.,* laid out a comprehensive framework for the regulation of gaming on Indian lands. Amongst other actions necessary to carry out the Commission's statutory duties, the Act directs the Commission to monitor class II gaming conducted on Indian lands on a continuing basis in order to adequately shield Indian gaming from organized crime and other corrupting influences, to ensure that the Indian tribe is the primary beneficiary of the gaming operation, and to assure that gaming is conducted fairly and honestly by both the operator and players. 25 U.S.C. 2702(2), 2706(b)(1). The Act allows Indian tribes to use ''electronic, computer, or other technologic aids'' to conduct class II gaming activities. 25 U.S.C. 2703(7)(A). The Commission is authorized to ''promulgate such regulations and guidelines as it deems appropriate to implement'' IGRA. 25 U.S.C. 2706(b)(10). The Commission has promulgated part 547 of title 25, Code of Federal Regulations, to aid it in monitoring class II gaming facilities that are using electronic, computer, or other technologic aids to conduct class II gaming.

Section 547.5(a)(2) requires that, for any grandfathered class II gaming system made available for use at any tribal gaming operation, the tribal gaming regulatory authority (TGRA): must retain copies of the gaming system's testing laboratory report, the TGRA's compliance certificate, and the TGRA's approval of its use; and must maintain records identifying these grandfathered class II gaming systems and their components. Section 547.5(b)(2) requires that, for any class II gaming system generally, the TGRA must retain a copy of the system's testing laboratory report, and maintain records identifying the system and its components. As long as a class II gaming system is available to the public for play, section 547.5(c)(3) requires a TGRA to maintain records of any modification to such gaming system and a copy of its testing laboratory report. Section 547.5(d)(3) requires a TGRA to maintain records of approved emergency hardware and software modifications to a class II gaming system (and a copy of the testing laboratory report) so long as the gaming system remains available to the public for play, and must make the records available to the Commission upon request. Section 547.5(f) requires a TGRA to maintain records of its following determinations: (i) regarding a testing laboratory's (that is owned or operated or affiliated with a tribe) independence from the manufacturer and gaming operator for whom it is providing the testing, evaluating, and reporting functions; (ii) regarding a testing laboratory's suitability determination based upon standards no less stringent than those set out in 25 CFR 533.6(b)(1)(ii) through (v) and based upon no less information than that required by 25 CFR 537.1; and/or (iii) the TGRA's acceptance of a testing laboratory's suitability determination made by any other gaming regulatory authority in the United States. The TGRA must maintain said records for a minimum of three years and must make the records available to the Commission upon request. Section 547.17 requires a TGRA to submit a detailed report for each enumerated standard for which the TGRA approves an alternate standard, and the report must include: (i) an explanation of how the alternate standard achieves a level of security and integrity sufficient to accomplish the purpose of the standard it is to replace; and (ii) the alternate standard as approved and the record on which the approval is based. This collection is mandatory and allows the NIGC to confirm tribal compliance with NIGC regulations on ''electronic, computer, or other technologic aids'' to conduct class II gaming activities.

Respondents: Tribal governing bodies.

Estimated Number of Respondents: 431.

Estimated Annual Responses: 431.

Estimated Time per Response: Depending on the type of submission, the range of time can vary from 6 burden hours to 33.5 burden hours for one item.

Frequency of Response: Annually.

Estimated Total Annual Hourly Burden to Respondents: 7,666.

Estimated Total Non-hour Cost Burden: $0.

Dated: June 3, 2022.

Christinia Thomas,

Deputy Chief of Staff.

[FR Doc. 2022–13219 Filed 6–17–22; 8:45 am]

BILLING CODE 7565–01–P

DEPARTMENT OF THE INTERIOR

Office of Surface Mining Reclamation and Enforcement

[S1D1S SS08011000 SX064A000 221S180110; S2D2S SS08011000 SX064A000 22XS501520; OMB Control Number 1029–0030]

State Processes for Designating Areas Unsuitable for Surface Coal Mining Operations

AGENCY: Office of Surface Mining Reclamation and Enforcement, Interior.

ACTION: Notice of information collection; request for comment.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, we, the Office of Surface Mining Reclamation and Enforcement (OSMRE), are proposing to renew an information collection.

DATES: Interested persons are invited to submit comments on or before August 22, 2022.

ADDRESSES: Send your comments on this information collection request (ICR) by mail to Mark Gehlhar, Office of Surface Mining Reclamation and Enforcement, 1849 C Street NW, Room 4556–MIB, Washington, DC 20240, or by email to *mgehlhar@osmre.gov.* Please reference OMB Control Number 1029–0030 in the subject line of your comments.

FOR FURTHER INFORMATION CONTACT: To request additional information about this ICR, contact Mark Gehlhar by email at *mgehlhar@osmre.gov,* or by telephone at 202–208–2716.

SUPPLEMENTARY INFORMATION: In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*) and 5 CFR 1320.8(d)(1), we provide the general public and other Federal agencies with an opportunity to comment on new, proposed, revised, and continuing collections of information. This helps us assess the impact of our information collection requirements and minimize the public's reporting burden. It also helps the public understand our information collection requirements and provide the requested data in the desired format.

We are soliciting comments on the proposed ICR that is described below. We are especially interested in public comment addressing the following issues: (1) is the collection necessary to the proper functions of the agency; (2) will this information be processed and used in a timely manner; (3) is the estimate of burden accurate; (4) how might the agency enhance the quality, utility, and clarity of the information to be collected; and (5) how might the agency minimize the burden of this collection on the respondents, including through the use of information technology.

Comments that you submit in response to this notice are a matter of public record. We will include or summarize each comment in our request to OMB to approve this ICR. Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—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.

Abstract: This part implements the requirement of section 522 of the Surface Mining Control and Reclamation Act of 1977 (SMCRA), Public Law 95–87, which provides authority for citizens to petition States to designate lands unsuitable for surface coal mining operations, or to terminate such designation. The regulatory authority uses the information to identify, locate, compare and evaluate the area requested to be designated as unsuitable, or terminate the designation, for surface coal mining operations.

Title of Collection: State Processes for Designating Areas Unsuitable for Surface Coal Mining Operations.

OMB Control Number: 1029–0030.

Form Number: None.

Type of Review: Extension of a currently approved collection.

Respondents/Affected Public: State and Tribal governments and individuals.

Total Estimated Number of Annual Respondents: 2.

Total Estimated Number of Annual Responses: 5.

Estimated Completion Time per Response: Varies 600 hours to 1,900 hours, depending on activity.

Total Estimated Number of Annual Burden Hours: 2,500.

Respondent's Obligation: Required to obtain or retain a benefit.

Frequency of Collection: One time.

Total Estimated Annual Nonhour Burden Cost: $120.

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 authority for this action is the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

Mark J. Gehlhar,

Information Collection Clearance Officer, Division of Regulatory Support.

[FR Doc. 2022–13245 Filed 6–17–22; 8:45 am]

BILLING CODE 4310–05–P

INTERNATIONAL TRADE COMMISSION

[Investigation Nos. 731–TA–1299, 1300, and 1302 (Review)]

Circular Welded Carbon-Quality Steel Pipe From Oman, Pakistan, and the United Arab Emirates; Scheduling of a Full Five-Year Review

AGENCY: United States International Trade Commission.

ACTION: Notice.

SUMMARY: The Commission hereby gives notice of the scheduling of a full review pursuant to the Tariff Act of 1930 (''the Act'') to determine whether revocation of the antidumping duty orders duty orders on circular welded carbon-quality steel pipe from Oman, Pakistan, and the United Arab Emirates would be likely to lead to continuation or recurrence of material injury within a reasonably foreseeable time. The Commission has determined to exercise its authority to extend the review period by up to 90 days.

DATES: June 14, 2022.

FOR FURTHER INFORMATION CONTACT: Jordan Harriman ((202) 205–2610), Office of Investigations, U.S. International Trade Commission, 500 E Street SW, Washington, DC 20436. Hearing-impaired persons can obtain information on this matter by contacting the Commission's TDD terminal on 202–205–1810. Persons with mobility impairments who will need special assistance in gaining access to the Commission should contact the Office of the Secretary at 202–205–2000. General information concerning the Commission may also be obtained by accessing its internet server (*https://www.usitc.gov*). The public record for this review may be viewed on the Commission's electronic docket (EDIS) at *https://edis.usitc.gov.*

SUPPLEMENTARY INFORMATION:

Background.—On February 4, 2022, the Commission determined that responses to its notice of institution of the subject five-year review were such that a full review should proceed (87 FR 9641, February 22, 2022); accordingly, a full review is being scheduled pursuant to section 751(c)(5) of the Tariff Act of 1930 (19 U.S.C. 1675(c)(5)). A record of the Commissioners' votes, the Commission's statement on adequacy, and any individual Commissioner's statements are available from the Office of the Secretary and at the Commission's website.

Participation in the review and public service list.—Persons, including industrial users of the subject merchandise and, if the merchandise is sold at the retail level, representative consumer organizations, wishing to participate in this review as parties must file an entry of appearance with the Secretary to the Commission, as provided in section 201.11 of the Commission's rules, by 45 days after publication of this notice. A party that filed a notice of appearance following publication of the Commission's notice of institution of the review need not file an additional notice of appearance. The Secretary will maintain a public service list containing the names and addresses of all persons, or their representatives, who are parties to the review.

For further information concerning the conduct of this review and rules of general application, consult the Commission's Rules of Practice and Procedure, part 201, subparts A and B (19 CFR part 201), and part 207, subparts A, D, E, and F (19 CFR part 207).

Please note the Secretary's Office will accept only electronic filings during this time. Filings must be made through the Commission's Electronic Document Information System (EDIS, *https://edis.usitc.gov.*) No in-person paper-based filings or paper copies of any electronic filings will be accepted until further notice.

Limited disclosure of business proprietary information (BPI) under an administrative protective order (APO) and BPI service list.—Pursuant to section 207.7(a) of the Commission's rules, the Secretary will make BPI gathered in this review available to authorized applicants under the APO issued in the review, provided that the application is made by 45 days after publication of this notice. Authorized applicants must represent interested parties, as defined by 19 U.S.C. 1677(9), who are parties to the review. A party granted access to BPI following publication of the Commission's notice of institution of the review need not reapply for such access. A separate service list will be maintained by the Secretary for those parties authorized to receive BPI under the APO.

Staff report.—The prehearing staff report in the review will be placed in the nonpublic record on September 22, 2022, and a public version will be issued thereafter, pursuant to section 207.64 of the Commission's rules.

Hearing.— The Commission will hold a hearing in connection with these reviews beginning at 9:30 a.m. on October 13, 2022. Information about the place and form of the hearing, including about how to participate in and/or view the hearing, will be posted on the Commission's website at *https://www.usitc.gov/calendarpad/calendar.html.* Interested parties should check the Commission's website periodically for updates. Requests to appear at the hearing should be filed in writing with the Secretary to the Commission on or before October 4, 2022. A nonparty who has testimony that may aid the Commission's deliberations may request permission to present a short statement at the hearing. All parties and nonparties desiring to appear at the hearing and make oral presentations should attend a prehearing conference to be held at 9:30 a.m. on October 6, 2022. Oral testimony and written materials to be submitted at the public hearing are governed by sections 201.6(b)(2), 201.13(f), and 207.24 of the Commission's rules. Parties must submit any request to present a portion of their hearing testimony *in camera* no later than 7 business days prior to the date of the hearing.

Written submissions.—Each party to the review may submit a prehearing brief to the Commission. Prehearing briefs must conform with the provisions of section 207.65 of the Commission's rules; the deadline for filing is September 30, 2022. Parties may also file written testimony in connection with their presentation at the hearing, as provided in section 207.24 of the Commission's rules, and posthearing briefs, which must conform with the provisions of section 207.67 of the Commission's rules. The deadline for filing posthearing briefs is October 25, 2022. In addition, any person who has not entered an appearance as a party to the review may submit a written statement of information pertinent to the subject of the review on or before October 25, 2022. On November 17, 2022, the Commission will make available to parties all information on which they have not had an opportunity to comment. Parties may submit final comments on this information on or before November 21, 2022, but such final comments must not contain new factual information and must otherwise comply with section 207.68 of the Commission's rules. All written submissions must conform with the provisions of section 201.8 of the Commission's rules; any submissions that contain BPI must also conform with the requirements of sections 201.6, 207.3, and 207.7 of the Commission's rules. The Commission's *Handbook on Filing Procedures,* available on the Commission's website at *https://www.usitc.gov/documents/handbook_on_filing_procedures.pdf,* elaborates upon the Commission's procedures with respect to filings.

Additional written submissions to the Commission, including requests pursuant to section 201.12 of the Commission's rules, shall not be accepted unless good cause is shown for accepting such submissions, or unless the submission is pursuant to a specific request by a Commissioner or Commission staff.

In accordance with sections 201.16(c) and 207.3 of the Commission's rules, each document filed by a party to the review must be served on all other parties to the review (as identified by either the public or BPI service list), and a certificate of service must be timely filed. The Secretary will not accept a document for filing without a certificate of service.

The Commission has determined that these reviews are extraordinarily complicated and therefore has determined to exercise its authority to extend the review period by up to 90 days pursuant to 19 U.S.C.1675(c)(5)(B).

Authority: This review is being conducted under authority of title VII of the Tariff Act of 1930; this notice is published pursuant to section 207.62 of the Commission's rules.

By order of the Commission.

Issued: June 14, 2022.

Lisa Barton,

Secretary to the Commission.

[FR Doc. 2022–13162 Filed 6–17–22; 8:45 am]

BILLING CODE 7020–02–P

INTERNATIONAL TRADE COMMISSION

[Investigation Nos. 701–TA–673–677 and 731–TA–1580–1583 (Final)]

Steel Nails From India, Oman, Sri Lanka, Thailand, and Turkey; Scheduling of the Final Phase of Countervailing Duty and Anti-Dumping Duty Investigations

AGENCY: United States International Trade Commission.

ACTION: Notice.

SUMMARY: The Commission hereby gives notice of the scheduling of the final phase of antidumping and countervailing duty investigation Nos. 701–TA–673–677 and 731–TA–1580–1583 (Final) pursuant to the Tariff Act of 1930 (''the Act'') to determine whether an industry in the United States is materially injured or threatened with material injury, or the establishment of an industry in the United States is materially retarded, by reason of imports of steel nails from India, Oman, Sri Lanka, Thailand, and Turkey, provided for in subheadings 7317.00.55, 7317.00.65, and 7317.00.75 of the Harmonized Tariff Schedule of the United States, preliminarily determined by the Department of Commerce (''Commerce'') to be subsidized. Determinations by Commerce with respect to sales at less-than-fair-value value of imports of steel nails from India, Sri Lanka, Thailand, and Turkey are pending.

DATES: June 7, 2022.

FOR FURTHER INFORMATION CONTACT: Nitin Joshi ((202) 708–1669), Office of Investigations, U.S. International Trade Commission, 500 E Street SW, Washington, DC 20436. Hearing-impaired persons can obtain information on this matter by contacting the Commission's TDD terminal on 202–205–1810. Persons with mobility impairments who will need special assistance in gaining access to the Commission should contact the Office of the Secretary at 202–205–2000. General information concerning the Commission may also be obtained by accessing its internet server (*https://www.usitc.gov*). The public record for these investigations may be viewed on the Commission's electronic docket (EDIS) at *https://edis.usitc.gov.*

SUPPLEMENTARY INFORMATION:

Scope.—For purposes of these investigations, Commerce has defined the subject merchandise as ''certain steel nails having a nominal shaft or shank length not exceeding 12 inches. Certain steel nails include, but are not limited to, nails made from round wire and nails that are cut from flat-rolled steel or long-rolled flat steel bars. Certain steel nails may be of one piece construction or constructed of two or more pieces. Examples of nails constructed of two or more pieces include, but are not limited to, anchors comprised of an anchor body made of zinc or nylon and a steel pin or a steel nail; crimp drive anchors; split-drive anchors, and strike pin anchors. Also included in the scope are anchors of one piece construction.''[1]

Background.—The final phase of these investigations is being scheduled pursuant to sections 705(b) and 731(b) of the Tariff Act of 1930 (19 U.S.C. 1671d(b) and 1673d(b)), as a result of affirmative preliminary determinations by Commerce that certain benefits which constitute subsidies within the meaning of § 703 of the Act (19 U.S.C. 1671b) are being provided to manufacturers, producers, or exporters in India, Oman, Sri Lanka, and Turkey of steel nails,[2] and pending preliminary determinations by Commerce regarding whether such products from India, Sri Lanka, Thailand, and Turkey are being sold in the United States at less than fair value within the meaning of § 733 of the Act (19 U.S.C. 1673b). The investigations were requested in petitions filed on December 30, 2021, by Mid Continent Steel & Wire, Inc., Poplar Bluff, Missouri.

For further information concerning the conduct of this phase of the investigations, hearing procedures, and rules of general application, consult the Commission's Rules of Practice and Procedure, part 201, subparts A and B (19 CFR part 201), and part 207, subparts A and C (19 CFR part 207).

Participation in the investigations and public service list.—Persons, including industrial users of the subject merchandise and, if the merchandise is sold at the retail level, representative consumer organizations, wishing to participate in the final phase of these investigations as parties must file an entry of appearance with the Secretary to the Commission, as provided in § 201.11 of the Commission's rules, no later than 21 days prior to the hearing date specified in this notice. A party that filed a notice of appearance during the preliminary phase of the investigations need not file an additional notice of appearance during this final phase. The Secretary will maintain a public service list containing the names and addresses of all persons, or their representatives, who are parties to the investigations.

Please note the Secretary's Office will accept only electronic filings during this time. Filings must be made through the Commission's Electronic Document Information System (EDIS, *https://edis.usitc.gov*.) No in-person paper-based filings or paper copies of any electronic filings will be accepted until further notice.

Limited disclosure of business proprietary information (BPI) under an administrative protective order (APO) and BPI service list.—Pursuant to § 207.7(a) of the Commission's rules, the Secretary will make BPI gathered in the final phase of these investigations available to authorized applicants under the APO issued in the investigations, provided that the application is made no later than 21 days prior to the hearing date specified in this notice. Authorized applicants must represent interested parties, as defined by 19 U.S.C. 1677(9), who are parties to the investigations. A party granted access to BPI in the preliminary phase of the investigations need not reapply for such access. A separate service list will be maintained by the Secretary for those parties authorized to receive BPI under the APO.

Staff report.—The prehearing staff report in the final phase of these investigations will be placed in the nonpublic record on August 4, 2022, and a public version will be issued thereafter, pursuant to § 207.22 of the Commission's rules.

Hearing.—The Commission will hold a hearing in connection with the final phase of these investigations beginning at 9:30 a.m. on August 17, 2022. Information about the place and form of the hearing, including about how to participate in and/or view the hearing, will be posted on the Commission's website at *https://www.usitc.gov/calendarpad/calendar.html*. Interested parties should check the Commission's website periodically for updates. Requests to appear at the hearing should be filed in writing with the Secretary to the Commission on or before August 12, 2022. A nonparty who has testimony that may aid the Commission's deliberations may request permission to present a short statement at the hearing. All parties and nonparties desiring to appear at the hearing and make oral presentations should attend a prehearing conference to be held at 9:30 a.m. on August 15, 2022. Oral testimony and written materials to be submitted at the public hearing are governed by sections 201.6(b)(2), 201.13(f), and 207.24 of the Commission's rules. Parties must submit any request to present a portion of their hearing testimony *in camera* no later than 7 business days prior to the date of the hearing.

Written submissions.—Each party who is an interested party shall submit a prehearing brief to the Commission. Prehearing briefs must conform with the provisions of § 207.23 of the Commission's rules; the deadline for filing is August 11, 2022. Parties may also file written testimony in connection with their presentation at the hearing, as provided in § 207.24 of the Commission's rules, and posthearing briefs, which must conform with the provisions of § 207.25 of the Commission's rules. The deadline for filing posthearing briefs is August 24, 2022. In addition, any person who has not entered an appearance as a party to the investigations may submit a written statement of information pertinent to the subject of the investigations, including statements of support or opposition to the petition, on or before August 24, 2022. On September 9, 2022, the Commission will make available to parties all information on which they have not had an opportunity to comment. Parties may submit final comments on this information on or before September 13, 2022, but such final comments must not contain new factual information and must otherwise comply with § 207.30 of the Commission's rules. All written submissions must conform with the provisions of § 201.8 of the Commission's rules; any submissions that contain BPI must also conform with the requirements of §§ 201.6, 207.3, and 207.7 of the Commission's rules. The Commission's *Handbook on Filing Procedures,* available on the Commission's website at *https://www.usitc.gov/documents/handbook_on_filing_procedures.pdf,* elaborates upon the Commission's procedures with respect to filings.

Additional written submissions to the Commission, including requests pursuant to § 201.12 of the Commission's rules, shall not be accepted unless good cause is shown for accepting such submissions, or unless the submission is pursuant to a specific request by a Commissioner or Commission staff.

In accordance with §§ 201.16(c) and 207.3 of the Commission's rules, each document filed by a party to the investigations must be served on all other parties to the investigations (as identified by either the public or BPI

[1] For Commerce's complete scope with exclusions, please see 87 FR 34654 (June 7, 2022).

[2] While Commerce has preliminarily determined that countervailable subsidies are not being provided to producers and exporters of steel nails from Thailand, the Commission also is continuing its investigative activities pursuant to Commission rule 207.21(c).

service list), and a certificate of service must be timely filed. The Secretary will not accept a document for filing without a certificate of service.

Authority: These investigations are being conducted under authority of title VII of the Tariff Act of 1930; this notice is published pursuant to § 207.21 of the Commission's rules.

By order of the Commission.

Issued: June 9, 2022.

Lisa Barton,

Secretary to the Commission.

[FR Doc. 2022–12953 Filed 6–17–22; 8:45 am]

BILLING CODE 7020–02–P

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

[Docket No. DEA–1026]

Importer of Controlled Substances Application: Alcami Carolinas Corporation

AGENCY: Drug Enforcement Administration, Justice.

ACTION: Notice of application.

SUMMARY: Alcami Carolinas Corporation has applied to be registered as an importer of basic class(es) of controlled substance(s). Refer to Supplementary Information listed below for further drug information.

DATES: Registered bulk manufacturers of the affected basic class(es), and applicants therefore, may submit electronic comments on or objections to the issuance of the proposed registration on or before July 21, 2022. Such persons may also file a written request for a hearing on the application on or before July 21, 2022.

ADDRESSES: The Drug Enforcement Administration (DEA) requires that all comments be submitted electronically through the Federal eRulemaking Portal, which provides the ability to type short comments directly into the comment field on the web page or attach a file for lengthier comments. Please go to *https://www.regulations.gov* and follow the online instructions at that site for submitting comments. Upon submission of your comment, you will receive a Comment Tracking Number. Please be aware that submitted comments are not instantaneously available for public view on *https://www.regulations.gov.* If you have received a Comment Tracking Number, your comment has been successfully submitted and there is no need to resubmit the same comment. All requests for a hearing must be sent to: (1) Drug Enforcement Administration, Attn: Hearing Clerk/OALJ, 8701 Morrissette Drive, Springfield, Virginia 22152; and (2) Drug Enforcement Administration, Attn: DEA Federal Register Representative/DPW, 8701 Morrissette Drive, Springfield, Virginia 22152. All requests for a hearing should also be sent to: Drug Enforcement Administration, Attn: Administrator, 8701 Morrissette Drive, Springfield, Virginia 22152.

SUPPLEMENTARY INFORMATION: In accordance with 21 CFR 1301.34(a), this is notice that on May 10, 2022, Alcami Carolinas Corporation, 1726 North 23rd Street, Attn: DEA Compliance Office, Wilmington, North Carolina 28405–1827, applied to be registered as an importer of the following basic class(es) of controlled substance(s):

Controlled substance	Drug code	Schedule
Psilocybin	7437	I
Psilocyn	7438	I
Pentobarbital	2270	II
Thebaine	9333	II

The company plans to import the listed controlled substances in bulk for the manufacturing of capsules/tablets for Phase II clinical trials. The company plans to import derivatives of Thebaine that have been determined by DEA to be captured under drug code (9333) Thebaine. No other activity for these drug codes are authorized for this registration.

Approval of permit applications will occur only when the registrant's business activity is consistent with what is authorized under 21 U.S.C. 952(a)(2). Authorization will not extend to the import of Food and Drug Administration-approved or non-approved finished dosage forms for commercial sale.

Kristi O'Malley,

Assistant Administrator.

[FR Doc. 2022–13246 Filed 6–17–22; 8:45 am]

BILLING CODE P

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

[Docket No. DEA–1028]

Importer of Controlled Substances Application: Arizona Department of Corrections

AGENCY: Drug Enforcement Administration, Justice.

ACTION: Notice of application.

SUMMARY: Arizona Department of Corrections has applied to be registered as an importer of basic class(es) of controlled substance(s). Refer to Supplementary Information listed below for further drug information.

DATES: Registered bulk manufacturers of the affected basic class(es), and applicants therefore, may submit electronic comments on or objections to the issuance of the proposed registration on or before July 21, 2022. Such persons may also file a written request for a hearing on the application on or before July 21, 2022.

ADDRESSES: The Drug Enforcement Administration requires that all comments be submitted electronically through the Federal eRulemaking Portal, which provides the ability to type short comments directly into the comment field on the web page or attach a file for lengthier comments. Please go to *https://www.regulations.gov* and follow the online instructions at that site for submitting comments. Upon submission of your comment, you will receive a Comment Tracking Number. Please be aware that submitted comments are not instantaneously available for public view on *https://www.regulations.gov.* If you have received a Comment Tracking Number, your comment has been successfully submitted and there is no need to resubmit the same comment. All requests for a hearing must be sent to: (1) Drug Enforcement Administration, Attn: Hearing Clerk/OALJ, 8701 Morrissette Drive, Springfield, Virginia 22152; and (2) Drug Enforcement Administration, Attn: DEA Federal Register Representative/DPW, 8701 Morrissette Drive, Springfield, Virginia 22152. All requests for a hearing should also be sent to: Drug Enforcement Administration, Attn: Administrator, 8701 Morrissette Drive, Springfield, Virginia 22152.

SUPPLEMENTARY INFORMATION: In accordance with 21 CFR 1301.34(a), this is notice that on May 13, 2022, Arizona Department of Corrections, 1305 East Butte Avenue, ASPC-Florence, Florence, Arizona 85132–9221, applied to be registered as an importer of the following basic class(es) of controlled substance(s):

Controlled substance	Drug code	Schedule
Pentobarbital	2270	II

The facility intends to import the above-listed controlled substance for legitimate use. This particular controlled substance is not available for the intended legitimate use within the current domestic supply of the United States. No other activity for these drug codes are authorized for this registration.

Approval of permit applications will occur only when the registrant's business activity is consistent with what is authorized under 21 U.S.C. 952(a)(2). Authorization will not extend to the import of Food and Drug Administration-approved or non-approved finished dosage forms for commercial sale.

Kristi O'Malley,

Assistant Administrator.

[FR Doc. 2022–13248 Filed 6–17–22; 8:45 am]

BILLING CODE P

DEPARTMENT OF JUSTICE

Notice of Lodging of Proposed Stipulation and Order of Settlement Under the Federal Insecticide, Fungicide, and Rodenticide Act

On June 13, 2022, the Department of Justice lodged a proposed Stipulation and Order of Settlement (''settlement'') with the District Court of the Southern District of New York in a lawsuit entitled *Tzumi Innovations, LLC* v. *Regan, et al.,* Civil Action No. 21–122.

In a counterclaim in this action, the United States seeks, as provided under the Federal Insecticide, Fungicide, and Rodenticide Act (''FIFRA''), a civil penalty and injunctive relief from Tzumi Innovations, LLC (''Tzumi'') in connection with Tzumi's distribution and sale of unregistered pesticides pursuant to FIFRA § 12(a)(1)(A), 7 U.S.C. 136j(a)(1)(A). The proposed settlement resolves the United States' counterclaim, requires Tzumi to pay $1.5 million, and imposes injunctive relief. It also resolves Tzumi's claims against the Environmental Protection Agency in the litigation.

The publication of this notice opens the public comment on the proposed settlement. Comments should be addressed to the Assistant Attorney General, Environment and Natural Resources Division, and should refer to *Tzumi Innovations, LLC* v. *Regan,* D.J. # 1–12610. All comments must be submitted no later than 30 days after the publication date of this notice. Comments may be submitted either by email or by mail:

To submit comments:	*Send them to:*
By email	*pubcomment-ees.enrd@usdoj.gov.*
By mail	Assistant Attorney General, U.S. DOJ—ENRD, P.O. Box 7611, Washington, DC 20044–7611.

During the public comment period, the settlement may be examined and downloaded at this Justice Department website: *http://www.usdoj.gov/enrd/Consent_Decrees.html.* We will provide a paper copy of the settlement upon written request and payment of reproduction costs. Please email your request and payment to: Consent Decree Library, U.S. DOJ—ENRD, P.O. Box 7611, Washington, DC 20044–7611.

Please enclose a check or money order for $6.50 (25 cents per page reproduction cost) payable to the United States Treasury.

Henry S. Friedman,

Assistant Section Chief, Environmental Enforcement Section, Environment and Natural Resources Division.

[FR Doc. 2022–13167 Filed 6–17–22; 8:45 am]

BILLING CODE 4410–15–P

DEPARTMENT OF LABOR

Agency Information Collection Activities; OSHA Strategic Partnership Program (OSSP) for Worker Safety and Health

ACTION: Notice of availability; request for comments.

SUMMARY: The Department of Labor (DOL) is submitting this Occupational Safety & Health Administration (OSHA)-sponsored information collection request (ICR) to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995 (PRA). Public comments on the ICR are invited.

DATES: The OMB will consider all written comments that the agency receives on or before July 21, 2022.

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.

Comments are invited on: (1) whether the collection of information is necessary for the proper performance of the functions of the Department, including whether the information will have practical utility; (2) the accuracy of the agency's estimates 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; 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.

FOR FURTHER INFORMATION CONTACT: Nicole Bouchet by telephone at 202–693–0213, or by email at *DOL_PRA_PUBLIC@dol.gov.*

SUPPLEMENTARY INFORMATION: The Occupational Safety and Health Act of 1970 (OSH Act) (29 U.S.C. 651 *et seq.*) authorizes information collection by employers as necessary or appropriate for enforcement of the OSH Act or for developing information regarding the causes and prevention of occupational injuries, illnesses, and accidents (29 U.S.C. 657). The OSH Act also requires that OSHA obtain such information with a minimum burden upon employers, especially those operating small businesses, and to reduce to the maximum extent feasible unnecessary duplication of efforts in obtaining said information (29 U.S.C. 657). The OSPP allows OSHA to enter into an extended, voluntary, cooperative relationship with groups of employers, employees, and representatives (sometimes including other stakeholders, and sometimes involving only one employer) to encourage, assist, and recognize their efforts to eliminate serious hazards and to achieve a high level of worker safety and health that goes beyond what historically has been achieved from traditional enforcement methods. Each OSHA Strategic Partnership (OSP) determines what information will be needed, determining the best collection method, and clarifying how the information will be used. At a minimum, each OSP must identify baseline injury and illness data corresponding to all summary line items on the OSHA 300 logs and must track changes at either the worksite level or participant-aggregate level. An OSP may also include other measures of success, such as training activity, self-inspections, and/or workers' compensation data. In this regard, the information collection requirements for the OSPP are used by the agency to gauge the effectiveness of programs, identify needed improvements, and ensure that resources are being used effectively and appropriately. For additional substantive information about this ICR, see the related notice published in the **Federal Register** on March 7, 2022 (87 FR 12735).

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 the OMB approves it and 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 OMB Control Number. *See* 5 CFR 1320.5(a) and 1320.6.

DOL seeks PRA authorization for this information collection for three (3) years. OMB authorization for an ICR cannot be for more than three (3) years without renewal. The DOL notes that information collection requirements submitted to the OMB for existing ICRs receive a month-to-month extension while they undergo review.

Agency: DOL–OSHA.

Title of Collection: OSHA Strategic Partnership Program (OSSP) for Worker Safety and Health.

OMB Control Number: 1218–0244.

Affected Public: Private Sector—Businesses or other for-profits.

Total Estimated Number of Respondents: 104.

Total Estimated Number of Responses: 3,040.

Total Estimated Annual Time Burden: 18,480 hours.

Total Estimated Annual Other Costs Burden: $0.

(Authority: 44 U.S.C. 3507(a)(1)(D))

Nicole Bouchet,

Senior PRA Analyst.

[FR Doc. 2022–13197 Filed 6–17–22; 8:45 am]

BILLING CODE 4510–26–P

NATIONAL ARCHIVES AND RECORDS ADMINISTRATION

[NARA–2022–055]

Office of Government Information Services Annual Meeting

AGENCY: Office of Government Information Services (OGIS), National Archives and Records Administration (NARA).

ACTION: Notice of annual open meeting.

SUMMARY: We are announcing OGIS's annual meeting, open to the public in accordance with the Freedom of Information Act (FOIA). The purpose of the meeting is to discuss OGIS's reviews and reports and allow interested people to appear and present oral or written statements.

DATES: The meeting will be on Wednesday, June 29, 2022, from 10:00 a.m. to 12:00 p.m. EDT. You must register by 11:59 p.m. EDT Monday, June 27, 2022, to attend the meeting.

ADDRESSES: This meeting will be a virtual meeting. We will send instructions on how to access it to those who register according to the instructions below.

FOR FURTHER INFORMATION CONTACT: Martha Murphy by email at *ogisopenmeeting@nara.gov* or by telephone at 202.741.5770.

SUPPLEMENTARY INFORMATION: This meeting is open to the public in accordance with FOIA provisions at 5 U.S.C. 552(h)(6). We will post all meeting materials at *https://www.archives.gov/ogis/outreach-events/annual-open-meeting.* OGIS's 2022 Report for Fiscal Year 2021 was posted on May 26, 2022, at *https://www.archives.gov/files/ogis/reports/ogis-2022-annual-report-final.pdf.* The report summarizes OGIS's work, in accordance with FOIA provisions at 5 U.S.C. 552(h)(4)(A). We will also hold two panel discussions—the first panel will discuss Estimated Dates of Completion (EDCs), and the second panel will discuss the Final Report and Recommendations of the 2020–2022 term of the FOIA Advisory Committee. You may submit extensive written statements or comments for OGIS to consider by emailing *ogisopenmeeting@nara.gov.* You may also submit written comments during the meeting either via Webex or NARA YouTube chat functions. We will not address individual OGIS cases or specific FOIA requests. If you are interested in presenting oral statements at the meeting you must register in advance via the Eventbrite link below. Each individual will be limited to three minutes each.

Procedures: This virtual meeting is open to the public. You must register in advance through the Eventbrite link *https://ogis-annual-open-mtg.eventbrite.com,* if you wish to attend, and you must include an email address so that we can send you access information. To request accommodations (*e.g.,* a transcript), email *ogis@nara.gov* or call 202.741.5770. Members of the media who wish to register, those who are unable to register online, and those who require special accommodations, should contact Martha Murphy (contact information listed above).

Alina M. Semo,

Office of Government Information Services Director.

[FR Doc. 2022–13177 Filed 6–17–22; 8:45 am]

BILLING CODE 7515–01–P

NATIONAL FOUNDATION ON THE ARTS AND THE HUMANITIES

Institute of Museum and Library Services

Submission for OMB Review, Comment Request, Proposed Collection: IMLS Evaluation of Four Grant Programs Serving Native American, Native Hawaiian, and Alaska Native Communities

AGENCY: Institute of Museum and Library Services, National Foundation on the Arts and the Humanities.

ACTION: Submission for OMB Review, request for comments, collection of information.

SUMMARY: The Institute of Museum and Library Services announces that the following information collection has been submitted to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act. This program helps to ensure that requested data can be provided in the desired format, reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and the impact of collection requirements on respondents can be properly assessed. This Notice proposes the clearance of the IMLS Evaluation of Four Grant Programs Serving Native American, Native Hawaiian, and Alaska Native Communities. A copy of the proposed information collection request can be obtained by contacting the individual listed below in the **FOR FURTHER INFORMATION CONTACT** section of this Notice.

DATES: Written comments must be submitted to the office listed in the **ADDRESSES** section below on or before July 20, 2022.

ADDRESSES: Written comments and recommendations for proposed information collection requests should be sent within 30 days of publication of this Notice to *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection request by selecting ''Institute of Museum and Library Services'' under ''Currently Under Review;'' then check the ''Only Show ICR for Public Comment'' checkbox. Once you have found this information collection request, select ''Comment,'' and enter or upload your comment and information. Alternatively, please mail your written comments to the Office of Information and Regulatory Affairs, Attn.: OMB Desk Officer for Education, Office of Management and Budget, Room 10235, Washington, DC 20503, or call (202) 395–7316.

OMB is particularly interested in comments that help the agency to:

• 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).

FOR FURTHER INFORMATION CONTACT: Matthew Birnbaum, Ph.D., Supervising Social Scientist, Office of Research and Evaluation, Institute of Museum and Library Services, 955 L'Enfant Plaza North SW, Suite 4000, Washington, DC 20024–2135. Dr. Birnbaum can be reached by telephone at 202–653–4760, or by email at *mbirnbaum@imls.gov.* Persons who are deaf or hard of hearing (TTY users) can contact IMLS at 202–207–7858 via 711 for TTY-Based Telecommunications Relay Service.

SUPPLEMENTARY INFORMATION: The Institute of Museum and Library Services is the primary source of federal support for the nation's libraries and museums. We advance, support, and empower America's museums, libraries, and related organizations through grantmaking, research, and policy development. To learn more, visit *www.imls.gov.*

Current Actions: This Notice proposes the clearance of the IMLS Evaluation of Four Grant Programs Serving Native American, Native Hawaiian, and Alaska Native Communities. The 60-day Notice was published in the **Federal Register** on January 14, 2022 (87 FR 2464–2465). No public comments were received under this Notice.

IMLS has four active grant programs designed to serve Native American, Native Hawaiian, and Alaska Native communities: the Native American Library Services: Basic Grants; Native American Library Services: Enhancement Grants; Native American/ Native Hawaiian Museum Services; and Native Hawaiian Library Services. The purpose of this evaluation is to determine how well the agency's grantmaking aligns with the needs of communities served by these specific programs; lay a foundation for improving the quality, reach, and impact of the agency's grant programs in the future; and inform increasing organizational capacity of eligible applicants to submit high-quality grant applications and of awardees to complete their award responsibilities successfully.

The evaluation will focus on the experiences of those who have prepared and submitted applications and those who have received awards through each of the four IMLS programs. It will also aim to determine whether such experiences differed before and during the COVID–19 pandemic. The specific primary information collection activities are:

1. semi-structured interviews with grantees, unsuccessful applicants, eligible non-applicants, service and intertribal organizations, funders, tribal leadership, and IMLS staff,

2. a survey of grantees and eligible non-applicants, and

3. a virtual convening of grantees, unsuccessful applicants, and eligible non-applicants using an appreciative inquiry model and a benefits-based, semi-structured discussion format.

This qualitative information collection will be coupled with a secondary analysis of publicly available information and IMLS administrative data relating to applications, awarded grants, and information extracted from grantees' interim and final performance reports.

IMLS will use the evaluation findings to establish a foundation for improving the quality, reach, and impact of the agency's grant programs in the future. IMLS will publicly post the final evaluation report on imls.gov and host at least one public virtual meeting to share and invite discussion of the findings.

Agency: Institute of Museum and Library Services.

Title: IMLS Evaluation of Four Grant Programs Serving Native American, Native Hawaiian, and Alaska Native Communities.

OMB Control Number: 3137–NEW.

Agency Number: 3137.

Affected Public: Museum and library professionals working at organizations that have sought or would like to seek public funding through IMLS's grant programs serving Native American, Native Hawaiian, and Alaska Native communities; individuals representing service and intertribal organizations; community leaders; and individuals working in public and private funding organizations.

Total Number of Respondents: 418.

Frequency of Response: Once per request.

Average Hours per Response: 0.64.

Total Burden Hours: 262.5.

Total Annualized Capital/Startup Costs: n/a.

Total Annual Cost Burden: $8,991.05.

Total Annual Federal Costs: $10,216.46.

Dated: June 15, 2022.

Suzanne Mbollo,

Grants Management Specialist, Institute of Museum and Library Services.

[FR Doc. 2022–13188 Filed 6–17–22; 8:45 am]

BILLING CODE 7036–01–P

NATIONAL FOUNDATION ON THE ARTS AND THE HUMANITIES

National Endowment for the Humanities

Meeting of Humanities Panel

AGENCY: National Endowment for the Humanities; National Foundation on the Arts and the Humanities.

ACTION: Notice of meeting.

SUMMARY: The National Endowment for the Humanities (NEH) will hold twenty-three meetings, by videoconference, of the Humanities Panel, a federal advisory committee, during June and July 2022. The purpose of the meetings is for panel review, discussion, evaluation, and recommendation of applications for financial assistance under the National Foundation on the Arts and the Humanities Act of 1965.

DATES: See **SUPPLEMENTARY INFORMATION** for meeting dates. The meetings will open at 8:30 a.m. and will adjourn by 5:00 p.m. on the dates specified below.

FOR FURTHER INFORMATION CONTACT: Elizabeth Voyatzis, Committee Management Officer, 400 7th Street SW, Room 4060, Washington, DC 20506; (202) 606–8322; *evoyatzis@neh.gov.*

SUPPLEMENTARY INFORMATION: Pursuant to section 10(a)(2) of the Federal Advisory Committee Act (5 U.S.C. App.), notice is hereby given of the following meetings:

1. Date: June 21, 2022

This video meeting will discuss applications on the topics of History and Social Sciences, for the NEH-Mellon Fellowships for Digital Publication program, submitted to the Division of Research Programs.

2. Date: June 23, 2022

This video meeting will discuss applications on the topics of Literature and the Arts, for the NEH-Mellon Fellowships for Digital Publication program, submitted to the Division of Research Programs.

3. Date: July 11, 2022

This video meeting will discuss applications on the topics of History and Culture, for the Infrastructure and Capacity Building Challenge Grants program, submitted to the Office of Challenge Programs.

4. Date: July 12, 2022

This video meeting will discuss applications on the topic of Museums, for the Infrastructure and Capacity Building Challenge Grants program, submitted to the Office of Challenge Programs.

5. Date: July 13, 2022

This video meeting will discuss applications on the topics of History and Culture, for the Infrastructure and Capacity Building Challenge Grants program, submitted to the Office of Challenge Programs.

6. Date: July 18, 2022

This video meeting will discuss applications on the topic of Digital Infrastructure, for the Infrastructure and Capacity Building Challenge Grants program, submitted to the Office of Challenge Programs.

7. Date: July 19, 2022

This video meeting will discuss applications on the topic of Higher Education, for the Infrastructure and Capacity Building Challenge Grants program, submitted to the Office of Challenge Programs.

8. Date: July 20, 2022

This video meeting will discuss applications on the topics of Philosophy and Religion, for the Awards for Faculty program, submitted to Division of Research Programs.

9. Date: July 20, 2022

This video meeting will discuss applications on the topics of American Literature, Language, and Studies, for the Awards for Faculty program, submitted to the Division of Research Programs.

10. Date: July 21, 2022

This video meeting will discuss applications on the topic of Arts, for the Awards for Faculty program, submitted to the Division of Research Programs.

11. Date: July 21, 2022

This video meeting will discuss applications on the topics of Literature and Cultural Studies, for the Awards for Faculty program, submitted to the Division of Research Programs.

12. Date: July 22, 2022

This video meeting will discuss applications on the topics of World History and Studies, for the Awards for Faculty program, submitted to the Division of Research Programs.

13. Date: July 22, 2022

This video meeting will discuss applications on the topics of American History and Studies, for the Awards for Faculty program, submitted to the Division of Research Programs.

14. Date: July 22, 2022

This video meeting will discuss applications on the topic of Museums, for the Infrastructure and Capacity Building Challenge Grants program, submitted to the Office of Challenge Programs.

15. Date: July 25, 2022

This video meeting will discuss applications on the topics of Humanities, Media, and Social Sciences, for the Awards for Faculty program, submitted to the Division of Research Programs.

16. Date: July 25, 2022

This video meeting will discuss applications for the Fellowships for Advanced Social Science Research on Japan program, submitted to the Division of Research Programs.

17. Date: July 26, 2022

This video meeting will discuss applications on the topic of U.S. History, for the Fellowships program, submitted to the Division of Research Programs.

18. Date: July 27, 2022

This video meeting will discuss applications on the topics of Music, Dance, and American Studies, for the Fellowships program, submitted to the Division of Research Programs.

19. Date: July 27, 2022

This video meeting will discuss applications on the topics of Anthropology and Social Sciences, for the Fellowships program, submitted to the Division of Research Programs.

20. Date: July 28, 2022

This video meeting will discuss applications on the topics of Latin American Studies and Latina/o Studies, for the Fellowships program, submitted to the Division of Research Programs.

21. Date: July 28, 2022

This video meeting will discuss applications on the topics of European and Comparative Literature and Studies, for the Fellowships program, submitted to the Division of Research Programs.

22. Date: July 28, 2022

This video meeting will discuss applications on the topics of Collection Care and Preservation Training, for the Preservation and Access Education and Training grant program, submitted to the Division of Preservation and Access.

23. Date: July 29, 2022

This video meeting will discuss applications on the topics of Art History and Film Studies, for the Fellowships grant program, submitted to the Division of Research Programs.

Because these meetings will include review of personal and/or proprietary financial and commercial information given in confidence to the agency by grant applicants, the meetings will be closed to the public pursuant to sections 552b(c)(4) and 552b(c)(6) of Title 5, U.S.C., as amended. I have made this determination pursuant to the authority granted me by the Chairman's Delegation of Authority to Close Advisory Committee Meetings dated April 15, 2016.

Dated: June 15, 2022.

Samuel Roth,

Attorney-Advisor, National Endowment for the Humanities.

[FR Doc. 2022–13228 Filed 6–17–22; 8:45 am]

BILLING CODE 7536–01–P

NATIONAL SCIENCE FOUNDATION

Advisory Committee for International Science and Engineering Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation (NSF) announces the following meeting:

Name and Committee Code: Advisory Committee for International Science and Engineering (#25104).

Date and Time: July 11, 2022, 10:00 a.m.–3:00 p.m. (Eastern Time).

Place: NSF, 2415 Eisenhower Avenue, Alexandria, VA 22314/Virtual.

Connect to the Virtual Meeting: To attend the AC–ISE virtual meeting, all visitors must process the meeting registration via Zoom:

Register in advance for the meeting at the Zoom attendee registration link: *https://nsf.zoomgov.com/webinar/register/WN_055Jp5i2RUyXryCFid6wpw.* After registering, you will receive a confirmation email with a unique link to join the meeting.

If you have any login questions, please contact Kirk Grabowski, OISE IT Specialist: *kgrabows@associates.nsf.gov.*

Type of Meeting: Open.

Contact Person: Christopher Street, National Science Foundation, 2415 Eisenhower Avenue, Alexandria, VA 22314. Email: *cstreet@nsf.gov.*

Purpose of Meeting: To provide advice, recommendations and counsel on major goals and policies pertaining to engineering programs and activities.

Agenda

- Updates on OISE activities
- Review of OISE Programs & Broadening Diversity of Institutions
- Review of Diplomatic Activities
- Meet with NSF leadership

Dated: June 14, 2022.

Crystal Robinson,

Committee Management Officer.

[FR Doc. 2022–13144 Filed 6–17–22; 8:45 am]

BILLING CODE 7555–01–P

OFFICE OF PERSONNEL MANAGEMENT

Privacy Act of 1974; System of Records

AGENCY: Office of Personnel Management.

ACTION: Notice of new system of records.

SUMMARY: In accordance with the Privacy Act of 1974, the Office of Personnel Management (OPM) proposes to establish a new system of records titled ''OPM/Central-26, FEDVIP, FLTCIP, and FSAFEDS Records.'' This system of records contains information about individuals and their family members who have applied for, are enrolled in, or have been enrolled in any of three benefit programs administered by OPM: the Federal Employees Dental and Vision Insurance Program (FEDVIP), the Federal Long Term Care Insurance Program (FLTCIP), and the Federal Flexible Spending Account Program (FSAFEDS). This newly established system of records will be included in OPM's inventory of record systems.

DATES: Please submit comments on or before July 21, 2022. This new system is effective upon publication in the **Federal Register**, with the exception of the routine uses, which become effective July 26, 2022.

ADDRESSES: You may submit written comments by the following method:

Federal Rulemaking Portal (https://www.regulations.gov): Follow the instructions for submitting comments. All submissions received must include the agency name and docket number 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 at *https://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

FOR FURTHER INFORMATION CONTACT: For general questions, please contact Dyan Dyttmer, 202–606–1412. For privacy questions, please contact Kellie Cosgrove Riley, Chief Privacy Officer, 202–360–6065.

SUPPLEMENTARY INFORMATION: In accordance with the Privacy Act of 1974, 5 U.S.C. 552a, the Office of Personnel Management proposes to establish a new system of records titled ''OPM/Central-26, FEDVIP, FLTCIP, and FSAFEDS Records.'' This system of records is being established to support OPM's administration of the Federal Employees Dental and Vision Insurance Program (FEDVIP), the Federal Long Term Care Insurance Program (FLTCIP), and the Federal Flexible Spending Account Program (FSAFEDS) and will contain information about individuals and their family members who have applied for, are covered under, or have been covered under one or more of these programs. The primary purpose of this system of records is to support the administration of these three programs, including enrollment confirmation, enrollment transactions, and premium/allotment processing and reconciliation, as well as to evaluate the effectiveness of these programs through statistical analysis, policy planning, and reporting.

FEDVIP is the Federal program that provides dental and vision insurance to eligible individuals, including Federal and United States Postal Service employees and annuitants, employees of the District of Columbia courts, miscellaneous groups enumerated at 5 U.S.C. 8901(1), retired members of the uniformed services, survivors of uniformed service members, and their eligible family members (dental and vision), family members of active duty uniformed services members, and reserve members of the uniformed services and their eligible family members (vision only). Under certain circumstances, a family member of a sponsor[1] may enroll in FEDVIP even though the sponsor is not an enrollee. In these circumstances where the sponsor is not an enrollee, the TRICARE Eligible Individual (TEI) family member may accept responsibility as ''TEI certifying family member'' to self-certify as an enrollee. Individuals eligible for FEDVIP enroll voluntarily for dental and/or vision insurance. Eligible individuals pay 100 percent of the premium for the plan they select. Individuals have the opportunity to enroll upon entry on duty and the opportunity to enroll or change enrollment during the annual Federal Benefits Open Season or upon experiencing a qualifying life event (QLE), such as marriage or the birth of a child. Individuals eligible for FEDVIP enroll using a secure enrollment website operated by an OPM contractor.

FLTCIP is the Federal program that provides group long-term care insurance to eligible Federal and United States Postal Service employees and annuitants, active and retired members of the uniformed services, and their qualified relatives. Individuals eligible for FLTCIP pay 100 percent of the premium for the plan they select. Eligible individuals may apply at any time by completing a full underwriting application. There is no regular open season for FLTCIP enrollment. Individuals eligible for FLTCIP may apply by accessing information and application materials from a website operated by an OPM contractor and submitting an application to this contractor.

FSAFEDS is the Federal program that permits employees of the Executive Branch of the Federal Government, the United States Postal Service, and the other adopting employers of the Federal Flexible Benefits Plan (''FedFlex'') to set aside pre-tax earnings to pay for eligible health care expenses with a Health Care or Limited Expense Health Care Flexible Spending Account (FSA or LEXFSA) and to pay for eligible child care or elder care expenses with a Dependent Care FSA. Individuals have the opportunity to enroll upon entry on duty, during the annual Federal Benefits Open Season and have the opportunity to enroll or change enrollment upon experiencing a QLE, such as marriage or the birth of a child. Individuals eligible for FSAFEDS enroll using a secure

[1] Under 5 CFR 894.101, a sponsor is defined as the individual who is eligible for medical or dental benefits under 10 U.S.C. chapter 55 based on his or her direct affiliation with the uniformed services (including members of the National Guard and Reserves), in accordance with § 894.804. The relationship to a sponsor conveys TEI status to a TEI family member.

enrollment website operated by an OPM contractor.

OPM uses several contractors to assist in the administration of these programs. One contractor operates BENEFEDS, an enrollment and premium processing portal (*www.BENEFEDS.com* and a toll-free number). BENEFEDS administers enrollment and premium payment processes for FEDVIP, administers premium payment processes for FLTCIP, and administers allotment collection for FSAFEDS. BENEFEDS is also responsible for processing billing, payment, and reconciliation tasks for these three programs. BENEFEDS communicates enrollment information directly to FEDVIP Carriers contracting with OPM to provide dental and vision insurance. BENEFEDS also communicates enrollment information to various Federal civilian and military payroll systems, OPM Retirement Services (RS), and other retirement systems for premium/allotment processing. BENEFEDS also communicates with Federal agencies, OPM RS, and other retirement systems to confirm enrollment.

OPM also uses a contractor to administer FLTCIP, including enrollment, underwriting, long-term claims processing, and maintenance of the program website (*www.LTCFEDS.com* and a toll-free number). OPM uses another contractor to operate the enrollment and claims processing website for FSAFEDS (*www.FSAFEDS.com* and a toll-free number).

The records contained in this new system of records to date have been included in OPM/Central-1, Civil Service Retirement and Insurance Records system of records (OPM/Central-1). However, OPM's organizational structure and its retirement and insurance programs have evolved, and OPM has determined that OPM/Central-1 no longer provides the public with clear and informative notice regarding the system of records, nor adequately facilitates individuals' ability to exercise their rights under the Privacy Act and OPM's ability to respond effectively.

Accordingly, OPM is in the process of regrouping the records currently contained in OPM/Central-1 and publishing the corresponding system of records notices. Additional system of records notices related to other record sets currently encompassed in OPM/Central-1 have been published or will be published separately.

FEDVIP, FLTCIP, and FSAFEDS records will now be governed through the system of records known as ''OPM/CENTRAL-26 FEDVIP, FLTCIP, and FSAFEDS Records.'' This newly established system of records will be included in OPM's inventory of records systems. In accordance with 5 U.S.C. 552a(r), OPM has provided a report of this system of records to Congress and to the Office of Management and Budget.

Office of Personnel Management.

Stephen Hickman,

Federal Register Liaison.

System Name and Number:

FEDVIP, FLTCIP, and FSAFEDS Records, OPM/Central-26.

SECURITY CLASSIFICATION:

Unclassified.

SYSTEM LOCATION:

Healthcare and Insurance, Office of Personnel Management, 1900 E Street NW, Washington, DC 20415, is responsible for this system of records. Records are maintained by OPM contractors in various locations. FLTCIP and FEDVIP records are maintained by a contractor in Portsmouth, New Hampshire, and FSAFEDS records are maintained by a contractor in Lexington, Kentucky.

SYSTEM MANAGER(S):

Associate Director, Healthcare and Insurance, Office of Personnel Management, 1900 E Street NW, Washington, DC 20415.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

FEDVIP and FLTCIP are authorized by 5 U.S.C. Chapter 89A, Enhanced Dental Benefits; 5 U.S.C. Chapter 89B, Enhanced Vision Benefits; and 5 U.S.C. Chapter 90, Long Term Care Insurance. FSAFEDS is operated in accordance with the Federal Flexible Benefits Plan (''FedFlex''), which qualifies as a ''cafeteria plan'' under Section 125 of the Internal Revenue Code of 1986, as amended, and corresponding regulations.

PURPOSE(S) OF THE SYSTEM:

The primary purpose of this system of records is to support the administration, including enrollment confirmation, enrollment transactions, premium/allotment processing, and reconciliation, for three benefits programs administered by OPM: the Federal Employees Dental and Vision Insurance Program (FEDVIP), the Federal Long Term Care Insurance Program (FLTCIP), and the Federal Flexible Spending Account Program (FSAFEDS). In addition, the records in this system of records are used to support the evaluation of the effectiveness of these programs, including statistical analysis, policy planning, reporting, and enrollee inquiries.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

Enrollees and their family members who are covered or have been covered under FEDVIP; applied, are covered or have been covered under FLTCIP; and individuals who are participating in or who have participated in FSAFEDS.

Individuals eligible to enroll in FEDVIP include: Federal and United States Postal Service employees and annuitants, employees of the District of Columbia courts, various groups enumerated at 5 U.S.C. 8901(1), retired members of the uniformed services, survivors of uniformed services members, and eligible family members (dental and vision); family members of active duty uniformed services members, and reserve members of the uniformed services and their eligible family members (vision only).

Individuals eligible to apply and enroll in FLTCIP include: Federal and United States Postal Service employees and annuitants, active and retired members of the uniformed services, and their qualified relatives.

Individuals eligible to participate in FSAFEDS include employees of the Executive Branch of the Federal Government, the United States Postal Service, and the other adopting employers of FedFlex.

CATEGORIES OF RECORDS IN THE SYSTEM:

a. Name, including any former names;

b. Social Security number (SSN) or other unique identification number(s);

c. Date of birth;

d. Gender;

e. Home address;

f. Work address;

g. Marital status;

h. Email address;

i. Telephone number;

j. Enrollee's employing agency;

k. Enrollee's payroll office number;

l. Enrollee's/Sponsor's Uniformed Services branch;

m. Enrollee's/Sponsor's date of death;

n. Effective date of plan coverage;

o. Medicare status (and Medicare Beneficiary Identifier) of the enrollee and any eligible family members;

p. Medicaid status of the enrollee and any eligible family members;

q. Information about other health insurance, including a plan through the Federal Employees Health Benefits (FEHB) Program, covering the enrollee and any eligible family members;

r. Information about other long-term care insurance policies in force;

s. Medical information and medical records;

t. FEDVIP plan and plan type, *e.g.,* Self, Self Plus One, or Self and Family;

u. Health and dependent care claims information;

v. FLTCIP beneficiary information;

w. Dependent relationship to Sponsor;

x. Dependent eligibility date and eligibility end date;

y. Dependent student indicator/incapable of self-support indicator;

z. Payroll or banking information;

aa. Information necessary to verify family member eligibility including but not limited to marriage certificates, birth certificates, and other information as set forth in OPM guidance;

bb. Power of attorney designation; and

cc. Any other record related to the enrollment and account administration of eligible individuals in FEDVIP, FLTCIP, or FSAFEDS.

RECORD SOURCE CATEGORIES:

Records are obtained directly from enrollees during the enrollment process in FEDVIP and the application process in FLTCIP and directly from participants during the enrollment process in FSAFEDS. Records are also obtained from health care practitioners and health care facilities as part of the administration of FLTCIP. For purposes of enrollment confirmation and reconciliation, records are obtained from Federal agencies, OPM Retirement Services (RS), other retirement systems, FEDVIP Carriers, and the FLTCIP Carrier. For purposes of flexible spending claims processing, records are also obtained from FEDVIP and FEHB carriers.

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 OPM 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) OPM, or any component thereof;

(2) Any employee or former employee of OPM in his or her official capacity;

(3) Any employee or former employee of OPM in his or her individual capacity where the Department of Justice or OPM 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 OPM 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) OPM suspects or has confirmed that there has been a breach of the system of records; (2) OPM has determined that as a result of the suspected or confirmed breach, there is a risk of harm to individuals, OPM (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 OPM'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 OPM 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 OPM when OPM 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 OPM employees.

h. To FEDVIP Carriers and the FLTCIP Carrier, information necessary to identify enrollment in a plan, change existing enrollments, cancel, and terminate enrollments, reconcile enrollment, and correct enrollment discrepancies.

i. To BENEFEDS, the enrollment information necessary for the purpose of premium processing for FEDVIP and FLTCIP and allotment processing for FSAFEDS.

j. To FSAFEDS, the claims information necessary to administer paperless reimbursement for those participants who have elected this option.

k. To any source from which information is requested, including Federal agencies and retirement systems, to establish an individual's eligibility for or enrollment in FEDVIP, FLTCIP, or FSAFEDS.

l. To Federal civilian and military payroll providers and retirement systems, the information necessary for FEDVIP and FLTCIP premium collection and for FSAFEDS allotment collection.

m. To an official of another Federal agency, uniformed services branch, or retirement system, the information needed to perform official duties related to employee benefits counseling, customer service, or operational readiness.

n. To an official of another Federal agency, information needed in the performance of official duties related to reconciling or reconstructing data files; compiling descriptive statistics; and/or making analytical studies to support the function for which the records were collected and maintained.

o. To an official of another Federal agency, information needed to adjudicate a claim for benefits under FEDVIP or the recipient's benefits program(s).

POLICIES AND PRACTICES FOR STORAGE OF RECORDS:

The records in this system of records are stored electronically. Access to the electronic systems is restricted to authorized users with a need to know. The backends of the FEDVIP, FLTICIP and FSAFEDS systems are databases hosted in a secure network environment. Any paper records received are imaged, stored electronically, and securely shredded.

POLICIES AND PRACTICES FOR RETRIEVAL OF RECORDS:

The records in this system of records are retrieved primarily by name and Social Security number but may be retrieved by any personal identifier.

POLICIES AND PRACTICES FOR RETENTION AND DISPOSAL OF RECORDS:

OPM contractors retain records for a time period no less than that described in their individual contracts. OPM is in the process of establishing a records schedule with the National Archives and Records Administration for the records in this system of records and other OPM Healthcare and Insurance records.

Until a records retention schedule is in place, records will be treated as permanent. Once that schedule is established, the method(s) for disposing of records that are no longer eligible for retention will be determined and implemented.

ADMINISTRATIVE, TECHNICAL, AND PHYSICAL SAFEGUARDS:

Records in this system are protected from unauthorized access and misuse through various administrative, technical, and physical security measures. The security measures utilized by OPM and OPM's contractors are in compliance with the Federal Information Security Modernization Act (Pub L. 113–203), associated OMB policies, and applicable standards and guidance from the National Institute of Standards and Technology (NIST).

RECORD ACCESS PROCEDURES:

Individuals seeking notification of and access to their records in this system of records may do so as follows:

a. In some circumstances, individuals may be able to locate and access their records directly through the secure websites maintained by or the customer service assistance offered by the OPM contractors operating the enrollment systems for FEDVIP, FLTCIP, and FSAFEDS.

b. Individuals may also submit a request in writing to the Office of Personnel Management, Office of Privacy and Information Management—FOIA, 1900 E Street NW, Room 5415, Washington, DC 20415–7900 or by emailing *foia@opm.gov*; ATTN: Healthcare and Insurance. Individuals must furnish the following information for their records to be located:

1. Full name, including any former name.
2. Date of birth.
3. Social Security number.
4. Name and address of employing agency, uniformed services branch, or retirement system.
5. Reasonable specification of the requested information.
6. The address to which the information should be sent.
7. Signature.

Individuals requesting access must also comply with OPM's Privacy Act regulations regarding verification of identity and access to records (5 CFR 297). Enrollees who request access to their records will have access to the entirety of their record, to include information about all covered individuals who are part of their enrollment record. Family members who request access to their records may have access only to their own information and not to that of the enrollee or other covered family members.

CONTESTING RECORD PROCEDURES:

Individuals wishing to request amendment of their records in this system of records may do so by writing to the to the Office of Personnel Management, Office of Privacy and Information Management—FOIA, 1900 E Street NW, Room 5415, Washington, DC 20415–7900 or by emailing *foia@opm.gov*; ATTN: Healthcare and Insurance. Requests for amendment of records should include the words ''PRIVACY ACT AMENDMENT REQUEST'' in capital letters at the top of the request letter; if emailed, please include those words in the subject line. Individuals must furnish the following information for their records to be located:

1. Full name, including any former name.
2. Date of birth.
3. Social Security number.
4. Name and address of employing agency, uniformed services branch, or retirement system.
5. Precise identification of the information to be amended.
7. Signature.

Individuals requesting amendment of their records must also comply with OPM's Privacy Act regulations regarding verification of identity and access to records (5 CFR 297). OPM may refer amendment requests to other entities when those entities are the original source of the record.

NOTIFICATION PROCEDURES:

See ''Record Access Procedures''

EXEMPTIONS PROMULGATED FOR THE SYSTEM:

None.

HISTORY:

OPM/Central-1, ''Civil Service Retirement and Insurance Records'', 73 FR 15013 (March 20, 2008), 80 FR 74815 (November 30, 2015).

[FR Doc. 2022–13216 Filed 6–17–22; 8:45 am]

BILLING CODE 6325–64–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–95104; File No. SR–ICEEU–2022–012]

Self-Regulatory Organizations; ICE Clear Europe Limited; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to Amendments to Part H of the ICE Clear Europe Delivery Procedures

June 14, 2022.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on June 9, 2022, ICE Clear Europe Limited (''ICE Clear Europe'' or the ''Clearing House'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule changes described in Items I, II, and III below, which Items have been prepared primarily by ICE Clear Europe. ICE Clear Europe filed the proposed rule change pursuant to Section 19(b)(3)(A) of the Act[3] and Rule 19b–4(f)(4)(ii) thereunder,[4] such that the proposed rule change was immediately effective upon filing with the Commission. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Clearing Agency's Statement of the Terms of Substance of the Proposed Rule Change

ICE Clear Europe Limited (''ICE Clear Europe'' or the ''Clearing House'') proposes to amend Part H of its Delivery Procedures (''Delivery Procedures'' or ''Procedures'') to correct a drafting inconsistency.

II. Clearing Agency's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, ICE Clear Europe included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. ICE Clear Europe has prepared summaries, set forth in sections (A), (B), and (C)

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78s(b)(3)(A).

[4] 17 CFR 240.19b–4(f)(4)(ii).

below, of the most significant aspects of such statements.

(A) Clearing Agency's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

(a) Purpose

ICE Clear Europe is proposing to amend Part H of the Delivery Procedures, which addresses delivery under the monthly ICE Endex German THE Natural Gas futures contract (''Monthly Contract''), and daily futures contract with respect to the same underlying commodity (''Daily Contract'') to correct an inconsistency in the delivery timetable for routine deliveries of Daily Contracts. Currently, the delivery timetable in Section 5.2 provides that for Daily Contracts Exchange for Physicals (''EFPs'') and Exchange for Swaps (''EFSs'') may be posted up to one hour following the cessation of trading. This is inconsistent with existing Section 2.6, which provides that with respect to Daily Contracts, EFPs and EFSs may be posted up to thirty minutes following the cessation of trading. The proposed amendment would change the delivery timetable to be consistent with Section 2.6, which sets forth the correct deadline.

(b) Statutory Basis

ICE Clear Europe believes that the proposed amendment to the Delivery Procedures is consistent with the requirements of Section 17A of the Act [5] and the regulations thereunder applicable to it. In particular, Section 17A(b)(3)(F) of the Act [6] requires, among other things, that the rules of a clearing agency be designed to promote the prompt and accurate clearance and settlement of securities transactions and, to the extent applicable, derivative agreements, contracts, and transactions, the safeguarding of securities and funds in the custody or control of the clearing agency or for which it is responsible, and the protection of investors and the public interest.

As discussed above, the amendment would modify Part H of the Delivery Procedures in order to correct an inconsistency regarding the deadline for submission of EFPs and EFSs with respect to Daily Contracts. In ICE Clear Europe's view the amendment would thus facilitate the clearing membership process, and related risk management by the Clearing House. The amendments would therefore facilitate the prompt and accurate clearing of cleared contracts and protect investors and the public interest in the sound operations of the Clearing House, consistent with the requirements of Section 17A(b)(3)(F).[7] Further, the amendments will not affect the safeguarding of securities and funds in the custody or control of the Clearing House or for which it is responsible, within the meaning Section 17A(b)(3)(F).[8]

The proposed amendment is also consistent with relevant provisions of Rule 17Ad–22.[9] Rule 17Ad–22(e)(10) [10] provides that, ''[e]ach covered clearing agency shall establish, implement, maintain and enforce written policies and procedures reasonable designed to, as applicable [. . .] establish and maintain transparent written standards that state its obligations with respect to the delivery of physical instruments, and establish and maintain operational practices that identify, monitor and manage the risks associated with such physical deliveries.'' The proposed amendment, which would correct an inconsistency regarding the deadline for submission of EFPs and EFSs with respect to Daily Contracts, would not otherwise change the delivery terms and conditions for the Daily Contracts or otherwise affect the ICE Clear Europe's existing financial resources, risk management, systems and operational arrangements supporting delivery. The amendment thus appropriately clarifies the role and responsibilities of the Clearing House and Clearing Members with respect to physical delivery. As a result, ICE Clear Europe believes the amendment is consistent with the requirements of Rule 17Ad–22(e)(10).[11]

(B) Clearing Agency's Statement on Burden on Competition

ICE Clear Europe does not believe the proposed amendment would have any impact, or impose any burden, on competition not necessary or appropriate in furtherance of the purposes of the Act. The proposed amendment to the Delivery Procedures is intended to correct an inconsistency in the delivery timetable for routine deliveries of Daily Contracts. ICE Clear Europe does not believe that the amendment would adversely affect competition among Clearing Members, materially affect the cost of clearing, adversely affect access to clearing for Clearing Members or their customers, or otherwise adversely affect competition in clearing services. Accordingly, ICE Clear Europe does not believe that the amendment would impose any impact or burden on competition that is not appropriate in furtherance of the purpose of the Act.

(C) Clearing Agency's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

Written comments relating to the proposed amendment has not been solicited or received by ICE Clear Europe. ICE Clear Europe will notify the Commission of any comments received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A) of the Act [12] and paragraph (f) of Rule 19b–4 [13] thereunder. At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. 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–ICEEU–2022–012 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–ICEEU–2022–012. 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

[5] 15 U.S.C. 78q–1.

[6] 15 U.S.C. 78q–1(b)(3)(F).

[7] 15 U.S.C. 78q–1(b)(3)(F).

[8] 15 U.S.C. 78q–1(b)(3)(F).

[9] 17 CFR 240.17 Ad–22.

[10] 17 CFR 240.17Ad–22(e)(10).

[11] 17 CFR 240.17Ad–22(e)(10).

[12] 15 U.S.C. 78s(b)(3)(A).

[13] 17 CFR 240.19b–4(f).

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 such filings will also be available for inspection and copying at the principal office of ICE Clear Europe and on ICE Clear Europe's website at *https://www.theice.com/clear-europe/regulation*. All comments received will be posted without change. Persons submitting comments are cautioned that we do not redact or edit 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–ICEEU–2022–012 and should be submitted on or before July 12, 2022.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[14]

J. Matthew DeLesDernier,

Assistant Secretary.

[FR Doc. 2022–13152 Filed 6–17–22; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–95101; File No. SR–ISE–2022–13]

Self-Regulatory Organizations; Nasdaq ISE, LLC; Notice of Filing of Proposed Rule Change To Permit the Listing and Trading of P.M.-Settled Nasdaq–100 Index Options That Expire on Tuesday or Thursday Under Its Nonstandard Expirations Pilot Program

June 14, 2022.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on June 1, 2022, Nasdaq ISE, LLC (''ISE'' or ''Exchange'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I and II below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to permit P.M.-settled Nasdaq–100 Index® (''NDX'') options that expire on Tuesday or Thursday under its Nonstandard Expirations Pilot Program.

The text of the proposed rule change is available on the Exchange's website at *https://listingcenter.nasdaq.com/rulebook/ise/rules,* at the principal office of the Exchange, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend Supplementary Material .07 of Options 4A, Section 12, which governs its Nonstandard Expirations Pilot Program (''Pilot Program''), to permit P.M.-settled Nasdaq–100 Index (''NDXP'') options that expire on Tuesday or Thursday. Under the existing Pilot Program, the Exchange is permitted to list P.M.-settled options on broad-based indexes that expire on: (1) any Monday, Wednesday, or Friday (''Weekly Expirations'') and (2) the last trading day of the month (''End of Month Expirations'' or ''EOMs'').[3] Today, Cboe Exchange, Inc. (''Cboe'') is permitted to list P.M.-settled S & P 500 Index options that expire on Tuesday or Thursday under its Nonstandard Expirations Pilot Program.[4]

Specifically, the proposed rule change amends Supplementary Material .07(a) of Options 4A, Section 12 to add NDXP options (P.M.-settled) that expire on Tuesday or Thursday as permissible Weekly Expirations under the Pilot Program (currently set to expire on November 4, 2022). The Exchange notes that permitting NDXP options with Tuesday and Thursday expirations, as proposed, is in addition to the NDXP options with Monday, Wednesday and Friday expirations that the Exchange may (and does) already list, as they are permissible Weekly Expirations for options on a broad-based index (*e.g.,* NDX) pursuant to Supplementary Material .07(a) of Options 4A, Section 12. The Pilot Program for Weekly Expirations will apply to NDXP options with Tuesday and Thursday expirations in the same manner as it currently applies to P.M.-settled broad-based index options with Monday, Wednesday and Friday expirations. That is, as proposed, Supplementary Material .07(a) of Options 4A, Section 12 provides that the Exchange may open for trading Weekly Expirations on any broad-based index eligible for standard options trading to expire on any Monday, Wednesday, or Friday (other than the third Friday-of-the-month or days that coincide with an EOM expiration). In addition, the Exchange may also open for trading Weekly Expirations on NDX options to expire on any Tuesday or Thursday (other than days that coincide with the third Friday-of-the-month or an EOM expiration).[5]

Monday, Wednesday and Friday weekly expirations are subject to all provisions of Supplementary Material .07(a) of Options 4A, Section 12 as would be the proposed Tuesday and Thursday expirations. Additionally, the Monday, Wednesday and Friday weekly expirations are treated the same as options on the same underlying index that expire on the third Friday of the expiration month as would be the proposed Tuesday and Thursday expirations; provided, however, that Weekly Expirations (including the new Tuesday and Thursday expirations) shall be P.M.-settled and new series in Weekly Expirations may be added up to and including on the expiration date for an expiring Weekly Expiration. The

[14] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Supplementary Material .07 of Options 4A, Section 12.

[4] *See* Securities Exchange Act Release No. 94682 (April 12, 2022), 87 FR 22993 (April 18, 2022) (SR–CBOE–2022–005) (Notice of Filing of Amendment No. 1 and Order Granting Accelerated Approval of a Proposed Rule Change, as Modified by Amendment No. 1, To Expand the Nonstandard Expirations Pilot Program To Include P.M.-Settled S&P 500 Index Options That Expire on Tuesday or Thursday).

[5] In the event that the third Friday of a given month is a holiday and the Exchange is not open for trading, the Exchange would not list both an A.M.-settled NDX option as well as P.M.-settled NDXP.

maximum number of expirations that may be listed for each Weekly Expiration (*i.e.,* a Monday expiration, Tuesday expiration, Wednesday expiration, Thursday expiration, or Friday expiration, as applicable) in a given class is the same as the maximum number of expirations permitted in Supplementary Material .07 of Options 4A, Section 12 for standard options on the same broad-based index (which is 12 for NDXP options).

Weekly Expirations need not be for consecutive Monday, Tuesday, Wednesday, Thursday, or Friday expirations as applicable; however, the expiration date of a non-consecutive expiration may not be beyond what would be considered the last expiration date if the maximum number of expirations were listed consecutively. Weekly Expirations that are first listed in a given class may expire up to four weeks from the actual listing date. If the Exchange lists EOMs and Weekly Expirations as applicable in a given class, the Exchange will list an EOM instead of a Weekly Expiration that expires on the same day in the given class.[6] Other expirations in the same class are not counted as part of the maximum number of Weekly Expirations for an applicable[7] broad-based index class.

If the Exchange is not open for business on a respective Monday, the normally Monday expiring Weekly Expirations will expire on the following business day. If the Exchange is not open for business on a respective Tuesday, Wednesday, Thursday, or Friday, the normally Tuesday, Wednesday, Thursday, or Friday expiring Weekly Expirations will expire on the previous business day.

The proposed rule change also adds that, if two different Weekly Expirations on NDX options would expire on the same day because the Exchange is not open for business on a certain weekday, the Exchange will list only one of such Weekly Expirations. The Exchange believes it is appropriate to clarify in the rule text that the Exchange will list just one Weekly Expiration in such a case, as the two Weekly Expirations would essentially be the same options contract. For example, if the Exchange listed NDXP options with proposed Thursday expirations and Friday expirations and the Exchange was closed for business on a Friday then, pursuant to current Supplementary Material .07(a) of Options 4A, Section 12, the normally expiring Friday expiration would expire on the previous business day—essentially making it an NDXP option with a Thursday expiration. Thus, expiring NDXP options in this case will always have the same weekday expiration (per the example, it is an NDXP option with a Thursday expiration, whether it was listed as an NDXP with a Thursday expiration or a Friday expiration). As such, for the sake of clarity in the rules and to mitigate any confusion regarding the listing of NDXP options when the Exchange is closed for business, the proposed rule change provides that the Exchange will list just one Weekly Expiration if two Weekly Expirations would expire on the same day due to the Exchange being closed for business. Transactions in Weekly Expirations may be effected on the Exchange between the hours of 9:30 a.m. (Eastern Time) and 4:15 p.m. (Eastern Time), except that on the last trading day, transactions in expiring p.m.-settled broad-based index options may be effected on the Exchange between the hours of 9:30 a.m. (Eastern time) and 4:00 p.m. (Eastern time).

The Exchange believes that that the introduction of NDXP options with Tuesday and Thursday expirations will expand hedging tools available to market participants while also providing greater trading opportunities. By offering NDXP options with Tuesday and Thursday expirations along with the current Monday, Wednesday and Friday expirations, the proposed rule change will allow market participants to purchase NDXP options in a manner more aligned with specific timing needs and more effectively tailor their investment and hedging strategies and manage their portfolios.

In particular, the proposed rule change will allow market participants to roll their positions on more trading days, thus with more precision, spread risk across more trading days and incorporate daily changes in the markets, which may reduce the premium cost of buying protection. The Exchange proposes to abide by the same reporting requirements for the trading of NDXP options that expire on any Tuesday or Thursday that it does for the trading of P.M.-settled options on broad-based indexes that expire on any Monday, Wednesday, or Friday pursuant to the Pilot Program.

Pilot Report

The Exchange intends to submit a rule change proposing permanency of the Nonstandard Pilot to the Commission and would include data regarding NDXP options that expire on Tuesdays or Thursdays as it does for current Weekly Expirations on any broad-based index option either by providing additional data in such proposal or in an annual report regarding NDXP options that expire on each trading day of the week, as proposed. The Exchange would continue to provide the Commission with ongoing data regarding NDXP options that expire on Tuesdays or Thursdays unless and until the Nonstandard Pilot is made permanent or discontinued.

As provided in the Pilot Program Approval Order,[8] the annual report will contain an analysis of volume, open interest and trading patterns. In addition, for series that exceed certain minimum open interest parameters, the annual report will provide analysis of index price volatility and, if needed, share trading activity.[9] Additionally, the Exchange will provide the Commission with any additional data or analyses the Commission requests because it deems such data or analyses necessary to determine whether the Pilot Program, including NDXP options with Tuesday and Thursday expirations as proposed, is consistent with the Exchange Act. As it does for current Pilot Program products, the Exchange will make public on its website all data and analyses in connection with NDXP options with Tuesday and Thursday expirations it submits to the Commission under the Pilot Program. Going forward, the Exchange will include the same areas of analysis for NDXP options with Tuesday and Thursday expirations. The Exchange also proposes to include the following

[6] Given that each trading day of the week, as proposed, could be the last trading day of the month and the day in which a Weekly Expiration expires, the Exchange updates this rule text to streamline the language.

[7] The Exchange updates the rule text for additional clarity.

[8] *See* Securities Exchange Act Release No. 82612 (February 1, 2018), 83 FR 5470 (February 7, 2018) (approving SR–ISE–2017–111) (Order Approving a Proposed Rule Change To Establish a Nonstandard Expirations Pilot Program) (''Pilot Program Approval Order'').

[9] Specifically, for all Weekly Expirations and EOM series, the annual report will contain the following volume and open interest data for each broad-based index overlying Weekly Expiration and EOM options: (1) Monthly volume aggregated for all Weekly Expiration and EOM series, (2) Volume in Weekly Expiration and EOM series aggregated by expiration date, (3) Month-end open interest aggregated for all Weekly Expiration and EOM series, (4) Month-end open interest for EOM series aggregated by expiration date and open interest for Weekly Expiration series aggregated by expiration date, (5) Ratio of monthly aggregate volume in Weekly Expiration and EOM series to total monthly class volume, and (6) Ratio of month-end open interest in EOM series to total month-end class open interest and ratio of open interest in each Weekly Expiration series to total class open interest. In addition, the annual report will contain the information noted above for standard Expiration Friday, AM-settled series, if applicable, for the period covered in the pilot report as well as for the six-month period prior to the initiation of the pilot. *See* Pilot Program Approval Order at 5471 and 5472.

market quality data, over sample periods determined by the Exchange and the Commission, for NDXP options (NDXP and standard NDX options) as part of the annual reports going forward: (1) time-weighted relative quoted spreads; (2) relative effective spreads; and (3) time-weighted bid and offer sizes.

The Exchange believes there is sufficient investor interest and demand in NDXP options with Tuesday and Thursday expirations to warrant inclusion in the Pilot Program and that the Pilot Program, as amended, will continue to provide investors with additional means of managing their risk exposures and carrying out their investment objectives.[10] The Exchange notes that during the Pilot Program's 4 year tenure, the Exchange has not observed any significant adverse market effects or identified any regulatory concerns as a result of the Pilot Program, nor does it believe that additional expirations listed under the Pilot Program would result in any such impact or regulatory concerns. Based on a study conducted by Commission staff on the pilot data (including quarterly, weekly, EOM and third Friday expirations for P.M.-settled NDX options),[11] there is no evidence of any significant adverse economic impact to the futures, index, or underlying index component securities markets as a result of the quantity of P.M.-settled NDX options that settle at the close or the amount of expiring open interest in P.M.-settled NDX options.[12]

With regard to the impact of this proposal on System capacity, the Exchange has analyzed its capacity and represents that it believes that the Exchange and OPRA have the necessary systems capacity to handle any potential additional traffic associated with trading of NDXP options with Tuesday and Thursday expirations. The Exchange does not believe that its Members will experience any capacity issues as a result of this proposal and represents that it will monitor the trading volume associated with any possible additional options series listed as a result of this proposal and the effect (if any) of these additional series on market fragmentation and on the capacity of the Exchange's automated systems. While this proposal may increase the number of strike intervals listed on ISE, the amount of additional strike intervals added should be insignificant.

Implementation

Provided this rule change is approved, the Exchange proposes to implement this rule change on or before August 1, 2022. The Exchange will issue an Options Trader Alert to notify Members of the implementation date.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act,[13] in general, and furthers the objectives of Section 6(b)(5) of the Act,[14] in particular, in that it is designed to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general to protect investors and the public interest. Specifically, the Exchange believes the proposed rule change is consistent with the Section 6(b)(5)[15] requirements that the rules of an exchange be designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in regulating, clearing, settling, processing information with respect to, and facilitation transactions in securities, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general, to protect investors and the public interest. Additionally, the Exchange believes the proposed rule change is consistent with the Section 6(b)(5)[16] requirement that the rules of an exchange not be designed to permit unfair discrimination between customers, issuers, brokers, or dealers.

In particular, the Exchange does not believe that the addition of NDXP options with Tuesday and Thursday expirations to the Pilot Program will raise any prohibitive regulatory concerns, nor adversely impact fair and orderly markets on expiration days. The Exchange has not experienced any meaningful regulatory concerns, nor adverse impact on fair and orderly markets, in connection with the Pilot Program that has permitted the listing and trading of NDXP options with Monday, Wednesday and Friday expirations since 2018. Particularly, and as described above, the Exchange does not believe increases in the number P.M.-settled NDX options series will have any significant adverse economic impact on the futures, index, or underlying index component securities markets. The Exchange believes that the proposed rule change will provide investors with greater trading and hedging opportunities and flexibility, allowing them to transact in NDXP options in a manner more aligned with specific timing needs and more effectively tailor their investment and hedging objectives by listing NDXP options that expire each trading day of the week.

The Exchange notes also that it will include analysis in connection with NDXP options that expire on Tuesdays and Thursdays, in the same manner that it currently does for other Pilot Program products, as well as the additional market quality data as described above, in either a permanency proposal or in an annual report it submits to the Commission, and will provide the Commission with any additional data or analyses that it may request if it deems such data or analyses necessary to determine whether the Pilot Program, including NDXP options with Tuesday and Thursday expirations as proposed, is consistent with the Exchange Act.

The Exchange represents that it believes that it has the necessary systems capacity to support any additional traffic associated with trading of NDXP options with Tuesday and Thursday expirations and does not believe that its Members will experience any capacity issues as a result of this proposal. The Exchange will monitor the trading volume associated with any possible additional options series listed and the effect (if any) of these additional series on market fragmentation and on the capacity of the Exchange's automated systems. The Exchange again notes that, as a result of an NDXP options strike mitigation initiative recently implemented by the Exchange, the number of NDXP options series listed on the Exchange once Tuesday and Thursday expirations become available will be less than the number of such series that were listed prior to the implementation of the strike mitigation initiative.

[10] The Exchange additionally notes that it already allows NDXP options to expire on Tuesdays for normally Monday or Wednesday expiring NDXP options when the Exchange is not open for business on a respective Monday or Wednesday (as applicable), and already allows NDXP options to expire on Thursdays for normally Friday expiring NDXP options when the Exchange is not open for business on a respective Friday.

[11] *See* Securities and Exchange Commission, Division of Economic Risk and Analysis, Memorandum, Cornerstone Analysis of PM Cash-Settled Index Option Pilots (February 2, 2021) (''DERA Staff PM Pilot Memo''), available at: *https://www.sec.gov/dera/staff-papers/studies-and-reports/analysis-of-pm-cash-settled-index-option-pilots.*

[12] *See* DERA Staff PM Pilot Memo at 3. For example, the largest settlement event that occurred during the time period of the study (a settlement of $100.4 billion of notional on December 29, 2017) had an estimated impact on the futures price of only approximately 0.02% (a predicted impact of $0.54 relative to a closing futures price of $2,677).

[13] 15 U.S.C. 78f(b).

[14] 15 U.S.C. 78f(b)(5).

[15] 15 U.S.C. 78f(b)(5).

[16] 15 U.S.C. 78f(b)(5).

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act. The Exchange does not believe that the proposed rule change will impose any burden on intra-market competition that is not necessary or appropriate in furtherance of the purposes of the Act because NDXP options with Tuesday and Thursday expirations will be available to all market participants. By listing NDXP options that expire Tuesdays and Thursdays, the proposed rule change will provide all investors that participate in the NDX options market greater trading and hedging opportunities and flexibility to meet their investment and hedging needs.

Additionally, Tuesday and Thursday expiring NDXP options will trade in the same manner as Weekly Expirations currently trade. The Exchange does not believe that the proposal to list NDXP options with Tuesday and Thursday expirations will impose any burden on inter-market competition that is not necessary or appropriate in furtherance of the purposes of the Act because NDX options (including NDXP options) are proprietary Exchange products. Also, Cboe similarly lists Tuesday and Thursday options within their non-standard program.[17] To the extent that the addition of NDXP options that expire on Tuesdays and Thursdays available for trading on the Exchange makes the Exchange a more attractive marketplace to market participants at other exchanges, such market participants are free to elect to become market participants on the Exchange.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Within 45 days of the date of publication of this notice in the **Federal Register** or within such longer period up to 90 days (i) as the Commission may designate if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the self-regulatory organization consents, the Commission will:

(A) by order approve or disapprove the proposed rule change, or

(B) institute proceedings to determine whether the proposed rule change should be disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. 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–ISE–2022–13 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–ISE–2022–13. 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 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–ISE–2022–13, and should be submitted on or before July 12, 2022.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[18]

J. Matthew DeLesDernier,

Assistant Secretary.

[FR Doc. 2022–13149 Filed 6–17–22; 8:45 am]

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SECURITIES AND EXCHANGE COMMISSION

Sunshine Act Meetings

TIME AND DATE: 2:00 p.m. on Thursday, June 23, 2022.

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.

[17] *See supra* note 4.

[18] 17 CFR 200.30–3(a)(12).

Dated: June 16, 2022.

Vanessa A. Countryman,

Secretary.

[FR Doc. 2022–13308 Filed 6–16–22; 11:15 am]

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SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–95102; File No. SR–CBOE–2022–027]

Self-Regulatory Organizations; Cboe Exchange, Inc.; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change to Amend Rule 5.4

June 14, 2022.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (the ''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on June 3, 2022, Cboe Exchange, Inc. (the ''Exchange'' or ''Cboe Options'') filed with the Securities and Exchange Commission (the ''Commission'') the proposed rule change as described in Items I and II, below, which Items have been prepared by the Exchange. The Exchange filed the proposal as a ''non-controversial'' proposed rule change pursuant to Section 19(b)(3)(A)(iii) of the Act[3] and Rule 19b–4(f)(6) thereunder.[4] The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78s(b)(3)(A)(iii).

[4] 17 CFR 240.19b–4(f)(6).

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

Cboe Exchange, Inc. (the ''Exchange'' or ''Cboe Options'') proposes to amend Rule 5.4. The text of the proposed rule change is provided below.

(additions are *underlined*; deletions are [bracketed])

* * * * *

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Rules of Cboe Exchange, Inc.

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Rule 5.4. Minimum Increments for Bids and Offers

(a) *Simple Orders for Equity and Index Options.* The minimum increments for bids and offers on simple orders for equity and index options are as follows:

Class	Increment	Series Trading Price
Class Not Participating in Penny Interval Program [(including all series of VIX options if the Exchange does not list VIX on a group basis pursuant to Rule 4.13) and series of VIX Options not listed under the Nonstandard Expirations Pilot Program (if the Exchange lists VIX on a group basis pursuant to Rule 4.13)]	$0.05 $0.10	Lower than $3.00 $3.00 and higher
Class Participating in Penny Interval Program	$0.01 $0.05	Lower than $3.00 $3.00 and higher
QQQs, IWM, and SPY, and XSP (as long as SPDR options (SPY) participate in the Penny Interval Program) and MRUT options (as long as iShares Russell 2000 ETF options (IWM) participate in the Penny Interval Program)	$0.01	All prices
Series of VIX options (if the Exchange does not list VIX on a group basis pursuant to Rule 4.13) and series of VIX Options not listed under the Nonstandard Expirations Pilot Program (if the Exchange lists VIX on a group basis pursuant to Rule 4.13)	$0.01 $0.05	Lower than $3.00 $3.00 and higher
Series of VIX Options listed under the Nonstandard Expirations Pilot Program (if the Exchange lists VIX on a group basis pursuant to Rule 4.13)	$0.01	All prices

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The text of the proposed rule change is also available on the Exchange's website (*http://www.cboe.com/AboutCBOE/CBOELegalRegulatoryHome.aspx*), at the Exchange's Office of the Secretary, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend Rule 5.4(a) to change the minimum increment for all series of options on the Cboe Volatility Index (''VIX options'') (if the Exchange does not list VIX options on a group basis) and series of VIX options not listed under the Nonstandard Expirations Pilot Program (if the Exchange lists VIX options on a group basis) to $0.01 for series trading lower than $3.00 and $0.05 for series trading at $3.00 or higher. Currently, the Exchange lists VIX options on a group basis, so series of VIX options listed under the Nonstandard Expirations Pilot Program (''VIXW options'') currently trade with a minimum increment of $0.01 for all series trading prices. The proposed rule change will permit the other group of VIX option series (those not listed under the Nonstandard Expirations Pilot Program, which are comprised of VIX options series that expire on the third Friday of the month) to trade in smaller increments.[5]

The Exchange believes market demand (including by retail investors, who generally prefer lower trading increments) supports a lower trading increment for these series. The Exchange expects this more granular pricing to lead to narrowing of the bid-ask spread for these options and increase the possible number of price points available to investors for these series. The Exchange believes tighter spreads will increase order flow in VIX options, which additional liquidity ultimately benefits all investors. Finer increments also permit more precise pricing in line with the theoretical value of these options. Additionally, penny pricing is available in weekly options on competitor products such as the iPath S&P 500 VIX Short-Term Futures exchange-traded note (''VXX''). As a result, the Exchange believes penny pricing for VIX options is necessary for competitive reasons to allow the Exchange to price these weekly options at the same level of granularity as permitted for competitor products.[6]

The Exchange also notes that, while the Penny Interval Program relates to multiply listed classes only, VIX options would be eligible for that program, and thus for the same minimum trading increments as being proposed in this rule filing. Specifically, pursuant to the Penny Interval Program, option classes among the 300 most actively traded multiply listed option classes overlying securities priced below $200, or any index at any index level below $200, may be added to the Penny Interval Program each year.[7] Currently, the class with the lowest cleared volume over the six-month period ending May 3, 2022 has a total volume of 988,078 contracts. During that same six-month period, VIX volume was 113,617,404 contracts, which would put it among the top five classes currently eligible for the Penny Interval Program. Additionally, the value of the VIX Index as of the close of regular trading hours on May 3, 2022, was under 30 (and thus well under 200). Therefore, VIX options have similar trading properties as other option classes that are otherwise eligible for penny and nickel pricing.

Further, the Exchange notes that a majority of VIX options already execute in penny increments. Specifically, in the first four months of 2022, approximately 62% of VIX option contract volume executed as part of complex orders, which may execute in penny increments.[8] In addition, during that same time period, nearly 5% of VIX option contract volume executed through an automated improvement mechanism (''AIM'') auction for simple orders, which also permits penny executions.[9] Therefore, the proposed rule change will impact the trading increment of approximately one-third of VIX options.

With regard to the impact of this proposed rule change on system capacity, the Exchange has analyzed its capacity and represents that it and the Options Price Reporting Authority have the necessary systems capacity to handle any potential additional traffic associated with this proposal. The Exchange does not believe any potential increased traffic will become unmanageable since this proposed rule change with respect to minimum trading increments is limited to a single class of options. The proposed rule change does not impact the number of expirations for VIX options the Exchange may list pursuant to Rule 4.13.

2. Statutory Basis

The Exchange believes the proposed rule change is consistent with the Securities Exchange Act of 1934 (the ''Act'') and the rules and regulations thereunder applicable to the Exchange and, in particular, the requirements of Section 6(b) of the Act.[10] Specifically, the Exchange believes the proposed rule change is consistent with the Section 6(b)(5)[11] requirements that the rules of an exchange be designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in regulating, clearing, settling, processing information with respect to, and facilitating transactions in securities, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general, to protect investors and the public interest. Additionally, the Exchange believes the proposed rule change is consistent with the Section 6(b)(5)[12] requirement that the rules of an exchange not be designed to permit unfair discrimination between customers, issuers, brokers, or dealers.

In particular, the proposed rule change will permit more granular pricing in VIX options, which may lead to narrowing of the bid-ask spread for these options and increase the possible number of price points available to investors for these series, which ultimately increases liquidity to the

[5] As proposed, if the Exchange were to stop listing VIX series on a group basis, then the proposed increments of $0.01 for series trading below $3.00 and $0.05 for series trade at or above $3.00 would apply to all VIX options series.

[6] The Exchange notes that other options that trade on the Exchange are currently permitted to trade in penny increments because competitive products are able to trade in penny increments, including VIXW options. *See* Rule 5.4 (the minimum for XSP options is $0.01 because that is the minimum increment for SPY options, and the minimum increment for DJX options is $0.01 for series below $3 and $0.05 for series $3 and above because that is the minimum increment for DIA options).

[7] *See* Rule 5.4(d).

[8] *See* Rule 5.4(b).

[9] *See* Rule 5.37(a)(4).

[10] 15 U.S.C. 78f(b).

[11] 15 U.S.C. 78f(b)(5).

[12] *Id.*

benefit of all investors. Additionally, as discussed above, at least one competitive product participates in the Penny Interval Program and thus may currently trade in penny and nickel increments. Therefore, the proposed will and promote just and equitable principles of trade and remove impediments to and perfect the mechanism of a free and open market by allowing VIX options to trade at the same level of granularity as permitted for competitor products.[13] The Exchange notes that VIX options have a volume and an underlying index price consistent with option classes eligible for the Penny Interval Program (and thus are able to trade in penny and nickel increments). Additionally, as noted above, VIXW options and the majority of VIX options already execute in penny increments.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act. The proposed rule change will not impose any burden on intramarket competition that is not necessary or appropriate, because all Trading Permit Holders will be able to trade VIX options in the proposed minimum trading increments. Additionally, all VIXW options may currently trade in penny increments, and approximately two-thirds of VIX options volume execute in penny increments as part of simple AIM or complex trading. The proposed rule change will not impose any burden on intermarket competition that is not necessary or appropriate, because it will permit VIX options to have pricing consistent with the pricing of a competitive product that is part of the Penny Interval Program and may currently trade in increments of $0.01 or $0.05. The Exchange reiterates that VIX options have a volume and an underlying index price consistent with option classes eligible for the Penny Interval Program (and thus are able to trade in penny and nickel increments).

Additionally, the proposed rule change to permit VIX options to be listed in penny and nickel increments may relieve any burden on, or otherwise promote, competition, as it will allow market participants to trade these options at the same level of granularity as permitted for competitor products. The Exchange notes that other options that trade on the Exchange are currently permitted to trade in penny increments because competitive products are able to trade in penny increments.[14] The Exchange also expects the more granular pricing to lead to narrowing of the bid-ask spread for these options, which the Exchange believes will increase order flow and price competition in VIX options.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

The Exchange neither solicited nor received comments on the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the foregoing proposed rule change does not: (i) significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A) of the Act[15] and Rule 19b–4(f)(6)[16] thereunder.

A proposed rule change filed under Rule 19b–4(f)(6)[17] normally does not become operative for 30 days after the date of filing. However, pursuant to Rule 19b–4(f)(6)(iii),[18] the Commission may designate a shorter time if such action is consistent with the protection of investors and the public interest. The Exchange has asked the Commission to waive the 30-day operative delay so that the filing may become operative immediately upon filing. As discussed above, the proposal will permit pricing of VIX options in an increment at the same level of granularity as currently is permitted for at least one competitor product and other products with similar volumes and underlying prices that are eligible for the Penny Interval Program. The Commission finds that waiving the operative delay is consistent with the protection of investors and the public interest because it will allow the Exchange to make this pricing option available to investors without delay. Therefore, the Commission waives the 30-day operative delay and designates the proposed rule change as operative upon filing.[19]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission will institute proceedings to determine whether the proposed rule change should be approved or disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. 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–CBOE–2022–027 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–CBOE–2022–027. 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

[13] The Exchange notes that other options that trade on the Exchange are currently permitted to trade in penny increments because competitive products are able to trade in penny increments. *See* 5.4 (the minimum for XSP options is $0.01 because that is the minimum increment for SPY options, and the minimum increment for DJX options is $0.01 for series below $3 and $0.05 for series $3 and above because that is the minimum increment for DIA options).

[14] *See* Rule 5.4(a) (the minimum for XSP options is $0.01 because that is the minimum increment for SPY options, and the minimum increment for DJX options is $0.01 for series below $3 and $0.05 for series $3 and above because that is the minimum increment for DIA options).

[15] 15 U.S.C. 78s(b)(3)(A).

[16] 17 CFR 240.19b–4(f)(6).

[17] 17 CFR 240.19b–4(f)(6).

[18] 17 CFR 240.19b–4(f)(6)(iii).

[19] For purposes only of waiving the 30-day operative delay, the Commission has also considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

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; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–CBOE–2022–027 and should be submitted on or before July 12, 2022.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[20]

J. Matthew DeLesDernier,

Assistant Secretary.

[FR Doc. 2022–13150 Filed 6–17–22; 8:45 am]

BILLING CODE 8011–01–P

[20] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Investment Company Act Release No. 34615; File No. 813–00405]

Viking Global Equities II LP and Viking Global Investors LP

June 14, 2022.

AGENCY: Securities and Exchange Commission (''Commission'' or ''SEC'').

ACTION: Notice.

Notice of application for an order (''Order'') under sections 6(b) and 6(e) of the Investment Company Act of 1940 (the ''Act'') granting an exemption from all provisions of the Act, except sections 9, 17, 30, and 36 through 53, and the rules and regulations under the Act (the ''Rules and Regulations''). With respect to sections 17(a), (d), (e), (f), (g), and (j) of the Act, sections 30(a), (b), (e), and (h) of the Act and the Rules and Regulations and rule 38a–1 under the Act, applicants request a limited exemption as set forth in the application.

SUMMARY OF APPLICATION: Applicants request an order to exempt certain limited partnerships, limited liability companies, business trusts or other entities (''Funds'') formed for the benefit of eligible employees of Viking Global Investors LP and its affiliates from certain provisions of the Act. Each Fund, and each series thereof with segregated assets and liabilities, will be an ''employees' securities company'' within the meaning of section 2(a)(13) of the Act.

APPLICANTS: Viking Global Equities II LP and Viking Global Investors LP.

FILING DATES: The application was filed on January 28, 2022 and amended on June 3, 2022.

HEARING OR NOTIFICATION OF HEARING: An order granting the requested relief will be issued unless the Commission orders a hearing. Interested persons may request a hearing on any application by emailing the SEC's Secretary at *Secretarys-Office@sec.gov* and serving the Applicants with a copy of the request by email, if an email address is listed for the relevant Applicant below, or personally or by mail, if a physical address is listed for the relevant Applicant below. Hearing requests should be received by the Commission by 5:30 p.m. on July 11, 2022, and should be accompanied by proof of service on applicants, in the form of an affidavit or, for lawyers, a certificate of service. Pursuant to rule 0–5 under the Act, hearing requests should state the nature of the writer's interest, any facts bearing upon the desirability of a hearing on the matter, the reason for the request, and the issues contested. Persons who wish to be notified of a hearing may request notification by emailing the Commission's Secretary at *Secretarys-Office@sec.gov*.

ADDRESSES: The Commission: *Secretarys-Office@sec.gov*. Applicants: Andrew M. Genser, *legalnotices@vikingglobal.com,* and John J. Mahon, *John.Mahon@srz.com*.

FOR FURTHER INFORMATION CONTACT: Jessica D. Leonardo, Senior Counsel, or Marc Mehrespand, Branch Chief, at (202) 551–6825 (Division of Investment Management, Chief Counsel's Office).

SUPPLEMENTARY INFORMATION: For Applicants' representations, legal analysis, and conditions, please refer to Applicants' first amended and restated application, dated June 3, 2022, which may be obtained via the Commission's website by searching for the file number at the top of this document, or for an Applicant using the Company name search field, on the SEC's EDGAR system. The SEC's EDGAR system may be searched at, at *http://www.sec.gov/edgar/searchedgar/legacy/companysearch.html*. You may also call the SEC's Public Reference Room at (202) 551–8090.

For the Commission, by the Division of Investment Management, under delegated authority.

J. Matthew DeLesDernier,

Assistant Secretary.

[FR Doc. 2022–13153 Filed 6–17–22; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–95100; File No. SR–Phlx–2022–22]

Self-Regulatory Organizations; Nasdaq PHLX LLC; Notice of Filing of Proposed Rule Change To Permit the Listing and Trading of P.M.-Settled Nasdaq–100 Index Options That Expire on Tuesday or Thursday Under Its Nonstandard Expirations Pilot Program

June 14, 2022.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on June 2, 2022, Nasdaq PHLX LLC (''Phlx'' or ''Exchange'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I and II below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to permit P.M.-settled Nasdaq–100 Index® (''NDX'') options that expire on Tuesday or Thursday under its Nonstandard Expirations Pilot Program.

The Exchange also proposes to make technical amendments within Options 5, Section 2, Order Protection; Options 8, Section 2, Definitions; and Options 8, Section 30, Crossing, Facilitation and Solicited Orders.

The text of the proposed rule change is available on the Exchange's website at *https://listingcenter.nasdaq.com/rulebook/phlx/rules,* at the principal office of the Exchange, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend Options 4A, Section 12(b)(5), which governs its Nonstandard Expirations Pilot Program (''Pilot Program''), to permit P.M.-settled Nasdaq–100 Index (''NDXP'') options that expire on Tuesday or Thursday. Under the existing Pilot Program, the Exchange is permitted to list P.M.-settled options on broad-based indexes that expire on: (1) any Monday, Wednesday, or Friday (''Weekly Expirations'') and (2) the last trading day of the month (''End of Month Expirations'' or ''EOMs'').[3] Today, Cboe Exchange, Inc. (''Cboe'') is permitted to list P.M.-settled S&P 500 Index options that expire on Tuesday or Thursday under its Nonstandard Expirations Pilot Program.[4]

Specifically, the proposed rule change amends Options 4A, Section 12(b)(5)(A) to add NDXP options (P.M.-settled) that expire on Tuesday or Thursday as permissible Weekly Expirations under the Pilot Program (currently set to expire on November 4, 2022). The Exchange notes that permitting NDXP options with Tuesday and Thursday expirations, as proposed, is in addition to the NDXP options with Monday, Wednesday and Friday expirations that the Exchange may (and does) already list, as they are permissible Weekly Expirations for options on a broad-based index (*e.g.,* NDX) pursuant to Options 4A, Section 12(b)(5)(A). The Pilot Program for Weekly Expirations will apply to NDXP options with Tuesday and Thursday expirations in the same manner as it currently applies to P.M.-settled broad-based index options with Monday, Wednesday and Friday expirations. That is, as proposed, Options 4A, Section 12(b)(5)(A) provides that the Exchange may open for trading Weekly Expirations on any broad-based index eligible for standard options trading to expire on any Monday, Wednesday, or Friday (other than the third Friday-of-the-month or days that coincide with an EOM expiration). In addition, the Exchange may also open for trading Weekly Expirations on NDX options to expire on any Tuesday or Thursday (other than days that coincide with the third Friday-of-the-month or an EOM expiration).[5]

Monday, Wednesday and Friday weekly expirations are subject to all provisions of Options 4A, Section 12(b)(5)(A) as would be the proposed Tuesday and Thursday expirations. Additionally, the Monday, Wednesday and Friday weekly expirations are treated the same as options on the same underlying index that expire on the third Friday of the expiration month as would be the proposed Tuesday and Thursday expirations; provided, however, that Weekly Expirations (including the new Tuesday and Thursday expirations) shall be P.M.-settled and new series in Weekly Expirations may be added up to and including on the expiration date for an expiring Weekly Expiration. The maximum number of expirations that may be listed for each Weekly Expiration (*i.e.,* a Monday expiration, Tuesday expiration, Wednesday expiration, Thursday expiration, or Friday expiration, as applicable) in a given class is the same as the maximum number of expirations permitted in Options 4A, Section 12(b)(5)(A) for standard options on the same broad-based index (which is 12 for NDXP options).

Weekly Expirations need not be for consecutive Monday, Tuesday, Wednesday, Thursday, or Friday expirations as applicable; however, the expiration date of a non-consecutive expiration may not be beyond what would be considered the last expiration date if the maximum number of expirations were listed consecutively. Weekly Expirations that are first listed in a given class may expire up to four weeks from the actual listing date. If the Exchange lists EOMs and Weekly Expirations as applicable in a given class, the Exchange will list an EOM instead of a Weekly Expiration that expires on the same day in the given class.[6] Other expirations in the same class are not counted as part of the maximum number of Weekly Expirations for an applicable[7] broad-based index class.

If the Exchange is not open for business on a respective Monday, the normally Monday expiring Weekly Expirations will expire on the following business day. If the Exchange is not open for business on a respective Tuesday, Wednesday, Thursday, or Friday, the normally Tuesday, Wednesday, Thursday, or Friday expiring Weekly Expirations will expire on the previous business day.

The proposed rule change also adds that, if two different Weekly Expirations on NDX options would expire on the same day because the Exchange is not open for business on a certain weekday, the Exchange will list only one of such Weekly Expirations. The Exchange believes it is appropriate to clarify in the rule text that the Exchange will list just one Weekly Expiration in such a case, as the two Weekly Expirations would essentially be the same options contract. For example, if the Exchange listed NDXP options with proposed Thursday expirations and Friday expirations and the Exchange was closed for business on a Friday then, pursuant to current Options 4A, Section 12(b)(5)(A), the normally expiring Friday expiration would expire on the previous business day—essentially making it an NDXP option with a Thursday expiration. Thus, expiring NDXP options in this case will always have the same weekday expiration (per the example, it is an NDXP option with a Thursday expiration, whether it was listed as an NDXP with a Thursday expiration or a Friday expiration). As such, for the sake of clarity in the rules and to mitigate any confusion regarding the listing of NDXP options when the Exchange is closed for business, the proposed rule change provides that the Exchange will list just one Weekly Expiration if two Weekly Expirations would expire on the same day due to the Exchange being closed for business. Transactions in Weekly Expirations may be effected on the Exchange between the hours of 9:30 a.m. (Eastern Time) and 4:15 p.m. (Eastern Time), except that on the last trading day, transactions in expiring Weekly Expirations may be effected on the Exchange between the hours of 9:30

[3] *See* Options 4A, Section 12(b)(5).

[4] *See* Securities Exchange Act Release No. 94682 (April 12, 2022), 87 FR 22993 (April 18, 2022) (SR–CBOE–2022–005) (Notice of Filing of Amendment No. 1 and Order Granting Accelerated Approval of a Proposed Rule Change, as Modified by Amendment No. 1, To Expand the Nonstandard Expirations Pilot Program To Include P.M.-Settled S&P 500 Index Options That Expire on Tuesday or Thursday).

[5] In the event that the third Friday of a given month is a holiday and the Exchange is not open for trading, the Exchange would not list both an A.M.-settled NDX option as well as P.M.-settled NDXP.

[6] Given that each trading day of the week, as proposed, could be the last trading day of the month and the day in which a Weekly Expiration expires, the Exchange updates this rule text to streamline the language.

[7] The Exchange updates the rule text for additional clarity.

a.m. (Eastern time) and 4:00 p.m. (Eastern time).

The Exchange believes that that the introduction of NDXP options with Tuesday and Thursday expirations will expand hedging tools available to market participants while also providing greater trading opportunities. By offering NDXP options with Tuesday and Thursday expirations along with the current Monday, Wednesday and Friday expirations, the proposed rule change will allow market participants to purchase NDXP options in a manner more aligned with specific timing needs and more effectively tailor their investment and hedging strategies and manage their portfolios.

In particular, the proposed rule change will allow market participants to roll their positions on more trading days, thus with more precision, spread risk across more trading days and incorporate daily changes in the markets, which may reduce the premium cost of buying protection. The Exchange proposes to abide by the same reporting requirements for the trading of NDXP options that expire on any Tuesday or Thursday that it does for the trading of P.M.-settled options on broad-based indexes that expire on any Monday, Wednesday, or Friday pursuant to the Pilot Program.

Pilot Report

The Exchange intends to submit a rule change proposing permanency of the Nonstandard Pilot to the Commission and would include data regarding NDXP options that expire on Tuesdays or Thursdays as it does for current Weekly Expirations on any broad-based index option either by providing additional data in such proposal or in an annual report regarding NDXP options that expire on each trading day of the week, as proposed. The Exchange would continue to provide the Commission with ongoing data regarding NDXP options that expire on Tuesdays or Thursdays unless and until the Nonstandard Pilot is made permanent or discontinued.

As provided in the Pilot Program Approval Order,[8] the annual report will contain an analysis of volume, open interest and trading patterns. In addition, for series that exceed certain minimum open interest parameters, the annual report will provide analysis of index price volatility and, if needed, share trading activity.[9] Additionally, the Exchange will provide the Commission with any additional data or analyses the Commission requests because it deems such data or analyses necessary to determine whether the Pilot Program, including NDXP options with Tuesday and Thursday expirations as proposed, is consistent with the Exchange Act. As it does for current Pilot Program products, the Exchange will make public on its website all data and analyses in connection with NDXP options with Tuesday and Thursday expirations it submits to the Commission under the Pilot Program. Going forward, the Exchange will include the same areas of analysis for NDXP options with Tuesday and Thursday expirations. The Exchange also proposes to include the following market quality data, over sample periods determined by the Exchange and the Commission, for NDXP options (NDXP and standard NDX options) as part of the annual reports going forward: (1) time-weighted relative quoted spreads; (2) relative effective spreads; and (3) time-weighted bid and offer sizes.

The Exchange believes there is sufficient investor interest and demand in NDXP options with Tuesday and Thursday expirations to warrant inclusion in the Pilot Program and that the Pilot Program, as amended, will continue to provide investors with additional means of managing their risk exposures and carrying out their investment objectives.[10] The Exchange notes that during the Pilot Program's 4 year tenure, the Exchange has not observed any significant adverse market effects or identified any regulatory concerns as a result of the Pilot Program, nor does it believe that additional expirations listed under the Pilot Program would result in any such impact or regulatory concerns. Based on a study conducted by Commission staff on the pilot data (including quarterly, weekly, EOM and third Friday expirations for P.M.-settled NDX options),[11] there is no evidence of any significant adverse economic impact to the futures, index, or underlying index component securities markets as a result of the quantity of P.M.-settled NDX options that settle at the close or the amount of expiring open interest in P.M.-settled NDX options.[12]

With regard to the impact of this proposal on System capacity, the Exchange has analyzed its capacity and represents that it believes that the Exchange and OPRA have the necessary systems capacity to handle any potential additional traffic associated with trading of NDXP options with Tuesday and Thursday expirations. The Exchange does not believe that its members or member organizations will experience any capacity issues as a result of this proposal and represents that it will monitor the trading volume associated with any possible additional options series listed as a result of this proposal and the effect (if any) of these additional series on market fragmentation and on the capacity of the Exchange's automated systems. While this proposal may increase the number of strike intervals listed on Phlx, the amount of additional strike intervals added should be insignificant.

Technical Amendments

The Exchange also proposes to amend Options 5, Section 2, Order Protection. The Exchange proposes to remove a citation to paragraph (c) within Options 5, Section 2(a). This rule has not paragraph (c).

[8] *See* Securities Exchange Act Release No. 82341 (December 15, 2017), 82 FR 60651 (December 21, 2017) (approving SR–Phlx–2017–79) (Order Approving a Proposed Rule Change, as Modified by Amendment No. 1 and Granting Accelerated Approval of Amendment No. 2, of a Proposed Rule Change To Establish a Nonstandard Expirations Pilot Program).

[9] Specifically, for all Weekly Expirations and EOM series, the annual report will contain the following volume and open interest data for each broad-based index overlying Weekly Expiration and EOM options: (1) Monthly volume aggregated for all Weekly Expiration and EOM series, (2) Volume in Weekly Expiration and EOM series aggregated by expiration date, (3) Month-end open interest aggregated for all Weekly Expiration and EOM series, (4) Month-end open interest for EOM series aggregated by expiration date and open interest for Weekly Expiration series aggregated by expiration date, (5) Ratio of monthly aggregate volume in Weekly Expiration and EOM series to total monthly class volume, and (6) Ratio of month-end open interest in EOM series to total month-end class open interest and ratio of open interest in each Weekly Expiration series to total class open interest. In addition, the annual report will contain the information noted above for standard Expiration Friday, AM-settled series, if applicable, for the period covered in the pilot report as well as for the six-month period prior to the initiation of the pilot. *See* Pilot Program Approval Order at 60652 and 60653.

[10] The Exchange additionally notes that it already allows NDXP options to expire on Tuesdays for normally Monday or Wednesday expiring NDXP options when the Exchange is not open for business on a respective Monday or Wednesday (as applicable), and already allows NDXP options to expire on Thursdays for normally Friday expiring NDXP options when the Exchange is not open for business on a respective Friday.

[11] *See* Securities and Exchange Commission, Division of Economic Risk and Analysis, Memorandum, Cornerstone Analysis of PM Cash-Settled Index Option Pilots (February 2, 2021) (''DERA Staff PM Pilot Memo''), available at: *https://www.sec.gov/dera/staff-papers/studies-and-reports/analysis-of-pm-cash-settled-index-option-pilots.*

[12] *See* DERA Staff PM Pilot Memo at 3. For example, the largest settlement event that occurred during the time period of the study (a settlement of $100.4 billion of notional on December 29, 2017) had an estimated impact on the futures price of only approximately 0.02% (a predicted impact of $0.54 relative to a closing futures price of $2,677).

The Exchange proposes to amend Options 8, Section 2, Definitions, to update an incorrect citation to Rule 1(z). The proper citation is to General 1, Section 1(23).

Finally, the Exchange proposes to amend Options 8, Section 30, Crossing, Facilitation and Solicited Orders to remove the stray word "Rule."

Implementation

Provided this rule change is approved, the Exchange proposes to implement this rule change on or before August 1, 2022. The Exchange will issue an Options Trader Alert to notify members and member organizations of the implementation date.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act,[13] in general, and furthers the objectives of Section 6(b)(5) of the Act,[14] in particular, in that it is designed to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general to protect investors and the public interest. Specifically, the Exchange believes the proposed rule change is consistent with the Section 6(b)(5)[15] requirements that the rules of an exchange be designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in regulating, clearing, settling, processing information with respect to, and facilitation transactions in securities, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general, to protect investors and the public interest. Additionally, the Exchange believes the proposed rule change is consistent with the Section 6(b)(5)[16] requirement that the rules of an exchange not be designed to permit unfair discrimination between customers, issuers, brokers, or dealers.

In particular, the Exchange does not believe that the addition of NDXP options with Tuesday and Thursday expirations to the Pilot Program will raise any prohibitive regulatory concerns, nor adversely impact fair and orderly markets on expiration days. The Exchange has not experienced any meaningful regulatory concerns, nor adverse impact on fair and orderly markets, in connection with the Pilot Program that has permitted the listing and trading of NDXP options with Monday, Wednesday and Friday expirations since 2018. Particularly, and as described above, the Exchange does not believe increases in the number P.M.-settled NDX options series will have any significant adverse economic impact on the futures, index, or underlying index component securities markets. The Exchange believes that the proposed rule change will provide investors with greater trading and hedging opportunities and flexibility, allowing them to transact in NDXP options in a manner more aligned with specific timing needs and more effectively tailor their investment and hedging objectives by listing NDXP options that expire each trading day of the week.

The Exchange notes also that it will include analysis in connection with NDXP options that expire on Tuesdays and Thursdays, in the same manner that it currently does for other Pilot Program products, as well as the additional market quality data as described above, in either a permanency proposal or in an annual report it submits to the Commission, and will provide the Commission with any additional data or analyses that it may request if it deems such data or analyses necessary to determine whether the Pilot Program, including NDXP options with Tuesday and Thursday expirations as proposed, is consistent with the Exchange Act.

The Exchange represents that it believes that it has the necessary systems capacity to support any additional traffic associated with trading of NDXP options with Tuesday and Thursday expirations and does not believe that its members and member organizations will experience any capacity issues as a result of this proposal. The Exchange will monitor the trading volume associated with any possible additional options series listed and the effect (if any) of these additional series on market fragmentation and on the capacity of the Exchange's automated systems. The Exchange again notes that, as a result of an NDXP options strike mitigation initiative recently implemented by the Exchange, the number of NDXP options series listed on the Exchange once Tuesday and Thursday expirations become available will be less than the number of such series that were listed prior to the implementation of the strike mitigation initiative.

Technical Amendments

The proposed amendments to Options 5, Section 2, Order Protection; Options 8, Section 2, Definitions; and Options 8, Section 30, Crossing, Facilitation and Solicited Orders are non-substantive technical amendments.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act. The Exchange does not believe that the proposed rule change will impose any burden on intra-market competition that is not necessary or appropriate in furtherance of the purposes of the Act because NDXP options with Tuesday and Thursday expirations will be available to all market participants. By listing NDXP options that expire Tuesdays and Thursdays, the proposed rule change will provide all investors that participate in the NDX options market greater trading and hedging opportunities and flexibility to meet their investment and hedging needs.

Additionally, Tuesday and Thursday expiring NDXP options will trade in the same manner as Weekly Expirations currently trade. The Exchange does not believe that the proposal to list NDXP options with Tuesday and Thursday expirations will impose any burden on inter-market competition that is not necessary or appropriate in furtherance of the purposes of the Act because NDX options (including NDXP options) are proprietary Exchange products. Also, Cboe similarly lists Tuesday and Thursday options within their non-standard program.[17] To the extent that the addition of NDXP options that expire on Tuesdays and Thursdays available for trading on the Exchange makes the Exchange a more attractive marketplace to market participants at other exchanges, such market participants are free to elect to become market participants on the Exchange.

Technical Amendments

The proposed amendments to Options 5, Section 2, Order Protection; Options 8, Section 2, Definitions; and Options 8, Section 30, Crossing, Facilitation and Solicited Orders are non-substantive technical amendments.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

[13] 15 U.S.C. 78f(b).

[14] 15 U.S.C. 78f(b)(5).

[15] 15 U.S.C. 78f(b)(5).

[16] 15 U.S.C. 78f(b)(5).

[17] *See supra* note 4.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Within 45 days of the date of publication of this notice in the **Federal Register** or within such longer period up to 90 days (i) as the Commission may designate if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the self-regulatory organization consents, the Commission will:

(A) by order approve or disapprove the proposed rule change, or

(B) institute proceedings to determine whether the proposed rule change should be disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. 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–Phlx–2022–22 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–Phlx–2022–22. 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 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–Phlx–2022–22, and should be submitted on or before July 12, 2022.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[18]

J. Matthew DeLesDernier,

Assistant Secretary.

[FR Doc. 2022–13148 Filed 6–17–22; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–95103; File No. SR–Phlx–2022–24]

Self-Regulatory Organizations; Nasdaq PHLX LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend its Schedule of Credits, at Equity 7, Section 3

June 14, 2022.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1], and Rule 19b–4 thereunder,[2] notice is hereby given that on June 1, 2022, Nasdaq PHLX LLC (''Phlx'' or ''Exchange'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I, II, and III, below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend the Exchange's schedule of credits, at Equity 7, Section 3, as described further below. The text of the proposed rule change is available on the Exchange's website at *https://listingcenter.nasdaq.com/rulebook/phlx/rules,* at the principal office of the Exchange, and at the Commission's Public Reference Room.

[18] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend its pricing schedule, at Equity 7, Section 3, to: (1) adopt a new $0.0025 per share executed credit for member organizations that provide non-displayed liquidity with midpoint pegging of at least one million shares average daily value during the month; and (2) modify the per share executed credit for member organizations that provide non-displayed liquidity with midpoint pegging for all other orders from $0.0023 to $0.0018.

Pursuant to Equity 7, Section 3, the Exchange currently provides a credit of $0.0023 per share executed to member organizations for all non-displayed orders with midpoint pegging that provide liquidity. The Exchange proposes to establish credit tiers for member organizations providing liquidity for non-displayed orders with midpoint pegging to provide an incentive for member organizations to engage in a significant amount of liquidity adding activity on the Exchange.

The Exchange proposes establishing a new credit that will reward a member organization with a credit of $0.0025 per share executed to the extent that it provides a daily average volume of at least one million shares of non-displayed liquidity with midpoint pegging during the month. The proposed new credit for non-displayed orders with midpoint pegging will provide an additional incentive to member organizations to add liquidity to the Exchange. Insofar as the proposed new credit will require a qualifying member organization to provide at least one million shares average daily value during the month in order to qualify for the $0.0025 per share credit, the Exchange believes it is reasonable for the amount of the proposed credit to be larger than the credit for other non-displayed orders with midpoint pegging, which the Exchange proposes to modify to $0.0018. To the extent that the proposed new credit structure succeeds in increasing liquidity on the Exchange, the quality of the Exchange's market will improve, to the benefit of all participants.

In addition, the Exchange proposes lowering the credit to member organizations for all other non-displayed orders with midpoint pegging that provide liquidity during the month from $0.0023 to $0.0018 per share executed. The Exchange has limited resources available to it to offer its member organizations market-improving incentives, and it allocates those limited resources to those segments of the market where it perceives the need to be greatest and/or where it determines that the incentive is likely to achieve its intended objective, such as the proposed new credit and away from those that are less effective, such as this existing credit for midpoint pegged orders that add liquidity to the Exchange. Accordingly, the Exchange is reducing the amount of this credit from $0.0023 to $0.0018 per share executed.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act,[3] in general, and furthers the objectives of Sections 6(b)(4) and 6(b)(5) of the Act,[4] in particular, in that it provides for the equitable allocation of reasonable dues, fees and other charges among member organizations and issuers and other persons using any facility, and is not designed to permit unfair discrimination between customers, issuers, brokers, or dealers.

The Exchange's proposed changes to its schedule of credits are reasonable in several respects. As a threshold matter, the Exchange is subject to significant competitive forces in the market for equity securities transaction services that constrain its pricing determinations in that market. The fact that this market is competitive has long been recognized by the courts. In *NetCoalition* v. *Securities and Exchange Commission,* the D.C. Circuit stated as follows: ''[n]o one disputes that competition for order flow is 'fierce.' . . . As the SEC explained, '[i]n the U.S. national market system, buyers and sellers of securities, and the broker-dealers that act as their order-routing agents, have a wide range of choices of where to route orders for execution'; [and] 'no exchange can afford to take its market share percentages for granted' because 'no exchange possesses a monopoly, regulatory or otherwise, in the execution of order flow from broker dealers'. . . .''[5]

The Commission and the courts have repeatedly expressed their preference for competition over regulatory intervention in determining prices, products, and services in the securities markets. In Regulation NMS, while adopting a series of steps to improve the current market model, the Commission highlighted the importance of market forces in determining prices and SRO revenues and, also, recognized that current regulation of the market system ''has been remarkably successful in promoting market competition in its broader forms that are most important to investors and listed companies.''[6]

Numerous indicia demonstrate the competitive nature of this market. For example, clear substitutes to the Exchange exist in the market for equity security transaction services. The Exchange is only one of several equity venues to which market participants may direct their order flow. Competing equity exchanges offer similar tiered pricing structures to that of the Exchange, including schedules of rebates and fees that apply based upon member organizations achieving certain volume thresholds.

Within this environment, market participants can freely and often do shift their order flow among the Exchange and competing venues in response to changes in their respective pricing schedules. As such, the proposal represents a reasonable attempt by the Exchange to increase its liquidity and market share relative to its competitors.

The Exchange believes that its proposals are reasonable, equitable, and not unfairly discriminatory to: (1) establish a new $0.0025 per share executed credit for non-displayed orders with midpoint pegging that provide liquidity of at least one million shares average daily value during the month; and (2) reduce from $0.0023 to $0.0018 per share executed its existing credit for all other non-displayed orders with midpoint pegging that provide liquidity to the Exchange. The Exchange assesses a particular need to increase liquidity on the Exchange as a means of improving market quality. The proposal is reasonable in serving that purpose by providing a new incentive for member organizations to add a substantial amount of liquidity to the Exchange, while reducing an existing incentive for member organizations that add a lesser amount of liquidity to the Exchange. As noted above, the Exchange has limited resources available to it to offer its member organizations market-improving incentives, and it allocates those limited resources to those segments of the market where it perceives the need to be greatest and/or where it determines that the incentive is likely to achieve its intended objective. It is reasonable and equitable to address the need for increased liquidity on the Exchange by allocating its limited resources to establish a new credit that rewards member organizations that provide a substantial volume of liquidity to the Exchange and reduce an existing credit that rewards member organizations for providing a lesser volume of liquidity to the Exchange.

The Exchange also believes that these proposals are an equitable allocation and not unfairly discriminatory because all market participants stand to benefit to the extent that the proposal is successful in increasing liquidity on the Exchange and improving market quality. Insofar as the $0.0025 credit will require a member organization to provide a daily average volume of at least one million shares of liquidity on the Exchange during the month, the Exchange believes it is reasonable, equitable, and not unfairly discriminatory for the amount of the proposed credit to be larger than the credit for all other non-displayed orders with midpoint pegging.

Any member organization that is dissatisfied with the proposed credits is free to shift their order flow to competing venues that provide more favorable rates or less stringent qualifying criteria.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

Intramarket Competition

The Exchange does not believe that its proposal will place any category of Exchange participants at a competitive disadvantage. As noted above, all member organizations of the Exchange will benefit from an increase in activity on the Exchange. Moreover, member organizations are free to trade on other venues to the extent they believe that the credits provided are not attractive or

[3] 15 U.S.C. 78f(b).

[4] 15 U.S.C. 78f(b)(4) and (5).

[5] *NetCoalition* v. *SEC,* 615 F.3d 525, 539 (DC Cir. 2010) (quoting Securities Exchange Act Release No. 59039 (December 2, 2008), 73 FR 74770, 74782–83 (December 9, 2008) (SR–NYSEArca–2006–21)).

[6] Securities Exchange Act Release No. 51808 (June 9, 2005), 70 FR 37496, 37499 (June 29, 2005) (''Regulation NMS Adopting Release'').

the qualifying criteria for such credits is too stringent. As one can observe by looking at any market share chart, price competition between exchanges is fierce, with liquidity and market share moving freely between exchanges in reaction to fee and credit changes.

Intermarket Competition

The Exchange believes that the proposed changes to its schedule of credits for non-displayed orders with midpoint pegging will not impose a burden on competition because the Exchange's execution services are completely voluntary and subject to extensive competition both from the other live exchanges and from off-exchange venues, which include alternative trading systems that trade national market system stock. The Exchange notes that it operates in a highly competitive market in which market participants can readily favor competing venues if they deem fee levels at a particular venue to be excessive, or rebate opportunities available at other venues to be more favorable. In such an environment, the Exchange must continually adjust its credits to remain competitive with other exchanges and with alternative trading systems that have been exempted from compliance with the statutory standards applicable to exchanges. Because competitors are free to modify their own credits and fees in response, and because market participants may readily adjust their order routing practices, the Exchange believes that the degree to which credit changes in this market may impose any burden on competition is extremely limited.

The proposed changes to the Exchange's credits for non-displayed orders with midpoint pegging are reflective of this competition because, as a threshold issue, the Exchange is a relatively small market so its ability to burden intermarket competition is limited. In this regard, even the largest U.S. equities exchange by volume only has 17–18% market share, which in most markets could hardly be categorized as having enough market power to burden competition. Moreover, as noted above, price competition between exchanges is fierce, with liquidity and market share moving freely between exchanges in reaction to fee and credit changes. This is in addition to free flow of order flow to and among off-exchange venues which comprises more than 40% of industry volume in recent months.

In sum, the Exchange intends for the proposed changes to credits for non-displayed orders with midpoint pegging to incent member organizations to add liquidity to the Exchange and to thereby contribute to market quality, which is reflective of fierce competition for order flow noted above; however, if the change proposed herein is unattractive to market participants, it is likely that the Exchange will either fail to increase its market share or even lose market share as a result. Accordingly, the Exchange does not believe that the proposed change will impair the ability of member organizations or competing order execution venues to maintain their competitive standing in the financial markets.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A)(ii) of the Act.[7]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is: (i) necessary or appropriate in the public interest; (ii) for the protection of investors; or (iii) otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. 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–Phlx–2022–24 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–Phlx–2022–24. 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 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–Phlx–2022–24 and should be submitted on or before July 12, 2022.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[8]

J. Matthew DeLesDernier,

Assistant Secretary.

[FR Doc. 2022–13151 Filed 6–17–22; 8:45 am]

BILLING CODE 8011–01–P

[7] 15 U.S.C. 78s(b)(3)(A)(ii).

[8] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[SEC File No. 270–255, OMB Control No.3235–0305]

Proposed Collection; Comment Request: Extension; Rule 13e–1

Upon Written Request Copies Available From: Securities and Exchange Commission, Office of FOIA Services, 100 F Street NE, Washington, DC 20549–2736

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 13e–1 (17 CFR 240.13e–1) under the Securities Exchange Act of 1934 (15 U.S.C. 78 *et seq.*) makes it unlawful for an issuer who has received notice that it is the subject of a tender offer made under Section 14(d)(1) of the Exchange Act to purchase any of its equity securities during the tender offer, unless it first files a statement with the Commission containing information required by the rule. This rule is in keeping with the Commission's statutory responsibility to prescribe rules and regulations that are necessary for the protection of investors. The information filed under Rule 13e–1 must be filed with the Commission and is publicly available. We estimate that it takes approximately 10 burden hours per response to provide the information required under Rule 13e–1 and that the information is filed by approximately 10 respondents. We estimate that 25% of the 10 hours per response (2.5 hours) is prepared by the company for a total annual reporting burden of 25 hours (2.5 hours per response × 10 responses).

Written comments are invited on: (a) whether this 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 by August 22, 2022.

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: June 14, 2022.

J. Matthew DeLesDernier,

Assistant Secretary.

[FR Doc. 2022–13159 Filed 6–17–22; 8:45 am]

BILLING CODE 8011–01–P

SMALL BUSINESS ADMINISTRATION

Generic Clearance for Formative Data Collections for Evaluation, Research, and Evidence-Building

ACTION: 30-Day notice.

SUMMARY: The Small Business Administration (SBA) is seeking approval from the Office of Management and Budget (OMB) for the information collection described below. In accordance with the Paperwork Reduction Act and OMB procedures, SBA is publishing this notice to allow all interested members of the public an additional 30 days to provide comments on the proposed collection of information.

DATES: Submit comments on or before July 21, 2022.

ADDRESSES: Submit comments by the deadline stated in the **DATES** section above using any of the following methods:

• *Federal eRulemaking Portal: https://www.regulations.gov.* Follow the instructions for submitting comments. Comments submitted electronically, including attachments to *https://www.regulations.gov,* will be posted to the docket unchanged.

• Office of Information and Regulatory Affairs. *www.reginfo.gov/public/do/PRAMain.* You can find this information collection by selecting ''Currently under Review—Open for Public Comments'' and searching by title, ''Generic Clearance for Formative Data Collections for Evaluation, Research, and Evidence-Building''.

• Small Business Administration. Curtis Rich, Agency Clearance Officer, *curtis.rich@sba.gov;* (202) 205–7030.

FOR FURTHER INFORMATION CONTACT: Requests for additional information should be directed to Shay Meinzer, Lead Program Evaluator, *shay.meinzer@sba.gov,* (202) 539–1429 Curtis Rich, Agency Clearance Officer, *curtis.rich@sba.gov,* (202) 205–7030, or the *SBA Desk Officer,* Office of Information and Regulatory Affairs, Office of Management and Budget, New Executive Office Building, Washington, DC 20503.

SUPPLEMENTARY INFORMATION:

Title: Generic Clearance for Formative Data Collections for Evaluation, Research, and Evidence-Building.

OMB Control Number: 3245–XXXX.

Abstract: This Information Collection Request establishes a new generic clearance to conduct formative studies that inform the U.S. Small Business Administration's (SBA) evaluation, research, and evidence-building activities. Under this generic clearance, the SBA plans to engage in a variety of formative and exploratory data collections with SBA grantees, program and potential program providers and participants, researchers, practitioners, and other stakeholders to fulfill the following goals:

• maintain a rigorous and relevant evaluation and research agenda,

• inform the development of SBA's future evidence-building activities,

• inform the delivery of targeted assistance and workflows related to program and grantee processes,

• inform the development and refinement of recordkeeping and communication systems,

• plan for the provision of programmatic or evidence-capacity-related training or technical assistance,

• obtain grantee or stakeholder input on the development or refinement of program logic models, evaluations, and performance measures, and

• test activities to strengthen programs in preparation for summative evaluations.

The SBA's formative studies will collect data using well-established methodologies, including but not limited to questionnaires and surveys, semi-structured small group discussions or focus groups, observation, interviews, cognitive interviews and user testing. To minimize the burden of information collections approved under this clearance, the SBA will collect information electronically and/or use online collaboration tools, as appropriate, ask for readily available information, and use short, easy-to-complete information collection instruments when possible.

Conducting formative evaluation, research, and evidence-building activities will help the SBA better understand emerging needs and issues, identify evidence gaps, and ensure that SBA leadership and program offices have current data and information to implement SBA programs and initiatives successfully. The data from formative studies will be used to improve internal decision-making and inform future studies but will not be highly systematic nor intended to be statistically representative. Findings from these formative studies will not be generalized to the broader population and are not intended to produce influential information that is expected to have a genuinely clear and substantial impact on major policy decisions. Information gathered may inform future evaluation, research, and evidence-building, which could inform future influential public policy decisions.

The primary purpose of data collected under this generic ICR is not for publication. However, because the formative data collection efforts are intended to inform SBA's decision-making related to evidence-building and programmatic activities, the findings may be incorporated into documents and presentations available to the public. Such documents may include design and method documents, process or journey maps, conceptual frameworks or logic models, background materials for technical workgroups, informational presentations, technical assistance plans, and evaluation or research reports. Shared findings will include a discussion of the limitations regarding generalizability and intended use, and when necessary, results will be labeled as formative or exploratory.

Description of Respondents: The populations to be studied include SBA grantees, program and potential program providers and participants, researchers, practitioners, and other stakeholder groups involved in SBA programs, experts in fields pertaining to SBA evaluation and research, or others involved in conducting SBA evaluation, research, or evidence-building projects.

Estimated Number of Respondents: Below is a preliminary estimate of the aggregate burden hours for this new collection. The Agency will provide refined estimates of burden in subsequent notices.

Estimated Number of Respondents per Activity: One response per respondent per activity.

Estimated Annual Responses: 900.

Estimated Annual Hour Burden: 832.5.

The public is invited to submit comments regarding any aspect of this information collection, including the following: (1) The necessity and utility of the proposed information collection for the proper performance of the Agency's functions; (2) the accuracy of the estimated burden; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) the use of automated collection techniques or other forms of information technology to minimize the information collection burden of those who are required to respond to the request for information.

Curtis B. Rich,

Agency Clearance Officer.

[FR Doc. 2022–13178 Filed 6–17–22; 8:45 am]

BILLING CODE 8026–09–P

SMALL BUSINESS ADMINISTRATION

National Small Business Development Center Advisory Board; Meeting

AGENCY: Small Business Administration.

ACTION: Notice of open Federal Advisory Committee meeting.

SUMMARY: The SBA is issuing this notice to announce the date, time and agenda for a meeting of the National Small Business Development Center Advisory Board. The meeting will be open to the public; however, advance notice of attendance is required.

DATES: Tuesday, July 26, 2022, at 4:00 p.m. EDT

ADDRESSES: Meeting will be held via Microsoft Teams.

FOR FURTHER INFORMATION CONTACT: Rachel Karton, Office of Small Business Development Centers, U.S. Small Business Administration, 409 Third Street SW, Washington, DC 20416; *Rachel.newman-karton@sba.gov;* 202–619–1816.

If anyone wishes to be a listening participant or would like to request accommodations, please contact Rachel Karton at the information above.

SUPPLEMENTARY INFORMATION: Pursuant to section l0(a) of the Federal Advisory Committee Act (5 U.S.C. Appendix 2), the SBA announces the meetings of the National SBDC Advisory Board. This Board provides advice and counsel to the SBA Administrator and Associate Administrator for Small Business Development Centers.

Purpose

The purpose of the meeting is to discuss the following issues pertaining to the SBDC Program:

- Administration Priorities
- Strategy for Increasing Board Awareness and Understanding of the SBDC Program
- ASBDC Conference—Townhall Planning

Andrienne Johnson,

Committee Management Officer.

[FR Doc. 2022–13214 Filed 6–17–22; 8:45 am]

BILLING CODE 8026–03–P

DEPARTMENT OF STATE

[Public Notice 11764]

Proposal To Extend Cultural Property Agreement Between the United States and Belize

ACTION: Public notice.

SUMMARY: Proposal to extend the *Memorandum of Understanding Between the Government of the United States of America and the Government of Belize Concerning the Imposition of Import Restrictions on Categories of Archaeological Material of Belize.*

FOR FURTHER INFORMATION CONTACT: Andrew Zonderman, Cultural Heritage Center, Bureau of Educational and Cultural Affairs: (202) 718–9481; *culprop@state.gov;* include ''Belize'' in the subject line.

SUPPLEMENTARY INFORMATION: The Assistant Secretary of State for Educational and Cultural Affairs proposes an extension of the *Memorandum of Understanding Between the Government of the United States of America and the Government of Belize Concerning the Imposition of Import Restrictions on Categories of Archaeological Material of Belize.* The Cultural Heritage Center website provides instructions for public comment and additional information on the request, including categories of material that may be included in import restrictions: *https://eca.state.gov/cultural-property-advisory-committee-meeting-july-26-27-2022.* This notice is published pursuant to authority vested in the Assistant Secretary of State for Educational and Cultural Affairs and pursuant to 19 U.S.C. 2602(f)(1).

Allison Davis,

Executive Director, Cultural Property Advisory Committee, Bureau of Educational and Cultural Affairs, Department of State.

[FR Doc. 2022–13187 Filed 6–17–22; 8:45 am]

BILLING CODE 4710–05–P

DEPARTMENT OF STATE

[Public Notice 11766]

Cultural Property Advisory Committee; Notice of Meeting

ACTION: Notice of meeting.

SUMMARY: The Department of State announces the location, dates, times, and agenda for the next meeting of the Cultural Property Advisory Committee (''the Committee'').

DATES AND TIMES: The Committee will meet July 26 and 27, 2022, from 9:00 a.m. to 5:00 p.m. (EDT).

PARTICIPATION: The public may participate in, or observe, the open session on July 26, 2022, from 2:00 p.m. to 3:00 p.m. (EDT). More information below.

FOR FURTHER INFORMATION CONTACT: Allison Davis, Bureau of Educational and Cultural Affairs—Cultural Heritage Center, (202–702–1166) (*culprop@state.gov*).

SUPPLEMENTARY INFORMATION: The Assistant Secretary of State for Educational and Cultural Affairs calls a meeting of the Cultural Property Advisory Committee (''the Committee'') in accordance with the Convention on Cultural Property Implementation Act (19 U.S.C. 2601–2613) (''the Act''). A portion of this meeting will be closed to the public pursuant to 5 U.S.C. 552b(c)(9)(B) and 19 U.S.C. 2605(h).

Meeting Agenda: The Committee will review the proposed extension of the cultural property agreement with the Government of Belize and the proposed extension of the cultural property agreement with the Government of the State of Libya.

The Open Session: The general public can observe the virtual open session on July 26, 2022. Registered participants may provide oral comments for a maximum of five (5) minutes. The Department provides specific instructions on how to observe or provide oral comments at the open session at *https://eca.state.gov/cultural-property-advisory-committee-meeting-july-26-27-2022.*

Oral Comments: Register to speak at the open session by sending an email with your name and organizational affiliation, as well as any requests for reasonable accommodation, to *culprop@state.gov* by July 19, 2022. Written comments are not required to make an oral comment during the open session.

Written Comments: The Committee will review written comments if received by 11:59 p.m. (EDT) on July 19, 2022. Written comments may be submitted in two ways, depending on whether they contain confidential information:

▪ *General Comments:* For general comments, use *http://www.regulations.gov,* enter the docket [DOS–2022–0015], and follow the prompts.

▪ *Confidential Comments:* For comments that contain privileged or confidential information (within the meaning of 19 U.S.C. 2605(i)(1)), please email submissions to *culprop@state.gov.* Include ''Belize'' and/or ''Libya'' in the subject line.

▪ *Disclaimer:* The Cultural Heritage Center website contains additional information about each agenda item, including categories of archaeological and ethnological material that may be included in import restrictions: *https://eca.state.gov/cultural-property-advisory-committee-meeting-july-26-27-2022.* Comments should relate specifically to the determinations specified in the Act at 19 U.S.C. 2602(a)(1). Written comments submitted via regulations.gov are not private and are posted at *https://www.regulations.gov.* Because written comments cannot be edited to remove any personally identifying or contact information, we caution against including any such information in an electronic submission without appropriate permission to disclose that information (including trade secrets and commercial or financial information that are privileged or confidential within the meaning of 19 U.S.C. 2605(i)(1)). We request that any party soliciting or aggregating written comments from other persons inform those persons that the Department will not edit their comments to remove any identifying or contact information and that they therefore should not include any such information in their comments that they do not want publicly disclosed.

Allison Davis,

Executive Director, Cultural Property Advisory Committee, Bureau of Educational and Cultural Affairs, Department of State.

[FR Doc. 2022–13191 Filed 6–17–22; 8:45 am]

BILLING CODE 4710–05–P

DEPARTMENT OF STATE

[Public Notice 11765]

Proposal To Extend Cultural Property Agreement Between the United States and Libya

ACTION: Public notice.

SUMMARY: Proposal to extend the *Memorandum of Understanding Between the Government of the United States of America and the Government of Libya Concerning the Imposition of Import Restrictions on Categories of Archaeological and Ethnological Material of Libya.*

FOR FURTHER INFORMATION CONTACT: Susan Cooke, Cultural Heritage Center, Bureau of Educational and Cultural Affairs: (202) 538–3091; *culprop@state.gov;* include ''Libya'' in the subject line.

SUPPLEMENTARY INFORMATION: The Assistant Secretary of State for Educational and Cultural Affairs proposes an extension of the *Memorandum of Understanding Between the Government of the United States of America and the Government of Libya Concerning the Imposition of Import Restrictions on Categories of Archaeological and Ethnological Material of Libya.* The Cultural Heritage Center website provides instructions for public comment and additional information on the request, including categories of archaeological and ethnological material that may be included in import restrictions: *https://eca.state.gov/cultural-property-advisory-committee-meeting-july-26-27-2022.* This notice is published pursuant to authority vested in the Assistant Secretary of State for Educational and Cultural Affairs and pursuant to 19 U.S.C. 2602(f)(1).

Allison Davis,

Executive Director, Cultural Property Advisory Committee, Bureau of Educational and Cultural Affairs, Department of State.

[FR Doc. 2022–13190 Filed 6–17–22; 8:45 am]

BILLING CODE 4710–05–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

[Docket No.: FAA–2022–0273; Summary Notice No. 2022–26]

Petition for Exemption; Summary of Petition Received; Aviation Specialties Unlimited, Inc.

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Notice.

SUMMARY: This notice contains a summary of a petition seeking relief from specified requirements of Federal Aviation Regulations. The purpose of this notice is to improve the public's awareness of, and participation in, the FAA's exemption process. Neither publication of this notice nor the inclusion nor omission of information in the summary is intended to affect the legal status of the petition or its final disposition.

DATES: Comments on this petition must identify the petition docket number and must be received on or before June 27, 2022.

ADDRESSES: Send comments identified by docket number FAA–2022–0273 using any of the following methods:

• *Federal eRulemaking Portal:* Go to *http://www.regulations.gov* and follow the online instructions for sending your comments electronically.

• *Mail:* Send comments to Docket Operations, M–30; U.S. Department of Transportation, 1200 New Jersey Avenue SE, Room W12–140, West Building Ground Floor, Washington, DC 20590–0001.

• *Hand Delivery or Courier:* Take comments to Docket Operations in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue SE, Washington, DC 20590–0001, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

- *Fax:* Fax comments to Docket Operations at (202) 493–2251.

Privacy: 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 *http://www.regulations.gov,* as described in the system of records notice (DOT/ALL–14 FDMS), which can be reviewed at *http://www.dot.gov/privacy.*

Docket: Background documents or comments received may be read at *http://www.regulations.gov* at any time. Follow the online instructions for accessing the docket or go to the Docket Operations in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue SE, Washington, DC 20590–0001, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Alphonso Pendergrass (202) 267–4713, Office of Rulemaking, Federal Aviation Administration, 800 Independence Avenue SW, Washington, DC 20591.

This notice is published pursuant to 14 CFR 11.85.

Issued in Washington, DC.

Angela O. Anderson,

Director, Regulatory Support Division, Office of Rulemaking.

PETITION FOR EXEMPTION

Docket No.: FAA–2022–0273.

Petitioner: Aviation Specialties Unlimited, Inc.

Section(s) of 14 CFR Affected: §§ 91.9(a) and 91.205(h)(7).

Description of Relief Sought: Aviation Specialties Unlimited, Inc. (ASU) petitions for relief from 14 CFR §§ 91.205(h)(7) and 91.9(a) to conduct Airplane Night Vision Goggle (ANVG) operations under part 135 and to provide flight training to other part 135 operators, part 141 training, FAA Aviation Safety Inspector Training, international students and organizations, agricultural aircraft operators, public aircraft operators, and internal annual and recurrent training with an unreliable or not normally functioning radar (radio) altimeter. These operations will take place under visual flight rules (VFR) conditions at night, to include night landings and takeoffs from General Aviation airports.

[FR Doc. 2022–13145 Filed 6–17–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Waiver of Aeronautical Land Use Assurance: Independence Municipal Airport (IDP), Independence, KS

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of Intent of Waiver with respect to land use change from aeronautical to non-aeronautical.

SUMMARY: The Federal Aviation Administration (FAA) is considering a proposal from the City of Independence, KS, to release a 7.857 acre parcel of land from the federal obligation dedicating it to aeronautical use and to authorize this parcel to be used for revenue-producing, non-aeronautical purposes.

DATES: Comments must be received on or before July 21, 2022.

ADDRESSES: Comments on this application may be mailed or delivered to the FAA at the following address: Amy J. Walter, Airports Land Specialist, Federal Aviation Administration, Airports Division, ACE–620G, 901 Locust Room 364, Kansas City, MO 64106. In addition, one copy of any comments submitted to the FAA must be mailed or delivered to: Kelly Paussauer, City Manager, City of Independence, 811 W Laurel Street, Independence, KS 67301, (620) 332–2506.

FOR FURTHER INFORMATION CONTACT: Amy J. Walter, Airports Land Specialist, Federal Aviation Administration, Airports Division, ACE–620G, 901 Locust Room 364, Kansas City, MO 64106, Telephone number (816) 329–2603, Fax number (816) 329–2611, email address: *amy.walter@faa.gov.*

SUPPLEMENTARY INFORMATION: The FAA invites public comment on the request to change three parcels of land totaling 7.857 acres of airport property at the Independence Municipal Airport (IDP) from aeronautical use to non-aeronautical for revenue producing use. This parcel will be leased to VSE Aviation Services, LLC to expand their existing building and construct a parking lot.

No airport landside or airside facilities are presently located on this parcel, nor are airport developments contemplated in the future. There is no current use of the surface of the parcel. The parcel will serve as a revenue producing lot with the proposed change from aeronautical to non-aeronautical. The request submitted by the Sponsor meets the procedural requirements of the Federal Aviation Administration and the change to non-aeronautical status of the property does not and will not impact future aviation needs at the airport. The FAA may approve the request, in whole or in part, no sooner than thirty days after the publication of this Notice.

The following is a brief overview of the request:

The Independence Municipal Airport (IDP) is proposing the use release of 7.857 acres of land from aeronautical to non-aeronautical. The use release of land is necessary to comply with Federal Aviation Administration Grant Assurances that do not allow federally acquired airport property to be used for non-aviation purposes. The rental of the subject property will result in the land at the Independence Municipal Airport (IDP) being changed from aeronautical to non-aeronautical use and release the lands from the conditions of the Airport Improvement Program Grant Agreement Grant Assurances. In accordance with 49 U.S.C. 47107(c) (2) (B) (i) and (iii), the airport will receive fair market rental value for the property. The annual income from rent payments will generate a long-term, revenue-producing stream that will further the Sponsor's obligation under FAA Grant Assurance number 24, to make the Independence Municipal Airport as financially self-sufficient as possible. Following is a legal description of the subject airport property at the Independence Municipal Airport (IDP):

A tract of land located in a portion of the Southeast Quarter of Section 21, Township 33 South, Range 15 East of the 6th P.M., Montgomery County, Kansas, being more particularly described as written by William A. Booe, LS 1046, 5–5–2022: Commencing at the Southeast corner of the Southeast Quarter; thence S 88°15′13″ W, along the South line of the Southeast Quarter a distance of 1655. 78 feet; thence N 01°24′44″ W, a distance of 395.10 feet to the Point of Beginning; thence N 01°24′44″ W, a distance of 610.00 feet; thence S 88°35′16″ W, a distance of 321. 77 feet; thence S 01°24′44″ E, a distance of 610.00 feet; thence N 88°35′16″ E, a distance of 321. 77 feet to the Point of Beginning. Containing 4.506 acres. And a tract of land located in a portion of the Southeast Quarter of Section 21, Township 33 South, Range 15 East of the 6th P.M., Montgomery County, Kansas, being more particularly described as written by William A. Booe, LS 1046, 5–5–2022: Commencing at the Southeast corner of the Southeast Quarter; thence S 88°15′13″ W, along the South line of the Southeast Quarter a distance of 1655. 78 feet; thence N 01°24′44″ W, a distance of 1005.10 feet;

thence S 88°35′16″ W, a distance of 321.77 feet; thence S 89°35′39″ W, a distance of 80.00 feet; thence S 88°47′00″ W, a distance of 158.02 feet to the Point of Beginning; thence S 88°47′00″ W, a distance of 128.21 feet; thence S 01°20′36″ E, a distance of 128.32 feet; thence N 88°47′00″ E, a distance of 128.53 feet; thence N 01°29′10″ W, a distance of 128.32 feet to the Point of Beginning. Containing 0.378 acres. And a tract of land located in a portion of the Southeast Quarter of Section 21, Township 33 South, Range 15 East of the 6th P.M., Montgomery County, Kansas, being more particularly described as written by William A. Booe, LS 1046, 5–5–2022: Commencing at the Southeast corner of the Southeast Quarter; thence S 88°15′13″ W, along the South line of the Southeast Quarter a distance of 1655.78 feet; thence N 01°24′44″ W, a distance of 1005.10 feet; thence S 88°35′16″ W, a distance of 321. 77 feet; thence S 89°35′39″ W, a distance of 80.00 feet to the point of beginning; thence S 88°47′00″ W, a distance of 158.02 feet; thence S 01°29′10″ E a distance of 128.32 feet; thence S 88°47′00″ W a distance of 128.53 feet; thence S 01°20′36″ E a distance of 380.38 feet; thence N 88°51′48″ E a distance of 287.45 feet; thence N 01°28′49″ W a distance of 509.10 feet to the point of beginning. Containing 2.973 acres.

Any person may inspect, by appointment, the request in person at the FAA office listed above. In addition, any person may upon request, inspect the application, notice and other documents determined by the FAA to be related to the application in person at the Independence Municipal Airport.

Issued in Kansas City, MO, on June 14, 2022.

James A. Johnson,

Director, FAA Central Region, Airports Division.

[FR Doc. 2022–13195 Filed 6–17–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

[FHWA Docket No. FHWA–2020–0008]

Surface Transportation Project Delivery Program; Ohio Department of Transportation Audit #4 Report

AGENCY: Federal Highway Administration (FHWA), U.S. Department of Transportation (DOT).

ACTION: Notice.

SUMMARY: The Moving Ahead for Progress in the 21st Century Act (MAP–21) established the Surface Transportation Project Delivery Program that allows a State to assume FHWA's environmental responsibilities for environmental review, consultation, and compliance under the National Environmental Policy Act (NEPA) for Federal highway projects. When a State assumes these Federal responsibilities, the State becomes solely responsible and liable for carrying out the responsibilities it has assumed, in lieu of FHWA. This program mandates annual audits during each of the first 4 years of State participation to ensure compliance with program requirements. This notice finalizes the findings of the fourth and last audit report for the Ohio Department of Transportation (ODOT).

FOR FURTHER INFORMATION CONTACT: Ms. Megan Cogburn, Office of Project Development and Environmental Review, (202) 366–2056, *megan.cogburn@dot.gov;* or Mr. Patrick Smith, Office of the Chief Counsel, (202) 366–1345, *patrick.c.smith@dot.gov;* Federal Highway Administration, U.S. Department of Transportation, 1200 New Jersey Avenue SE, Washington, DC 20590. Office hours are from 8:00 a.m. to 4:30 p.m., e.t., Monday through Friday, except Federal holidays.

SUPPLEMENTARY INFORMATION:

Electronic Access

An electronic copy of this notice may be downloaded from the specific docket page at *www.regulations.gov.*

Background

The Surface Transportation Project Delivery Program, codified at 23 United States Code (U.S.C.) 327, commonly known as the NEPA Assignment Program, allows a State to assume FHWA's responsibilities for environmental review, consultation, and compliance for Federal highway projects. When a State assumes these Federal responsibilities, the State becomes solely liable for carrying out the responsibilities it has assumed, in lieu of the FHWA. The ODOT published its application for assumption under the NEPA Assignment Program on April 12, 2015, and made it available for public comment for 30 days. After considering public comments, ODOT submitted its application to FHWA on May 27, 2015. The application served as the basis for developing the memorandum of understanding (MOU) that identifies the responsibilities and obligations that ODOT would assume. The FHWA published a notice of the draft MOU in the **Federal Register** on October 15, 2015, at 80 FR 62153, with a 30-day comment period to solicit the views of the public and Federal agencies. After the comment period closed, FHWA and ODOT considered comments and executed the MOU. The FHWA and ODOT amended the MOU on June 6, 2018, to update recent national program guidance and objectives for consistency with other States under the NEPA Assignment Program. The FHWA and ODOT renewed the MOU on December 14, 2020, for a new 5-year term effective December 28, 2020.

Section 327(g) of Title 23, U.S.C., requires the Secretary to conduct annual audits to ensure compliance with the MOU during each of the first 4 years of State participation and, after the fourth year, monitor compliance. The results of each audit must be made available for public comment. The first audit report of ODOT compliance was finalized on July 7, 2017. The second audit report of ODOT compliance was finalized on October 3, 2018. The third audit report was finalized on November 13, 2019. The FHWA published a notice in the **Federal Register** on June 17, 2020, at 85 FR 36661, soliciting public comment for 30 days on the draft fourth audit report. The FHWA received comments on the draft report from the American Road and Transportation Builders Association (ARTBA) and ODOT. The ARTBA's comments supported the Surface Transportation Project Delivery Program and did not relate specifically to Audit #4. The comments submitted by ODOT on the draft audit report were substantially similar to comments that had previously been discussed by the Audit Team with ODOT during the development of the audit report. The FHWA considered these comments during the audit process and determined they did not warrant changes to FHWA's observations. This notice announces the availability of the fourth and final audit report for ODOT.

Authority: Section 1313 of Public Law 112–141; Section 6005 of Public Law 109–59; 23 U.S.C. 327; 23 CFR part 773.

Stephanie Pollack,

Deputy Administrator, Federal Highway Administration.

Surface Transportation Project Delivery Program

Final FHWA Audit #4 of the Ohio Department of Transportation

July 29, 2019 to August 2, 2019

Executive Summary

This is a report of the Federal Highway Administration's (FHWA) fourth and final audit of the Ohio Department of Transportation's (ODOT) assumption of National Environmental Policy Act (NEPA) responsibilities. A team of FHWA staff (the team) conducted the audit. The ODOT made the effective date of the project-level NEPA and environmental review responsibilities it assumed from FHWA on December 28, 2015, as specified in a memorandum of understanding (MOU) signed on December 11, 2015, and amended on June 6, 2018. Within ODOT, the Division of Planning Office of Environmental Services (OES) is responsible for delivering the environmental program. This audit examined ODOT's performance under the MOU regarding responsibilities and obligations assigned therein.

Prior to the on-site visit, the team performed reviews of ODOT's project NEPA approval documentation in EnviroNet (ODOT's official environmental document filing system). This audit consisted of a review of a statistically valid random sample of 72 project files out of 1,113 approved documents for Federal-aid projects in ODOT's EnviroNet system with an environmental approval date between April 1, 2018, and March 31, 2019. The team conducted 100 percent sampling of the 2 Environmental Impact Statement (EIS) re-evaluations, 5 Environmental Assessment (EA) re-evaluations, and 1 new EA approved by ODOT as part of the sample. The team also reviewed ODOT's response to the pre-audit information request (PAIR) and ODOT's Self-Assessment Report. In addition, the team reviewed ODOT's environmental processes, manuals, and guidance; ODOT NEPA Quality Control and Quality Assurance Processes and Procedures; and the ODOT NEPA Assignment Training Plan (collectively, ''ODOT procedures''). The team conducted an on-site review during the week of July 29 to August 2, 2019. The team conducted interviews with ODOT's Central Office staff on July 29, 2019, and with staff from three district offices on July 30, 2019. The team also interviewed staff with the U.S. Fish and Wildlife Service (USFWS) on August 9, 2019, as part of the review.

Overall, the team found ODOT to be in substantial compliance with the terms of the MOU. The ODOT continues to make reasonable progress in implementing the NEPA Assignment Program based on the results of four audits, which demonstrates commitment to the success of the program. For Audit #4, the team found zero non-compliance observations, but did note one successful practice and four general observations. The FHWA looks forward to continuing to work collaboratively with ODOT during the monitoring phase of the program.

Background

The NEPA Assignment Program allows a State to assume FHWA's responsibilities for review, consultation, and compliance with environmental laws for Federal-aid highway projects. When a State assumes these responsibilities, it becomes solely responsible and liable for carrying out the responsibilities assumed, in lieu of FHWA.

The State of Ohio, represented by ODOT, completed the application process and entered an MOU with FHWA on December 28, 2015, which was amended on June 6, 2018. The FHWA and ODOT renewed the MOU for a new 5-year term effective December 28, 2020. With this MOU, ODOT assumed FHWA's project approval responsibilities under NEPA and NEPA-related Federal environmental laws.

The FHWA must conduct four annual compliance audits of ODOT's compliance with the provisions of the MOU. Audits serve as FHWA's primary mechanism of determining ODOT's compliance with the MOU, applicable Federal laws and policies, evaluating ODOT's progress toward achieving the performance measures identified in the MOU, and collecting information needed for the Secretary's annual report to Congress.

The team provided a draft of the Audit #4 report to ODOT for its review. The team considered ODOT's comments in the draft made available for public review and comment. The FHWA considered the public comments received on the draft in finalizing this report.

Scope and Methodology

The team conducted a careful examination of the ODOT NEPA Assignment Program through a review of ODOT procedures and project documentation, ODOT's PAIR response, and the Self-Assessment summary report, as well as interviews with ODOT central office and district environmental staff and resource agency staff. This review focused on the following six NEPA Assignment Program elements: (1) program management; (2) documentation and records management; (3) quality assurance/quality control (QA/QC); (4) legal sufficiency; (5) performance measurement; and, (6) training.

The PAIR consisted of 18 questions based on the responsibilities assigned to ODOT in the MOU. The team reviewed ODOT's PAIR response and compared the responses to ODOT's written procedures. The team utilized ODOT's responses to draft interview questions to clarify information in ODOT's PAIR response.

The ODOT provided its NEPA Assignment Self-Assessment summary report 30 days prior to the team's on-site review. The team considered this summary report both in focusing on issues during the project file reviews and in drafting interview questions. The team compared the report against the previous year's Self-Assessment report and the requirements in the MOU to identify any trends.

Between April 1 and May 31, 2019, the team conducted a review using a statistically valid random sample of 72 project files out of 1,113 approved documents for Federal-aid projects in ODOT's EnviroNet system with an environmental approval date between April 1, 2018, and March 31, 2019. The team conducted a 100 percent sampling of the 2 EIS re-evaluations, 5 EA re-evaluations, and 1 new EA approved by ODOT as part of the audit. The projects reviewed represented all NEPA classes of action available, with coverage of 11 out of 12 of the ODOT Districts and the Ohio Rail Development Commission (ORDC) within those districts.

In addition, the team reviewed ODOT's project file review associated with its self-assessment to determine if ODOT evaluated its projects in a similar fashion and using similar standards to that of the Federal portion of this review. The ODOT reviewed projects within the same sampling period as FHWA. The ODOT reviewed a statistically valid random sample of 199 projects, including 154 categorically excluded (CE) c-listed projects, 38 CE d-listed projects, 5 EAs, and 2 EISs. The ODOT's review included projects in all districts including ORDC and included representatives of all classes of action.

During the on-site review week, the team conducted interviews with 20 ODOT staff members at the central office and three districts: District 2 (Bowling Green), District 3 (Ashland), and District 8 (Lebanon). Interviewees included ODOT OES management and subject matter experts, District Environmental Coordinators (DEC), and environmental staff, representing a diverse range of expertise and experience. These interviews focused on NEPA Assignment with an emphasis on items where additional information was necessary to complete the review.

The team conducted a phone interview with USFWS on August 9, 2019, to determine if the resource agency had any potential concerns regarding ODOT's performance and relationships with partner resource agencies. The USFWS reported that ODOT continues to perform well and offered no concern at the program-level. The ODOT staff continues to partner with Agency staff in the delivery of projects and for the protection of threatened and endangered species.

The team identified gaps between the information from the desktop review of ODOT procedures, PAIR, Self-Assessment, project file review, and interviews. The team documented the results of its reviews and interviews and consolidated the results into related topics or themes. From these topics or themes, the team developed successful practices and review observations.

Overall, the team found ODOT to be in substantial compliance with the terms of the MOU. The ODOT continues to make reasonable progress in management of the NEPA Assignment Program based on the results of four audits, which demonstrates commitment to the success of the program. For Audit #4, the team found zero non-compliance observations, but did note one successful practice and four general observations.

The FHWA team urges ODOT to monitor and make additional improvements to the program for continued success moving forward.

Successful Practices and General Observations

This section summarizes one successful practice, as well as four observations on issues that ODOT may want to consider as areas to improve. Further information on these successful practices and observations are in the following subsections that address the six MOU program elements: program management; document and records management; QA/QC; legal sufficiency; performance measures; and training.

Program Management

Successful Practice 1: ODOT developed improvements to EnviroNet to provide access to the federally recognized American Indian Tribes with ties to Ohio.

The ODOT has developed an enhancement to EnviroNet, which allows Tribal representatives to customize a Tribal profile and receive notifications and project information based on their preferences. This notification system allows Tribes to tailor the types of projects, locations of projects, and the point in the project development process for which they want to be notified (via email) and become involved. These upgrades also provide the Tribes the opportunity to enter comments and receive responses for each project. It is important to note that this system does not replace personal relationships with Tribal representatives as this is an important part of Tribal consultation. The ODOT and FHWA will continue to host on-site meetings for the Tribes and agencies to consult on the Federal-aid highway program, projects, concerns, and processes in Ohio.

Observation 1: There are opportunities for ODOT to continue to improve upon the identification and engagement of Environmental Justice (EJ) populations to ensure full and fair participation in the transportation decisionmaking process.

During each of the previous audits, both FHWA and ODOT identified project-level compliance issues for EJ and public involvement (PI). The team notes and appreciates ongoing efforts by ODOT to improve its processes, documentation, and training in the areas of EJ and PI in response to previous audits and self-assessments. While substantial progress has been made in these areas, there are opportunities for ODOT to continue to improve upon the identification and engagement of EJ populations to ensure full and fair participation in the transportation decisionmaking process.

During this year's audit, the team found that ODOT tends to use general PI activities in lieu of targeted EJ outreach and engagement activities. As a result, ODOT's CE documentation does not always include a discussion of the steps taken to provide meaningful opportunities for PI by members of minority and/or low-income populations in the decisionmaking process, including the identification of potential effects, alternatives, and mitigation measures.

Identification of EJ populations, soliciting and understanding their issues or concerns, and actively engaging them throughout project development is a continuing concern for FHWA. The team encourages ODOT to continue to improve its EJ identification and outreach practices to ensure full and fair participation in the transportation decisionmaking process.

Documentation and Records Management

Observation 2: Opportunities exist to improve documentation by the ODOT Districts and LPAs in response to ODOT's File Management Plan and other guidance.

Over the course of NEPA assignment, ODOT has developed many procedures relating to the NEPA process to improve its processes and meet Federal requirements. The updates included changes to ODOT's internal documentation and filing guidelines and updates to EnviroNet. These changes appear to have positively impacted the program and we continue to support ODOT's use of these procedures.

The team heard throughout the Audit #4 process that some districts had concerns about the requirements in the ODOT NEPA File Management and Documentation Guidance and other applicable guidance that did not allow the CE to include what they viewed as decision documents.

The districts' concerns and resulting levels of understanding of ODOT guidance appear to support the findings of both the team and ODOT's OES. The team and ODOT's Self-Assessment both noted during the project file reviews that the districts and local public agencies (LPA) exhibit documentation inconsistencies pursuant to ODOT's File Management Plan and related guidance. Between FHWA and ODOT data, approximately 31 percent of projects exhibited these types of inconsistencies.

The team met with ODOT to discuss individual inconsistencies noted by both FHWA and ODOT OES during this audit. The ODOT evaluated these findings and then communicated them individually with the districts. The ODOT remains committed to improvements in documentation, with plans to continue updates to EnviroNet and guidance as needed and with the training required to deliver effective results.

Observation 3: Opportunities exist for ODOT to develop written procedures and guidance for the re-evaluation of EAs and EISs.

The team found that ODOT has robust guidance for documentation expectations for CEs and specific resource areas. However, during the project file review, the team and ODOT both noted inconsistencies regarding the preparation of re-evaluations for EAs and EISs. While there is no required format for written re-evaluations, a written re-evaluation should briefly document any changes in the project, applicable laws or regulations, the project study area, and any resulting impacts (beneficial and/or adverse). The re-evaluation should succinctly acknowledge areas where there are few or no changes, and document any public or agency consultation, if appropriate and undertaken. A conclusion or finding as to whether the previous NEPA document remains valid, should be plainly evident.

During the audit, the team found one of the two EIS re-evaluations and three of the five EA re-evaluations had inconsistencies related to FHWA regulation, policy, and guidance on re-evaluation requirements discussed above. During the onsite interviews, several ODOT staff members agreed that it could be beneficial to develop a written procedure to establish expectations and memorialize ODOT's re-evaluation process in compliance with Federal requirements. The team also made note that in ODOT's Self-Assessment, several ODOT districts requested development of re-evaluation guidance. Based on these concerns, the team supports consideration of the development of written procedures and guidance for the re-evaluation of EAs and EISs to reduce risk to ODOT's program.

Quality Assurance/Quality Control (QA/QC)

Observation 4: Opportunities exist to improve QA/QC procedures relevant to c-listed CE documentation.

The ODOT NEPA Quality Control and Quality Assurance Processes and Procedures, dated April 6, 2017, indicates d-listed CEs (D2 and D3 actions per ODOT's CE guidance), EAs, and EISs will be peer reviewed by OES staff and c-listed and d-listed CEs (D1 actions per ODOT's guidance) will be reviewed by district environmental staff prior to review and approval by the DEC. The team learned through all four audits that district staff have their own methods of conducting reviews which may lead to inconsistencies across the districts in the review of c-listed projects. EnviroNet provides some programmed QA/QC. The system itself does not identify missing support documentation under the project file tab, or mistakes in data entry into the system, which comprise most of the errors found by both FHWA and ODOT's Self-Assessment. A more robust QA/QC process for c-level projects could reduce risk and improve efficiency in ODOT's program. In addition, there is no stand-alone QA/QC training to train ODOT personnel per ODOT's expectations and guidance.

Legal Sufficiency Review

The ODOT did not have any documents that required legal sufficiency reviews during the Audit #4 timeframe; therefore, the team had no observations related to legal sufficiency.

Performance Measures

The MOU Section 10.2 requires the development of performance measures. The ODOT has refined its performance measures to provide a better overall indication of ODOT's execution of its responsibilities as assigned by the MOU. The team found evidence that the results obtained through the performance measures are allowing ODOT to make appropriate changes as it manages its environmental program. The team had no observations related to performance measures.

Training Program

Previous audits noted that ODOT had a robust environmental training program and provided adequate budget and time for staff to access a variety of internal and external training. The ODOT continues to enhance its traditional training program and plan with the development of additional online courses. The ODOT currently offers 28 online trainings for free to ODOT staff, consultants, LPAs, partner agencies, and anyone else who desires to take them. The ODOT utilizes the Ohio's Local Technical Assistance Program to manage the courses. This free online training makes training more accessible to a greater number of staff and consultants and allows consistent, self-paced, and individualized training. Also, the previous audit noted ODOT's training plan required environmental consultants to take the pre-qualification training courses and all ODOT environmental staff (both central and district offices) take all environmental courses.

The team encourages ODOT to broaden its training program and training collaboration with other Federal agencies and environmental organizations. The team commends ODOT for its efforts in taking external ecological and cultural resource courses, but feels there is room for improvement exploring external human environment training. During the interviews, ODOT staff noted they are reluctant to take National Highway Institute training courses because of their broad perspective; however, they did express interest in taking specialized FHWA training that focus on specific topics such as the recently offered FHWA Resource Center Air Quality Workshop. The ODOT also expressed interest in getting assistance from FHWA to develop training case studies that were relevant to its transportation program, which the audit team supports. The team had no observations related to training.

Finalization of Report

The FHWA published a notice in the **Federal Register** on June 17, 2020, at 85 FR 36661, soliciting public comment for 30 days on the draft fourth audit report. The FHWA received comments on the draft report from the American Road and Transportation Builders Association (ARTBA) and ODOT. The ARTBA's comments supported the Surface Transportation Project Delivery Program and did not relate specifically to Audit #4. The comments submitted by ODOT on the draft audit report were substantially similar to comments that had previously been discussed by the Audit Team with ODOT during the development of the audit report. The FHWA considered these comments during the audit process and determined they did not warrant changes to FHWA's observations. This final report is substantively the same as the draft version. The FHWA looks forward to continuing to work collaboratively with ODOT during the monitoring phase of the program.

[FR Doc. 2022–13172 Filed 6–17–22; 8:45 am]

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DEPARTMENT OF TRANSPORTATION

Federal Transit Administration

Limitation on Claims Against Proposed Public Transportation Project—East-West Bus Rapid Transit (BRT) Project

AGENCY: Federal Transit Administration (FTA), Department of Transportation (DOT).

ACTION: Notice.

SUMMARY: This notice announces final environmental actions taken by the Federal Transit Administration (FTA) regarding the East-West Bus Rapid Transit (BRT) Project in Madison, Wisconsin. The purpose of this notice is to announce publicly the environmental decisions by FTA on the subject project and to activate the limitation on any claims that may challenge these final environmental actions.

DATES: A claim seeking judicial review of FTA actions announced herein for the listed public transportation project will be barred unless the claim is filed on or before November 18, 2022.

FOR FURTHER INFORMATION CONTACT: Kathryn Loster, Assistant Chief Counsel, Office of Chief Counsel, (312) 353–3869, or Saadat Khan, Environmental Protection Specialist, Office of Environmental Programs, (202) 366–9647. FTA is located at 1200 New Jersey Avenue SE, Washington, DC 20590. Office hours are from 9:00 a.m. to 5:00 p.m., Monday through Friday, except Federal holidays.

SUPPLEMENTARY INFORMATION: Notice is hereby given that FTA has taken final agency actions subject to 23 U.S.C. 139(l) by issuing certain approvals for the public transportation project listed below. The actions on the project, as well as the laws under which such actions were taken, are described in the documentation issued in connection with the project to comply with the National Environmental Policy Act (NEPA) and in other documents in the FTA environmental project files for the project. Interested parties may contact either the project sponsor or the relevant FTA Regional Office for more information. Contact information for FTA's Regional Offices may be found at *https://www.transit.dot.gov.*

This notice applies to all FTA decisions on the listed project as of the issuance date of this notice and all laws under which such actions were taken, including, but not limited to, NEPA (42 U.S.C. 4321–4375), Section 4(f) requirements (23 U.S.C. 138, 49 U.S.C. 303), Section 106 of the National Historic Preservation Act (54 U.S.C. 306108), Endangered Species Act (16 U.S.C. 1531), Clean Water Act (33 U.S.C. 1251), and the Clean Air Act (42 U.S.C. 7401–7671q). This notice does not, however, alter or extend the limitation period for challenges of project decisions subject to previous notices published in the **Federal Register**. The project and actions that are the subject of this notice follow:

Project name and location: East-West Bus Rapid Transit (BRT) Project, Madison, Wisconsin. *Project Sponsor:* City of Madison, Madison, Wisconsin. *Project description:* The East-West Bus Rapid Transit (BRT) Project is a 15-mile route that will connect the east and west sides of Madison, running through the isthmus, downtown, and the University of Wisconsin (UW) campus. The Project route will operate in a combination of exclusive, semi-exclusive, and mixed traffic lanes within the existing transportation right-of-way. The Project involves construction of 32 BRT stations and a park-and-ride facility at Junction Road, purchase of diesel and electric buses, implementation of traffic signal priority, purchase and installation of electric bus charging stations and other associated roadway and infrastructure improvements.

Final agency actions: Section 4(f) *de minimis* impact determination, dated May 16, 2022; Section 106 No Adverse Effect determination, dated March 3, 2022; and Determination of the applicability of a categorical exclusion pursuant to 23 CFR 771.118(c)(9), dated May 16, 2022. *Supporting documentation:* Categorical Exclusion (CE) determination and supporting materials, dated May 16, 2022. The CE determination and associated documents can be viewed and downloaded from: *https://www.cityofmadison.com/metro/routes-schedules/bus-rapid-transit/environmental-review.*

(Authority: 23 U.S.C. 139(l)(1))

Mark A. Ferroni,

Deputy Associate Administrator for Planning and Environment.

[FR Doc. 2022–13199 Filed 6–17–22; 8:45 am]

BILLING CODE P

UNIFIED CARRIER REGISTRATION PLAN

Sunshine Act; Meeting

TIME AND DATE: June 23, 2022, 12:00 p.m. to 2:00 p.m., Eastern time.

PLACE: This meeting will be accessible via conference call and via Zoom Meeting and Screenshare. Any interested person may call (i) 1–929–205–6099 (US Toll) or 1–669–900–6833 (US Toll) or (ii) 1–877–853–5247 (US Toll Free) or 1–888–788–0099 (US Toll Free), Meeting ID: 965 6995 2102, to listen and participate in this meeting. The website to participate via Zoom Meeting and Screenshare is *https://kellen.zoom.us/meeting/register/tJIoceChqzkrGtbudVTIPzmbuubhOP9F9o9N.*

STATUS: This meeting will be open to the public.

MATTERS TO BE CONSIDERED: The Unified Carrier Registration Plan Education and Training Subcommittee (the ''Subcommittee'') will continue its work in developing and implementing the Unified Carrier Registration Plan and Agreement. The subject matter of this meeting will include:

Proposed Agenda

I. Call to Order—Subcommittee Chair

The Subcommittee Chair will welcome attendees, call the meeting to order, call roll for the Subcommittee, confirm whether a quorum is present, and facilitate self-introductions.

II. Verification of Publication of Meeting Notice—UCR Executive Director

The UCR Executive Director will verify the publication of the meeting notice on the UCR website and distribution to the UCR contact list via email followed by the subsequent publication of the notice in the **Federal Register**.

III. Review and Approval of Subcommittee Agenda and Setting of Ground Rules—Subcommittee Chair

For Discussion and Possible Subcommittee Action

The Agenda will be reviewed, and the Subcommittee will consider adoption of the agenda.

Ground Rules

➢ Subcommittee action only to be taken in designated areas on agenda

IV. Review and Approval of Subcommittee Minutes From the May 12, 2022 Subcommittee Meeting—Subcommittee Chair

For Discussion and Possible Subcommittee Action

Draft minutes from the May 12, 2022 Subcommittee meeting via teleconference will be reviewed. The Subcommittee will consider action to approve the minutes of the meeting.

V. Roadside Enforcement Module Video Update—Subcommittee Chair

The Subcommittee chair will provide an update on the Roadside Enforcement Module that describes the steps a roadside law enforcement officer would use to enforce UCR.

VI. UCR Education and E-Certificate Strategy—Subcommittee Chair

The Subcommittee Chair will discuss the UCR E-Certificate.

VII. UCR Volunteer Training Module—UCR Operations Manager

The UCR Operations Manager will discuss the UCR Volunteer Training Module.

VIII. Other Business—Subcommittee Chair

The Subcommittee Chair will call for any other items Subcommittee members would like to discuss.

IX. Adjournment—Subcommittee Chair

The Subcommittee Chair will adjourn the meeting.

The agenda will be available no later than 5:00 p.m. Eastern time, June 16, 2022 at: *https://plan.ucr.gov.*

CONTACT PERSON FOR MORE INFORMATION: Elizabeth Leaman, Chair, Unified Carrier Registration Plan Board of Directors, (617) 305–3783, *eleaman@board.ucr.gov.*

Alex B. Leath,

Chief Legal Officer, Unified Carrier Registration Plan.

[FR Doc. 2022–13356 Filed 6–16–22; 4:15 pm]

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FEDERAL REGISTER

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Part II

Environmental Protection Agency

40 CFR Parts 9 and 98

Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 9 and 98

[EPA–HQ–OAR–2019–0424; FRL–7230–02–OAR]

RIN 2060–AU35

Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing to amend specific provisions in the Greenhouse Gas Reporting Rule to improve the quality and consistency of the data collected under the rule, streamline and improve implementation, and clarify or propose minor updates to certain provisions that have been the subject of questions from reporting entities. These proposed changes include revisions to improve the existing calculation, recordkeeping, and reporting requirements by incorporating updates to existing emissions estimation methodologies and providing for collection of additional data to understand new source categories or new emission sources for specific sectors. The proposed changes would improve understanding of the sector-specific processes or other factors that influence greenhouse gas emissions rates, improve verification of collected data, and complement or inform other EPA programs. The EPA is also proposing revisions that would improve implementation of the Greenhouse Gas Reporting Rule such as updates to applicability estimation methodologies, providing flexibility for or simplifying calculation and monitoring methodologies, streamlining recordkeeping and reporting, and other minor technical corrections or clarifications. This action also proposes to establish and amend confidentiality determinations for the reporting of certain data elements to be added or substantially revised in these proposed amendments. Further, this action includes a request for comment to solicit information that may aid in potential future revisions to the Greenhouse Gas Reporting Rule.

DATES:

Comments. Comments must be received on or before August 22, 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 August 22, 2022.

Public hearing. The EPA does not plan to conduct a public hearing unless requested. If anyone contacts us requesting a public hearing on or before June 27, 2022, we will hold a virtual public hearing. See **SUPPLEMENTARY INFORMATION** for information on requesting and registering for a public hearing.

ADDRESSES:

Comments. You may submit your comments, identified by Docket Id. No. EPA–HQ–OAR–2019–0424, by any of the following methods:

Federal eRulemaking Portal: https://www.regulations.gov (our preferred method). Follow the online instructions for submitting comments.

Mail: U.S. Environmental Protection Agency, EPA Docket Center, Air and Radiation Docket, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.

Hand Delivery or Courier (by scheduled appointment only): EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operations 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 proposed rulemaking. Comments received may be posted without change to *https://www.regulations.gov/,* including any personal information provided. 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 Coronavirus 2019 (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.*

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

FOR FURTHER INFORMATION CONTACT: Jennifer Bohman, Climate Change Division, Office of Atmospheric Programs (MC–6207A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460; telephone number: (202) 343–9548; email address: *GHGReporting@epa.gov.* For technical information, please go to the Greenhouse Gas Reporting Program (GHGRP) website, *https://www.epa.gov/ghgreporting.* To submit a question, select Help Center, followed by ''Contact Us.''

World wide web (WWW). In addition to being available in the docket, an electronic copy of this proposal will also be available through the WWW. Following the Administrator's signature, a copy of this proposed rule will be posted on the EPA's GHGRP website at *https://www.epa.gov/ghgreporting.*

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.

To request a hearing, please contact the person listed in the following **FOR FURTHER INFORMATION CONTACT** section by June 27, 2022. If requested, the virtual hearing will be held on July 6, 2022. The hearing will convene at 9 a.m. Eastern Time (ET) and will conclude at 3 p.m. ET. The EPA may close the hearing 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. The EPA will provide further information about the hearing on its website (*https://www.epa.gov/ghgreporting*) if a hearing is requested.

Upon publication of this document in the **Federal Register** (FR), the EPA will begin pre-registering speakers for the hearing, if a hearing is requested. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/ghgreporting.* If you have questions regarding registration, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section. The last day to pre-register to speak at the hearing will be July 5, 2022. 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/ghgreporting.*

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 *GHGReporting@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.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/ghgreporting.* While the EPA expects the hearing to go forward as set forth above, please monitor our website or contact us by email at *GHGReporting@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the services of a translator or a special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by June 28, 2022. The EPA may not be able to arrange accommodations without advanced notice.

Regulated entities. These proposed revisions would affect certain entities that must submit annual greenhouse gas (GHG) reports under the GHGRP (40 CFR part 98). These are proposed amendments to existing regulations. If finalized, these amended regulations would also affect owners or operators of certain suppliers and direct emitters of GHGs. Regulated categories and entities include, but are not limited to, those listed in Table 1 of this preamble:

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY

Category	NAICS	Examples of affected facilities
General Stationary Fuel Combustion Sources.		Facilities operating boilers, process heaters, incinerators, turbines, and internal combustion engines.
	211	Extractors of crude petroleum and natural gas.
	321	Manufacturers of lumber and wood products.
	322	Pulp and paper mills.
	325	Chemical manufacturers.
	324	Petroleum refineries, and manufacturers of coal products.
	316, 326, 339	Manufacturers of rubber and miscellaneous plastic products.
	331	Steel works, blast furnaces.
	332	Electroplating, plating, polishing, anodizing, and coloring.
	336	Manufacturers of motor vehicle parts and accessories.
	221	Electric, gas, and sanitary services.
	622	Health services.
	611	Educational services.
Electric Power Generation	2211	Generation facilities that produce electric energy.
Ammonia Manufacturing	325311	Anhydrous and aqueous ammonia manufacturing facilities.
Cement Production	327310	Portland cement manufacturing plants.
Electronics Manufacturing	334111	Microcomputers manufacturing facilities.
	334413	Semiconductor, photovoltaic (PV) (solid-state) device manufacturing facilities.
	334419	Liquid crystal display (LCD) unit screens manufacturing facilities; Microelectromechanical (MEMS) manufacturing facilities.
Ferroalloy Production	331110	Ferroalloys manufacturing facilities.
Fluorinated Greenhouse Gas Production	325120	Industrial gases manufacturing facilities.
Glass Production	327211	Flat glass manufacturing facilities.
	327213	Glass container manufacturing facilities.
	327212	Other pressed and blown glass and glassware manufacturing facilities.
Hydrogen Production	325120	Hydrogen manufacturing facilities.
Iron and Steel Production	333110	Integrated iron and steel mills, steel companies, sinter plants, blast furnaces, basic oxygen process furnace (BOPF) shops.
Lime Manufacturing	327410	Calcium oxide, calcium hydroxide, dolomitic hydrates manufacturing facilities.
Miscellaneous Uses of Carbonate	Facilities included elsewhere.	
Petroleum and Natural Gas Systems	486210	Pipeline transportation of natural gas.
	221210	Natural gas distribution facilities.
	211120	Crude petroleum extraction.
	211130	Natural gas extraction.
Petrochemical Production	325110	Ethylene dichloride manufacturing facilities.
	325199	Acrylonitrile, ethylene oxide, methanol manufacturing facilities.
	325110	Ethylene manufacturing facilities.
	325180	Other basic inorganic chemical manufacturing.
Petroleum Refineries	324110	Petroleum refineries.
Silicon Carbide Production	327910	Silicon carbide abrasives manufacturing facilities.
Electrical Equipment Use	221121	Electric bulk power transmission and control facilities.

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY—Continued

Category	NAICS	Examples of affected facilities
Underground Coal Mines	212113	Underground anthracite coal mining operations.
	212112	Underground bituminous coal mining operations.
Zinc Production	331419	Primary zinc refining facilities.
	331492	Zinc dust recycling facilities, recovering from scrap and/or alloying purchased metals.
	311411	Frozen fruit, juice, and vegetable manufacturing facilities.
	311421	Fruit and vegetable canning facilities.
Municipal Solid Waste Landfills	562212	Solid waste landfills.
	221320	Sewage treatment facilities.
Suppliers of Coal-based Liquid Fuels	211130	Coal liquefaction at mine sites.
Suppliers of Natural Gas and Natural Gas Liquids.	221210	Natural gas distribution facilities.
	211112	Natural gas liquid extraction facilities.
Suppliers of Petroleum Products	324110	Petroleum refineries.
Suppliers of Carbon Dioxide	325120	Industrial gas manufacturing facilities.
Suppliers of Industrial Greenhouse Gases.	325120	Industrial greenhouse gas manufacturing facilities.
Electrical Equipment Manufacture or Refurbishment.	33531	Power transmission and distribution switchgear and specialty transformers manufacturing facilities.
Carbon Dioxide Enhanced Oil Recovery Projects.	211	Oil and gas extraction projects using carbon dioxide enhanced oil recovery.
Calcium Carbide Production	325180	Other basic inorganic chemical manufacturing.
Coke Calcining	324199	All other petroleum and coal products manufacturing.
Glyoxal, Glyoxylic Acid, and Caprolactam Production.	325199	All other basic organic chemical manufacturing.
Ceramics Manufacturing	327110	Pottery, ceramics, and plumbing fixture manufacturing.
	327120	Clay building material and refractories manufacturing.

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding facilities likely to be affected by this proposed action. Other types of facilities than those listed in the table could also be subject to reporting requirements. To determine whether you would be affected by this proposed action, you should carefully examine the applicability criteria found in 40 CFR part 98, subpart A (General Provisions) and each source category. Many facilities that are affected by 40 CFR part 98 have greenhouse gas emissions from multiple source categories listed in Table 1 of this preamble.

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

AGA American Gas Association
AIM American Innovation and Manufacturing Act of 2020
AMLD Advanced Mobile Leak Detection
ANOVA analysis of variance
ANSI American National Standards Institute
API American Petroleum Institute
ASTM American Society for Testing and Materials
BAMM best available monitoring methods
BEF by-product emission factor
BOEM Bureau of Ocean Energy Management
BOPF basic oxygen process furnace
C&D construction and demolition
CAA Clean Air Act
CARB California Air Resources Board
CBI confidential business information
CBP U.S. Customs and Border Protection
CCUS carbon capture, utilization, and sequestration
CDA clean dry air
CDC Centers for Disease Control and Prevention
CEMS continuous emission monitoring system
CFR Code of Federal Regulations
CGA cylinder gas audit
CF_4 perfluoromethane
CH_4 methane
CKD cement kiln dust
CO_2 carbon dioxide
CO_2e carbon dioxide equivalent
CO carbon monoxide
COF_2 carbonic difluoride
COVID–19 Coronavirus 2019
CSA CSA Group
CVD chemical vapor deposition
DAC direct air capture
DCU delayed coking unit
DOC degradable organic carbon
DOT Department of Transportation
DRE destruction or removal efficiency
e-GGRT electronic Greenhouse Gas Reporting Tool
EAF electric arc furnace
EDC ethylene dichloride
EF emission factor
EG emission guidelines
EIA Energy Information Administration
EOR enhanced oil recovery
EPA U.S. Environmental Protection Agency
EREF Environmental Research and Education Foundation
ET Eastern time
FAQ frequently asked question
FR Federal Register
F–GHG fluorinated greenhouse gas
F–HTFs fluorinated heat transfer fluids
FTIR Fourier Transform Infrared
GCS gas collection system
GHG greenhouse gas
GHGRP Greenhouse Gas Reporting Program
GIE gas-insulated equipment
GIS geographic information systems
GOR gas-to-oil ratio
GRI Gas Research Institute
GWP global warming potential
HCFC hydrochlorofluorocarbons
HFC hydrofluorocarbons
HHV high heating value
HTS Harmonized Tariff System
HVAE high voltage anode effect
IAI International Aluminium Institute
ICR Information Collection Request
IPCC Intergovernmental Panel on Climate Change
IRC Internal Revenue Code
IRS Internal Revenue Service
ISBN International Standard Book Number
ISO International Standards Organization
IVT Inputs Verification Tool
k first order decay rate
kg kilograms
LCA life cycle analysis
LCD liquid crystal display
LDC local distribution company
LNG liquified natural gas
LVAE low voltage anode effect
MCF moisture correction factor
MDEA methyl diethanolamine
MEA monoethanolamine
MEMS microelectromechanical systems
mmBtu/hr million British thermal units per hour
MMscf million standard cubic feet
MRV monitoring, reporting, and verification plan
MSHA Mine Safety and Health Administration
MSW municipal solid waste
$mtCO_2e$ metric tons carbon dioxide equivalent

N_2O nitrous oxide
NAICS North American Industry Classification System
NGLs natural gas liquids
NSPS New Source Performance Standards
OAR Office of Air and Radiation
OEM original equipment manufacturer
OGI optical gas imaging
OMB Office of Management and Budget
OMP operations management plan
PCA Portland Cement Association
PFC perfluorocarbon
PRA Paperwork Reduction Act
ppmv parts per million by volume
PV photovoltaic
QA/QC quality assurance/quality control
QMS Quadrupole Mass Spectroscopy
RFA Regulatory Flexibility Act
RMA Rubber Manufacturers Association
RPC remote plasma cleaning
RY reporting year
scfh standard cubic feet per hour
SF_6 sulfur hexafluoride
SIA Semiconductor Industry Association
SIC Standard Industrial Classification System
SSM startup, shutdown, and malfunction
TBD to be determined
TFI The Fertilizer Institute
TSCA Toxic Substances Control Act
TSD technical support document
UIC underground injection control
U.S. United States
UMRA Unfunded Mandates Reform Act of 1995
USGS U.S. Geological Survey
USTMA U.S. Tire Manufacturers Association
VCM vinyl chloride monomer
VOC volatile organic compound
WMO World Meteorological Organization
WWW World Wide Web

Table of Contents

I. Background

A. How is this preamble organized?

The first section of this preamble contains background information regarding the origin of the proposed amendments. This section also discusses the EPA's legal authority under the Clean Air Act (CAA) to promulgate (including subsequent amendments to) the Greenhouse Gas Reporting Rule, codified at 40 CFR part 98 (hereinafter referred to as ''part 98''), and the EPA's legal authority to make confidentiality determinations for new or revised data elements required by these amendments or for existing data elements for which a confidentiality determination has not previously been proposed. Section II of this preamble describes the types of amendments included in this proposed rulemaking and includes the rationale for each type of proposed change. Section III of this preamble is organized by part 98 subpart and contains detailed information on the proposed revisions to part 98 and the rationale for the proposed amendments in each section. Section IV of this preamble discusses additional requests for comments related to potentially expanding or adding new source categories and other potential future amendments to the GHG Reporting Rule. Section V of this preamble discusses when the proposed revisions to part 98 would apply to reporters. Section VI of this preamble discusses the proposed confidentiality determinations for new or substantially revised (*i.e.,* requiring additional or different data to be reported) data reporting elements, as well as for certain existing data elements for which a determination has not been previously established. Section VII of this preamble discusses the impacts of the proposed amendments. Section VIII of this preamble describes the statutory and executive order requirements applicable to this action.

B. Executive Summary

The EPA is proposing amendments to part 98 to implement improvements to the GHGRP. After more than 10 years of implementation of the program, the EPA has assessed the data collected, emissions, and trends established from annual reports in each industrial sector required to report. In this review, the EPA has evaluated the requirements of the GHGRP to identify areas of improvement, such as where the rule may be modified to reflect the EPA's current understanding of United States (U.S.) GHG emission trends, or to improve data collection and reporting where additional data may be necessary to better understand emissions from specific sectors or inform future policy decisions. The EPA has subsequently identified improvements to the calculation, monitoring, and reporting requirements that would incorporate new data or updated scientific knowledge; reflect new emissions sources; improve analysis and verification of collected data; provide additional data to complement or inform other EPA programs; or streamline calculation, monitoring, or reporting to provide flexibility or increase the efficiency of data collection.

The proposed amendments include improvements to requirements that would enhance the quality of the data collected, clarify elements of the rule, and streamlining changes. The types of proposed amendments that would improve the quality of the data collected under the rule include revisions to update emission factors to more accurately reflect industry emissions; refinements to existing emissions calculation methodologies to reflect an improved understanding of emissions sources and end uses of GHGs; providing for collection of additional data to understand new source categories or new emission sources for specific sectors; additions or modifications to reporting requirements in order to eliminate data gaps and improve verification of emissions estimates; revisions that address prior commenter concerns or clarify requirements, and editorial corrections that would improve the public's understanding of the rule.

The types of streamlining changes that the EPA is proposing include revisions to applicability for certain industry sectors to account for changes in usage of certain GHGs or where the current applicability estimation methodology may overestimate emissions; revisions that provide flexibility for or simplify monitoring and calculation methods; and revisions to streamline reported data elements or recordkeeping where the current requirements are redundant, where reported data are not currently useful for verification or analysis, or for which continued collection of the data at the same frequency would not likely provide new insights or knowledge of the industry sector, emissions, or trends at this time.

This action also includes a request for comment related to potentially expanding existing categories or including additional new source categories to the Greenhouse Gas Reporting Rule. In these cases, the EPA is seeking additional information to better inform our consideration of proposing these new source categories to the GHGRP. Therefore, the EPA is specifically requesting comment related to the potential expanded or new source categories described in this section. The EPA is also requesting comment on potential future amendments to add new calculation, monitoring, and reporting requirements for the aluminum production source category. If the Agency becomes comfortable that the information available is sufficient to support a rule revision, the EPA may consider undertaking a future action to revise or add source categories or to incorporate updated calculation and reporting requirements.

Further, this action includes a proposal to update 40 CFR part 9 in accordance with the publication requirements of the PRA to include the OMB control number issued under the PRA for the information collection request (ICR) for the GHGRP.

Finally, this action proposes to establish and/or revise confidentiality determinations for the reporting of certain data elements added or revised in these proposed amendments, and for certain existing data elements for which no confidentiality determination has been previously proposed, or for which we are proposing to amend a previously established confidentiality determination.

Most of the changes that are proposed are not anticipated to significantly increase the recordkeeping and reporting burden associated with the GHGRP. The proposed changes are anticipated to improve the quality of the data reported under the program. Some of the proposed revisions could potentially increase burden in cases where the proposed amendments add or revise reporting requirements. The estimated incremental costs include an average burden of $1,424,775 per year beginning in reporting year (RY) 2023.

The EPA anticipates that the proposed changes may take effect on January 1, 2023 and would apply beginning with reports submitted for RY2023, which are required to be submitted to the EPA by April 1, 2024.

C. Background on This Proposed Rule

The GHG Reporting Rule was published in the **Federal Register** (FR) on October 30, 2009 (74 FR 56260) (hereafter referred to as the 2009 Final Rule). The 2009 Final Rule became effective on December 29, 2009 and requires reporting of GHGs from various facilities and suppliers, consistent with the 2008 Consolidated Appropriations Act.[1] The EPA issued additional rules in 2010 finalizing the requirements for subpart T (Magnesium Production), subpart FF (Underground Coal Mines), subpart II (Industrial Wastewater Treatment), and subpart TT (Industrial Waste Landfills) (75 FR 39736, July 12, 2010); subpart W (Petroleum and Natural Gas Systems) (75 FR 74458, November 30, 2010); subpart I (Electronics Manufacturing), subpart L (Fluorinated Gas Production), subpart DD (Electrical Transmission and Distribution Equipment Use), subpart QQ (Importers and Exporters of Fluorinated GHGs Contained in Pre-Charged Equipment or Closed-Cell Foams), and subpart SS (Electrical Equipment Manufacture or Refurbishment) (75 FR 74774, December 1, 2010); and subpart RR (Geologic Sequestration of Carbon Dioxide) and subpart UU (Injection of Carbon Dioxide) (75 FR 75060, December 1, 2010). Following the promulgation of these subparts, the EPA finalized several technical and clarifying amendments to these and other subparts under the GHGRP (75 FR 79092, December 17, 2010; 76 FR 22825, April 25, 2011; 76 FR 36339, June 22, 2011; 76 FR 59533, September 27, 2011; 76 FR 59542, September 27, 2011; 76 FR 73866, November 29, 2011; 76 FR 80554, December 23, 2011; 77 FR 10373, February 22, 2012; 77 FR 48072, August 13, 2012; 77 FR 51477, August 24, 2012; 78 FR 25392, May 1, 2013; 78 FR 68162, November 13, 2013; 78 FR 71904, November 29, 2013; 79 FR 63750, October 24, 2014; 79 FR 70352, November 25, 2014; 79 FR 73750, December 11, 2014; 80 FR 64262, October 22, 2015; and 81 FR 86490, November 30, 2016). The amendments generally added or revised requirements in the existing subparts of part 98, including revisions that were intended to improve clarity and consistency across the calculation, monitoring, and data reporting requirements. The EPA finalized additional amendments (81 FR 89188, December 6, 2016) to streamline implementation of the rule, to improve the quality and consistency of the data collected under the rule, and to clarify or provide updates to certain provisions that have been the subject of questions from reporting entities. The EPA is proposing additional amendments and requesting comment in a continuation of the effort to improve the GHGRP.

D. Legal Authority

The EPA is proposing these rule amendments under its existing CAA authority provided in CAA section 114. As stated in the preamble to the 2009 Final Rule (74 FR 56260), CAA section 114(a)(1) provides the EPA broad authority to require the information

[1] Consolidated Appropriations Act, 2008, Public Law 110–161, 121 Stat. 1844, 2128. See *https://www.congress.gov/110/plaws/publ161/PLAW-110publ161.pdf* (accessed September 7, 2021).

proposed to be gathered by this rule because such data would inform and are relevant to the EPA's carrying out of a wide variety of CAA provisions. See the preambles to the proposed GHG Reporting Rule (74 FR 16606, October 10, 2009) and the 2009 Final Rule for further information.

II. Overview and Rationale for Proposed Amendments to 40 CFR Part 98 and 40 CFR Part 9

Since 2010, the GHGRP has been a reliable and high-quality source of GHG data. The data collected under 40 CFR part 98 is used to inform the EPA's understanding of the relative emissions and distribution of emissions from specific industries, the factors that influence GHG emission rates, and to inform policy options and potential regulations. The data published under the GHGRP also serves to enable key stakeholders to understand, track, and compare greenhouse gas emissions and identify and take action on emission reduction opportunities. Further, the data collected under the GHGRP has also been used to inform other regulations, for example, proposed New Source Performance Standards (NSPS) and Emission Guidelines for the oil and gas industry and for municipal solid waste (MSW) landfills under 40 CFR part 60.

Throughout the life of the GHGRP, the EPA has made several improvements to the rule to address data gaps, reflect updates to scientific information, or to incorporate improvements to calculation, monitoring, or measurement methodologies. For example, in 2013, the EPA finalized technical amendments including changes to applicability, improvements to calculation methods, and updated reporting requirements, as well as amendments to incorporate new data from the Intergovernmental Panel on Climate Change (IPCC) on estimated global warming potentials (GWPs) (78 FR 71904, November 29, 2013). More recently, the EPA finalized edits to the petroleum and natural gas systems source category to address potential gaps in coverage, improve methods, and ensure high quality data reporting (81 FR 86490, November 30, 2016). The EPA last updated the GHGRP in 2016, when it implemented revisions to streamline and improve implementation of the rule and to improve the quality of the data collected, including expanding monitoring and reporting requirements that were necessary to improve verification and served to improve the accuracy of the data used to inform the Inventory of U.S. Greenhouse Gas Emissions and Sinks (hereafter referred to as the ''U.S. GHG Inventory'') (81 FR 89188, December 9, 2016).

The EPA has also continuously conducted outreach to stakeholders through various means, including responding to questions from reporters, engaging through compliance assistance webinars, soliciting feedback via a public testing process, interacting with reporters during the verification of submitted data, and soliciting comments during rulemakings. Thus, the EPA has subsequently identified, proposed, and finalized several technical and clarifying amendments to various subparts under the GHGRP to enhance the quality of the data reported, improve our understanding of GHG emission sources and trends, and improve implementation, particularly where we have identified changes to industry processes, emissions trends, types of emissions sources, or new data or scientific knowledge that would allow us to better understand the quantity and distribution of U.S. GHG emissions.

The EPA recently evaluated the requirements of the GHGRP to identify areas of improvement, such as where the rule may be modified to reflect the EPA's current understanding of U.S. GHG emission trends, or to improve data collection and reporting where additional data may be necessary to better understand emissions from specific sectors or inform future policy decisions. The proposed amendments include improvements to the calculation, monitoring, and reporting requirements that would incorporate updates to existing emissions estimation methodologies; implement requirements to collect additional data to understand new source categories or new emission sources for specific sectors; improve the EPA's understanding of the sector-specific processes or other factors that influence GHG emission rates and improve verification of collected data; and provide additional data to complement or inform other EPA programs. We are also proposing revisions that clarify or update provisions that have been unclear. The proposed amendments include:

- Amendments to update emission factors to incorporate new measurement data that more accurately reflects industry emissions;
- Revisions to refine existing emissions calculation methodologies to reflect an improved understanding of emissions sources and end uses of GHGs, or to incorporate more recent research on GHG emissions or formation;
- Revisions to specific sectors to expand reporting to include new source categories or new emission sources, in order to improve the accuracy and completeness of the data provided by the GHGRP;
- Adding or modifying reporting requirements to eliminate data gaps and improve verification of emissions estimates; and
- Revisions that address prior commenter concerns or provide additional information for reporters to better or more fully understand their compliance obligations, that clarify requirements that reporters have previously found vague to ensure that accurate data are being collected, and editorial corrections or harmonizing changes that would improve the public's understanding of the rule.

The EPA is also soliciting additional comment on potentially expanding existing subparts or adding other new subparts to collect data for several new source categories, as well as requesting comment on potential future amendments to add new calculation, monitoring, and reporting requirements for the aluminum production source category, as discussed in section IV of this preamble.

The EPA has also identified additional areas in the GHGRP where revisions to part 98 could be streamlined. Through this document, the EPA is proposing several amendments to revise specific provisions in part 98 that would streamline calculation, monitoring, or reporting to provide flexibility or increase the efficiency of data collection. The types of revisions we are proposing would simplify requirements while maintaining the quality of the data collected under part 98, where continued collection of information assists in evaluation and support of EPA programs and policies. The proposed revisions include:

- Revisions to applicability for certain industry sectors without the 25,000 metric tons carbon dioxide equivalent ($mtCO_2e$) per year reporting threshold to account for changes in usage of certain GHGs, or where the current applicability estimation methodology may overestimate emissions;
- Providing flexibility for and simplifying monitoring and calculation methods where further monitoring and data collection would not likely significantly improve our understanding of emission sources at this time, or where we currently allow similar less burdensome methodologies for other sources; and
- Revisions to streamline reported data elements or recordkeeping where the current requirements are redundant

or where reported data are not currently useful for verification or analysis, or for which continued collection of the data at the same frequency would not likely provide new insights or knowledge of the industry sector, emissions, or trends at this time.

Sections II.A and II.B of this preamble describe the above changes in more detail and provide rationale for the changes included in each category. Additional details for the specific amendments proposed for each subpart are included in section III of this preamble. We are seeking public comment only on the proposed revisions and issues specifically identified in this document for the identified subparts. We expect to deem any comments received addressing other aspects of 40 CFR part 98 to be outside of the scope of this proposed rulemaking.

Finally, we are also proposing a technical amendment to 40 CFR part 9 to update the table that lists the OMB control numbers issued under the PRA to include the ICR for 40 CFR part 98. This amendment is described in section II.C of this preamble.

A. Revisions To Improve the Quality of Data Collected Under 40 CFR Part 98 and Other Minor Revisions or Clarifications

The data collected under part 98 are used to inform the EPA's understanding of the relative emissions and distribution of emissions from specific industries, the factors that influence GHG emission rates, and to inform policy options and potential regulations. Following several years of implementation and outreach, the EPA has identified certain areas of the rule where updates to emissions factors or other default factors; improvements to calculation methodologies; collection of additional data on GHG emissions, emissions sources, or end uses; additions or revisions to data elements or other reporting requirements; and other technical amendments, clarifications, and corrections would enhance the quality and accuracy of the data collected under the GHGRP. These proposed changes include consideration of comments raised by stakeholders in prior rulemakings that would more closely align rule requirements with the processes conducted at specific facilities, consideration of data gaps identified in collected data where additional data would improve verification of data reported to the GHGRP, and consideration of additional data needed to help better understand changing industry emission trends. Overall, these proposed changes would provide a more comprehensive, nationwide GHG emissions profile reflective of the origin and distribution of GHG emissions in the United States and would more accurately inform EPA policy options for potential regulatory or non-regulatory CAA programs. The EPA additionally uses the data from the GHGRP, which would include data from these proposed changes, to improve estimates used in the U.S. GHG Inventory.

In some cases, we are proposing to redefine certain industry sectors to include additional GHGs not previously reported, or to add emissions estimations methodologies and include reporting of GHGs from newly identified sources of emissions in certain industry sectors, to better account for changes in industry emission trends. The proposed amendments reflect adjustments to the rule where we have identified changes in the type and scope of GHGs emitted or supplied, such as certain sectors that have implemented alternative equipment technology, switched to use of GHGs with a lower GWP, or that have implemented new end uses for GHGs that are emitted or supplied. In other cases, we have identified gaps in the current coverage of the GHGRP that leave out potentially significant emission sources, for example, large, atypical release events at oil and gas facilities such as wellhead leaks. The proposed amendments would also add a new source category that would provide additional data on amounts of CO_2 that are geologically sequestered in association with enhanced oil recovery (EOR) operations. Many of the revisions proposed in this action would better capture the changing landscape of greenhouse gas emissions and provide for more complete coverage of U.S. GHG emission sources. Such changes are necessary for the EPA to continue to analyze the relative emissions and distribution of emissions from specific industries and to improve the overall quality of the data collected under the GHGRP. These changes would also complement other EPA regulations, such as NSPS and emission guidelines (EG) for the oil and gas industry and would also be used to inform and improve future policy decisions.

The specific changes that we are proposing, as described in this section, are described in detail for each subpart in sections III.A through III.W of this preamble.

1. Updates to Emission Factors To Improve Accuracy of Reported Data

In order to improve the accuracy of the data collected under the GHGRP, we are proposing to revise emission factors where we have received improved measurement data or feedback from stakeholders. Some of the calculation methodologies provided in the GHGRP rely on the use of emission factors, and the use of emissions or default factors decreases the need for additional monitoring or measurements from individual facilities. The proposed rule includes revisions to emission factors in a number of source categories, where we have received or identified updated measurement data. For example, we are proposing several updates to the emission factors and default destruction and removal efficiency values in subpart I (Electronics Manufacturing). The proposed emission factors are based on review of newly submitted data from the 2017 and 2020 technology assessment reports submitted with RY2016 and RY2019 annual reports, as well as consideration of new emission factors available in the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories* (hereafter ''*2019 Refinement*'').[2] We are also proposing updates to the emission factor calculation methods that are used to calculate utilization and by-product emission rates submitted in the technology assessment report under subpart I, in order to ensure that emission factors are developed in a consistent manner across facilities and over time and to allow the EPA to compare emission factors across the industry and track trends in industry emission rates.

In some cases, the proposed emission factors would improve reported data by better reflecting recent industry trends. For example, based on input from stakeholders, we are proposing updated emission factors for the modeling of methane (CH_4) generation from waste disposed at landfills in subpart HH (Municipal Waste Landfills). The updated emission factors reflect an industry trend of increased disposal of inert materials that do not contribute to CH_4 generation. The EPA received data from stakeholders in the waste industry following comments received during the expert and public review period for the U.S. GHG Inventory, which uses directly reported emissions values from subpart HH to estimate national CH_4 emissions from MSW landfills

[2] Intergovernmental Panel on Climate Change (IPCC). *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,* Calvo Buendia, E., Tanabe, K., Kranjc, A., Baasansuren, J., Fukuda, M., Ngarize, S., Osako, A., Pyrozhenko, Y., Shermanau, P. and Federici, S. (eds). Published: IPCC, Switzerland. 2019. *https://www.ipcc-nggip.iges.or.jp/public/2019rf/index.html.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

throughout the entire United States. The proposed change will update default factors and will result in more accurate estimates of landfill emissions and pose no additional reporting burden.

We are also proposing to update the default biogenic fraction for tire combustion in subpart C (General Stationary Fuel Combustion) and the emission factors for natural gas pneumatic devices and for equipment leaks from natural gas distribution sources (including pipeline mains and services, below grade transmission-distribution transfer stations, and below grade metering-regulating stations) and equipment at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities in subpart W (Petroleum and Natural Gas Systems). The proposed emission factors are more representative of GHG emissions sources and would improve the overall accuracy of the data collected under the GHGRP and would ultimately benefit stakeholders who rely on GHGRP data to understand the sources and magnitude of GHGs from specific facilities, as well as improve the quality of data used to inform future policy or regulation.

2. Improvements To Existing Emissions Estimation Methodologies

We are proposing several revisions to modify calculation equations to incorporate refinements to methodologies based on an improved understanding of emission sources. In some cases, we have become aware of discrepancies between assumptions in the current emission estimation methods and the processes or activities conducted at specific facilities, where the proposed revisions would reduce reporter errors. In other cases, we are proposing to revise the emissions estimation methodologies to incorporate recent studies on GHG emissions or formation that reflect updates to scientific understanding of GHG emissions sources. The proposed changes will improve the quality and accuracy of the data collected under the GHGRP, increase our understanding of the relative distribution of GHGs that are emitted, and better reflect GHG end uses or where GHGs are bound in products.

For example, for subpart I, we are proposing several edits to the stack testing methodology, including adding new equations and a table of default weighting factors to calculate the fraction of fluorinated input gases and by-products exhausted from tools with abatement systems; revising equations that calculate the weighted average DREs for individual fluorinated greenhouse gases (F–GHGs) across process types; requiring that all stacks be tested if the stack test method is used; and updating a set of equations that will more accurately account for emissions when pre-control emissions of a F–GHG approach or exceed the consumption of that gas during the test period.

For other subparts, including subparts G (Ammonia Manufacturing), P (Hydrogen Production), and S (Lime Manufacturing), we are proposing revisions to the calculation methodology to allow for subtraction of carbon dioxide (CO_2) that is captured and bound in other products (*e.g.,* urea or methanol) from calculated and reported emissions. The proposed changes, by removing the CO_2 that is not directly emitted from these facilities from the calculation methodology, would provide a more accurate estimate of the direct sector emissions and would provide consistency in our approach across the GHGRP.

For subpart Y (Petroleum Refineries), we are proposing to amend the calculation methodology for delayed coking units (DCUs), which uses a steam generation model to estimate emissions. The proposed changes are targeted to address issues identified during verification of reported data, where we have noticed that the activities conducted at certain facilities do not comport with some of the underlying assumptions of the steam generation model. The proposed changes will modify the current equation to more accurately estimate emissions and to be more universally applicable to these facilities.

Additional details of these types of proposed changes are discussed in section III of this preamble.

3. Revisions To Address Potential Gaps in Reporting of Emissions Data for Specific Sectors

We are proposing several amendments to include reporting of additional emissions or emissions sources for specific sectors to address potential gaps in reporting. We are also proposing to improve the existing rule requirements by proposing new or revised calculation, monitoring, or reporting requirements that would help us to better understand and track emissions in specific sectors; establish requirements for a new source category for quantifying geologic sequestration of CO_2 in association with EOR operations; and identify end uses of GHGs that are not currently accounted for in existing reporting, for consideration in future policy development. Such data would continue to inform, and are relevant to, the EPA's carrying out a wide variety of CAA provisions. For example, identifying new emissions or new emission sources from direct emitters could inform decisions about whether and how to use section 111 of the CAA to establish NSPS for various source categories emitting GHGs. The data may also inform the EPA's implementation of section 103(g) of the CAA regarding improvements in nonregulatory strategies and technologies for preventing or reducing air pollutants. The data published under the GHGRP serves to enable the Agency and stakeholders to understand, track, and compare greenhouse gas emissions and identify emission reduction opportunities. Over the last 10 years, the collection of these data has allowed the Agency and relevant stakeholders to identify changes in industry and emissions trends, such as transitions in equipment technology or use of alternative lower-GWP greenhouses gases, that may be beneficial for informing other EPA programs under the CAA. The amendments we are proposing are intended to address data gaps that have been identified in the implementation of the program or from review of improved scientific assessments and would allow the EPA to better characterize U.S. GHG emissions. The improved data would subsequently better inform other agency policies and programs under the CAA.

For example, we are proposing several revisions to subparts DD (Electrical Transmission and Distribution Equipment Use) and SS (Electrical Equipment Manufacture or Refurbishment) to improve the quality of the data collected from these industrial sectors. Currently, these subparts include ''all electric transmission and distribution equipment and servicing inventory'' used within an electric power system, and related manufacturing and refurbishing processes, that use or include sulfur hexafluoride (SF_6) and perfluorocarbons (PFCs). When the final rule establishing subpart DD was published in 2010 (75 FR 74774, December 1, 2010, hereinafter referred to as the 2010 Final Rule for Additional Sources of Fluorinated GHGs), SF_6 was the most commonly used insulating gas in the electrical power industry, and PFCs were occasionally used as dielectrics and heat transfer fluids in power transformers. During the implementation of the reporting program, electrical power systems equipment manufacturers and fluorinated greenhouse gas suppliers have introduced alternative technologies and replacements for SF_6 with lower GWPs, including fluorinated gas mixtures. We are proposing to revise the existing calculation, monitoring, and reporting requirements of these subparts to require reporting of additional F–GHGs, in order to better track emissions from equipment using alternative gases that are not currently accounted for.

Additionally, we have become aware of potentially significant sources of emissions in specific industry sectors for which there are no current emission estimation methods within part 98. For example, under subpart I, we are proposing a calculation methodology to estimate emissions of perfluoromethane (CF_4) from hydrocarbon-based emissions control systems. The proposed changes reflect recent studies that have shown that direct reaction between molecular fluorine (F_2) and hydrocarbons to form CF_4 can occur in hydrocarbon-fueled combustion emissions control systems, and we are proposing to incorporate calculations from the *2019 Refinement* to account for the formation and emission of CF_4 from this potentially significant emissions source.

For subpart W, we are proposing to add calculation methodologies and requirements to report GHG emissions for several additional sources. We are proposing to add a new emissions source, referred to as ''other large release events,'' to capture abnormal emission events that are not accurately accounted for using existing methods in subpart W. This additional source would cover events such as storage wellhead leaks, well blowouts, and other large, atypical release events and would apply to all types of facilities subject to subpart W. Reporters would calculate GHG emissions using measurement data or engineering estimates of the amount of gas released and measurement data, if available, or process knowledge (best available data) to estimate the composition of the released gas. We are also proposing to require reporting of existing emission sources by additional industry segments. For example, we are proposing to require liquified natural gas (LNG) import/export facilities to begin calculating and reporting emissions from acid gas removal vents.

In other cases, we are proposing changes to improve our understanding of end-uses of GHGs and to better understand GHG supply. For subpart OO (Suppliers of Industrial Greenhouse Gases), we are proposing to require suppliers of nitrous oxide (N_2O), saturated PFCs, and SF_6 to identify the end uses for which the N_2O, SF_6, or PFC is used, and the quantities of N_2O, SF_6, or each PFC transferred to each end use, if known. This requirement would help to inform the development of GHG policies and programs by providing information on N_2O, SF_6, and PFC uses and their relative importance, where the GWP-weighted quantities of these compounds that are supplied annually to the U.S. economy are relatively large, and where the identities and magnitudes of the uses of these compounds are less well understood.

The EPA is also proposing revisions to incorporate a new source category to add calculation and reporting requirements for quantifying geologic sequestration of CO_2 in association with EOR operations. The proposed requirements would be included under a new subpart VV and would apply to reporters that choose to use the International Standards Organization (ISO) standard designated as CSA Group (CSA)/American National Standards Institute (ANSI) ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage*[3] *Using Enhanced Oil Recovery (CO_2-EOR)* (hereafter referred to as ''CSA/ANSI ISO 27916:2019'') as a means of quantifying geologic sequestration. Under existing GHGRP requirements, facilities that sequester CO_2 through EOR operations may opt into subpart RR. Proposed new subpart VV provides an alternative method of reporting geologic sequestration in association with CO_2-EOR presenting another option for reporters who are sequestering CO_2 through their EOR operations but do not choose to report under subpart RR. We are proposing to add this new source category because collecting additional information from these sources would improve our knowledge on the amounts of CO_2 that are geologically sequestered in association with EOR operations and allow the Agency to more comprehensively track and document the flow of CO_2 through the economy to better inform EPA policy and programs under the CAA related to the use of CO_2 capture and geologic sequestration. Thus, the rationale for proposing subpart VV is analogous to the rationale for originally proposing and finalizing subpart RR, that is to enable the EPA to monitor the growth and efficacy of geologic sequestration as a greenhouse gas mitigation technology over time, to evaluate relevant policy options, and to reconcile information obtained with data obtained from 40 CFR part 98, subpart PP on CO_2 supplied to the economy. The proposed requirements are discussed in section III.W of this preamble.

The proposed changes would improve the overall quality and completeness of the data collected by the GHGRP, and would be useful for informing future policy decisions, such as opportunities to reduce emissions. The EPA is also soliciting additional comment on potential collection of data under other new source categories, as discussed in section IV of this preamble.

4. Revisions to Reporting Requirements To Improve Verification and the Accuracy of the Data Collected

The EPA is proposing several revisions to existing reporting requirements to improve the quality of the data that are currently reported, or to collect more useful data that would improve verification of reported data. Such revisions would better characterize U.S. GHG emissions and trends and would better enable the EPA to obtain data that is of sufficient quality that it can be used to support a range of future climate change policies and regulations, including but not limited to information relevant to carrying out provisions involving research, evaluating and setting standards, endangerment determinations, or informing EPA non-regulatory programs.

For example, we are proposing revisions to the reporting of unit level information under subpart C. Currently, individual unit information (*i.e.,* the unit type and the maximum rated heat input capacity) is only required to be reported for specific individual unit reporting configurations. The individual unit information allows the EPA to aggregate emissions according to unit type and size and provides a better understanding of the emissions from specific unit types. To improve verification and analysis of reported data, the EPA is proposing to require reporting of certain unit level information for each unit in an aggregation of units or common pipe configuration, excluding units less than 10 million British thermal units per hour (mmBtu/hr).

Under subpart H (Cement Production) and subpart S, we are proposing to collect additional data elements where the EPA has little data on which to build verification checks. For these subparts, we are proposing to collect annual averages of chemical composition input data on a facility-basis. The proposed data elements would assist the EPA in verification of continuous emission monitoring systems (CEMS) facility emissions.

[3] The terms ''geologic sequestration'' and ''geologic storage'' are used synonymously for purposes of this subpart.

Because CEMS facilities typically include combustion and process emissions that are vented through the same stack, process and combustion emissions are usually mixed and indifferentiable. By collecting average chemical composition data, the EPA would be able to compare and differentiate process emissions from CEMS facilities. Such additions to reporting would improve the accuracy of the emissions data and render such information more valuable and useful.

For subpart W, we are proposing to add or revise reporting requirements to better understand and characterize the emissions for several emission sources. For example, we are proposing to collect additional information from facilities with liquids unloadings to differentiate between manual and automated unloadings.

Additionally, under subpart GG (Zinc Production), the EPA is proposing that facilities report the total amount of electric arc furnace (EAF) dust annually consumed by all Waelz kilns at the facility. In this case, because the amount of EAF dust consumed in Waelz kilns is strongly correlated with CO_2 emissions, the proposed data element would serve as a useful data validation point and could potentially be used for the future development of an emission factor.

The proposed revisions to add new reporting requirements would also extend the usefulness of GHGRP data to improve the EPA's ability to carry out other CAA programs. For example, we are proposing under subpart HH to require MSW landfills to report data on the landfill CH_4 emissions that are destroyed versus sent to landfill gas energy projects. This information would additionally help inform the development of GHG policies and programs by providing information on the amount of recovered CH_4 that is beneficially used in energy recovery projects and would inform the EPA, as well as state and local government officials, on progress towards renewable energy targets, and would also be useful to other stakeholders. As discussed in prior amendments, the GHGRP is also intended to supplement and complement the U.S. GHG Inventory and other EPA programs by advancing the understanding of emission processes and monitoring methodologies for particular source categories or sectors. The GHGRP also provides data from individual facilities and suppliers above certain thresholds, which can additionally be used to improve the assumptions and emissions values used in the U.S. GHG Inventory (see 81 FR 2546, January 15, 2016). The facility, unit, and process level GHG emissions data for industrial sources collected under the GHGRP does not replace the system in place to produce the top-down U.S. GHG Inventory, but can be additionally used to improve the accuracy of the U.S. GHG Inventory by confirming the national statistics and emission estimation methodologies. Therefore, the EPA periodically reviews the data from the GHGRP to consider whether there are data that are useful to the GHGRP and that would also improve the accuracy of the data included in the U.S. GHG Inventory or improve our ability to inform the development of GHG policies and programs. We are proposing several amendments that would improve the data collected by the GHGRP, and subsequently, would provide data that would benefit and support the U.S. GHG Inventory. For example, we are proposing to revise the current requirements for subpart N (Glass Production) facilities to require reporting the annual quantities of glass produced by glass type. In general, the emissions profile of a specific glass type is relatively consistent with the composition of the glass, based on the major raw materials (limestone, dolomite, and soda ash). Collecting data on annual production by glass type would improve verification for the GHGRP by allowing the EPA to compare emissions by glass types produced and would also provide useful information to improve analysis of this sector in the U.S. GHG Inventory.

5. Technical Amendments, Clarifications, and Corrections

We are proposing other technical amendments, corrections, and clarifications that would improve understanding of the rule. These revisions primarily include revisions of requirements to better reflect the EPA's intent or editorial changes. Some of these proposed changes result from consideration of questions raised by reporters through the GHGRP Help Desk or electronic Greenhouse Gas Reporting Tool (e-GGRT) and are intended to resolve uncertainties in the regulatory text. For example, we are proposing amendments in several subparts that would clarify requirements that have led to reporter uncertainty, such as reported data elements that may be unclear and misread by reporters. In several cases, these provisions may have introduced uncertainty into the rule and resulted in reporting that is inconsistent with the rule requirements. The proposed clarifications would reduce the uncertainty associated with certain reported data elements and increase the likelihood that reporters will submit accurate reports the first time. For example, we are proposing a revision to subpart Y to resolve the potential discrepancy between the flare emission calculations at 40 CFR 98.253(b), which requires that all gas discharged through the flare stack must be included in the calculations except for pilot gas, and the requirements at 40 CFR 98.253(b)(1)(iii), which excludes startup, shutdown, and malfunction (SSM) events less than 500,000 standard cubic feet per day (scf/day) from equation Y–3. As another example, under subpart W, the EPA is proposing to clarify the calculation of emissions from open thief hatches on atmospheric storage tanks that use vapor recovery systems and flares, by revising 40 CFR 98.233(j)(4) and (5) to specify how to account for those emissions. The EPA's intent is that reporters should be including emissions from open thief hatches, but the current rule does not provide explicit provisions for them. We are also proposing to revise 40 CFR 98.236(j)(1) to clarify reporting of emissions from atmospheric storage tanks with vapor recovery systems and flares. These proposed clarifications and corrections would also reduce the burden associated with reporting, data verification, and EPA review. Additional details of these types of proposed changes are discussed in section III of this preamble.

Other minor changes being proposed include correction edits to fix typos, minor clarifications such as adding a missing word, harmonizing changes to match other proposed revisions, reordering of paragraphs so that a larger number of paragraphs need not be renumbered, and others as reflected in the draft proposed redline regulatory text in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

B. Revisions To Streamline and Improve Implementation of 40 CFR Part 98

Since 2010, the EPA has collected data through the GHGRP to assess industry emissions, and has, through review of annually submitted data, gained substantial knowledge of the types, quantities, and distribution of emissions across industry sectors. Through this process, the EPA has engaged in stakeholder outreach, solicited feedback, responded to questions from reporters, and identified site specific scenarios or issues that could impact the quality of the data reported. In a recent review of the requirements of the program, we have identified several areas of part 98 that could be revised or simplified to reduce technical challenges associated with implementation or improve the efficiency of the requirements, while maintaining the quality of the data collected. We are subsequently proposing several revisions that would streamline the calculation, monitoring, and reporting burden associated with the rule. These revisions would revise applicability estimation methodologies, provide flexibility for or simplifying calculation and monitoring methodologies, streamline recordkeeping and reporting, and other minor technical corrections or clarifications.

The specific changes that we are proposing that are intended to streamline part 98, as described in this section, are described in detail for each subpart in sections III.A through III.W of this preamble.

1. Revisions To Applicability for Certain Industry Sectors

We are proposing to change the applicability criteria for three subparts to account for changes in usage of certain GHGs, or where the current applicability estimation methodology may overestimate emissions. The proposed changes would improve the estimation methodologies used to determine applicability for specific subparts and more accurately focus GHGRP and reporter resources on coverage of large industrial emitters within these sectors; such changes are in keeping with our goal to maximize coverage and collection of GHG emissions data from each sector while excluding small emitters.

Currently, any facility that contains a source category listed in Table A–3 of subpart A of part 98 (General Provisions) is subject to reporting under part 98 (referred to as ''all-in'' source categories because reporting applies regardless of other source category or stationary fuel combustion emissions at the facility). Table A–3 defines a few of the ''all-in'' source categories using thresholds that use metrics other than $mtCO_2e$ of emissions. A facility that contains a source category listed in Table A–4 of subpart A of part 98 must report only if estimated annual emissions from all applicable source categories in Tables A–3 and Table A–4 of part 98 are 25,000 $mtCO_2e$ or more (referred to as ''threshold'' source categories). The EPA has used the ''threshold'' approach where a source category contains emitters with a range in emissions quantity and the EPA wants to capture those facilities within the source category with larger total emissions from multiple process units or collocated source categories that emit significant levels of GHGs collectively, and not burden smaller emitters with a reporting obligation. The EPA has used the ''all-in'' approach for industries for which all facilities are emitters of a similar quantity or to gather data on certain industries to identify the parameters that influence GHG emissions from the source category.

The EPA used alternative metrics for some subparts in Table A–3 for a variety of reasons. In some cases, the metric provides a more straightforward way for facilities within that source category to evaluate their applicability. For example, for subpart DD (Electrical Transmission and Distribution Equipment), the metric is based on the total nameplate capacity of SF_6 and PFC-containing equipment and was approximated as equivalent to the 25,000 metric tons of CO_2 threshold. To ensure that the GHGRP data collected better reflects the current electrical power system industry, we are proposing to remove the existing nameplate capacity threshold, and instead provide a calculation method for facilities to estimate total annual GHG emissions for comparison to the 25,000 metric tons of CO_2 threshold. These changes align with proposed changes to redefine the source category to include equipment containing ''fluorinated GHGs (F–GHGs), including but not limited to sulfur-hexafluoride (SF_6) or and perfluorocarbons (PFCs)'', and reflect that some facilities within the industry sector have begun to use lower GWP F–GHGs, which is not reflected when using only the nameplate capacity of the equipment to determine applicability. The proposed changes would establish an updated comparison to the threshold and would account for additional fluorinated gases (including F–GHG mixtures) used in industry. The proposed changes to the threshold would decrease the number of facilities with annual emissions less than 25,000 metric tons CO_2e that would be required to report. The proposed changes would require tracking of additional fluorinated gases and the equipment they are contained in; however, this additional burden is expected to be small as these gases are not yet widely used.

Similarly, we are proposing to revise the threshold for subpart SS (Electrical Equipment Manufacture or Refurbishment), which is based on total annual purchases of SF_6 and PFCs. As with subpart DD, we are proposing to revise the existing requirements of subpart SS to require reporting of additional F–GHGs beyond SF_6 and PFCs, and we are proposing to revise the subpart SS threshold to align with these changes. The proposed changes would continue to be based on the total annual purchases of F–GHGs but would establish a calculation method for comparison to the 25,000 metric tons of CO_2 threshold, and would better account for the additional fluorinated gases (including F–GHG mixtures) reported by industry. The proposed changes would require tracking of additional fluorinated gases and the equipment they are contained in; however, this additional burden is expected to be small as these gases are not yet widely used.

We are also proposing revisions to provide a second option for an alternative calculation methodology, that is consumption-based, that reporters subject to subpart I (Electronics Manufacturing) could use to determine whether they meet the emissions threshold for reporting applicability. For subpart I (Electronics Manufacturing), the current provisions of 40 CFR 98.91 require facilities to estimate whether the 25,000 metric tons of CO_2e threshold is met based on emissions estimates assuming the facility operates at its annual manufacturing capacity, which may result in significant over-estimation of emissions. The capacity-based methodology has required reporting by some electronics manufacturing facilities that use smaller amounts of F–GHGs. For subpart I, the method for determining the applicability was chosen to reduce the burden on low-emitting facilities by providing a simplified method to estimate emissions for the purpose of assessing applicability. However, for subpart I, the applicability threshold provisions may currently require certain lower-emitting facilities to report where the capacity-based estimation methodology overestimates emissions. We are proposing to revise the applicability estimation methodology in subpart I to provide a second option for an alternative calculation method using a gas-consumption basis, and to use updated emission factors, so that facilities may choose instead to use a separate method that more accurately calculates potential facility emissions. This may result in fewer facilities reporting under subpart I, but these facilities are expected to have annual emissions that are lower than 25,000 metric tons of CO_2e. The gas consumption-based approach to determining applicability would require tracking gas consumption, which is not required by the production capacity-based threshold when determining applicability; however, this option to determine applicability is less burdensome than reporting to subpart I, which a facility would be required to do under the current rule if their capacity were above the capacity-based threshold. Under the current rule, facilities reporting under subpart I must collect gas consumption data to complete their subpart I report. Thus, overall, the burden for potential new entrants to the program would decrease.

We are proposing to revise the applicability of these subparts to more accurately estimate facility emissions and to more accurately focus GHGRP and reporter resources on the collection of data for the larger industrial emitters within these sectors. These changes would continue to maximize coverage of GHG emissions data from the sector while excluding small emitters. The proposed revisions would also adjust the applicability provisions for each of these subparts for consistency across part 98. The proposed changes to subparts I, DD, and SS are described in sections III.E, III.N, and III.U of this preamble.

2. Revisions To Streamline Monitoring and Calculation Methodologies

We are proposing revisions to provide flexibility for or simplify some calculation methods or monitoring requirements. We are proposing options to revise monitoring requirements in instances where we currently allow a less burdensome methodology for similar emissions sources; or where continuing to collect the data on the same frequency would be unlikely to provide significantly different values.

In some cases, we are proposing amendments that would add flexibility to the calculation methods to add less burdensome options that would correspond with a decrease in actual data collection. These types of proposed changes would simplify monitoring for reporters without impacting the quality of the data reported. For example, for subpart Y (Petroleum Refineries), we are proposing to allow the use of mass spectrometer analyzers to determine gas composition and molecular weight without the use of a gas chromatograph. The proposed revisions would allow reporters to use the same analyzers used for process control or for compliance with continuous sampling required under the National Emissions Standards for Hazardous Air Pollutants from Petroleum Refineries (40 CFR part 63, subpart CC) to comply with the GHGRP requirements in subpart Y. Currently, these reporters must conduct separate periodic sampling of these gas streams for analysis using gas chromatography to comply with GHGRP requirements in subpart Y, and the proposed revisions would provide flexibility for and reduce burden for these reporters.

We are also proposing to clarify applicability provisions to reduce uncertainty regarding which calculation method should be used. For example, for subpart W (Petroleum and Natural Gas Systems), we are proposing to revise the definition of the Onshore Natural Gas Processing industry segment so that reporters have more certainty regarding the industry segment and calculation methods that are applicable from the beginning of the year. The current definition of the Onshore Natural Gas Processing industry segment includes processing plants that fractionate gas liquids and processing plants that do not fractionate gas liquids but have an annual average throughput of 25 million standard cubic feet (MMscf) per day or greater. Processing plants that do not fractionate gas liquids and have an annual average throughput of less than 25 MMscf per day may be part of a facility in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment. Processing plants that do not fractionate gas liquids and generally operate close to the 25 MMscf per day threshold do not know until the end of the year whether they will be above or below the threshold, so they must be prepared to report under whichever industry segment is ultimately applicable. The two potentially applicable segments report emissions from different sources and with different calculation methods. For example, facilities in the Onshore Natural Gas Processing industry segment are not required to report emissions from atmospheric storage tanks and are required to measure leaks from individual compressors, while facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment are required to report emissions from atmospheric storage tanks but may use emission factors to calculate emissions from compressors rather than conducting measurements. Therefore, we are proposing to revise the Onshore Natural Gas Processing industry segment definition in 40 CFR 98.230(a)(3) to remove the 25 MMscf per day threshold and more closely align subpart W with the definitions of natural gas processing in other rules (*e.g.,* 40 CFR part 60, subpart OOOOa). This proposed revision to the Onshore Natural Gas Processing industry segment definition would make it clear to reporters whether a processing plant would be classified as an Onshore Natural Gas Processing facility or as part of an Onshore Petroleum and Natural Gas Gathering and Boosting facility, and the applicable segment would not have the potential to change from one year to the next simply based on the facility throughput. As discussed in greater detail in section III.J.2.h of this preamble, we are also proposing several other changes to the Onshore Natural Gas Processing industry segment definition. Collectively, these proposed amendments are not expected to significantly affect the overall coverage of the GHGRP for the petroleum and natural gas systems industry, although we anticipate that some facilities would report under a different industry segment going forward.

Additional details of these types of proposed changes may be found in section III of this preamble.

3. Revisions To Streamline or Revise Recordkeeping and Reporting Requirements

Other proposed revisions to the rule include changes that would streamline the rule, such as revising certain reporting and recordkeeping requirements that are redundant or no longer being used, or that would remove duplicative reporting across EPA programs. For example, for subpart C (General Stationary Fuel Combustion Sources), we are proposing to amend certain provisions in 40 CFR 98.36 that require facilities with the aggregation of units or common pipe configuration types to report the total annual CO_2 mass emissions from the combustion of all fossil fuels combined. In this case, the reported configuration-level annual CO_2 emissions from all fossil fuels does not factor into any subpart- or facility-level total CO_2 emission calculations and is not integrated into e-GGRT's programmed ''roll up'' of emissions. Because we can adequately verify reports and interpret and analyze the reported data without these data elements, they are currently redundant and would not likely provide new insights or knowledge of the industry sector, emissions, or trends at this time.

In some cases, we are proposing to correct inconsistencies in the current rule. Under subpart Y, we are proposing a change to correct an inconsistency introduced by the amendments to the DCU calculations published on December 9, 2016 (81 FR 89188). Although the prior amendments removed the option to calculate CH_4 emissions from DCUs using the process vent method, the associated recordkeeping requirements for the process vent method were inadvertently not removed from the rule. Therefore, we are therefore proposing to remove the associated recordkeeping requirements.

For subpart W, we are proposing to revise reporting requirements related to atmospheric pressure fixed roof storage tanks receiving hydrocarbon liquids that follow the methodology specified in 40 CFR 98.233(j)(3) and equation W–15. The calculation methodology uses population emission factors and the count of applicable separators, wells, or non-separator equipment to determine the annual total volumetric GHG emissions at standard conditions. The associated reporting requirements in 40 CFR 98.236(j)(2)(i)(E) through (F) require reporters to delineate the counts used in equation W–15. Based on feedback from reporters, the EPA has determined that the reporting requirements are inconsistent with the language used in the calculation methodology and are not inclusive of all equipment to be included. Therefore, we are proposing to revise the reporting requirements to better align the requirement with the calculation methodology and streamline the requirements for all facilities reporting atmospheric storage tanks emissions using the methodology in 40 CFR 98.233(j)(3).

In some cases, we are streamlining reporting by removing duplicative reporting elements within or across GHGRP subparts. For example, we are proposing to eliminate duplicative reporting between subpart NN (Suppliers of Natural Gas and Natural Gas Liquids) and subpart W where both subparts require similar data elements to be reported to e-GGRT. For instance, for fractionators of natural gas liquids (NGLs), both subpart W (under the Onshore Natural Gas Processing segment) and subpart NN require reporting of the volume of natural gas received and the volume of NGLs received. The proposed amendments would limit the reporting of these data elements to facilities that do not report under subpart NN, thus removing the duplicative requirements from subpart W for facilities that report to both subparts. This will streamline reporting and reduce the burden on reporters.

We are also proposing to reduce the frequency of reporting information that we anticipate will not change on a frequent basis, such as the data collected for technology assessment reports under subpart I (Electronics Manufacturing). Based on the data collected in the initial technology assessment reports (currently required by 40 CFR 98.96(y)), we do not anticipate significant variations in these data elements within a three-year period going forward, as discussed in section III.E.2 of this preamble. Further, we are proposing several significant improvements to the technology assessment reports that will improve the usefulness and quality of the data provided in the reports. The proposed improvements would allow the EPA to collect these data less frequently while continuing to provide the EPA with updates to the gases and technologies used in semiconductor manufacturing.

Additional details of these types of proposed changes may be found in section III of this preamble.

C. Revisions to 40 CFR Part 9

The EPA is proposing a related change to update 40 CFR part 9 to include the OMB control number issued under the PRA for the ICR for the GHGRP. The OMB control numbers for EPA regulations in Title 40 of the CFR (after appearing in the **Federal Register**) are listed in 40 CFR part 9 and are included on the related collection instrument or form, if applicable. The EPA is proposing to amend the table in 40 CFR part 9 to list the OMB approval number under which the ICR for activities in the existing part 98 regulations that were previously approved by OMB have been consolidated. The prior approvals are included in OMB No. 2060–0629; OMB No. 2060–0629 has not previously been added to 40 CFR part 9 due to an oversight. This listing of the OMB control number and the subsequent codification in the CFR would correct this oversight and satisfy the display requirements of the PRA and OMB's implementing regulations at 5 CFR part 1320.

III. Proposed Amendments to 40 CFR Part 98

This section summarizes the specific substantive amendments proposed for each subpart, as generally described in section II of this preamble. The impacts of the proposed revisions are summarized in section VII of this preamble. A full discussion of the cost impacts for the proposed revisions may be found in the memorandum, *Assessment of Burden Impacts for Proposed Revisions for the Greenhouse Gas Reporting Rule* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

A. Subpart A—General Provisions

1. Proposed Revisions To Improve the Quality of Data Collected for Subpart A

In this action, we are proposing several clarifying revisions to subpart A of part 98 (General Provisions). For the reasons described in section II.A.5 of this preamble, we are proposing to clarify in 40 CFR 98.2(i)(1) and (2) that the provision to allow cessation of reporting or ''off-ramping,'' due to meeting either the 15,000 mtCO_2e level or the 25,000 mtCO_2e level for the number of years specified in 40 CFR 98.2(i), is based on the CO_2e reported, calculated in accordance with 40 CFR 98.3(c)(4)(i) (*i.e.,* the annual emissions report value as specified in that provision). The proposed changes clarify that reporters must rely on the emissions estimation methodologies used to report emissions and their annual emissions report totals to determine their ability to off-ramp. We are also proposing to clarify the off-ramp provisions at 40 CFR 98.2(i)(1) and (2) to specify that after an owner or operator off-ramps, the owner or operator must use equation A–1 and follow the requirements of 40 CFR 98.2(b)(4) in subsequent years to determine if emissions exceed the 25,000 mtCO_2e applicability threshold and whether the facility or supplier must resume reporting. The requirements of 40 CFR 98.2(b) are different from the requirements of 40 CFR 98.3(c) in that the applicability determination requires more flexible calculation methods (*e.g.,* facilities may use any subpart C tier to estimate combustion emissions on 40 CFR 98.2(b), whereas they must follow the applicable subpart C tier to calculate combustion emissions under 40 CFR 98.3(c)). The proposed revisions make clear that reporters who have previously off-ramped would continue to follow the emission estimation methods used for determination of applicability to determine if they must resume reporting.

We are also proposing to revise 40 CFR 98.2(f)(1) to clarify how to calculate GHG quantities for comparison to the 25,000 mtCO_2e threshold for importers and exporters of industrial greenhouse gases; the proposed changes specify that the calculation must include the fluorinated heat transfer fluids (F–HTFs) that are imported or exported during the year. In the December 9, 2016 final rule, *2015 Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule* (81 FR 89234), the EPA expanded the definition of the source category for importers and exporters of industrial greenhouse gases to include facilities that destroy 25,000 mtCO_2e or more of industrial F–GHGs or F–HTFs annually, and entities that produce, import, or export F–HTFs that are not also F–GHGs. It was our intent that suppliers of F–HTFs be subject to the same thresholds.[4] However, we inadvertently neglected to update 40 CFR 98.2(f) to include F–HTFs in the calculation requirements. Similarly, we are proposing to add a new paragraph (k) to 40 CFR 98.2, specifying how to calculate the quantities of F–GHGs and F–HTFs destroyed for purposes of comparing them to the 25,000 $mtCO_2e$ threshold for stand-alone industrial F–GHG or F–HTF destruction facilities. This paragraph was inadvertently omitted when the rule was revised to cover stand-alone destruction facilities in 2016. The proposed changes would clarify that imported, exported, and destroyed F–HTFs and F–GHGs must be calculated and included when determining applicability.

We are also proposing new paragraph 40 CFR 98.4(n) that would apply in lieu of 40 CFR 98.4(h) for changes in the owner or operator of a facility in the four industry segments in subpart W (Petroleum and Natural Gas Systems) that have unique definitions of facility: Onshore Petroleum and Natural Gas Production; Onshore Petroleum and Natural Gas Gathering and Boosting; Natural Gas Distribution; and Onshore Natural Gas Transmission Pipeline. For these industry segments, particularly Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting, asset transactions between owners and operators can involve only some emission sources at the facility rather than the entire facility. In those cases, reporters have submitted numerous questions to the e-GGRT Help Desk requesting guidance regarding which owner or operator should report for the year in which the transaction occurred as well as which owner or operator is responsible for submitting revisions and responding to questions from the EPA regarding previous annual GHG reports. To address some of these questions, the EPA previously developed Frequently Asked Questions (FAQ) Q749.[5] However, neither the FAQ nor the existing requirements in subpart A explicitly explain the responsibilities for the situations for which reporters have requested guidance.

Therefore, the EPA is proposing to add specific provisions to subpart A that would define which owner or operator is responsible for current and future reporting years' reports and clarify how to determine responsibility for revisions to annual reports for reporting years prior to owner or operator changes for specific industry segments in subpart W, beginning with RY2023 reports. The provisions would also specify when an owner or operator should submit an annual report using an e-GGRT identifier assigned to an existing facility and when an owner or operator should register a new facility in e-GGRT. As described in more detail in this section, the provisions would vary based upon whether the selling owner or operator will retain any emission sources, the number of purchasing owners or operators, and whether the purchasing owners or operators already report to the GHGRP in the same industry segment and basin or state (as applicable). The proposed provisions would apply in lieu of 40 CFR 98.4(h) for these industry segments. These proposed revisions are expected to improve data quality as described in section II.A.4 of this preamble by ensuring that the EPA receives a more complete data set, and they are also expected to improve understanding of the rule, as described in section II.A.5 of this preamble.

We expect all the transactions will fall into one of four general categories, and we are proposing provisions that would define the responsibilities for reporting for each of those general categories. First, if the entire facility is sold to a single purchaser and the purchasing owner or operator does not already report to the GHGRP in that industry segment (and basin or state, as applicable), then we are proposing that the facility's certificate of representation must be updated within 90 days of the transaction to reflect the new owner or operator. In other words, the e-GGRT identifier and associated facility within e-GGRT would be transferred from the seller to the purchaser. The purchasing owner or operator would be responsible for submitting the facility's annual report for the entire reporting year in which the acquisition occurred (*i.e.,* the owner or operator as of December 31 would be responsible for the report for that entire reporting year) and each reporting year thereafter. In addition, because the definitions of facility for each of these segments encompass all of the emission sources in a particular geographic area (*i.e.,* basin, state, or nation), the purchasing owner or operator would include any previously owned applicable emission sources in the same geographic area as part of the purchased facility beginning with the reporting year in which the acquisition occurred.

Second, if the entire facility is sold to a single purchaser and the purchasing owner or operator already reports to the GHGRP in that industry segment (and basin or state, as applicable), then we are proposing that the purchasing owner or operator would merge the acquired facility with their existing facility for purposes of reporting under the GHGRP. In other words, the acquired facility would become part of the purchaser's existing facility under the GHGRP and emissions for the combined facility would be reported under the e-GGRT identifier for the purchaser's existing facility. The purchaser would update the acquired facility's certificate of representation within 90 days of the transaction to reflect the new owner or operator. The purchaser would then follow the provisions of 40 CFR 98.2(i)(6) to notify the EPA that the purchased facility has merged with their existing facility and would provide the e-GGRT identifier for the merged, or reconstituted, facility. Finally, the purchaser would be responsible for submitting the merged facility's annual report for the entire reporting year in which the acquisition occurred (*i.e.,* the owner or operator as of December 31 would be responsible for the report for that entire reporting year) and each reporting year thereafter.

Third, if the selling owner or operator retains some of the emission sources and sells the other emission sources of the seller's facility to one or more purchasing owners or operators, we are proposing that the selling owner or operator would continue to report under subpart W for the retained emission sources unless and until that facility meets one of the criteria in 40 CFR 98.2(i) and complies with those provisions. Each purchasing owner or operator that does not already report to the GHGRP in that industry segment (and basin or state, as applicable) would begin reporting as a new facility for the entire reporting year beginning with the reporting year in which the acquisition occurred. The new facility would include the acquired applicable emission sources as well as any previously owned applicable emission

[4] In the 2016 proposed rule, we specified "Suppliers of fluorinated HTFs would be subject to the same thresholds as suppliers of fluorinated GHGs. That is, there would be no threshold for producers of fluorinated HTFs, but the threshold for importers, exporters, and destroyers of fluorinated HTFs would be 25,000 $mtCO_2e$ of fluorinated HTFs or GHGs." (81 FR 2572, January 15, 2016).

[5] U.S. EPA. *Q749: "What are the notification requirements when an Onshore Petroleum and Natural Gas Production facility, reporting under subpart W, sells wells and associated equipment in a basin?"* September 26, 2019. *https://ccdsupport.com/confluence/pages/viewpage.action?pageId=198705183.* Note that although FAQ Q749 specifically describes facilities in the Onshore Petroleum and Natural Gas Production segment, the EPA does consider the scenarios described to be relevant to the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment as well, because facilities in both segments are defined at the basin level rather than at the level of the subpart A definition of facility.

sources. Each purchasing owner or operator that already reports to the GHGRP in that industry segment (and basin or state, as applicable) would add the acquired applicable emission sources to their existing facility for purposes of reporting under subpart W and would be responsible for submitting the annual report for their entire facility, including the acquired emission sources, for the entire reporting year beginning with the reporting year in which the acquisition occurred.

Fourth, if the selling owner or operator does not retain any of the emission sources and sells all of the facility's emission sources to more than one purchasing owner or operator, we are proposing that the selling owner or operator for the existing facility would notify the EPA within 90 days of the transaction that all of the facility's emission sources were acquired by multiple purchasers. The purchasing owners or operators would begin submitting annual reports for the acquired emission sources for the reporting year in which the acquisition occurred following the same provisions as in the third scenario. In other words, each owner or operator would either begin reporting their acquired applicable emission sources as a new facility or add the acquired applicable emission sources to their existing facility.

Finally, for all of these types of transactions, we are proposing one set of provisions to clarify responsibility for annual GHG reports for reporting years prior to the reporting year in which the acquisition occurred. This set of proposed provisions would apply to annual GHG reports for facilities where these types of transactions occur after the effective date of the final amendments, if adopted. In other words, if the effective date of the final amendments is January 1, 2023, as described in section V of this preamble, then for ownership transactions that occur on or after January 1, 2023, we are proposing that the proposed requirements for the current and future reporting years described in the previous paragraphs would apply. In addition, the proposed provisions for annual GHG reports for reporting years prior to the transaction would also apply. For example, if an ownership transaction occurs on June 30, 2025, then the selling owner or operator and purchasing owner or operator would follow the applicable provisions previously described in this section for the RY2025 report and for future reporting years. We are also proposing that the provisions described in the next paragraph would apply for RY2024 and prior years' reports.

Specifically, we are proposing that as part of each ownership transaction described previously in this section, the selling owner or operator and purchasing owner or operator would agree upon the entity that would be responsible for revisions to annual GHG reports for previous reporting years. That entity would then select a representative for each facility that would respond to any EPA questions regarding GHG reports for previous reporting years and would submit corrected versions of GHG reports for previous reporting years as needed. If that individual is not the designated representative for the facility, the individual would need to be appointed as the alternate designated representative or an agent for the facility. In many situations, particularly for the first two categories of transactions described in this section, the EPA expects that the purchaser would agree to select a representative to address revisions to previous years' annual GHG reports. In addition, there may be cases in which the selling owner or operator's company will no longer be operating after the transaction, so it may be appropriate for one of the purchasing owners or operators to select that representative. In other situations, the parties may determine that it is appropriate for the seller to select the representative to address revisions to annual GHG reports for reporting years prior to the reporting year in which the acquisition occurred. Alternatively, parties to the transaction may agree on another independent party that would act as the representative regarding annual GHG reports for previous reporting years, such as a consultant. The EPA expects that the decision regarding the responsible entity would be made as part of the acquisition agreement or ownership transfer contract between the selling owner or operator and purchasing owner or operator and that if the entity responsible for revisions to annual GHG reports is not the selling owner or operator, copies of the records required to be retained per 40 CFR 98.3(g) and (h) would be transferred to the responsible entity at that time.

We are also proposing to amend 40 CFR 98.1(c) to clarify that the terms ''owner'' and ''operator'' used in subpart A have the same meaning as the terms ''gathering and boosting system owner or operator'' and ''onshore natural gas transmission pipeline owner or operator'' for the Onshore Petroleum and Natural Gas Gathering and Boosting and Onshore Natural Gas Transmission Pipeline industry segments of subpart W, respectively. This paragraph was inadvertently not amended when those two industry segments and the industry segment-specific definitions of owner or operator were added to subpart W (80 FR 64275, October 22, 2015), and this proposed amendment would correct that oversight.

In addition, we are proposing to revise 40 CFR 98.3(h)(4) to limit the total number of days a reporter can request to extend the time period for resolving a substantive error either by submitting a revised report or providing information demonstrating that the previously submitted report does not contain the substantive error. According to 40 CFR 98.3(h) a substantive error may either be identified by the EPA or discovered by the facility itself. If discovered by the facility, a revised report correcting the error must be submitted within 45 days. If identified by the EPA, once the facility is notified of the error, the facility must either resubmit the corrected report or provide information demonstrating that the previously submitted report does not contain the identified substantive error within 45 days. The rule also states that if requested in either case, the EPA may provide reasonable extensions to the 45-day period, including an automatically granted extension of 30 days. Additional extensions may be granted if the facility submits a request that is received prior to the expiration of the automatic 30-day extension. The current rule states that the Administrator will approve the additional extension request if the request demonstrates that it is not practicable to collect and process the data needed to resolve potential reporting errors within 75 days. However, since the GHGRP was implemented, we have encountered instances where a facility has repeatedly requested an extension of the time period by which they must either submit a revised report or provide information that the previously submitted report does not contain a substantive error. As such, the EPA cannot verify the facility's report in a timely manner. To avoid such instances in the future, we are proposing to add to 40 CFR 98.3(h)(4) that the Administrator will only approve extension requests for a total of 180 days from the initial notification of a substantive error. We expect that 180 days is a reasonable amount of time for a facility to examine company records, gather additional data, and/or perform recalculations to submit a revised report or provide the necessary information such that the report may be verified.

The EPA is also proposing revisions to two terms consistent with the proposed amendments for reporting for glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day described in section III.J of this preamble. The EPA is proposing to amend the definition of ''dehydrator vent emissions'' in 40 CFR 98.6 to confirm that dehydrator emissions reporting should include emissions from both the dehydrator still vent, and if applicable, the dehydrator flash vent. Additionally, the EPA is proposing to amend the definition of ''vapor recovery system'' in 40 CFR 98.6 to clarify that routing emissions from a dehydrator vent to the regenerator firebox/fire tubes does not qualify as vapor recovery. The EPA has noted significant variability in the dehydrator emissions values reported over the past several years, with values ranging from extremely high to almost negligible emissions, which indicates that there are likely inconsistencies in how these terms are being interpreted among subpart W reporters. In making these clarifying edits, the EPA expects to improve the quality of the emissions data reported and alleviate any confusion surrounding the applicability of these terms.

As a corollary to proposed amendments to subpart W to remove desiccant dehydrators as an emissions source, we are proposing to remove the definition of ''desiccant'' and to revise the definition of ''dehydrator'' in 40 CFR 98.6. The definition of ''desiccant'' would no longer be needed if the emission calculation and reporting requirements for desiccant dehydrators are removed from subpart W, as discussed in section III.J of this preamble. Similarly, the definition of ''dehydrator'' would no longer need to include a reference to desiccant. Thus, we are proposing to revise the definition of ''dehydrator'' to indicate that a dehydrator is ''a device in which a liquid absorbent (*e.g.,* ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.''

We are proposing revisions to 40 CFR 98.6 to add a definition for ''Direct air capture'' and amend the definition of ''Carbon dioxide stream''. These proposed changes are being made in conjunction with other proposed revisions to subpart PP of part 98 (Suppliers of Carbon Dioxide) and are discussed in section III.T of this preamble.

In addition, we are proposing two harmonizing changes to 40 CFR 98.7 to incorporate by reference ASTM International (ASTM) E415–17, *Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry* (2017) for subpart Q (Iron and Steel Production) and CSA/ANSI ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2-EOR)* for proposed subpart VV (Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916). These proposed changes are further described in sections III.H and III.W of this preamble.

Lastly, we are proposing two updates to Table A–1, the list of GWPs used in the GHGRP, to revise GWPs that, based on recent information, overestimate the atmospheric impacts of certain compounds by a large margin (*i.e.,* by factor of 2,000). We are not proposing any other updates to the Table A–1 GWPs. First, we are proposing to adopt a chemical-specific GWP for carbonic difluoride (COF_2). Emissions of COF_2 of 1–2 metric tons per year have been reported under the GHGRP from fluorinated gas production. (Carbonic difluoride is also used in the electronics industry as an etching agent and surface treatment, although emissions of COF_2 from electronics manufacturing have not been reported under the GHGRP). No peer-reviewed, chemical-specific GWP was available for COF_2 in 2014, when we last updated the set of GWPs in Table A–1 (79 FR 73750, December 11, 2014). It is therefore currently classified as an ''Other fluorinated GHG'' and is assigned a default GWP of 2,000 under the GHGRP. However, the World Meteorological Organization (WMO) recently published an atmospheric lifetime, radiative efficiency, and GWP for COF_2 in its *Scientific Assessment of Ozone Depletion*[6] (2018). Like the IPCC Assessment Reports upon which the GWPs in Table A–1 are based, the WMO Scientific Assessments include regularly updated international reviews of the scientific findings on the impacts of trace gases in the atmosphere, including their atmospheric lifetimes and radiative efficiencies. According to the 2018 WMO Scientific Assessment, COF_2 has a lifetime of approximately seven days, and 20-year and 100-year GWPs of less than one. The 2018 WMO Scientific Assessment listed the 100-year GWP of COF_2 as ''<1,'' so we calculated and are proposing a precise GWP for COF_2 of 0.14 using the atmospheric lifetime and radiative efficiency provided in the 2018 WMO Scientific Assessment. (The method we used to calculate the GWP of COF_2 was the method we used to calculate precise GWPs for low-GWP compounds in the most recent update to GHGRP GWPs (79 FR 73750, December 11, 2014)). This recent information supports that including a chemical-specific GWP for COF_2 of 0.14 would reflect its atmospheric impacts far more accurately than the currently applied GHGRP default GWP of 2,000.

Second, we are proposing to expand one of the F–GHG groups to which a default GWP of 1 is applied to include additional unsaturated fluorocarbons. The ninth F–GHG group in Table A–1 to subpart A currently includes unsaturated PFCs, unsaturated HFCs, unsaturated hydrochlorofluorocarbons (HCFCs), unsaturated halogenated ethers, unsaturated halogenated esters, fluorinated aldehydes, and fluorinated ketones. We are proposing to add unsaturated bromofluorocarbons, unsaturated chlorofluorocarbons, unsaturated bromochlorofluorocarbons, unsaturated hydrobromofluorocarbons, and unsaturated hydrobromochlorofluorocarbons to this set. These F–GHGs do not have chemical-specific GWPs in Table A–1, and facilities and suppliers that currently report these F–GHGs generally classify them as ''Other fluorinated GHGs,'' which are assigned a default GWP of 2,000. However, two lines of evidence indicate that unsaturated bromofluorocarbons, unsaturated chlorofluorocarbons, unsaturated bromochlorofluorocarbons, unsaturated hydrobromofluorocarbons, and unsaturated hydrobromochlorofluorocarbons are likely to have GWPs near 1. First, like many of the types of compounds currently included in the ninth F–GHG group, they are unsaturated (*i.e.,* they include double and triple bonds between carbon atoms), and unsaturated GHGs in general tend to have very short atmospheric lifetimes and GWPs near or below 1. Second, evaluations of individual unsaturated chlorofluorocarbons and unsaturated bromofluorocarbons have all found very short atmospheric lifetimes and (where assessed) low GWPs for these compounds. The 2018 WMO Scientific Assessment provides atmospheric lifetimes for three unsaturated chlorofluorocarbons and four unsaturated bromofluorocarbons, and it provides an atmospheric lifetime and a 100-year GWP for one unsaturated

[6] WMO. Scientific Assessment of Ozone Depletion: 2018, Global Ozone Research and Monitoring Project–Report No. 58, 588 pp., Geneva, Switzerland, 2018. *https://www.esrl.noaa.gov/csd/assessments/ozone/2018/downloads/2018OzoneAssessment.pdf.* Retrieved July 29, 2019. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

bromochlorofluorocarbon (4-bromo-3-chloro-3,4,4-trifluoro-1-butene). All of the atmospheric lifetimes are under 8 days,[7] and the 100-year GWP is listed as ''<1.'' Therefore, the EPA's assessment is that, due to their short atmospheric lifetimes, unsaturated bromofluorocarbons, unsaturated chlorofluorocarbons, unsaturated bromochlorofluorocarbons, unsaturated hydrobromofluorocarbons, and unsaturated hydrobromochlorofluorocarbons are likely to have a GWP near 1 (the default GWP for the ninth F–GHG group) rather than 2,000 (the default GWP for ''Other Fluorinated GHGs''). The EPA is proposing to add these additional unsaturated fluorocarbons to the ninth F–GHG group to result in more accurate estimation of the reported $mtCO_2e$.

We are proposing to incorporate a harmonizing change based on the addition of a new source category for quantifying geologic sequestration in association with EOR operations. Specifically, we are proposing to add the new subpart, subpart VV (Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916), in Table A–3 to subpart A.

As discussed in section III.W of this preamble, facilities that conduct EOR currently have the option to either report basic information on CO_2 received under subpart UU (Injection of Carbon Dioxide), or report CO_2 sequestered under subpart RR (Geologic Sequestration of Carbon Dioxide). Facilities that conduct EOR are not required to report under subpart RR unless the owner or operator chooses to opt-in to subpart RR, or the well is permitted as an Underground Injection Control (UIC) Class VI well. We are proposing that facilities that use the standard *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2-EOR)* (CSA/ANSI ISO 27916:2019) for quantifying geologic sequestration of CO_2 in association with EOR operations would similarly have the option to report under the proposed subpart VV instead of subpart UU. Facilities that conduct EOR would therefore have two options to report amounts of CO_2 that are geologically sequestered: subpart RR or subpart VV.

We are proposing to include the new subpart VV in Table A–3 to subpart A. In addition, we are proposing that this new subpart would not include a reporting threshold for applicability. The EPA previously promulgated subparts RR and UU with no threshold (*i.e.,* as ''all-in'' source categories in Table A–3 to subpart A) due to variability in CO_2 injection amounts from year to year and based on limited knowledge of which EOR reporters that are not required to report under subpart RR would choose to report geologic sequestration (see 75 FR 18454, April 10, 2010 and 75 FR 75070, December 1, 2010). The facilities affected by the proposed subpart include facilities that are currently reporting under subpart UU and that do not currently report amounts of CO_2 sequestered. The EPA is proposing no threshold for the proposed subpart VV so that all EOR facilities that quantify CO_2 sequestration using the CSA/ANSI ISO 27916:2019 standard and that do not report under subpart RR would have the option to either report under the proposed subpart VV, or would otherwise continue to report under subpart UU. For these reasons, we do not anticipate that the new subpart would increase the number of facilities subject to the GHGRP. Further, it is difficult to predict how many injection facilities would choose to report using the ISO standard in lieu of continuing to report under subpart UU. Therefore, we are proposing that subpart VV would be an ''all-in'' reporting subpart in order to allow the Agency to continue to comprehensively track all CO_2 that is injected underground, and to remain consistent with the ''all-in'' requirements for EOR or injection facilities that currently report under subparts RR or UU. Reporters who choose to report under this subpart would be required to meet the requirements of 40 CFR 98.2(a)(1). However, as proposed in new 40 CFR 98.480(c), facilities subject only to new subpart VV would not be required to report emissions under subpart C or any other subpart listed in 40 CFR 98.2(a)(1) or (2), consistent with the requirements for the existing facilities under subpart UU.

Additionally, we are proposing that facilities subject to proposed subpart VV would not be required to meet the off-ramp requirements of 40 CFR 98.2(i). Instead, once a facility opts-in to proposed subpart VV, the owner or operator must continue for each year thereafter to comply with all requirements of the subpart, including the requirement to submit annual reports, until the facility demonstrates termination of the CO_2-EOR project following the requirements of CSA/ANSI ISO 27916:2019. The EPA is proposing that the operator notify the Administrator of its intent to cease reporting and provide a copy of the CO_2-EOR project termination documentation prepared for CSA/ANSI ISO 27916:2019. See section III.W of this preamble for additional details on the proposed revisions.

2. Proposed Amendments To Streamline and Improve Implementation for Subpart A

For the reasons described in sections II.B.1, III.N, and III.U of this preamble, we are proposing harmonizing edits in subpart A of part 98 to revise the rule applicability for subparts DD (Electrical Transmission and Distribution Equipment Use) and subpart SS (Electrical Equipment Manufacture or Refurbishment). The proposed applicability threshold for subparts DD and SS would be based on total emissions equivalent to the 25,000 $mtCO_2e$ or more per year, rather than the current threshold levels that are based on the total nameplate capacity of the equipment or the annual consumption, respectively. For subpart DD, we are proposing to revise Table A–3 such that the threshold is based on total estimated emissions from F–GHGs, as determined under 40 CFR 98.301 (subpart DD), that are equivalent to 25,000 $mtCO_2e$ or more per year. For subpart SS, we are proposing to revise Tables A–3 and Tables A–4 such that: (1) subpart SS would be removed from Table A–3; and (2) Table A–4 would be revised to specify that subpart SS facilities would be included in 40 CFR 98.2(a)(2) and Table A–4, as determined under the requirements of 40 CFR 98.451 (subpart SS), which provide estimation methods for total estimated emissions from F–GHGs for comparison to a threshold equivalent to 25,000 $mtCO_2e$ or more per year. Refer to sections III.N and III.U of this preamble for a detailed discussion of these proposed changes and how the proposed new thresholds would be implemented. The proposed revisions are intended to harmonize Tables A–3 and A–4 with the proposed changes described in sections II.B.1, III.N, and III.U of this preamble, which would update the threshold to be consistent with the threshold set for the majority of subparts and would account for additional fluorinated gases (including F–GHG mixtures) reported by industry, and for subpart DD, would also streamline the reporting requirements to

[7] The IPCC Fifth Assessment Report lists 100-year GWPs of less than one for all the compounds for which the report lists an atmospheric lifetime of less than 8 days. The IPCC Fifth Assessment Report is the source of the chemical-specific GWPs for the compounds in the ninth F–GHG group in Table A–1. See 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. *https://www.ipcc.ch/site/assets/uploads/2018/02/WG1AR5_Chapter08_FINAL.pdf.*

focus Agency resources on the substantial emission sources within the sector by excluding facilities or operations that may report emissions that are consistently and substantially below 25,000 $mtCO_2e$ per year (see section IV.C (''Rationale for Selection of Thresholds'') of the preamble to the 2009 Proposed Rule (74 FR 16467, April 10, 2009)).

B. Subpart C—General Stationary Fuel Combustion Sources

1. Proposed Revisions To Improve the Quality of Data Collected for Subpart C

We are proposing several amendments to improve the quality of the data collected under subpart C of part 98 (General Stationary Fuel Combustion Sources). This section describes the specific changes proposed.

First, for the reasons provided in section II.A.2 of this preamble, we are proposing to modify the Tier 3 calculation methodology in subpart C. Reporters to subpart C may use the Tier 3 methodology provided in 40 CFR 98.33(a)(3) for determining annual CO_2 emissions from combustion units. The Tier 3 methodology requires a calculation based on annual fuel use, measured carbon content, and for gaseous fuels, measured molecular weight. For gaseous fuels, equation C–5 at 40 CFR 98.33(a)(3)(iii) requires that the carbon content and molecular weight be in units of kilogram (kg) C/kg fuel and kg/kg-mole, respectively, and be determined using the same procedures as specified for high heating value (HHV) at 40 CFR 98.33(a)(2)(ii). However, when using equation C–2b at 40 CFR 98.33(a)(2)(ii)(A) in this manner, the fuel carbon content is on a mass basis (*i.e.,* kg C/kg fuel) while the fuel flow is on a volumetric basis (*i.e.,* scf), resulting in a weighting factor that is potentially problematic because the units of measure are not in equivalent terms, *i.e.,* the average annual carbon content should be in mass terms (*i.e.,* kg C/kg fuel). When using equation C–2b for calculating an annual flow-weighted molecular weight, a similar situation occurs. This has been the case since the 2009 Final Rule (74 FR 56397).

To address this matter, the EPA is proposing to modify the Tier 3 calculation methodology in 40 CFR 98.33(a)(3)(iii) to provide new equations C–5a and C–5b for calculating a weighted annual average carbon content and a weighted annual average molecular weight. respectively. These new proposed equations incorporate the molar volume conversion factor at standard conditions (as defined at 40 CFR 98.6) and for annual average carbon content, the measured molecular weight of the fuel, in order to convert the fuel flow to the appropriate units of measure. This proposed change will correct the calculation method for Tier 3 gaseous fuels. The EPA does not expect a significant change in reported emissions because the change to the values for carbon content and molecular weight is expected to be minimal under the proposed calculation methods. Additionally, some reporters have previously exercised the option to manually override the calculated emission values with their own calculated values to address this issue when it has been identified.

We are also proposing several revisions to rule provisions pertaining to the calculation of biogenic emissions from tire combustion to improve the existing calculation methodology. First, for the reasons described in section II.A.2 of this preamble, the EPA is proposing to revise the calculation methods that must be used to determine the total annual CO_2 emissions under 40 CFR 98.33(e)(3)(iv)(A) when determining the biogenic CO_2 emissions of MSW or tires under 40 CFR 98.33(e)(3)(iv). Currently, 40 CFR 98.33(e)(3)(iv) provides procedures in certain circumstances to estimate the annual biogenic CO_2 emissions in the combustion of MSW or tires, which start with requiring that the Tier 1 calculation method be used to determine the total annual CO_2 emissions from MSW or tires under 40 CFR 98.33(e)(3)(iv)(A). The value determined under 40 CFR 98.33(e)(3)(iv)(A) is then multiplied by the applicable default biogenic fraction specified at 40 CFR 98.33(e)(3)(iv)(B) to determine the total biogenic CO_2 emissions. At the same time, 40 CFR 98.33(a) provides four calculation methodologies, Tier 1 through 4, and an alternative methodology for certain units subject to 40 CFR part 75, for calculating CO_2 emission for fuel combustion. In certain circumstances, a reporter may be required under 40 CFR 98.33(a) to calculate CO_2 emissions from combustion of MSW or tires using Tiers 2 or 3 for the purposes of annual reporting, but then must also calculate the total CO_2 emissions using Tier 1 under 40 CFR 98.33(e)(3)(iv)(A) for the purpose of determining and reporting the biogenic CO_2 emissions from combustion of MSW or tires under 40 CFR 98.33(e)(3)(iv). This has previously resulted in some confusion for reporters where total CO_2 emissions are calculated twice using different tiers, one tier for one aspect of annual reporting and another tier for biogenic calculation and reporting, and a redundancy in calculation of total CO_2 emissions by reporters. This has also resulted in some confusion when comparing the calculated total CO_2 emissions under 40 CFR 98.33(a) to the estimated total biogenic CO_2 emissions under 40 CFR 98.33(e)(3)(iv), since they are based on different calculation methodologies. The EPA is proposing to revise 40 CFR 98.33(e)(3)(iv)(A) so that total annual CO_2 emissions will be calculated using the applicable methodology in paragraphs 40 CFR 98.33(a)(1) through (3) for units using Tier 1 through 3 for purposes of 40 CFR 98.33(a), and using the Tier 1 calculation methodology in paragraph 40 CFR 98.33(a)(1) for units using the Tier 4 or part 75 for purposes of 40 CFR 98.33(a), when determining the biogenic component of MSW or tires under 40 CFR 98.33(e)(3)(iv).

The EPA is proposing two additional substantive revisions to the procedures for calculating and reporting emissions of biogenic CO_2 from the combustion of tires. First, for the reasons discussed in section II.A.1 of this preamble, we are proposing to update a default factor that is used to determine biogenic CO_2 emissions from the combustion of tires. Separately reporting the biogenic CO_2 emissions (*i.e.,* specifying which emissions are biogenic) from the combustion of tires is currently optional, but if a reporter elects to do so, then 40 CFR 98.33(e)(3) specifies the calculation procedure. Under 40 CFR 98.33(e)(3), if tires provide more than 10 percent of the annual heat input to a unit and the owner or operator elects to separately report the biogenic CO_2 emissions from the combustion of tires, then the owner or operator must conduct testing using ASTM method D6866–16, *Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis* (2016) and ASTM method D7459–08, *Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources* (2016) to determine the biogenic fraction of CO_2.[8] But if tires provide 10 percent or less of the annual heat input, then reporters have the option to separately report the biogenic CO_2 emissions by multiplying the total CO_2 emissions by a default factor of 0.20. The 0.20 factor is based on

[8] ASTM D7459–08 was approved for use in the October 30, 2009 final rule (74 FR 56291), see Docket Id. No. EPA–HQ–OAR–2008–0508. ASTM D6866–16 was approved for use in the December 9, 2016 final rule (81 FR 89196), see Docket Id. No. EPA–HQ–OAR–2015–0526.

information from the Rubber Manufacturers Association (RMA) that was based on most current data available at the time of the publication of the GHG Reporting Rule revisions in the **Federal Register** on December 17, 2010 (75 FR 79092) (hereafter referred to as the 2010 Final Revisions Rule) and represented an arithmetic average of the natural rubber content (*i.e.,* composition) of passenger and commercial tires sold and thus available for combustion.[9] Since publication of the 2010 Final Revisions Rule, we have received a memorandum from the U.S. Tire Manufacturers Association (USTMA, formerly RMA) that based on updated data, the weighted average composition of natural rubber in tires is now 24 percent.[10 11] The proposed default value was calculated by weighting the average rubber content, average weight, and shipment percentage of both light duty vehicle and commercial vehicle scrap tires, which is more accurate than would result from using the arithmetic average. In addition to the comments and information provided by the USTMA, the Portland Cement Association (PCA) provided supporting information from one of its member companies, Mitsubishi Cement. Operational data (total count and weight of tires combusted) and analytical data (percent of biogenic carbon based on ASTM D6866–20) from 2020 was provided.[12] The EPA reviewed these data and determined that they support the USTMA's recommended 0.24 default biogenic fraction for tires.[13] We are therefore proposing to revise 40 CFR 98.33(e)(3)(iv)(B) to update the default biogenic fraction to 0.24.[14]

Second, for the reasons described in section II.A.3 of this preamble, we are proposing that all units that combust tires must separately report biogenic CO_2 emissions. The separate reporting of biogenic CO_2 from tires was made optional in a 2010 final rule (75 FR 79100, December 17, 2010). For that rulemaking, we received no public comments on the proposal to make separate biogenic CO_2 emissions reporting optional for the combustion of tires, and the proposal was finalized without modification. In the final rule preamble, however, we stated: ''No comments were received on the proposal to make biogenic CO_2 emissions reporting optional for the combustion of tires, and the proposal has been finalized without modification. However, tire-derived fuel has a biomass component, and perhaps it should be treated in the same manner as MSW, which is also partly biogenic. A number of units that are subject to part 98 combust tires as the primary fuel or as a secondary fuel. Therefore, we are considering whether these units should be required to separately account for their biogenic CO_2 emissions. However, before making this mandatory we intend to open it to notice and comment in a future rulemaking'' (75 FR 79109). In conjunction with this change, we are proposing to remove the restriction in 40 CFR 98.33(e)(3)(iv) that the default factor may only be used to estimate the annual biogenic CO_2 emissions from the combustion of tires if the combustion of tires represents ''no more than 10 percent annual heat input to a unit.'' Following the 2010 Final Revisions Rule, reporters that chose to optionally report biogenic CO_2 emissions from tire combustion were required to use quarterly flue-gas testing using ASTM methods, except that small units (*i.e.,* units in which tires provide no more than 10 percent of the annual heat input to a unit) could alternatively use the default factor. The proposal to remove the current restriction allowing only small units to use the default factor (*i.e.,* allowing the use of the default factor for all units that combust tires), when combined with the proposed requirement to report biogenic CO_2 emissions from tire combustion, would result in a more accurate characterization of emissions from larger units since no units that combust tires alone or in conjunction with fossil fuels have reported, for RY2015 through RY2018, biogenic CO_2 emissions that were calculated using the quarterly flue-gas testing results. Therefore, the proposed addition of reporting of biogenic CO_2 emissions for tire combustion should require no additional monitoring or data collection and could be reported with minimal additional reporting burden. The EPA is proposing that this change would only be finalized if the proposed requirement to report biogenic CO_2 emissions from tire combustion is also finalized. Additionally, we are proposing another change that would only be finalized if the proposed requirement to report biogenic CO_2 emissions from tire combustion is also finalized. Specifically, 40 CFR 98.33(b)(1)(vii) currently allows units that combust MSW and/or tires to use Tier 1 if the combined heat input from both fuels is not greater than 10 percent of the heat input to the unit but also provides that, if a reporter choose the option to not report biogenic CO_2 from tire combustion, the 10 percent threshold applies only to the MSW fuel. If the proposed mandatory reporting of biogenic CO_2 from tire combustion is finalized, we are proposing that the additional provision in 40 CFR 98.33(b)(1)(vii) on how to apply the threshold to only MSW fuel would be deleted, since it would no longer be applicable. This may result in fewer facilities being able to use Tier 1 to calculate MSW and/or tire CO_2 emissions since the tire heat input would now always be included in conjunction with the MSW heat input to compare to the 10 percent threshold.

In conjunction with these proposed revisions, we are also proposing to remove the language in 40 CFR 98.33(e) and 40 CFR 98.36(e)(2)(xi) referring to optional biogenic CO_2 emissions reporting from tire combustion, and to revise 40 CFR 98.34(d) to reference 40 CFR 98.33(e)(3)(iv) instead of 40 CFR 98.33(b)(1)(vi) and (vii). We are proposing the latter change because 40 CFR 98.34(d) incorrectly references 40 CFR 98.33(b)(1)(vi) and (vii), which specify certain provisions when Tier 1 can be used, whereas 40 CFR 98.33(e)(3)(iv) specifies when the default biogenic factor for MSW can be used (*i.e.,* in cases where combustion of MSW provides no more than 10 percent of the annual heat input to the unit or if a small, batch incinerator combusts no more than 1,000 tons per year of MSW) and is the correct reference for 40 CFR 98.34(d). This revision is being proposed to correct this reference in accordance with other proposed changes. Additionally, we are proposing a clarifying correction to 40 CFR 98.33(e), *Biogenic CO_2 emissions from combustion of biomass with other fuels.* Section 98.33(e)(1) specifies that equation C–1 of subpart C can be used to calculate the annual CO_2 mass emissions from the combustion of the biomass fuels listed in Table C–1 of this subpart (except MSW and tires). We are proposing to delete the parenthetical clause ''(except MSW and tires)'' in 40 CFR 98.33(e)(1) because, although MSW and tires are partially biogenic, they were never categorized as biomass fuels

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9 Please refer to the memorandum, *Natural Rubber Fraction in Tire Derived Fuel* by Matt Hakos and Cassy Becker, RTI International to Michael Hannan, EPA (August 2021), available in the docket for this rulemaking, Docket Id. No EPA–HQ–OAR–2019–0424, for more detail.

10 See the memorandum, *Methodology for Determining the Natural Rubber Fraction in Tire Derived Fuel,* by Sarah Amick and Jesse Levine, USTMA to U.S. EPA (April 11, 2019), available in Docket Id. EPA–HQ–OAR–2019–0424.

11 *Supra* note 9.

12 See ''Tire Biogenic Content Data Provided by the Portland Cement Association'' (August 2021), available in Docket Id. EPA–HQ–OAR–2019–0434.

13 *Supra* note 9.

14 *Supra* note 9.

in Table C–1 of subpart C and thus no aspect of Table C–1 was excepted by this parenthetical clause. This deletion would correct the drafting oversight and will not result in any change to the reporting requirements.

Next, for the reasons discussed in section II.A.5 of this preamble, we are proposing to correct the equation C–11 term definition for the variable ''R''. Equation C–11 is used to calculate the CO_2 emissions from sorbent use when the chemical reaction between the acid gas and sorbent produces CO_2 emissions and when these emissions are not monitored with a CEMS. The term ''R'' is currently defined as the number of moles of CO_2 released upon capture of one mole of the acid gas species being removed (R = 1.00 when the sorbent is $CaCO_3$ and the targeted acid gas species is SO_2). However, the units of measure for the equation as presented do not currently result in metric tons CO_2 emitted. We are proposing to revise the definition of the term ''R'' as ''the number of moles of CO_2 released per mole of sorbent used (R = 1.00 when the sorbent is $CaCO_3$ and the targeted acid gas species is SO_2)'' so that the equation is dimensionally correct (*i.e.,* results in metric tons CO_2 emitted).

We are also proposing to amend 40 CFR 98.33(c)(6)(i), (ii), (ii)(A), and (iii)(C), and delete (ii)(B) to clarify the methods used to calculate CH_4 and N_2O emissions for blended fuels when heat input is determined after the fuels are mixed and combusted. There would be no new reporting requirements because of this proposed clarification.

For the reasons described in section II.A.4 of this preamble, we are proposing a substantive revision to rule provisions pertaining to the reporting of unit level information for the aggregation of units and common pipe configurations. Currently, subpart C allows facilities to report data using six different configurations. These configurations are:

- Individual unit using Tiers 1, 2, or 3 to calculate emissions.
- Individual unit using Tier 4 to calculate emissions.
- Group of units using the aggregation of units reporting alternative with Tiers 1, 2 or 3.
- Group of units using the common pipe configuration reporting alternative with Tiers 1, 2, or 3.
- Group of units using Tier 4 to calculate emissions and reporting under the monitored common stack or duct configuration reporting alternative.
- Part 75 units using the alternative CO_2 mass emissions calculation methods.
- For RY2019, the approximate use of reporting configurations and the percent of emissions for each is summarized:

Configuration type	Number of Subpart C configurations	Percent of total Subpart C configurations	Percent of total Subpart C CO_2 emissions
Individual Unit (Tiers 1–3)	9,185	58	36
Individual Unit (Tier 4)	208	1	9
Aggregation of Units (Tiers 1–3)	4,362	27	24
Common Pipe (Tiers 1–3)	1,905	12	26
Common Stack (Tier 4)	21	0.1	2
Alternative Part 75	192	1	2

Individual unit information (*i.e.,* the unit type and the maximum rated heat input capacity) is currently only required to be reported for the individual unit (Tiers 1–3 and Tier 4) reporting configurations. The individual unit information allows the EPA to aggregate emissions according to unit type and size and provides a better understanding of the emissions from specific unit types.

Individual unit information is not reported for the aggregation of units, common pipe, common stack, or alternative part 75 reporting configurations. As such, the EPA is currently unable to aggregate emissions by unit type and size for these reporting configurations, which represent 40 percent of the configurations used and 54 percent of the emissions reported in subpart C.

The aggregation of units and common pipe configurations are the second and third most used configurations and together, they represent approximately 39 percent of the configurations and 50 percent of the emissions reported to subpart C. Both of these reporting alternatives allow multiple units to be reported under one configuration group. Because the unit type and maximum rated heat input capacity are currently not reported for the individual units within these two configurations, there is a significant gap in the EPA's ability to aggregate subpart C emissions data by unit type and size.

To better analyze reported data by unit type and size, the EPA is proposing to revise 40 CFR 98.36(c)(1) and (3) (by adding 40 CFR 98.36(c)(1)(ii) and (c)(3)(xi)) to require reporting for each unit in either an aggregation of units or common pipe configuration, excluding units less than 10 mmBtu/hr from both, of the unit type, maximum rated heat input capacity, and an estimate of the fraction of the total annual heat input. Under the proposed amendments, unit level information would be reported for four of the six configuration types. This would allow the EPA to aggregate data according to unit type and size for approximately 98 percent of the configurations and 95 percent of the emissions in subpart C (the actual percent of emissions that could be aggregated by unit type would be somewhat lower than 95 percent because units less than 10 would be excluded from the additional reporting requirements) to provide unit level information for the aggregated unit and common pipe configurations. We expect the percent of emissions to be only somewhat lower than 95 percent because units less than 10 mmBtu/hr are estimated to have minor emissions contributions in aggregated unit and common pipe configurations, as previously described in the 2016 final rulemaking (81 FR 89203, December 9, 2016). Given the relatively low emissions from the common stack (Tier 4) and part 75 configurations, the EPA is not proposing to require reporting of individual unit information for these configurations at this time. The EPA seeks comment on whether to propose these requirements for the common stack (Tier 4) and part 75 configurations.

The proposed reporting requirements are not expected to significantly increase burden for reporters. The requirement to report the cumulative maximum rated heat input capacity for the aggregation of units or common pipe configurations began with the 2017 reporting year (81 FR 89188). Accordingly, facilities have been reporting cumulative maximum rated heat input capacity for four years. To determine this value, facilities must know the maximum rated heat input capacity of all units in each aggregation of units or common pipe configuration (greater than or equal to 10 mmBtu/hr), because these values are summed to determine the cumulative value. The EPA expects that the other requirements (*i.e.,* unit type and estimate of the fraction of annual heat input) can be determined from existing company records. The total fraction of annual heat input for each unit in the group will be determined by dividing the estimated actual heat input for that unit by the sum of the estimated actual heat input for all units in the group. Accordingly, any new burden incurred from this proposed requirement is expected to be minimal and associated with calculating the fraction of the total annual heat input and entering data into the e-GGRT software. To minimize the burden of reporting these data in e-GGRT, the EPA intends to evaluate developing a bulk unit details reporting form similar to the existing bulk equation input reporting forms for Tiers 2 and 3.

For the reasons described, the EPA has proposed these new reporting requirements under 40 CFR 98.36(c)(1)(ii) (aggregation of units) and 40 CFR 98.36(c)(3)(xi) (common pipe). These proposed amendments will better inform future policy and programs by addressing a data gap in unit information that currently exists for these two reporting configurations. We are proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

As a corollary to proposed amendments to subpart W (Petroleum and Natural Gas Systems) to address uncombusted methane emissions from compressor drivers (see section III.J.1.n of this preamble), we are proposing that natural gas-fired compressor drivers located at facilities that are subject to subpart W would be required to use the CH_4 emission factors in Table W–9 to subpart W rather than the default CH_4 emission factor for natural gas in Table C–2 to subpart C. Specifically, we are proposing to revise the ‘‘EF’’ term in each of the equations in 40 CFR 98.33(c) (*i.e.,* equations C–8, C–8a, C–8b, C–9a, C–9b, and C–10) to reference the CH_4 emission factors in Table W–9 to subpart W for natural gas compressor drivers. We are also proposing to add a footnote to Table C–2 that specifies that for reporters subject to subpart W, the default CH_4 emission factor for natural gas may only be used for natural gas-fired combustion units that are not compressor drivers. Finally, we are proposing to amend 40 CFR 98.36(c)(1) and (c)(3). Under the proposed amendments, reporters may not report a combination of one design class of compressor driver (using one Table W–9 CH_4 emission factor) and other combustion units (*e.g.,* using a Table C–2 CH_4 emission factor or another Table W–9 CH_4 emission factor) in the same aggregation of units or common pipe configuration. This change would ensure that all units in an aggregation of units or common pipe configuration are using the same CH_4 emission factor for each fuel combusted in the unit.

We are proposing two additional clarifications to existing reporting and record keeping requirements, for the reasons described in section II.A.5 of this preamble. First, we are proposing to revise the first sentence of 40 CFR 98.36(e)(2)(ii)(C) to clarify that both the annual average, and, where applicable, monthly high heat values are required to be reported. The monthly HHV reporting requirement was always clear based on the language in this provision and the proposed clarification plainly states that the annual average high heat value is also a reporting requirement (for reporters who do not use the electronic inputs verification tool (IVT) within e-GGRT). There are no new reporting requirements because of this proposed clarification.

Second, we are proposing to revise 40 CFR 98.37(b)(9), (10), (11), (14), (18), (20), (22), and (23) to specify recordkeeping data that is currently contained in the file generated by the verification software that is already required to be retained by reporters under 40 CFR 98.37(b) but was inadvertently omitted from being specified in those subparagraphs. These proposed revisions correct omissions that currently exist in the verification software recordkeeping requirements specific to equations C–2a, C–2b, C–3, C–4, and C–5. They also align the verification software recordkeeping requirements with the proposed revisions to equation C–5 at 40 CFR 98.33(a)(3)(iii), as noted above. These proposed revisions do not require any new action from affected reporters, as all new recordkeeping data proposed is already contained in the file generated by the verification software.

2. Proposed Revisions To Streamline Implementation and Reduce Burden for Subpart C

We are proposing several revisions to subpart C to streamline requirements and to adopt minor revisions to improve implementation of the rule.

For the reasons described in section II.B.2 of this preamble, the EPA is proposing to amend 40 CFR 98.34(c)(6). In the 2010 Final Revisions Rule (75 FR 79092), the EPA added 40 CFR 98.34(c)(6), which allowed cylinder gas audits (CGAs) of the CO_2 monitor to be performed using calibration gas concentrations of 40–60 percent and 80–100 percent of CO_2 span, when the CO_2 span value is set higher than 20 percent CO_2. Under appendix F of 40 CFR part 60, CGAs of the CO_2 analyzer are required at two calibration gas concentrations (*i.e.,* 5–8 percent and 10–14 percent CO_2 by volume). These CO_2 concentration levels are appropriate for certain stationary combustion applications (*e.g.,* a typical span value for a CO_2 monitor installed on a coal-fired boiler is 20 percent CO_2). These CGA concentrations represent 25–40 percent and 50–70 percent of the CO_2 span value, when the CO_2 span is at 20 percent CO_2. When the CO_2 span exceeds the typical span value of the fuel being evaluated (*e.g.,* 20 percent CO_2 on a coal-fired boiler), the CGA concentrations specified in part 60 are no longer representative, as they only evaluate the lower portion of the measurement scale. Since the EPA had information indicating that there were cases when the CO_2 span was set greater than 20 percent CO_2 (*e.g.,* process and combustion emissions from cement manufacturing may require 30 percent CO_2 span), 40 CFR 98.34(c)(6) was added so that CGAs could be conducted at two separate portions of the measurement scale, as opposed to just the lower portion (see 75 FR 79111, December 17, 2010).

Since 2010, the EPA has received questions through GHGRP Help Desk indicating that industrial flue gases also occur where the measured CO_2 concentration is very low (*e.g.,* natural gas turbines typically have about 5 percent CO_2 in flue gas). In this case, the required calibration gas concentrations (*i.e.,* 5–8 percent and 10–14 percent CO_2 by volume) under appendix F of 40 CFR part 60 would not be appropriate because they may be above the CO_2 span value and so would not provide information regarding accuracy of the monitor at actual representative stack gas concentrations. Accordingly, the EPA is proposing to amend 40 CFR 98.34(c)(6) to allow CGAs to be performed using calibration gas concentrations of 40–60 percent and 80–100 percent of CO_2 span, whenever the required CO_2 span value for a flue gas does is not appropriate for the prescribed audit ranges in appendix F of 40 CFR part 60. This will allow CGAs to check the response of the CO_2 analyzer at two calibration gas concentrations, representing separate portions of the measurement scale, when the CO_2 span is significantly lower or higher than 20 percent CO_2.

For the reasons described in section II.B.3 of this preamble, the EPA is proposing to amend certain provisions in 40 CFR 98.36 that require facilities with the aggregation of units or common pipe configuration types to report the annual CO_2 mass emissions from the combustion of all fossil fuels, per the requirements in 40 CFR 98.36(c)(1)(vi) and 40 CFR 98.36(c)(3)(vi). The EPA has reviewed the data provided under these reporting requirements and has tentatively concluded that they are no longer required for the verification or analysis of subpart C annual reports. In addition, the reporting of this data for the aggregation of units or common pipe configuration types has caused confusion for reporters because they mistakenly believe that the value is used in subpart C total CO_2 emission calculations. Therefore, we are proposing to revise the provisions in 40 CFR 98.36(c)(1)(vi) and 40 CFR 98.36(c)(3)(vi) to remove the language requiring reporting of the total annual CO_2 mass emissions from all fossil fuels combined.

For these two configuration types (aggregation of units and common pipe), the reported configuration-level annual CO_2 emissions from all fossil fuels does not factor into any subpart- or facility-level total CO_2 emission calculations. The e-GGRT calculates the subpart-level non-biogenic CO_2 emissions for these two configuration types by summing the reported fuel-level CO_2 emissions values from each fuel, regardless of whether it is biogenic or not, then subtracting the reported configuration-level biogenic CO_2 emissions values. For the aggregation of units configuration type, the reported configuration-level sorbent CO_2 emissions value, which is typically zero, is also added into this ''rolled-up'' non-biogenic CO_2 emissions total. The calculation was specifically designed in this manner because the reported fuel-level information for Table C–1 partially biogenic fuels (*i.e.,* tires, MSW) and some ''other'' or ''blend'' fuels that contain biogenic material is not sufficient to allow the calculation of biogenic CO_2 emissions for each fuel such that it could be accurately subtracted from the fuel-level CO_2 emissions values. Thus, the reported configuration-level biogenic CO_2 emissions must be used in the subpart total calculations. Many reporters then assume that the configuration-level annual CO_2 emissions from all fossil fuels is also used in the subpart total calculations, which creates confusion for reporters and has resulted in GHGRP Help Desk submissions stating that these requirements are redundant and confusing. By proposing to revise the provisions in 40 CFR 98.36(c)(1)(vi) and 40 CFR 98.36(c)(3)(vi) to remove the language requiring reporting of the total annual CO_2 mass emissions from all fossil fuels combined, we would remove this unnecessary confusion for reporters with aggregation of units and common pipe configuration types.

C. Subpart G—Ammonia Manufacturing

For the reasons discussed in section II.A.2 of this preamble, we are proposing several revisions to subpart G of part 98 (Ammonia Manufacturing) to improve the quality of the data collected from this subpart. Subpart G estimates CO_2 emissions from ammonia manufacturing based on a carbon mass balance, which assumes that all carbon contained in feedstocks is transformed to CO_2 and all CO_2 is emitted from the ammonia manufacturing process. The EPA has received numerous comments from The Fertilizer Institute (TFI) related to the calculation of CO_2 emissions from the production of ammonia in subpart G. Most comments from TFI were related to the carbon mass balance methodology, especially with regard to other products that could be produced using the CO_2 emissions from ammonia production. TFI has asserted that most ammonia manufacturing facilities capture and use the CO_2 resulting from the ammonia manufacturing process to produce urea. Subpart G does not currently allow the subtraction of the CO_2 that is bound in urea from calculated and reported emissions or otherwise allow separate reporting of that CO_2.

In response to the 2009 Proposed Rule, TFI submitted a comment letter dated June 9, 2009, and provided comments via a public hearing on April 6, 2009, stating that the CO_2 produced through ammonia manufacturing is often utilized in the manufacturing of urea and that the EPA mistakenly assumed that all CO_2 in urea will be released into the atmosphere.[15] [16] In response, in the 2009 Final Rule, the EPA changed the rule requirements to collect information on urea production and uses of the urea if known, stating ''Collecting information on urea production and its uses will help [the] EPA to improve methodologies for estimating emissions from ammonia manufacturing, urea production and urea consumption in the future.''

The EPA next revised 40 CFR 98.72(a) and 40 CFR 98.73(b)(5) in subpart G (75 FR 79092, December 17, 2010) to explain that the ''CO_2 process emissions reported under this subpart may include CO_2 that is later consumed on site for urea production, and therefore is not released to the ambient air from the ammonia manufacturing process unit.'' This revision was proposed pursuant to a settlement agreement with TFI, after TFI challenged the 2009 rulemaking.[17]

In response to an April 2, 2013 EPA-proposed rule (78 FR 19802), TFI submitted a comment letter dated May 2, 2013, requesting that the EPA revise subpart G to require only the reporting of CO_2 emitted directly to the atmosphere from the synthetic ammonia production process instead of continuing to include the CO_2 captured during ammonia production and used to produce urea, noting its view that the captured CO_2 ''does not contribute to the CO_2 emission estimates for ammonia production.'' [18] TFI further argued the existing methodology is inconsistent with other source categories covered by the rule (namely subpart P (Hydrogen Production) and subpart X (Petrochemical Production)) and is contrary to the EPA's methodology used in the U.S. GHG Inventory. TFI pointed to similarities between the structure of subpart G and subpart P, and argued that the structure of subpart G be revised to be more consistent with subpart X, which allows sources to account for carbon (*i.e.,* subtract from direct facility emissions) that is being shipped off-site in products. In response, the EPA responded that TFI had raised a consistency issue within part 98 that ''merits evaluation and requires further analysis by the EPA.'' However, the EPA explained that no changes were made at that time because TFI's comment was outside of the scope of the rulemaking.[19]

[15] TFI's Comments on the ''*Proposed Mandatory Reporting of Greenhouse Gases Rule*'' Docket Id. No. *EPA–HQ–OAR–2008–0508–2376,* June 9, 2009. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[16] *USEPA Public Hearing for Proposed Rulemaking for Mandatory Reporting of Greenhouse Gases.* Transcript Day One of Two. April 6, 2009. Docket Id. No. EPA–HQ–OAR–2008–0508–0212. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[17] *The Fertilizer Institute* v. *EPA,* Docket Id. No. 09–1329 (D.C. Circuit), 2010. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[18] TFI's Comments on the Proposed ''*2013 Revisions to the Greenhouse Gas Reporting Rule and Proposed Confidentiality Determinations for New or Substantially Revised Data Elements,*'' Docket Id. No. EPA–HQ–OAR–2012–0934–0036, May 2, 2013. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[19] *Summary of Public Comments and Responses for Greenhouse Gas Reporting Rule: 2013 Revisions to the Greenhouse Gas Reporting Rule and Confidentiality Determinations for New or Substantially Revised Data Elements.* Docket Id. No.

Continued

In response to a January 15, 2016 EPA-proposed rule (81 FR 2536), TFI submitted a comment letter dated March 30, 2016, again requesting that part 98 be made consistent with the methodology used in the U.S. GHG Inventory, such that CO_2 bound in urea would not be considered an emission from the ammonia manufacturing process.[20] Also, TFI asked for clarification regarding a new requirement in subpart G to report the amount of methanol produced at the ammonia manufacturing facility. In response, the EPA noted the potential of using a future rulemaking to address TFI's suggested revisions ''to require reporting only CO_2 that is emitted directly to the atmosphere from ammonia manufacturing, rather than reporting CO_2 that is bound in the urea that is produced from ammonia at some facilities,'' but explained that the comment was outside the scope of that rulemaking. The EPA clarified in the preamble and in the final rule (81 FR 89188, December 9, 2016) that the quantity of methanol being reported only includes methanol that is ''intentionally produced as a desired product'' and does not include the quantity of methanol that is vented or destroyed.

TFI submitted two other comment letters in 2017. The letter dated March 31, 2017 was submitted to the Department of Commerce as part of a request for information ''Impact of Federal Regulations on Domestic Manufacturing'' (82 FR 12786, March 7, 2017).[21] The letter dated May 15, 2017 was submitted to the EPA's request for comment on ''Evaluation of Existing Regulations'' (82 FR 17793, April 13, 2017).[22] Both letters contained similar language asking that the GHGRP be amended to ''report the quantity of GHG that is actually emitted to the atmosphere as part of the manufacturing processes'' instead of ''GHG emissions that are captured and either sold or used in other industrial processes.''

After consideration of the comments from TFI summarized above, the EPA has tentatively concluded that requiring reporters subject to subpart G to report the GHG emissions that occur directly from the ammonia manufacturing process (*i.e.,* net CO_2 process emissions) after subtracting out carbon or CO_2 captured and used in other products would provide a more accurate estimate of the emissions and would provide consistency in our approach across the GHGRP. Therefore, for the reasons described in this section and in section II.A.2 of this preamble, we are proposing multiple amendments to subpart G. Under the proposed rule, equation G–4 and equation G–5 would be combined into a new equation G–4 and paragraph 98.73(b)(5) would be deleted. The reporting requirement in paragraph 98.76(b)(1) specifies emissions for each individual ammonia manufacturing processing unit, so determining the combined CO_2 emissions from all ammonia manufacturing processing units using equation G–5 is not necessary for reporting. The new equation G–4 would allow reporters to subtract CO_2 used in the production of urea and carbon bound in methanol that is intentionally produced as a desired product instead of assuming that the CO_2 bound in urea is emitted or that the carbon contained in methanol is converted to CO_2 and emitted, resulting in the calculation of net CO_2 emissions that occur directly from ammonia manufacturing. We are also proposing a harmonizing revision to the introductory paragraph of 40 CFR 98.73. These proposed changes are not expected to result in an increase in burden because the monthly equation inputs for the new equation G–4 would already be available to calculate the annual values of CO_2 collected from ammonia production and consumed on-site for urea production and the quantity of intentionally produced methanol, both of which are already reported. Similarly, for reporters that do not produce urea or methanol, the burden under the new equation to calculate CO_2 emissions remains unchanged. Further, because we are retaining the requirement to report the CO_2 collected from ammonia for urea production and methanol production, the proposed amendments would not result in any negative impacts to the quality of the data collected under the GHGRP and such data would remain available for potential policy evaluation.

As a result of the new proposed equation G–4, two new monthly recordkeeping data elements are being proposed as part of the verification software records required in 40 CFR 98.77(c), including: (1) quantity of CO_2 collected from ammonia production and consumed on site for urea production each month; and (2) quantity of methanol intentionally produced as a desired product each month. These recordkeeping changes are not expected to result in a significant increase in burden because both elements are already being reported on an annual basis (40 CFR 98.76(b)(13) and (15)). For reporters that do not produce urea or methanol, the requirements for recordkeeping remain unchanged. We are proposing harmonizing revisions to the introductory paragraph of 40 CFR 98.76 and to the reported data elements at 40 CFR 98.76(b)(1) to clarify that reporters must provide the ''annual net CO_2 process emissions'' for each ammonia manufacturing unit, and at 40 CFR 98.76(b)(13) to clarify that reports must provide the ''annual amount of CO_2 collected from ammonia production (metric tons) and consumed on site for urea production and the method used to determine the CO_2 consumed in urea production.'' The proposed revision to the reported emissions value excludes any CO_2 used in the production of urea and carbon bound in methanol that is intentionally produced as a desired product. We are proposing related confidentiality determinations for the revised data elements, as discussed in section VI of this preamble.

Finally, corresponding amendments are being proposed to remove the language specified above that was added in the 2010 Final Revisions Rule (75 FR 79092), described above. Paragraph 98.72(a) will be amended to read, ''CO_2 process emissions from steam reforming of a hydrocarbon or the gasification of solid and liquid raw material, reported for each ammonia manufacturing unit following the requirements of this subpart.''

In addition, minor amendments to equation G–1, equation G–2, and equation G–3 are being proposed to simplify the equations by removing the process unit ''k'' designation in the terms ''$CO_{2,G,k}$,'' ''$CO_{2,L,k}$,'' and ''$CO_{2,S,k}$.'' The introductory paragraph to each of these equations already specifies that emissions must be calculated for each ammonia manufacturing unit. Removing the extra subscript will

EPA–HQ–OAR–2012–0934–0127, November 2013. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[20] TFI's Comments on the Proposed ''*2015 Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule,*'' Docket Id. No. EPA–HQ–OAR–2015–0526–0064, March 30, 2016. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[21] TFI, *Impact of Federal Regulations on Domestic Manufacturing,* Docket Id. No. DOC–2017–0001–0064, March 31, 2017, available in *Compilation of Comments Related to the Greenhouse Gas Reporting Program submitted to the Department of Commerce under Docket ID No. DOC–2017–0001 and the Environmental Protection Agency under Docket ID No. EPA–HQ–OA–2017–0190* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[22] TFI, *Comments on* ''*Evaluation of Existing Regulations,*'' Docket Id. No. EPA–HQ–OA–2017–0190–40791, May 15, 2017, available in *Compilation of Comments Related to the Greenhouse Gas Reporting Program submitted to the Department of Commerce under Docket ID No. DOC–2017–0001 and the Environmental Protection Agency under Docket ID No. EPA–HQ–OA–2017–0190* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

clarify the equations. No changes to burden are expected from these changes.

D. Subpart H—Cement Production

For the reasons described in section II.A.4 of this preamble, we are proposing to add new data elements to the data reporting requirements for subpart H of part 98 (Cement Production) to enhance the quality and accuracy of the data collected. Specifically, we are proposing to collect new data elements under 40 CFR 98.86(a) and 40 CFR 98.86(b). Subpart H currently requires calculation of CO_2 emissions using one of two methodologies, either direct measurement using CEMS, or a mass balance (non-CEMS) methodology based on mass, carbonate content, and fraction of calcination for each carbonate-based material. For the mass balance method, facilities enter input data that is used to calculate emissions factors for produced materials. These inputs include, for example, monthly measurements of calcium oxide content and magnesium oxide content. Subpart H emission equations inputs are not collected under the GHGRP, and so the EPA has little data on which to build verification checks for these inputs in the reporting system. In order to improve the data verification process, we are proposing to collect annual averages for these chemical composition input data on a facility-basis. The proposed data elements (for both facilities that report CEMS data and those that report using a mass-balance method) include the annual arithmetic average weight fraction of: total CaO content, non-calcined CaO content, total MgO content, and non-calcined MgO content of clinker at the facility; and total CaO content of cement kiln dust (CKD) not recycled to the kiln(s), non-calcined CaO content of CKD not recycled to the kiln(s), total MgO content of CKD not recycled to the kiln(s), and non-calcined MgO content of CKD not recycled to the kiln(s) at the facility. The proposed data elements would rely on an arithmetic average of the measurements rather than requiring reporters to weigh by quantity produced in each month. CEMS facility emissions calculations are importantly different from non-CEMS emissions calculations because combustion and process emissions are typically vented through the same stack, causing process and combustion emissions to be mixed and indifferentiable. Therefore, in addition to improving the input verification process, collecting average chemical composition data for CEMS facilities will provide the EPA the ability to check the reported CEMS emission data for accuracy by creating the ability to back-estimate process emissions. In order to be able to estimate and check the accuracy of process emissions, we are also proposing to collect other data elements for both facilities using CEMS and those that report using the mass-balance method, including annual facility CKD not recycled to the kiln(s) in tons and raw kiln feed consumed annually at the facility in tons (dry basis). Facilities are already required to report or maintain records of other production data that would be needed to perform these estimates. Facilities using the mass-balance method currently collect CKD not recycled to the kiln(s) on a quarterly basis to estimate CO_2 emissions from clinker production. Similarly, facilities also record the annual raw kiln feed for each kiln, which is used to determine the CO_2 emissions from raw materials for each kiln in equation H–5. The proposed data elements would instead sum the CKD not recycled and raw kiln feed quantity across all kilns at a facility. The proposed data elements will allow us to estimate process emissions for comparison to facility reported emissions estimates as a verification check. In addition to improving verification and data quality for cement emissions, the proposed data elements will also improve the U.S. GHG Inventory. The U.S. GHG Inventory can use the proposed data elements to internally disaggregate process and combustion emissions that are reported by facilities using CEMS, and create more accurate national-level cement emissions profile.

In general, we do not anticipate that the proposed data elements would require any additional monitoring or data collection by reporters, as these data are likely already available in existing company records. These additions would result in especially minimal reporting changes for non-CEMS facilities, as the chemical composition averages can be calculated using the input data that is already required to be entered in the reporting system. However, we are requesting comment on whether any of the above listed data elements would not be readily available to reporters. We are proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

Finally, for the reasons described in section II.A.5 of this preamble, we are proposing to clarify equations H–1 and H–5. We are proposing to clarify that equation H–5 calculates the CO_2 emissions from raw materials on a per kiln basis. Facilities currently maintain records of the amount and organic carbon content of raw materials and raw kiln feed consumed annually per kiln, and enter this data into the e-GGRT verification software during submission of their annual reports. The verification software collects the kiln-level data to verify the inputs and generates a file containing the records, which are specified in 40 CFR 98.87(c)(14) through (17). The CO_2 emissions for the facility are then summed for all kilns at the facility-level using equation H–1, which sums the annual CO_2 emissions from clinker production (from equation H–2) and the annual emissions from raw materials for each kiln (from equation H–5). We are proposing revisions to the inputs ''rm,'' ''$CO_{2\ rm,}$'' and ''TOC_{rm}'' in equation H–5 to clarify that the data elements are input on a per-kiln basis, and to add brackets to clarify that emissions are calculated as the sum of emissions from all raw materials or raw kiln feed used in the kiln. Similarly, we are proposing to revise equation H–1 to add brackets to clarify the summation of clinker and raw material emissions for each kiln, and updating the definition of ''$CO_{2\ rm}$'' to clarify the raw material input is on a per-kiln basis. The proposed revisions are corrections that would harmonize equations H–1 and H–5 with the existing recordkeeping requirements and align the calculation methodology in the rule and e-GGRT. We are also proposing minor corrections to the parameters of equation H–4 for quarterly non-calcined CaO content of CKD not recycled to the kiln and quarterly non-calcined MgO content of CKD not recycled to the kiln. The 2009 final rule inadvertently defined the equation parameters for both quarterly non-calcined CaO content and quarterly non-calcined MgO content as ''CKD_{CaO}'' and ''CKD_{MgO}'', respectively, while equation H–4 defines these parameters as ''CKD_{ncCaO}'' and ''CKD_{ncMgO}''. To remove any confusion for reporters, we are proposing to correct the defined parameters for quarterly non-calcined CaO content and quarterly non-calcined MgO content of CKD not recycled to ''CKD_{ncCaO}'' and ''CKD_{ncMgO}'', respectively. These clarifications would not require any changes to the monitoring, recordkeeping, or reporting provisions, or impact how reporters currently collect or enter data for their annual reports.

E. Subpart I—Electronics Manufacturing

Under subpart I of part 98 (Electronics Manufacturing), electronics manufacturing facilities must report F–GHG and F–HTF emissions from electronic manufacturing production processes and N_2O emissions from chemical vapor deposition (CVD) and other electronics manufacturing processes. Facilities must also report CO_2, CH_4, and N_2O emissions from each stationary combustion unit by following the requirements of subpart C (General Stationary Combustion Sources).

We are proposing several amendments and clarifications to the calculation methodologies requirements in subpart I. In addition, the EPA is proposing conforming changes to the reporting and recordkeeping requirements of subpart I. Changes include updating existing default emission factors and destruction or removal efficiencies (DREs) based on new data, revising certain calculation methods, adding a calculation method for calculating by-products produced in abatement systems, amending data reporting requirements, and providing clarification on reporting requirements. We are proposing revisions that will better reflect new industry data and current practice, improve the quality of the data collected, and streamline the reporting requirements. We are also proposing related confidentiality determinations for the proposed new or revised data elements, as discussed in section VI of this preamble.

1. Proposed Revisions To Improve the Quality of Data Collected for Subpart I

a. Revisions To Improve the Calculation Methodology for Stack Testing

We are proposing to revise 40 CFR 98.93(i), which specifies how to calculate GHG emissions based on stack testing, in order to improve, simplify, and correct the calculation method. As discussed in section II.A.2 of this preamble, the proposed edits would improve the quality of the data collection and calculation requirements associated with stack testing. First, we are proposing to add new equations I–24C and I–24D and a table of default weighting factors (new Table I–18) to calculate the fraction of fluorinated input gases exhausted from tools with abatement systems, $a_{i,f}$, for use in equations I–19A through I–19C and I–21, and the fraction of by-products exhausted from tools with abatement systems, $a_{k,i,f}$, for use in equations I–20 and I–22. Second, we are proposing to revise equations I–24A and I–24B, which calculate the weighted average DREs for individual F–GHGs across process types in each fab.[23] Third, we are proposing at 40 CFR 98.93(i)(3) to require that all stacks be tested if the stack test method is used. Finally, we are proposing to replace equation I–19 with a set of equations (*i.e.,* equations I–19A, I–19B, and I–19C) that will more accurately account for emissions when pre-control emissions of an F–GHG come close to or exceed the consumption of that F–GHG during the stack testing period.

The first three changes to the stack test method would remove the requirements to apportion gas consumption to different process types, to manufacturing tools equipped versus not equipped with abatement systems, and to tested versus untested stacks. Currently, the fractions of fluorinated input gases and by-product gases exhausted from manufacturing tools with abatement systems, used in equations 1–19a through I–22, must be estimated by apportioning gas consumption to these tools. The proposed equations I–24C and I–24D would add the option to calculate the fraction of each input gas ''i'' and by-product gas ''k'' exhausted from tools with abatement systems based on the number of tools that are equipped versus not equipped with abatement systems, along with weighting factors that account for the different per-tool emission rates that apply to different process types. Facilities would continue to have the option to apportion gas consumption to tools with and without abatement systems by using paragraph 98.93(e). They would also have the option to apportion gas consumption to the different process types and sub-types, calculating $a_{i,f}$ and $a_{k,i,f}$ based on the numbers of tools with and without abatement systems within each process type or sub-type.

Weighting factors are necessary when: (1) per-tool pre-control emission rates differ between different process types; (2) an input gas is consumed by more than one process type; (3) the use of the input gas is not apportioned between the process types; and (4) the fractions of tools equipped with emissions control technologies differ between process types. The weighting factors ($\gamma_{i,p}$ for input gases and $\gamma_{k,i,p}$ for by-product gases, provided in Table I–18) are based on data submitted by semiconductor manufacturers during the process of developing the *2019 Refinement*.[24] This data source was used in lieu of subpart I data, as the EPA does not collect data on gas consumption or gas consumption per tool. The calculated weighting factors were within the expected range, considering the differences between the emission factors used and the expected per-tool gas consumption for the different process types. For microelectromechanical systems (MEMS) or PV manufacturing that uses semiconductor tools and processes, the weighting factors in Table I–18 can be used. For processes without a weighting factor in Table I–18, a default of 10 must be used. More information on the data used to develop the weighting factors in Table I–18 can be found in the document, *Technical Support for Proposed Revisions to Subpart I (2021)* (hereafter referred to as ''subpart I TSD''), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

Equations I–24A and I–24B, which calculate the weighted average DREs for individual F–GHGs across process types, would rarely be used if the EPA adopts the same default DREs for all process types as discussed in section III.E.1.b of this preamble, because there will rarely be any need to calculate weighted average DREs across process types in that case. The sole exception may occur when a facility uses one or more abatement systems with a certified DRE value that is different from the default to calculate and report controlled emissions. To accommodate this situation and to simplify equations I–24A and I–24B, we are proposing to modify equations I–24A and I–24B to calculate the average DRE for each input gas ''i'' and by-product gas ''k'' based on tool counts and the same weighting factors that would be used in equations I–24C and I–24D. This would eliminate the requirement to apportion gas consumption by process type when using the stack test method, even for those facilities that use abatement systems with different DREs for the same input gas ''i'' or by-product gas ''k''.

Requiring that all stacks be tested (if the stack test method is used) would remove not only the need to apportion gas usage to tested versus untested stacks, but also the requirement to perform a preliminary calculation of the emissions from each stack system (we are proposing to remove the requirements at 40 CFR 98.93(i)(1)). The EPA expects that the data received would be more accurate due to requiring testing of all stacks. The EPA also expects that the revision to measure all stacks instead of apportioning gas usage between process type and subtype and between tested and untested stacks would streamline the implementation of the stack testing method at facilities and increase the likelihood of this method being used instead of the emission factor approach. Currently, to account

[23] Fab is defined in 40 CFR 98.98 as ''the portion of an electronics manufacturing facility located in a separate physical structure that began manufacturing on a certain date.''

[24] The data used to develop the gamma weighting factors are also available in the IPCC workbook, ''Gamma Data Submitted by Industry.xlsx,'' (2019), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

for emissions from untested stacks, facilities must calculate gas consumption of each F–GHG used in tools that are vented from untested stacks by apportioning gas between untested and tested stacks. When abatement is used, facilities also currently need to apportion by process type. Apportioning gas requires using a fab-specific engineering model that must be based on a quantifiable metric, such as wafer passes or wafer starts, or direct measurement of input gas consumption and must be verified by demonstrating its precision and accuracy as described in 40 CFR 98.94(c)(1). As the number of stacks at each fab is expected to be small (*e.g.,* one to two), the EPA expects that measuring all stacks would be more accurate and less burdensome than developing and verifying an apportioning model.

We also seek comment on whether stack testing should also be used to estimate N_2O emissions if stack testing is the calculation method elected. Currently, the stack testing option in subpart I is limited to estimating emissions from F–GHGs; N_2O emissions must be estimated using the default emission factors in Table I–8. The use of the stack testing method for N_2O was not previously recommended by industry due to: (1) the high monthly and yearly variability in measured N_2O emission factors estimated from stack testing for some fabs; and (2) the observation that estimated N_2O emission factors from stack testing also often exceeded 1, indicating a second, unidentified, source of N_2O.[25] No source for the additional N_2O formation or the high variability was identified. The EPA requests comment on the extent to which the sources of N_2O formation from electronics manufacturing have been identified. We are also requesting comment on the expected variability of the estimated N_2O emission factor from stack testing if using the current or revised methods for estimating emissions using stack testing and whether new data are available. If estimated N_2O emission factors are now expected to be consistent over time, the use of N_2O in stack testing could be re-evaluated during a future rulemaking.

We are also proposing to replace equation I–19 with a set of equations that will more accurately account for by-product emissions when that by-product F–GHG is also an input gas. Specifically, the new equations will more accurately account for emissions when emissions of an F–GHG prior to entering any abatement system (*i.e.,* pre-control emissions) would approach or exceed the consumption of that F–GHG during the stack testing period. Pre-control emissions of an F–GHG can approach or exceed consumption of that F–GHG when the F–GHG is generated as a by-product of other F–GHGs used in the fab. To ensure that calculated emission factors reflect this physical reality, any excess pre-control emissions of the F–GHG should be assumed to be formed as a by-product. Currently, the paragraph containing equation I–19, 40 CFR 98.93(i)(3)(iii), does not sufficiently account for such by-product formation, potentially resulting in overestimated input gas emission factors and underestimated by-product gas emission factors.

This potential inaccuracy arises because 40 CFR 98.93(i)(3)(iii), in its assignment of portions of the emissions to either input gases or by-products, does not currently account for the utilization (dissociation) of the input gas or for any abatement of the input gas. Instead, the provision compares the total measured emissions of the F–GHG, which may have passed through abatement systems prior to measurement, to the consumption (termed ''activity'' in equation I–19) of that F–GHG during the stack testing period. If the measured emissions equal or exceed consumption, the term for total emissions in equation I–19, $\mathbf{\Sigma}_s E_{i,s}$, is equated to consumption to calculate the input gas emission factor, and any difference between the measured emissions of the F–GHG and the consumption of the F–GHG is treated as by-product emissions and used to calculate a by-product emission factor (BEF) in equation I–20. While this approach avoids assigning a controlled emission factor greater than 1.0 to the input gas, in cases where the measured emissions are greater than consumption, the corresponding pre-control emission factor is either equal to 1.0 (if the measured emissions are uncontrolled) or greater than 1.0 (if the measured emissions are controlled). In the first case, the pre-control emission factor fails to account for any utilization of the input gas. In the second case, the pre-control emission factor both fails to account for any utilization of the input gas and attributes emissions to the input gas for which the input gas cannot possibly be the source (because that would violate conservation of mass).

To more accurately assign emissions of the gas to by-product or input gas emissions, a better methodology is to compare the measured emissions to the maximum expected controlled emissions of the input gas during the stack testing period, rather than to the consumption during that period. To make this change, we are proposing to remove equation I–19 and replace that equation with equations I–19A, I–19B, and I–19C, making corresponding changes to 40 CFR 98.93(i)(3)(iii). Equation I–19A estimates the maximum expected controlled emissions for each F–GHG from the fab during the stack testing period at a utilization rate (U) equal to 0.2 (*i.e.,* a 1–U or input gas emission factor of 0.8) and at the levels of abatement and abatement system uptime observed during the stack testing period. If the total emissions measured during the stack testing period are less than the maximum expected controlled emissions calculated using I–19A, then all emissions of gas i are attributed to the consumption of gas ''i'' and equation I–19B is used to calculate the input gas emission factor for gas ''i''. Equation I–19B is similar to equation I–19 in the current rule, but with an updated process-independent variable for the DRE. However, if the total measured emissions are greater than the estimate of the maximum controlled emissions, then the input gas emission factor is assumed to be equal to the maximum controlled emission rate at an uptime equal to 1, as calculated in equation I–19C. The remaining emissions (the difference between the measured emissions and the value calculated in equation I–19A) are used to calculate the BEF for that gas from other input gases in equation I–20.

The revised equations improve upon the current equations because they account both for any control of the emissions and for some utilization of the input gas. The input gas emission factor (1–U) of 0.8 used in equations I–19A and I–19C is the same as the default 1–U factor that would be assigned where a default is not available in Tables I–3 and I–4, as discussed in III.E.2.b of this preamble. Using a value of 0.8 as a maximum input gas emission factor (1–U) would be consistent with the other proposed changes and is expected to increase the accuracy of the stack testing method, as some utilization of the input gas is expected. These changes to the stack testing equations would improve the quality of the stack testing method by more accurately assigning emissions to their source.

In addition to the substantive changes to equation I–19, the EPA is proposing to clarify the definitions of the variables

[25] See Semiconductor Industry Association (SIA) *Response to EPA's Stack Test Question 1,* March 7, 2012, and *Technical Support for Other Technical Issues Addressed in Revisions to Subpart I,* U.S. EPA, August 2012, both of which are available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

d_{if} and d_{kif}, the average DREs for input gases and by-product gases respectively, in equations I–19A, I–19B, I–19C, and I–19D, in equations I–20 through I–22, in equations I–24A and B, and in equation I–28 of subpart I. Currently, the definition for the variable d_{if} reads ''Fraction of fluorinated GHG input gas i destroyed or removed in abatement systems connected to process tools in fab f,'' which could be interpreted to reflect both the fraction of emissions of gas i that is fed into abatement systems and the fraction of gas i that is destroyed once gas i is fed into abatement systems. However, d_{if} (and d_{kif}) are only intended to reflect the fraction of gas i (or by-product gas k) that is destroyed once gas i (or by-product gas k) is fed into abatement systems. To make this clear, we are proposing to change the definition of d_{if} to read ''Fraction of fluorinated GHG input gas i destroyed or removed when fed into abatement systems by process tools in fab f,'' and we are proposing a parallel change to the definition of d_{kif}.

b. Revisions To Clarify and Revise Calculation Methodologies and Required Data Elements for Data Submitted in the Technology Assessment Report

For the reasons described in section II.A.1 of this preamble, we are proposing to require that three emission factor calculation methods, specified in this section and described in the subpart I TSD (available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424), be used when calculating utilization and by-product emission rates submitted in technology assessment reports. These three methods would be used to report the results of each emissions test. Based on a comparison among the results of the three methods, we may ultimately require use of a single method through a future rulemaking.

As stated in the preamble to the 2013 final rule that established the requirement to submit technology assessment reports (78 FR 68175, November 13, 2013), one of the EPA's goals in collecting emission factor data through the reports is to better understand how emission factors may be changing as a result of technological changes in the semiconductor industry, and whether the changes to the emission factors may justify further data collection to comprehensively update the default emission factors in Tables I–3 and I–4. To meet this goal, the emission factors submitted in the technology assessment reports should be calculated the same way as the emission factors already in the EPA's database were calculated; otherwise, differences attributable to differences in calculation methods may amplify or obscure differences attributable to technology changes. To date, the EPA has not initiated a broad data collection to comprehensively update the default emission factors, but the EPA is now proposing to use the emission factor data submitted in the 2017 and 2020 technology assessment reports to make minor updates to the default emission factors, and the EPA may continue this practice in the future. This introduces a second goal for the emission factors submitted in the technology assessment report, which is that they be robust to ensure that the resulting updated default emission factors are robust. To meet this goal, the reported emission factors should be broadly applicable because they reflect physical reality as much as possible and are not unduly affected by changing proportions of input gases. In addition, the reported emission factors should be consistently calculated across facilities and processes to ensure that the resulting defaults are not biased by ''cherry-picking'' of methods to achieve a desired result for a given process or facility (or set of processes or facilities). Requiring facilities to (1) use specified methods to calculate emission factors and (2) use all three methods for each test meets these goals to different extents and in different ways.

Requiring facilities to use specified emission factor calculation methods would ensure that the emission factors are robust insofar as the calculation methods are designed to yield robust factors. It would also help ensure that the emission factors are developed in a reasonably, though not perfectly, consistent manner across processes and facilities and over time, given that the proposed calculation methods are similar but not identical. (As discussed in this section, two of the proposed emission factor calculation methods are based closely on the emission factor calculation methods used for the emission factors already in the EPA's database.) The EPA has previously received emission factors calculated via a variety of methods, as described further in this section. This has sometimes made it difficult to determine whether changes in calculated emission factors are due to changes in technology or to changes in the emission factor calculation method. In some cases, we have not been able to use submitted emission factor data because it was found to be calculated using a method that was significantly different from previous methods and that appeared unlikely to represent actual gas behavior. (The lead authors of the Electronics chapter of the *2019 Refinement* declined to use this data for similar reasons.)[26] Specifying emission factor calculation methods would at least partially address these problems.

Requiring facilities to submit three sets of emission factors for each test would more fully address these problems by enabling us: (1) to directly compare the new emission factor data to the emission factor data that is already in the EPA's database and that was calculated using the same method; and (2) to compare the results across the available emission factor calculation methods and to identify any systematic differences in the results of the different methods for each gas and process type. By identifying and quantifying systematic differences in the results of the different methods, we would be better able to distinguish these differences from differences attributable to technology changes. This would enable us to build a bridge between the data sets resulting from the different methods, which would be useful in the event that we ultimately required facilities to submit emission factors using one method only, particularly if that method was not one of the methods used historically. We would also be able to evaluate how much the results of each method varied for each gas and process type; high variability may indicate that the results of a method are being affected by varying input gas proportions rather than differences in gas behavior, as discussed further in this section. Ultimately, these analyses would enable us to more accurately characterize emissions from semiconductor manufacturing by selecting the most robust emission factor data for updating the default emission factors in Tables I–3 and I–4. Because we plan to incorporate the three methods into spreadsheets that would calculate three sets of emission factors based on a single set of entered data, we do not anticipate that requiring reporting of the results of the three methods would significantly increase burden. We are proposing the three emission factor calculation methods in 40 CFR 98.96(y)(2)(iv)(A) through (C).

Two of the proposed methods are closely based on the methods that have been used historically to calculate emission factors for processes that use multiple gases: ''all-input gas method''

[26] See *Volume 3, Chapter 6. Electronics Industry Emissions* to the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,* as cited above in this document.

and the ''dominant gas method''.[27] [28] Consequently, the emission factors calculated using these methods are generally expected to be comparable to the emission factors calculated and submitted to the EPA in the past. The emission factors calculated using these methods are also expected to be reasonably robust except under certain circumstances discussed further in this section. To increase the robustness of the emission factors calculated using these methods under those circumstances, we are proposing to modify the methods to avoid input gas emission factors greater than 0.8 for processes that use multiple gases.

Historically, both the all-input gas and dominant gas methods have calculated the input gas emission rate in the same way: all emissions of each F–GHG that is an input gas have been attributed to the 1–U factor for that gas (kg of input gas emitted/kg of input gas used); that is, both methods imply that if an F–GHG is used as an input gas, that F–GHG is *not* also formed as a by-product. However, the two methods treat by-product F–GHGs that are not used as input gases differently. The dominant gas convention assigns all emissions of F–GHG by-products to the carbon-containing F–GHG input gas accounting for the largest share by mass of the input gases (kg of by-product emitted/kg of dominant gas used), while the all-input gas convention assigns emissions of F–GHG by-products to all F–GHG input gases (kg of by-product emitted/kg of all F–GHGs used). With a slight modification, the all-input convention has also been used to assign emissions of F–GHG by-products to only all carbon-containing F–GHG input gases, *i.e.,* not to SF_6 or NF_3 input gases (kg of by-product emitted/kg of all F–GHGs used).

Due to the complex set of chemical reactions necessary to describe plasma etching by multiple input gas processes, it is not generally known what fractions of a by-product gas are produced by each input gases, or what fractions of an emitted input gas consist of unreacted residual gas versus newly formed by-products of other gases. Both methods of assigning emission factors described above have historically been based on the assumption that the emissions of each input gas (1–U) are much larger than the emissions of the same gas as a by-product of the other input gases (*e.g.,* CF_4 produced from C_2F_6) and thus, the BEF can be approximated as zero. However, as stated in section III.E.1.c of this preamble on updates to the default emission factors, it has been well established that most input gases produce CF_4 and C_2F_6 in significant quantities. Thus, in cases where C_2F_6 or CF_4 is an input gas (and possibly for some additional cases), assigning all of the emissions of C_2F_6 or CF_4 to the C_2F_6 or CF_4 input gas, respectively, may not be a good approximation and can lead to cases where the reported emission factor is greater than 1, which violates conservation of mass. This is most likely to happen when an input gas such as CF_4 makes up a relatively small share of the total input gas mass and is also generated in significant quantities as a by-product by the other input gases.

To address this issue, our proposed methods include a modification to both of the historically recommended methods to avoid an input gas emission factor greater than 0.8 when multiple gases are used, and we are also proposing to introduce an additional calculation method. The modified methods would attribute emissions of each F–GHG used as an input gas to that input gas until the mass emitted equaled 80 percent of the mass fed into the process, that is, until the 1–U factor equaled 0.8. The methods would then assign the remaining emissions of the F–GHG either to the dominant input gas as a by-product (in the dominant gas method) or to the other input gases as a by-product in proportion to the quantity of each input gas used in the process (in the all-input gas method). This approach avoids violating conservation of mass and better reflects the expectation that at least a small portion of the input gas will be utilized in the process. Nevertheless, because 0.8 represents an upper bound for input gas emission factors, even the modified methods have the potential to significantly overestimate input gas emission factors. To the extent that these factors are later applied to processes where the input gas accounts for a larger share of the total input gas mass (*e.g.,* because they are used to calculate default factors), they will overestimate emissions of the input gas.

A third convention, the reference emission factor method, is likely to provide more robust, realistic results, although it represents a somewhat larger change from the emission factor calculation conventions historically used. The reference emission factor method begins with the average input gas utilizations (1–U factors) and/or BEFs observed based on single gas recipes. In single-gas recipes, all emissions of an input gas clearly originate from its use as an input gas, and all emissions of a by-product clearly originate from its generation as a by-product; thus, the 1–U factor and BEFs based on single-gas recipes are not affected by the uncertainties regarding the origins of the emissions that can affect these factors for multi-gas recipes.

Since it is not known whether the 1–U factor or BEFs are more likely to change in moving from single- to multiple-gas recipes, the reference emission factor method calculates emissions using the 1–U and the BEFs that are observed in single gas recipes and then adjusts both factors based on the ratio between the emissions calculated based on the factors and the emissions actually observed in the multi-gas process. This approach uses all the information available on utilization and by-product generation rates from single-gas recipes while avoiding assumptions about which of these are changing in the multi-gas recipe.

In summary, the chief advantage of the dominant gas method proposed at 40 CFR 98.96(y)(2)(iv)(A) and the all-input gas method proposed at 40 CFR 98.96(y)(2)(iv)(B) is that they are the methods used previously to calculate the emission factors that are already in the EPA's database and that form the basis of the current subpart I default 1–U and BEFs. Therefore, new emission factors calculated using these methods are expected to be comparable [29] to the emission factors already in the EPA's database, facilitating efforts to identify changes in emission factors that are attributable to technology changes. The chief disadvantage of these two methods is that they can result in a significantly overestimated 1–U value when the share of an input gas such as CF_4 declines.

[27] See section 2.0 of the document, *Technical Support for Modifications to the Fluorinated Greenhouse Gas Emission Estimation Method Option for Semiconductor Facilities under Subpart I* (2012), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).

[28] Previously, the EPA had suggested that the all-input gas method be used for etch emission factors (*Ibid.*), and most of the etch data in the data set used to develop the current emission factors used this method (see 78 FR 68185 and previously submitted data sets *Etch Process Equipment Emissions Characterization Data* and *International SEMATECH Manufacturing Initiative Environmental Safety and Health Technology Center,* February 2012, and the document *Draft Emission Factors for Refined Semiconductor Manufacturing Process Categories* (2010), all available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424). However, some of this data was calculated using the dominant gas method.

[29] As discussed further in the document Technical Support for Modifications to the Fluorinated Greenhouse Gas Emission Estimation Method Option for Semiconductor Facilities under Subpart I, cited above in this section, trends in gas usage, such as the use of more and more individual input gases, may introduce apparent, but not real, trends in the 1–U values calculated using these methods.

This disadvantage is mitigated partly, but not completely, by capping 1–U values at 0.8. At the same time, however, capping 1–U values at 0.8 decreases the comparability of these methods with those previously used to calculate and report emission factors. The EPA requests comment on whether the gain in robustness achieved by capping 1–U values at 0.8 justifies the accompanying loss in comparability to previously submitted data, particularly given that we are proposing to require submission of results using both the historically used methods and the new, likely more robust, reference emission factor method. The reference emission factor method is being proposed at 40 CFR 98.96(y)(2)(iv)(C). The advantages and disadvantages of the three methods are described further in the document *Technical Support for Modifications to the Fluorinated Greenhouse Gas Emission Estimation Method Option for Semiconductor Facilities under Subpart I,* cited above in this section. The EPA also considered requiring use of one specific method for the data submitted in future technology assessment reports. This would allow all future reports to have comparable data. However, if one of the historically used methods were specified, the resulting emission factors might not be as robust as they would be if the reference emission factor method were specified. On the other hand, if the reference emission factor method were specified, the resulting emission factors would not be fully consistent with previously submitted emission factors, and this inconsistency would be difficult to address without having seen the results of the different methods side-by-side at least once. Another option would be to let the reporter choose one of three methods in 40 CFR 98.96(y)(2)(iv)(A) through (C) for subsequent reports. This option would result in a loss of comparability between tests. The EPA is requesting comment on these alternatives.

We request comment on the methods proposed at 40 CFR 98.96(y)(2)(iv)(A) through (C) for calculating emission factors for multi-gas recipes, particularly concerning their reliability as indicators of actual emission rates and emission rate trends. In addition, the EPA requests comment on the use of 0.8 as the maximum 1–U value in the modified dominant-gas and all-input gas methods.

We also request comment on the reference emission factor method proposed at 40 CFR 98.96(y)(2)(iv)(C). While this method differs from the historically used methods, the differences are not expected to become important except where CF_4 or C_2F_6 make up a small share of the input gas mass, that is, where the historically used methods are known to yield inaccurate results. The EPA believes that the increase in accuracy gained through the new method justifies some loss of time series consistency (*i.e.,* comparability between newly submitted emission factor data and previously submitted emission factor data). Moreover, because we are proposing to require reporting of the results of each test using all three calculation methods, we can compensate for the loss of time series consistency between the historically used methods and the reference emission factor method by: (1) comparing the emission factors already in the EPA's database to the versions of the new emission factors calculated using the historically used methods (*i.e.,* the all-input gas and dominant gas methods); and (2) analyzing systematic differences that occur between the results of the historically used methods and of the reference emission factor method so that these can be considered in future comparisons between new and existing data. We also request comment on whether BEFs based on multi-gas recipes should be included in the reference BEFs for the reference emission factor method. The benefit of including BEFs based on multi-gas recipes in the reference BEFs is that this would increase the number of data points used as a basis for those BEFs, in some cases providing reference BEFs where none are available from the single gas data set (due to a lack of data). The drawback of including BEFs based on multi-gas recipes is that these BEFs are subject to some uncertainty. BEFs measured for multi-gas recipes where the by-product F–GHG is not also used as an input gas are less uncertain than BEFs where the by-product F–GHG is also an input gas. However, uncertainty remains regarding which of the multiple input gases are primarily responsible for the formation of that by-product and whether all input gases contribute to the formation of each by-product. For more information on the advantages and disadvantages of using only single-gas measurements or all measurement to determine reference emission factors see the subpart I TSD, cited above in this section.

We also seek comment on whether there are alternative methods for calculating utilization and by-product formation rates that the EPA should consider in the future. To enable us to evaluate any suggested methods, we request that commenters suggesting an alternative method also provide information on the rationale for using the alternative method instead of one of the methods described above and a comparison between a representative group of emission factors (both 1–U and BEFs) calculated using the alternative method and a group of emission factors based on the same data but calculated using the all-input gas method, the dominant gas method, and the reference emission factor method. The EPA may evaluate, at a future date, such alternative methods based, for example, on the likely accuracy of the alternative calculation method and its consistency with previously used calculation methods.[30]

We are also proposing that where reporters provide any data on utilization and by-product formation rates in the technology assessment report, they must also specify the method used to calculate the reported utilization and by-product formation rates and assign and provide an identifying record number for each data set. This information allows the EPA to better understand the data being submitted. For example, this information helps the EPA identify all the gases used in a multi-gas test and understand the influence of the calculation method and gas mixtures on the resulting emission factors. This detailed understanding may help us to develop new or revised emission factors that are representative of the industry. Without collecting these data, the EPA may not be able to effectively evaluate the influence of different emission factor calculation methods or gas combinations on the resulting emission factors.

We are also proposing at 40 CFR 98.96(y)(2)(iv) that for any destruction or removal efficiency (DRE) data submitted, the report must include whether the abatement system used for the measurement is specifically designed to abate the gas measured under the operating condition used for the measurement. This information will help the EPA understand whether the submitted data should be considered to be a result for a certified abatement system for the gas being measured. The efficacy of abatement systems generally depends on both whether it is designed to abate the F–GHG and whether it is installed, operated, and maintained according to the manufacturer's specifications. Abatement systems are known to have reduced efficacy when the individual process gas and total gas flow rates (including any added purge

[30] See document *Technical Support for Proposed Revisions to Subpart I (2021),* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

gases) as specified by the abatement system supplier are exceeded.

c. Updates to Default Emission Factors and Destruction or Removal Efficiencies To Improve the Accuracy of Emissions Estimates

The EPA is proposing to update the default emission factors and destruction or removal efficiencies (DREs) in subpart I based on new data submitted as part of the 2017 technology assessment report (submitted with the RY2016 annual report) and the 2020 technology assessment report (submitted with the RY2019 annual report).[31] First, we are proposing to update the utilization rates and BEFs for F–GHGs used in semiconductor manufacturing in Tables I–3, I–4, I–11 and I–12 to reflect new data received in the 2017 and 2020 technology assessment reports, to correct errors identified in the data set on which the current default emission factors are based, and to remove BEFs where both the emission factor and the GWP of the emitted by-product are very low. Second, we are also proposing to update and expand the default emission factors for N_2O used in all electronics manufacturing in Table I–8 based on both new data from the 2017 and 2020 technology assessment reports and new emission factors available in the *2019 Refinement.* Third, we are proposing at 40 CFR 98.93(a)(6) to revise the utilization rate and BEF values assigned to gas/process combinations where no default utilization rate is available. Finally, we are proposing to update the default DREs in Table I–16 to reflect the incorporation of new data from the 2017 and 2020 technology assessment reports and a new approach to abatement system certification. These updates are expected to increase the accuracy of the emissions reported by facilities under subpart I.

The proposed emission factors for Tables I–3, I–4, I–11, and I–12 were calculated from measured data submitted by U.S. semiconductor manufacturers as part of the 2020 technology assessment report, 2017 technology assessment report, and data collected in previous years.[32] The total data set contains 4,358 input gas and BEFs across all commonly used gas and process type combinations, with 1,506 of these data points newly available via the 2020 and 2017 triennial technology assessment report. All the data submitted via the 2020 and 2017 triennial technology assessment report were applicable to the 300-mm wafer size. All data sets were reviewed for errors, including, but not limited to, transcription errors and violations of the fluorine balance. Calculated emission factors (1–U or BEFs) greater than 1.00 (a total of 18 data points) were excluded from the calculation of the proposed default emission factors (EFs). Input gas and by-product gas emission factors were also analyzed for each test to see whether the fluorine balance was violated. This resulted in the exclusion of 40 data points from the calculation of the proposed default emission factors. There were also a small number of transcription or other errors, including duplicate rows of data, that were corrected or excluded prior to calculating the proposed emission factors. Transcription and other errors resulted in the exclusion of 33 data points. A single reported by-product value for SF_6 was also excluded from the calculation, as there was no source of sulfur. Four emission factors for NF_3 in remote plasma cleaning (RPC) processes that were previously excluded[33] were re-included in the data set, as discussed in the subpart I TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

Submitted data were also reviewed for methodological consistency with previously submitted data. As discussed earlier in III.E.1.b of the preamble, data submitted to the EPA prior to 2017 used either the dominant gas or all-input gas convention. However, many of the data points for etching submitted as part of the 2020 and 2017 technology assessment report used an alternative convention that had not been previously used. This new ''multi-gas'' convention differed in how it assigned emissions of input gases. Instead of assigning measured emissions of an input gas entirely to the input gas, emissions of an input gas were assigned to all input F–GHGs used in the process by dividing the measured mass emitted of a specific input gas by the total mass of all input F–GHGs and assigning this emission factor to each input F–GHG as either the 1–U factor or the by-product factor, *i.e.,* all input F–GHGs were considered to equally contribute to the emissions of each input gas. This method was inconsistent with the methods of the previous data set, and the alternative method often resulted in large increases to the reported BEFs and concurrently large decreases to the reported 1–U. This change appeared to be largely a result of the change in methodology; however, it was not possible, based on the data received, to fully assess the effect of the new methodology as the data were not directly comparable to previously submitted data. The data points that were affected by the change in convention were excluded from the calculation of the proposed default EFs, resulting in the exclusion of 338 data points. This left a total of 3,951 data points in the combined data set that were included in the calculations of the proposed default emission factors in Tables I–3 and I–4.

The proposed default EFs for Tables I–3 and I–4 were calculated using a simple arithmetic mean of all EF data that used either the all-input gas or the dominant gas convention. The technology assessment reports reported no major changes to semiconductor production technology, and the differences between the average emission rates calculated based on the new and previously submitted data, respectively, are generally small (*i.e.,* less than ± 20 percent for most commonly used input gases). Therefore, it is assumed in most cases that the proposed default emission factors for F–GHGs reflect increased and/or improved data rather than changes in actual emission or utilization rates. This means that for each wafer size (<200 mm and 300 mm), the proposed emission factors are generally likely to represent emission rates over all the years of the GHGRP. However, for a few gas and process type combinations for the 300-mm wafer size, the differences between the averages calculated based on the new and previously submitted data are more significant and could have an appreciable impact on the overall calculated CO_2e emissions. More information on the differences between the data contained in the two technology assessment reports received to-date and the previously submitted data is available in the subpart I TSD,

[31] Available in ''*UPDATED Appendix A Process Emissions Characterization Data,*'' Semiconductor Industry Association, April 2018, and ''2020 Subpart I Consolidated Triennial Report, Appendices A–B,'' Semiconductor Industry Association, March 2020, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[32] The data submitted in previous years can be found in *Semiconductor Industry Association; Etch Process Equipment Emissions Characterization Data,* International SEMATECH Manufacturing Initiative Environmental Safety and Health Technology Center, February 2012, and *Draft Emission Factors for Refined Semiconductor Manufacturing Process Categories,* Office of Air and Radiation, May 2010, each of which is available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[33] See *Technical Support Document for Process Emissions from Electronics Manufacture (e.g., Micro-Electro-Mechanical Systems, Liquid Crystal Displays, Photovoltaics, and Semiconductors): Proposed Rule for Mandatory Reporting of Greenhouse Gases, Revised,* November 2010, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424. In light of these findings, we request comment on whether the new data reflect recent technology changes or simply better represent technologies that have been in use over the long term (*i.e.,* at least since 2011, the first year of reporting under the GHGRP). This is important for understanding the time period to which the new data for these four factors are applicable.

We are also proposing to update the calculation methodology for MEMs and PV manufacturing to allow use of 40 CFR 98.3(a)(1), the current methodology for semiconductor manufacturing, in lieu of using 40 CFR 98.3(a)(2) for manufacture of MEMs and PV using semiconductor tools and processes. This would have the effect of applying the default emission factors in Tables I–3 and I–4 to these processes. In the *2019 Refinement,* use of semiconductor default emission factors for MEMs manufacturing is recommended when using semiconductor tools to manufacture MEMs. Similarly, we are also proposing the use of semiconductor emission factors for PV manufacturing that uses semiconductor manufacturing tools. It is expected that the use of semiconductor emission factors will result in more accurate emissions estimates when semiconductor manufacturing tools and processes are used.

The current Table I–8 does not distinguish N_2O emission factors either by the type of electronic device manufactured (semiconductor versus LCD) or by wafer size. Due to the increased availability of N_2O emission factor data, we are proposing to update Table I–8 to include distinct utilization rates for N_2O for semiconductor manufacturing and LCD manufacturing and, for semiconductor manufacturing, utilization rates by wafer size (<200 mm and 300 mm) and by process type.[34] The proposed emission factor for N_2O used in CVD thin film deposition for LCD manufacturing can be found in the *2019 Refinement.*[35] Currently there is no LCD manufacturing in the United States and thus, no U.S. data is available for LCD manufacturing.

We are also proposing to remove BEFs from Tables I–3 and I–4 where there is a combination of both a low BEF and a low GWP, resulting in very low reported emissions per metric ton of input gas used (<0.03 $mtCO_2e$ and less than 0.0002 percent of emissions (in CO_2e) per metric ton of input gas consumed). This would result in: (1) removing the BEFs for C_4F_6 and C_5F_8 for all input gases used in wafer cleaning or plasma etching processes due to the combination of a low GWP (0.003 and 1.97, respectively) and low BEFs (less than 0.009); and (2) not adding BEFs for COF_2 and C_2F_4 for any input gas/process combination from the new data received in the 2020 or 2017 technology assessment reports because these BEFs are less than 0.2 and COF_2 and C_2F_4 have low GWPs (0.14 and 0.004, respectively). COF_2 does not have a chemical specific GWP in Table A–1 (it is currently assigned a default GWP of 2000 as an ''Other Fluorinated GHG''), but the 2018 WMO Scientific Assessment listed the 100-year GWP of COF_2 as ''<1.'' We calculated a precise GWP for COF_2 of 0.14 using the atmospheric lifetime and radiative efficiency provided in the 2018 WMO Scientific Assessment. (The method we used to calculate the GWP of COF_2 was the method we used to calculate precise GWPs for low-GWP compounds in the most recent update to GHGRP GWPs (79 FR 73750, December 11, 2014)). Currently, Table I–3 lists the BEF for C_4F_6 from all input gases as 'NA'. Similarly, Table I–4 currently lists the BEF for C_5F_8 from all input gases as 'NA'. Thus, for these two cases, there will be no change in reported emissions. Data reported to the GHGRP in 2013 [36] indicates that, in total, for all semiconductor manufacturers reporting to the GHGRP in 2013, by-product emissions of C_5F_8 and C_4F_6 totaled 0.27 and 0.0004 $mtCO_2e$, respectively. Similarly, it is estimated that based on 2013 gas consumption COF_2 and C_2F_4 by-product emissions for the semiconductor fabs reporting to the GHGRP in 2013 would have been 0.43 $mtCO_2e$ and 0.005 $mtCO_2e$, respectively, if COF_2 and C_2F_4 emission factors were adopted. For the largest fabs, generation of all by-products listed above whose emission factors are being proposed for removal or exclusion from Tables I–3 and I–4 would result in less than 0.6 $mtCO_2e$ in combined emissions per fab and significantly less for smaller fabs. We are also proposing to modify the applicability of carbon-containing BEFs to chamber cleaning process subtypes where neither the input gas(es) nor the films being processed by the chamber contain carbon. In the emission factor tables in subpart I (*e.g.,* Table I–3 and I–4), there are cases where a perfluorocarbon BEF is provided even when the input gas i does not contain carbon (*e.g.,* NF_3). However, when none of the input gases contain carbon (*e.g.,* NF_3 or SF_6), and when the chamber being cleaned does not process films that contain carbon, then neither CF_4 nor other carbon-containing gases are expected to be formed during the process.[37] Thus, we are proposing that in cases where neither the input gas nor the films being processed in the tool contain carbon, the BEF for the carbon-containing by-products be set to zero (refer to variable ''B_{kij}'' in proposed equation I–8B). We are proposing to apply this provision at the process subtype level; a BEF of zero would only be used for a combination of input gas and chamber cleaning process subtype (*e.g.,* NF_3 in RPC) if no carbon-containing materials were removed using that combination of input gas and chamber cleaning process subtype during the year and no carbon-containing input gases were used on those tools. Otherwise, the default BEF would be used for that combination of input gas and chamber cleaning process subtype for all of that gas consumed for that subtype in the fab for the year. An alternative approach would be to implement this change at the individual process or tool level, tracking gas consumption used in processes and tools that deposit films that contain carbon. This would lead to a more precise estimate of carbon-containing by-product emissions but may require

[34] More information regarding the development of the proposed default emission factors can be found in the workbook titled, ''Data sets Supporting Revised Emission Factors.xlsx,'' (U.S. EPA, April 2020) and in the subpart I TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[35] See *Volume 3, Chapter 6. Electronics Industry Emissions* to the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,* as cited above in this document.

[36] GHGRP data from RY2013 was used for this analysis as it is the last year for which it was relatively simple to estimate gas consumption due to revisions to the default emission factors applied in 2014 and later. For more information on how gas consumption was estimated, see U.S. EPA. *Inventory of Greenhouse Gas Emissions and Sinks:1990–2017* (2019). *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2017.*

[37] Chamber cleaning processes, which typically use only one input gas, are not expected to generate carbon-containing byproducts from that input gas unless either the input gas or the film being removed contains carbon. The situation with etching and wafer cleaning processes, where multiple input gases are often used, is more complex. This is because input gases that do not contain carbon can still contribute fluorine to carbon-containing F–GHG by-products that obtain their carbon from other input gases, particularly if relatively fluorine-rich and carbon-poor by-products such as CF_4 predominate. The data set supporting the default emission factors proposed in this action includes by-product emission factors that have sometimes been calculated assuming that carbon-containing by-products are attributable to all input gases (including those lacking carbon) and that have other times been calculated assuming that carbon-containing by-products are only attributable to input gases that contain carbon.

greater apportioning than is otherwise required by the rule. We request comment on this alternative approach. Whether this revision was implemented at the process subtype or process level, it would improve the accuracy of the emissions estimate compared to the current rule by differentiating between process subtypes (or processes) where there is a source of carbon from which carbon-containing by-products may be generated and process subtypes (or processes) where there is no source of carbon from which carbon-containing by-products may be generated.

In addition, we are proposing to update the default emission factors for semiconductor manufacturing for use with the stack test method (Tables I–11 and I–12). These tables will continue to be needed to calculate emissions from consumption of each intermittent low-use F–GHG as defined in 40 CFR 98.98. The proposed default emission factors for Tables I–11 and I–12 were developed using the same data used to calculate revised emissions factors for Tables I–3 and I–4, as discussed above. To calculate the proposed default emission factors for Tables I–11 and I–12, which are process-independent, gas consumption by process type and wafer size was first estimated from emissions data reported under subpart I for RY2013. Gas consumption by process type was then used to weight the process-dependent emission factors from Tables I–3 and I–4 to arrive at the proposed default emission factors for Tables I–11 and I–12, respectively. Gas consumption by process type was used as a weighting factor to arrive at process-independent emission factors in order to have default emission factors that represent the average emission factor over total gas consumption by the industry for each wafer size.[38] Although the proposed emission factors proposed in this rulemaking differ slightly from the *2019 Refinement* due to the inclusion of newly available data, the methodology for developing Tables I–11 and I–12 are the same as those used to develop the Tier 2b tables in the *2019 Refinement.* For more information on the EPA's method for estimating gas consumption from emission data reported under subpart I for RY2013, which was used in the *2019 Refinement,* see the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2017.*[39] The workbook ''Data Sets Supporting Revised Emission Factors'' also shows the calculations for deriving the emissions factors in Tables I–11 and I–12 from Tables I–3 and I–4 (available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).

We are requesting comment on three options regarding default emission factors for MEMS and PV manufacturing. One option is to allow MEMS and/or PV manufacturers to use either the current default emission factors for those sub-sectors in Tables I–5 (MEMS) and I–7 (PV) or the default emission factors for semiconductor manufacturing in Tables I–3 and I–4, as applicable. The second option is to remove Tables I–5 and I–7 from subpart I and to require MEMS and/or PV manufacturers to use the default emission factors in Tables I–3 and I–4, as applicable. The third option is to continue to require MEMS and PV manufacturers to use the default factors in Tables I–5 and I–7, respectively. Information gathered during the development of the *2019 Refinement* and through the GHGRP indicates that the emission factors for semiconductor manufacturing in Tables I–3 and I–4, as applicable, are often, and perhaps always, applicable to MEMS and PV manufacturing. (In the *2019 Refinement,* semiconductor default emission factors are applied to MEMS manufacturing that is ''carried out using tools and processes similar to those used to manufacture semiconductors.'') However, we request comment on the extent to which semiconductor manufacturing default emission factors are applicable to MEMS and PV manufacturing. We also request comment on whether the distinction between different wafer sizes that separates Table I–3 from Table I–4 is applicable to MEMS and/or PV manufacturing.

We are also proposing to revise the input gas and BEF values assigned to gas/process combinations where no default input gas emission factor is available (due to a lack of data) in 40 CFR 98.93(a)(6). Currently, if no default input gas emission factor is available for a particular gas/process combination, reporters must use a general default value of one for the input gas emission factor (*i.e.,* a utilization rate of zero) and a general default value of zero for the BEFs. This assumes that emissions equal consumption, *i.e.,* all gas used in a process is emitted, without any utilization or conversion into other gases. However, in the majority of cases where emission factor data are available, both CF_4 and C_2F_6 are emitted as by-products, and both CF_4 and C_2F_6 are long-lived GHGs with very high GWPs (see Table A–1). Where the input gas has a GWP similar to those of PFCs, accounting for the generation of CF_4 and C_2F_6 by-products is not expected to significantly change the GWP-weighted emissions calculated for the process compared to the current method, but where the input gas has a GWP significantly lower than those of PFCs, accounting for the generation of the by-products would considerably improve the estimate of GWP-weighted emissions compared to the current method. In both cases, accounting for the likely emissions of CF_4 and C_2F_6 would also lead to a better estimate of each species emitted. Thus, we propose to revise the general defaults where no default input gas emission factor is available to account for the likely partial conversion of the input gas into CF_4 and C_2F_6. Specifically, for a gas/process combination where no default input gas emission factor is available in Tables I–3, I–4, I–5, I–6, and I–7, we are proposing at 40 CFR 98.93(a)(6) that reporters would use an input gas emission factor (1–U) equal to 0.8 (*i.e.,* a default utilization rate or U equal to 0.2) with BEFs of 0.15 for CF_4 and 0.05 for C_2F_6. It is assumed here in cases where data do not exist, that the input gas is partially converted into CF_4 and C_2F_6 during the process and the remainder is emitted. The default input gas emission factor is conservatively based on the least efficient gas in Table I–4 for etch processes (C_2F_6 in the revised Table I–4). The remainder of the input gas is assigned to CF_4 and C_2F_6. Due to a generally higher CF_4 BEF for most input gas/process combinations, the majority (75 percent) of the remaining mass is assigned to CF_4.

Additionally, we are proposing to update the default DREs in Table I–16 to reflect the incorporation of new data from the 2017 and 2020 technology assessment reports and a new approach to abatement system certification. Currently, Table I–16 to subpart I lists default DREs by gas and process type. Where data were unavailable for some gas and chamber cleaning process combinations, DRE values were set to a conservative value of 60 percent in the current tables.[40] Commenters have

[38] For more information on the development of the proposed emission factors for Tables I–11 and I–12, see the explanation for the equivalent Tier 2b tables in the subpart I TSD in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

[39] U.S. EPA 2019. Available at *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2017.*

[40] For more information, see ''Technical Support for Accounting for Destruction or Removal Efficiency for Electronics Manufacturing Facilities under subpart I,'' (August 2012) prepared for the Final Amendments and Confidentiality

Continued

previously noted that where exceptionally conservative DREs exist, there is a large incentive to invest in measuring site-specific DREs. Based on the measured data received by the EPA, the EPA is proposing to assign chemical-specific DREs to all commonly used F–GHGs for the semiconductor manufacturing sub-sector without distinguishing between process types.[41]

We are proposing to revise the default DREs in Table I–16 by incorporating new data received via the 2017 and 2020 technology assessment reports. The proposed DREs were calculated using a simple arithmetic mean of all DRE data by gas. The DRE data sets submitted to the EPA by the U.S. electronics manufacturing industry, including both data received via the technology assessment reports and previously submitted data, contains 1,353 data points for DREs of F–GHGs (for a discussion on DREs for N_2O, see the subpart I TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424). Of these, 58 of the data points corresponded to gases that are not known to be input gases or significant by-products (C_2F_4 and COF_2, see previous discussion on emission factors excluded from Tables I–3 and I–4). Thus, we are not proposing default DREs in Table I–16 for these gases. Data points were not included in the calculations of the proposed DREs if the data points were reported as corresponding to emissions control systems that were not certified to abate that particular gas. Additional data points were excluded from the calculations of the proposed DREs if an accurate DRE could not be measured due to detection limits. Negative DREs were also excluded from the calculation for all F–GHGs. All but two of the negative DREs submitted for F–GHGs were on emissions control devices that were not designed to abate that particular gas. For the two cases where the system was designed to abate the gas, the testers noted either low gas inlet or inherent noise in the measurement (*e.g.,* due to low inlet). For the DREs from systems recorded as not designed or certified to abate the input gas, the negative DREs were reported only for CF_4 and COF_2. Results from literature[42] indicate that CF_4 can be formed within some emission control systems that use hydrocarbon fuels by reaction between the fuel and fluorinated species (*e.g.,* F_2) emitted from a NF_3 remote plasma chamber clean. All but one of the negative CF_4 DREs are from remote plasma chamber cleaning processes. However, since not all abatement systems form CF_4, these data points were excluded from this analysis and this formation of CF_4 is accounted for separately in the proposed rule. Data points were also excluded from the calculation if the gas being measured was noted as being less than two percent of the total inlet fluoride to the abatement system during testing, as the error in measuring DREs for such low inlet concentrations may have biased the DREs low. It is also known in the industry that when extremely low concentrations (*e.g.,* 100 ppm) of F–GHGs in the abatement system are present, the system is less efficient at destroying the F–GHG. Including these DREs in an unweighted average would have a disproportionate effect on the estimated emissions. Lastly, additional data points were excluded if the abatement system required maintenance or repair (*e.g.,* due to fouling of the system due to poor water quality), or the abatement system was operated in a manner inconsistent with the manufacturer's recommendations (*e.g.,* using clean dry air (CDA) instead of O_2 as the oxidant, as is recommended by the manufacturer). The data sets include data for most gas-process combinations. The EPA also considered using the DREs published in the *2019 Refinement.*[43] However, some of the data included in the *2019 Refinement* are not available to the EPA due to confidentiality concerns. Thus, the EPA was only able to determine how this subset differed on average to the EPA data sets. The confidential data set had higher average DREs for most F–GHGs. This may be due to fact that this subset contained DREs as measured by abatement system manufacturers and may not be representative of actual fab conditions. The EPA has also received additional data via the 2020 technology assessment report that was not available during the development of the *2019 Refinement.* The most recent data set received from industry via the 2020 technology assessment report included a significant number of DRE values that were significant outliers. Many of these outliers were excluded due to the reasons discussed above. The EPA considered excluding additional data points from the DRE calculations for Table I–16 but did not have enough information to determine whether the data points were representative of fab operating conditions, due to abnormal conditions, or due to operating the abatement system outside of manufacturer specifications. The EPA is requesting comment on the conditions under which data points were measured and whether any correspond to conditions that were atypical or outside of the manufacturer's recommendation for operation of the abatement system. The DREs in the proposed rule include data from the 2020 and 2017 technology assessment reports and earlier data sets. As discussed above, all DRE data points from the technology assessment reports from abatement systems designed to abate the F–GHG input gas were included in the calculations of the proposed default DREs except in cases where: (1) the DRE was negative; (2) there were detection limit issues; (3) the inlet gas flow of the F–GHG measured was less than 2 percent of the inlet gas; (4) the abatement system required maintenance or repair; or (5) the abatement system was operated in manner inconsistent with the manufacturer's specifications. The subpart I TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424, describes the full data set and the default DREs considered, including the option of excluding significant outliers. Where data for gas-process combinations still do not exist (or there were less than 5 data points), there are sufficient data across the various gas/process combinations to assign DREs based on analogy with gases with similar chemical structures. The revised Table I–16 also includes proposed DREs for C_2HF_5, C_5F_8, and C_4F_8O based on their similarity to CHF_3 (for C_2HF_5 and C_5F_8) and c-C_4F_8 (for C_4F_8O). This results in C_2HF_5 and C_5F_8 being assigned a default DRE of 97 percent. Based on its similarity to c-C_4F_8, C_4F_8O is assigned a default DRE of 93 percent. The EPA is proposing to base the DRE for C_3F_8 on the DREs for a chemically similar F–GHG for which the EPA does have data.

Determination for Electronics Manufacturing Final Rule (78 FR 68162, November 13, 2013), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[41] See data sets ''UPDATED–04–02–2018-Triennial Report Data for EPA,'' ''Attachment B. New and Revised DRE Test Used in SIA Analysis of Alternative Default DREs'' from Comments of the SIA on the Greenhouse Gas Reporting Program: Proposed Amendments and Confidentiality Determinations for Subpart I (Docket Id. No EPA–HQ–OAR–2011–0028–0095), and ''Etch DRE Testing With Flow Data, March 6, 2012,'' [2020 Triennial Data set]. All are available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[42] S.N. Li, *et al.* ''FTIR spectrometers measure scrubber abatement efficiencies,'' Solid State Technology, Vol. 45. (2002); Gray, Fraser, and Afroza Banu, ''Influence of CH_4-F_2 mixing on CF_4 by-product formation in the combustive abatement of F_2,'' Research Disclosure, Sept. 2018, both available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[43] See *Volume 3, Chapter 6. Electronics Industry Emissions* to the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,* as cited above in this document.

C_3F_8 is expected to be no more difficult to abate than C_2F_6. Thus, the EPA is proposing to apply the DRE value for C_2F_6 (98 percent) to C_3F_8. A value of 98 is slightly higher than the DRE for C_3F_8 in the current rule (97 percent).[44 45]

Since the data does not show statistically significant differences between process types,[46] we are proposing to remove the distinction by process type from Table I–16. In addition, we are proposing to equate the default DRE for each F–GHG to the straight average of the measured DREs for that F–GHG rather than setting the default DRE slightly below the average. The DREs currently in Table I–16 were developed using analysis of variance (ANOVA), which took into account the likely variations in abatement device performance across fabs and within a single fab (see the memorandum, *Final Technical Documentation—Revision of Default Utilization Rates and By-Product Formation Rates; Revision of Default Destruction and Removal Efficiencies for Semiconductor Facilities under subpart I; and Revision of Maximum Field Detection Limits for the Stack Test Method* (Alexis McKittrick, U.S. EPA, August 16, 2013), which was used in the development of the 2013 Final Rule (78 FR 68182, November 13, 2013) and is available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424). A conservative approach was used because the DRE performance of abatement equipment can vary depending on the specific design of each manufacturer, which is often proprietary, and the actual conditions in the fab. However, here, we are proposing a more refined method for estimating controlled emissions that would still account for variability across manufacturers.

To account for the variations in device performance, we are proposing to modify the conditions under which the default DRE can be claimed. Currently, in 40 CFR 98.94(f), in order to claim the defaults provided in Table I–16, abatement equipment must be certified as specifically designed for F–GHG or N_2O abatement, and the abatement system must be certified as being properly installed, operated, and maintained according to the site maintenance plan for abatement systems. Site maintenance plans must also be based on the manufacturer's recommendations and specifications. The EPA is proposing to clarify the definition of operational mode in 40 CFR 98.98 to specify that operational mode means that the system is operated within the range of parameters as specified in the DRE certification documentation. Thus, the abatement system should only be considered operational and the default or certified lower DRE claimed when the system is operated within the range of parameters for which the system is certified to meet or exceed the claimed DRE. The specified parameters must include a range of total F–GHG or N_2O flows and total gas flows (with N_2 dilution accounted for) through the emissions control systems. For systems operated outside the range of parameters specified in the documentation supporting the DRE certification (*e.g.,* with total flows exceeding the original equipment manufacturer (OEM) specifications), a site-specific DRE could be measured and claimed. The system could then be considered operational within the range of parameters used to develop a site-specific DRE. We are also proposing to modify the conditions in 40 CFR 98.94(f) under which the default DRE may be claimed to require that the reporter, in order to claim the default value for that abatement system and gas, must: (1) certify that the abatement device is able to achieve a value equal to or greater than the default DRE value under the worst-case flow conditions during which the facility is claiming that the system is operational; and (2) provide supporting documentation. Worst-case flow conditions would be defined as the highest total F–GHG or N_2O flows through each model of emissions control systems (gas by gas and process type by process type across the facility) and the highest total flow scenarios (with N_2 dilution accounted for) across the facility during which the emission control system is claimed to be operational. The certification would be based on testing of the abatement system model by the abatement system manufacturer using a scientifically sound, industry-accepted measurement methodology that accounts for dilution through the abatement system, such as the *Protocol for Measuring Destruction or Removal Efficiency (DRE) of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing* (March 2010) (EPA 430–R–10–003, hereinafter ''EPA DRE Protocol,'' available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424). If the equipment is certified to abate the F–GHG or N_2O but at a value lower than the default DRE, facilities would not be able to claim the default; however, facilities would be allowed to claim the lower manufacturer verified value. Site-specific measurements by the electronics manufacturer would still be required to claim a higher DRE than the default. The updated DREs reflect increased data and a refined approach rather than changes in the actual destruction rates. The updates to the DREs in Table I–16 would increase the accuracy of emissions reported by facilities and would be expected to reduce the number of facilities that choose to measure site-specific DREs.

d. Calculation of By-Products Produced in Hydrocarbon Fueled Abatement Systems To Improve the Accuracy of Emissions Estimates

We are proposing to add a calculation methodology that would estimate the emissions of CF_4 produced in hydrocarbon-fuel based emissions control systems that are not certified not to generate CF_4. (In this section III.E.1.d, all references to ''uncertified hydrocarbon-fuel based emission control systems'' refer to hydrocarbon-fuel based emissions control systems that are not certified not to generate CF_4.) The proposed calculation would be codified in equation I–9; we are proposing to renumber the previous equation I–9 as equation I–8b. Hydrocarbon-fuel based emission control systems are hydrocarbon-fuel based combustion devices that are designed to reduce emissions from exhaust streams from electronics manufacturing processes and include, but are not limited to, abatement systems that are designed to abate F–GHGs or N_2O. Studies have shown that direct reaction between molecular fluorine (F_2) and hydrocarbons (*e.g.,* CH_4) to form CF_4 can occur in hydrocarbon-fueled combustion emissions control systems, and the *2019 Refinement* includes calculations to account for the formation and emission of CF_4 from this source.[47] Where emissions control systems that generate CF_4 are used to abate NF_3 from RPC processes, the CF_4 is expected to account for 1.5 times the emissions of NF_3 (in CO_2e) that would have occurred with no abatement (see the subpart I

[44] The 98-percent DRE for C_3F_8 in the current rule was assigned by analogy with C_2F_6, which also has an assigned DRE of 97 percent in the current rule (78 FR 68192, November 13, 2013).

[45] More information on the EPA's analysis of the DRE data can be found in the subpart I TSD and supporting documents (''Combined DRE data sets.xlsx'') in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

[46] *Id.*

[47] S.N. Li, *et al.* ''FTIR spectrometers measure scrubber abatement efficiencies,'' Solid State Technology, Vol. 45. (2002); Gray, Fraser, and Afroza Banu, ''Influence of CH_4-F_2 mixing on CF_4 by-product formation in the combustive abatement of F_2,'' Research Disclosure, Sept. 2018, both available in this docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

TSD available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).

Equation I–9 would be used to estimate the emissions of CF_4 from generation in emissions control systems by calculating the mass of the fluorine entering uncertified hydrocarbon-fuel based emissions control systems (the product of the consumption of the input gas, the emission factor for fluorine, and a_i, where a_i is the ratio of the number of tools with uncertified abatement devices for the gas-process combination to the total number of process tools for the gas-process combination) and multiplying that mass by a CF_4 emission factor, $AB_{CF4,F2}$. The proposed default emission factor for this reaction ($AB_{CF4,F2}$) is 0.116.[48] This reaction is expected to result in significant emissions only where F_2 is used as an input gas or where large amounts of F_2 can be formed as a by-product of the decomposition of the cleaning gas into atomic fluorine and subsequent recombination of the unreacted fluorine into F_2. Thus, this equation would only apply to processes that use F_2 as an input gas or to RPC processes that use NF_3 as an input gas. When NF_3 is used as a cleaning gas during the RPC process, the vast majority of the NF_3 molecules (approximately 98 percent, based on the default values for ($1-U_{NF3,RPC}$)) are decomposed within the remote plasma unit to form fluorine and nitrogen radicals, ions, and excited species. While some of the fluorinated species clean the solid residues deposited on the chamber walls by combining with the residues to form gaseous by-products such as SiF_4, HF, COF_2, and CF_4, some fluorine atoms recombine to form molecular fluorine (F_2). Based on confidential data received from Edwards, Ltd.,[49] a manufacturer of abatement equipment, the proposed BEF for F_2 from NF_3 used in remote plasma clean processes is 0.5. This data was also used to update the *2019 Refinement.* The proposed by-product is reasonable considering that emission factor data for NF_3 from RPC processes submitted to the EPA show that emissions of NF_3 and CF_4 accounted for less than 20 percent of the total mass of fluorine in the NF_3 used in the process in all but one of the 123 processes measured, and generally significantly less, leaving at least 80 percent of the fluorine available to form F_2, SiF_4, and HF. (The last two compounds are formed when fluorine combines with solid residue on the chamber walls, but the EPA's emission factor data do not include specific information on the quantities of those compounds—or of the fluorine—formed in the process.) No data from processes that use F_2 as an input gas are currently available for the 1–U of F_2; however, data from NF_3-using processes (where most of the NF_3 is dissociated into atomic fluorine during the process) indicate that the 1–U value for F_2 may be near 0.7 (Confidential data received from Edwards, Ltd.,[50] 2018, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).[51]

As for other gas and process combinations where no data is available (listed as ''NA'' in Tables I–3 and I–4), a 1–U of 0.8 would be used for F_2 in equation I–9 for all process types. The EPA is seeking comment on whether there is data available to support an alternative 1–U for F_2. The addition of this calculation is expected to increase the accuracy of emissions estimates from electronics manufacturers that use emissions control equipment. Along with the new calculation, we are proposing corresponding monitoring, reporting, and recordkeeping requirements (see 40 CFR 98.94(e), 40 CFR 98.96(o), and 40 CFR 98.97(b), respectively) for facilities that: (1) use hydrocarbon-fuel-based emissions control systems to control emissions from tools that use either NF_3 as an input gas in RPC processes or F_2 as an input gas in any process; and (2) assume in equation I–9 that one or more of those systems do not form CF_4 from F_2. These proposed provisions, which are patterned after the current provisions covering abatement systems from which facilities quantify emission reductions, would require that the facility certify and document that the model for each of the systems that the facility assumes does not form CF_4 from F_2 has been tested and verified to produce less than 0.1 percent CF_4 from F_2, and that each of these systems is installed, operated, and maintained in accordance with the directions of the emissions control system manufacturer. The facility could perform the testing itself, or it could supply documentation from the emissions control system manufacturer that supports the certification. If the facility performed the testing, it would be required to measure the rate of conversion from F_2 to CF_4 using a scientifically sound, industry-accepted method that accounts for dilution through the abatement device, such as the EPA DRE Protocol, adjusted to calculate the rate of conversion from F_2 to CF_4 rather than the DRE. The EPA requests comment on whether there are other measurement methods that should be cited as examples or listed as options for this measurement. The EPA has considered that it may be difficult to adapt the EPA DRE Protocol to measure the rate of conversion from F_2 to CF_4 if the analytical methods cited in the Protocol (Fourier Transform Infrared (FTIR) and Quadrupole Mass Spectroscopy (QMS)) do not work well to measure F_2 flows. Instead, other measuring or metering methods, such as calibrated mass-flow controllers or electrochemical cells, may be more effective. The EPA requests comment on this and any other issues that may arise in adapting the EPA DRE Protocol to measure the rate of conversion from F_2 to CF_4 in hydrocarbon-fuel-based emissions control systems. These issues and means of handling them could then be specifically addressed in the final rule.

Given the potential sensitivity of a calculated stack emission factor to any emissions of CF_4 produced in hydrocarbon-fuel based emissions control systems, we are also proposing to amend paragraph 40 CFR 98.94(j)(1)(i) to require that the uptime (*i.e.,* the fraction of time that abatement system is operational and maintained according to the site maintenance plan for abatement systems) during the stack testing period average at least 90 percent for uncertified hydrocarbon-fueled emissions control systems. This would ensure that the calculated stack emission factor for CF_4 will not be underestimated due to a significant fraction of uncertified systems not

[48] See *Volume 3, Chapter 6. Electronics Industry Emissions* to the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,* as cited above in this document, and the subpart I TSD (available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).

[49] The by-product emission factor for F_2 from NF_3 was calculated from 15 measurements of remote plasma clean processes following a variety of different Thin Film Deposition (TFD) processes. F_2 generation was estimated using a mass-balance approach that compared the mass of atomic fluorine (F) flowing into each process chamber in the form of NF_3 with the mass of fluorine exiting the process chambers in the form of SiF_4, COF_2, HF, and NF_3. The mass of fluorine that was not accounted for at the exhaust of the process chamber was assumed to be in the form of F_2.

[50] The by-product emission factor for F_2 from NF_3 was calculated from 15 measurements of remote plasma clean processes following a variety of different Thin Film Deposition (TFD) processes. F_2 generation was estimated using a mass-balance approach that compared the mass of atomic fluorine (F) flowing into each process chamber in the form of NF_3 with the mass of fluorine exiting the process chambers in the form of SiF_4, COF_2, HF, and NF_3. The mass of fluorine that was not accounted for at the exhaust of the process chamber was assumed to be in the form of F_2.

[51] All documents in the docket are listed at *https://www.regulations.gov.* Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute.

operating during the stack test. This proposed amendment is similar to the current requirement in 40 CFR 98.98(j)(1)(i), which requires at least 90 percent uptime averaged over all abatement systems during the stack testing period, but would now require that this specific set, hydrocarbon-fueled abatement systems that are not certified not to generate CF_4, also average at least 90 percent uptime during the test.

Because CF_4 may be formed from F_2 in any hydrocarbon-fuel-based emissions control system, not only abatement systems from which facilities claim reductions for purposes of reporting under subpart I, we are proposing to apply these provisions to all hydrocarbon-fuel-based emissions control systems used in electronics manufacturing facilities. This includes, but is not limited to, abatement systems as defined at 40 CFR 98.98. We are proposing to add a definition of ''hydrocarbon-fuel-based emissions control system'' to clarify the scope of coverage.

e. Revisions to Calibration Requirements for Abatement Systems

We are proposing to modify 40 CFR 98.97(d)(9)(ii) to require that a vacuum pump's purge flow indicators are calibrated every time a vacuum pump is serviced or exchanged. Some vacuum pumps' purge flow indicators are inaccurate and could deliver higher than indicated purge flow, exceeding the manufacturer's maximum flow specification for an abatement system.[52] Requiring calibration of the vacuum pumps would make it less likely that facilities would unknowingly claim an abatement system as operational during a time period when the abatement system is being operated outside of the manufacturer's flow specifications. Operating outside of the manufacturer's flow specifications is problematic because abatement systems are generally certified to meet or exceed the claimed DRE only when operated within a specified range of flow. We expect that this requirement would require calibrations every 1 to 6 months, depending on the process. The EPA is requesting comment on whether this approach and expected frequency is recommended or an approach that specifies the frequency of calibration, such as a minimum calibration of twice a year, would be a sufficient approach to maintain accurate flow rates.

[52] See *Volume 3, Chapter 6. Electronics Industry Emissions* to the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,* as cited above in this document.

2. Revisions To Streamline and Improve Implementation for Subpart I

a. Revisions to the Applicability Calculations for Subpart I

As discussed in section II.B.1 of this preamble, we are proposing to revise the applicability of subpart I. We are proposing to do this by adding a second option in 40 CFR 98.91(a) for estimating GHG emissions for semiconductor, MEMS, and LCD manufacturers; by revising the current applicability calculation for PV manufacturers; and by updating the emission factors used in the current applicability calculations for MEMS and LCD manufacturers. Currently, semiconductor, MEMS, and LCD manufacturers that have not previously reported under the GHGRP are required to calculate the subpart I contribution toward the 25,000 $mtCO_2e$ reporting threshold by using a calculation based on annual manufacturing capacity in substrate area (square meters, m^2). The calculation based on manufacturing capacity was adopted in part to limit the burden required for facilities to estimate their electronics manufacturing emissions for purposes of assessing the applicability of the GHGRP, as this method does not require either tracking gas consumption or apportioning gas consumption by process type. Instead, it is based on production capacity in terms of substrate area and default emission factors based on manufacturing type. However, this method may not be suitable for some facilities that have emissions per m^2 rates that are atypical and could consequently require some facilities that emit considerably less than 25,000 $mtCO_2e$ (unabated) to report under the GHGRP.

We are therefore proposing to add a second option for estimating emissions in 40 CFR 98.91(a)(1) and (2) that includes two new equations, I–1B and I–2B (and renumbering equations I–1 and I–2 to I–1A and I–2A, respectively). Specifically, we are proposing to add an optional calculation method that uses gas consumption multiplied by a simple set of emission factors (along with GWPs and a factor to account for heat transfer fluid) to estimate emissions in 40 CFR 98.91(a)(1) and (2). To estimate emissions, facilities would, for each F–GHG, apply an input gas emission factor of 0.8 and by-product gas formation factors of 0.15 for CF_4 and 0.05 for C_2F_6. The emission factors we are proposing for this optional calculation method are included in proposed new Table I–2 of subpart I of part 98 and are the same as the emission factors we are proposing in this rulemaking for gas and process combinations for which there is no default in Tables I–3, I–4, or I–5, as applicable; and the factors are discussed further under the updates to emission factors in section III.E.1.c of this preamble. As discussed in III.E.1.c of this preamble, almost all gas and process combinations emit CF_4 and C_2F_6 as by-products. Assigning default values for these by-products, instead of assuming emissions to be equal to gas consumption, would result in a more accurate emissions estimate, especially in cases where the input gas has a significantly lower or higher GWP than average. An emission factor of 1.0 would be applied to N_2O. Finally, as is currently required for the production-based method, the calculated emissions of each F–GHG and N_2O would be multiplied by the chemical-specific or default GWP for that GHG and the resulting CO_2e emissions would be summed across GHGs. The total would continue to be multiplied by a factor to account for the use of F–HTFs using equation I–4. The result would be the calculated subpart I contribution toward the 25,000 $mtCO_2e$-per-year emissions threshold in 40 CFR 98.2(a)(2).

Facilities that choose to use this option for their calculation method would be required to track annual gas consumption by GHG but would not be required to apportion consumption by process type for the purposes of assessing rule applicability. The EPA is proposing a simplified consumption-based calculation method option for semiconductor, MEMS, and LCD manufacturing facilities to provide a calculation method that could appropriately exclude some lower-emitting facilities that would otherwise be subject to subpart I. Facilities would continue to have the option to use the manufacturing capacity-based method for estimating emissions in 40 CFR 98.91(a)(1) and (2). Facilities using either method would continue to calculate total annual GHG emissions, including combined emissions from stationary fuel combustion units and other applicable source categories, for comparison to the 25,000 $mtCO_2e$ per year emission threshold in 40 CFR 98.2(a)(2).

Facilities that manufacture PV already have a consumption-based method in the current rule. However, currently, the applicability calculation for PV manufacturing includes only GHGs ''that have listed GWP values in Table A–1 to subpart A of this part.'' Because default GWPs are now available for F–GHGs that do not have chemical-specific GWPs in Table A–1, we are proposing to delete the limiting phrase ''that have listed GWP values in Table A–1.'' We are also proposing to revise equation I–3 to be identical to the new equations I–1B and I–2B and to also use newly proposed Table I–2. As for semiconductor, MEMS, and LCD manufacturers, this revision is expected to increase the accuracy of the estimated emissions for determining applicability.

We are also proposing to revise the emission factors in Table I–1 used for estimating emissions for MEMS and LCD manufacturing when equation I–1A (based on production in substrate area) is used to assess the applicability of part 98. The emission factors currently in Table I–1 include emissions factors for semiconductor, LCD, and MEMS manufacturing. For semiconductor and LCD manufacturing, the emissions factors that are currently in Table I–1 are based on the Tier 1 default emission factors in Vol. 3, Ch. 6 *Electronics Industry Emissions* in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories.*[53]

For MEMS manufacturing, there were no IPCC Tier 1 factors available at the time of the 2010 Final Rule for Additional Sources of Fluorinated GHGs (75 FR 74774), and the emission factors were instead based on the IPCC Tier 2b SF_6 emission factor for semiconductors.[54] The *2019 Refinement* included an update to the IPCC Guidelines Tier 1 emission factors using newly available data.[55] For LCD and MEMS manufacturing, the EPA has tentatively determined that the new Tier 1 emission factors in the *2019 Refinement* would better reflect industry-wide technological trends and are expected to improve the accuracy of the emissions estimated for the GHGRP using Table I–1. However, for semiconductor manufacturing, emission rates vary significantly depending on the wafer size used for manufacturing, and therefore no single set of default emission factors accurately estimates emissions for all wafer sizes. The Tier 1 emission factors in the *2019 Refinement* are, overall, lower than those in the 2006 IPCC Guidelines because they reflect the increasing importance of the 300-mm wafer size technology, which has lower emission rates than the older but still significant 200-mm (or smaller) wafer size technology. (The Tier 1 emission factors in the *2019 Refinement* were developed assuming a 50/50 split between 200-mm and 300-mm wafer production.) To estimate emissions for manufacturing using the 200-mm wafer size, the *2019 Refinement* recommends that the Tier 1 emission factors in the 2006 IPCC Guidelines be used because they more accurately reflect emission rates for that wafer size than do the Tier 1 emission factors in the *2019 Refinement.* Use of the Tier 1 emission factors in the *2019 Refinement* would underestimate emissions from facilities manufacturing on wafers sized 200 mm or smaller. In addition, our analysis (CBI TSD *Comparison of Subpart I Emissions to New Tier 1 EFs,* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424 [56]) indicates that use of these factors would underestimate emissions from a few facilities manufacturing on wafers sized 300 mm. To maintain the simplicity of the applicability calculation in equation I–1A for semiconductors, the EPA prefers to retain a single set of default emission factors for semiconductors in Table I–1, and to ensure that facilities manufacturing on the 200-mm wafer size are not improperly excluded from coverage by the GHGRP, we are not proposing to revise the emission factors for semiconductor manufacturing in Table I–1. While this could result in overestimated emissions for some facilities that manufacture on the 300-mm wafer size, the EPA notes that such facilities would have the option to use gas consumption data rather than capacity in square meters to assess applicability, as discussed above.

There is no expected impact on the number of LCD manufacturing facilities reporting to the GHGRP due to the proposed update to those emission factors, as there are currently no known LCD manufacturers in the United States. For MEMS manufacturers, the proposed update to Table I–1 could possibly result in one additional facility reporting to the GHGRP (estimated to have annual emissions greater than or equal to 25,000 $mtCO_2e$). However, due to a lack of actual capacity data, it is difficult to assess with precision how many facilities, if any, would be impacted.

b. Revisions to the Frequency and Applicability of the Technology Assessment Report

For the reasons described in section II.B.3 of this preamble, we are proposing to revise the frequency and applicability of the technology assessment report requirements in 40 CFR 98.96(y), which applies to semiconductor manufacturing facilities with GHG emissions from subpart I processes greater than 40,000 $mtCO_2e$ per year. (Other proposed changes to 40 CFR 98.96(y) are discussed in section III.E.1 of this preamble.) The purpose of the technology assessment report is to provide regular review of technology changes in the semiconductor manufacturing industry and ensure that default gas utilization rates, by-product formation rates, and DRE values accurately reflect changes in the industry's practices, such as the introduction of manufacturing on 450-mm sized wafers. In the 2012 proposed amendments to subpart I (77 FR 63538, October 16, 2020), we noted that the semiconductor manufacturing industry had historically been ''fast-evolving, achieving exponentially increasing processor speeds and improving manufacturing efficiencies through the rapid adoption of new manufacturing processes'' (see 77 FR 63565). At that time the EPA had identified the potential introduction of 450 mm wafer technology, as well as other new process technologies that could affect emissions. Therefore, we considered a three-year report appropriate for collecting information on changes in the semiconductor industry that would potentially affect emissions. However, following submission and review of the first three-year reports, we have determined that industrial advancements are occurring at a slower pace. As such, we are proposing to amend 40 CFR 98.96(y) to decrease the frequency of submission of the reports from every three years to every five years. Under the current rule, semiconductor manufacturing facilities are required to submit their next technology assessment report by March 31st, 2023 (concurrent with their RY2022 annual report). This proposed revision would affect the due date for that technology assessment, moving the due date from March 31, 2023, to March 31, 2025. Our review of the technology assessment reports submitted for RY2016 and RY2019 did not find significant technology changes within the industry over the three years the reports covered. Based on an assessment of the RY2016 and RY2019 reports (CBI memorandum, *Review of 2017 Subpart*

[53] IPCC. Guidelines for National Greenhouse Gas Inventories, Volume 3, Ch. 6 Electronics Industry Emissions, 2006. *https://www.ipcc-nggip.iges.or.jp/public/2006gl/.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[54] Refer to *Technical Support Document for Process Emissions from Electronics Manufacture (e.g., Micro-electro-mechanical Systems, Liquid Crystal Display, Photovoltaics, and Semiconductors),* November 2010, available in the docket for this rulemaking, Docket Id. No, EPA–HQ–OAR–2019–0424.

[55] See *Volume 3, Chapter 6. Electronics Industry Emissions* to the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,* as cited above in this document.

[56] *Supra* note 51.

I Triennial Reports Submitted by the Electronics Industry (Transcarbon International, 2017, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424) [57] gas emissions and wafer size data that have been submitted to e-GGRT in annual reports, and information gathered from outside sources (summarized in a literature review, *Memorandum: Review of trade and scientific publications to identify significant recent changes in technologies and gas usage in electronic devices manufacturing,* prepared by Sébastien Raoux, Transcarbon International, and Brian Palmer, Eastern Research Group, Inc. (April 3, 2017), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424), we believe that a five-year period would provide updates to the EPA more in line with the pace of technological change within the semiconductor industry. Revising the frequency of submission to every five years would increase the likelihood that reports will include updates in technology rather than conclusions that technology has not changed. Because we have found that changes within the industry have been incorporated at a slower pace and do not anticipate significant changes in technology on a three-year frequency, the proposal to require submission of these reports on a five-year frequency would likely not significantly affect the quality of the data available annually in the GHGRP.

Second, we are proposing to revise the applicability of 40 CFR 98.96(y). Currently, any facility with emissions greater than 40,000 mtCO$_2$e in their most recently submitted emissions report must submit a technology assessment report, including facilities manufacturing devices only using wafer sizes smaller than 200 mm (*e.g.,* 150 mm). Because the focus of the technology assessment report is on semiconductor manufacturing using 200-mm, 300-mm, and potentially 450-mm wafers (see 40 CFR 98.96(y)(2)(i)–(iii)), we are proposing to restrict the reporting requirement in 40 CFR 98.96(y) to facilities that emitted greater than 40,000 mtCO$_2$e and produced wafer sizes greater than 150 mm (*i.e.,* 200 mm or larger) during the period covered by the technology assessment report. We are also proposing to explicitly state that semiconductor manufacturing facilities that manufacture only 150-mm or smaller wafers are not required to prepare and submit a technology assessment report. The applicability of 40 CFR 98.96(y) is currently based on the emissions in a facility's most recently submitted report (typically the emissions occurring in the second-to-last year covered in the technology assessment report, *e.g.,* RY2022 emissions for the technology reports that would be submitted in 2023). However, because facilities that cease all operations related to subpart I are eligible to discontinue reporting under 40 CFR 98.2(i)(3), we are also proposing to further revise the applicability of 40 CR 98.96(y) to clarify that a technology assessment report need not be submitted by a facility that has ceased (and has not resumed) semiconductor manufacturing before the last reporting year covered by the technology assessment report (*i.e.,* no manufacturing at the facility for the entirety of the year immediately before the year during which the technology assessment report is due). For example, if a facility manufacturing on 300-mm wafers exceeded the 40,000 mtCO$_2$e threshold in 2023 but ceased operations in December of that year and has not since then resumed operations, that facility would not be required to submit a technology assessment report in March of 2025.

F. Subpart N—Glass Production

For the reasons described in section II.A.4 of this preamble, we are proposing two revisions to the recordkeeping and reporting requirements of subpart N of part 98 (Glass Production) to enhance the quality and accuracy of the data collected under the GHGRP. Subpart N currently requires calculation of CO_2 emissions using one of two methodologies, either direct measurement using CEMS, or a mass balance methodology based on mass, carbonate content, and fraction of calcination for each carbonate-based input material. For each option, reporters are required to provide the annual quantities of glass produced from each glass melting furnace, and the annual quantities of glass produced from all furnaces combined. The annual quantities of glass produced have been used historically in verification of reported emissions under the GHGRP for comparison to, and to check for temporal consistency with, carbonate content data and emissions estimates provided by facilities. Facilities also maintain records of monthly glass production rate for each glass furnace. We are proposing to revise the existing reporting and recordkeeping requirements for both CEMS and non-CEMS reporters to require that facilities report and maintain records of annual glass production by glass type. Specifically, we are proposing to revise 40 CFR 98.146(a)(2) and (b)(3) to require the annual quantity of glass produced in tons, by glass type, from each continuous glass melting furnace and from all furnaces combined, and the annual quantity of glass produced in tons, by glass type, from each continuous glass melting furnace and from all furnaces combined. The major raw materials (*i.e.,* fluxes and stabilizers) that emit process-related CO_2 emissions in glass production are limestone, dolomite, and soda ash, though there are variations in ingredients and other carbonates may be used in smaller quantities. In general, the composition profile of raw materials is relatively consistent among individual glass types (*e.g.,* container, flat glass, fiber glass, specialty glass), however, some facilities make use of recycled glass in their production process. Differences in the use of recycled material, and other factors, lead to differences in emissions from the production of different glass types. The annual quantities of glass produced by type would provide a useful metric for understanding variations and differences in emissions estimates that may not be apparent in the existing annual production data collected, improve our understanding of industry trends, and improve verification for the GHGRP. The proposed data elements would also provide useful information to improve analysis of this sector in the U.S. GHG Inventory. As noted in the 2019 U.S. GHG Inventory report,[58] the EPA reviews the GHGRP data in the development of inventory estimates for this sector to help understand the completeness of emission estimates and for quality control. Including glass product type would increase the transparency of the data set produced by the Inventory. In addition to the proposed reporting of these data elements, we are proposing harmonizing revisions in 40 CFR 98.147(a)(1) and (b)(1), to add that records must also be kept on the basis of glass type.

We do not anticipate that the proposed data elements would require any additional monitoring or data collection by reporters, as annual production data by glass type is likely available in existing company records. The proposed changes would therefore result in minimal additional burden to reporters. We are also proposing related confidentiality determinations for the

[57] *Supra* note 51.

[58] See U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019* (EPA 2021), available at: *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019.*

additional data elements, as discussed in section VI of this preamble.

G. Subpart P—Hydrogen Production

1. Proposed Revisions To Improve the Quality of Data Collected for Subpart P

As discussed in section II.A of this preamble, we are proposing several amendments to enhance the quality of the data collected under subpart P of part 98 (Hydrogen Production).

Subpart P estimates CO_2 emissions from hydrogen production units using a carbon mass balance along with an assumption that all carbon is transformed to CO_2 and is emitted from the hydrogen production process. This assumption is reasonable for the majority of hydrogen production units because these facilities produce hydrogen using either steam methane reforming or partial oxidation, followed by a water-gas-shift reaction. The first step (steam methane reforming or partial oxidation) produces a mixture of carbon monoxide (CO) and hydrogen, commonly referred to as syngas. The water gas shift reaction uses water to react with the CO in the syngas to produce CO_2 and additional hydrogen. While the majority of hydrogen production units use the water-gas-shift reaction, some facilities only produce syngas as their product. Some facilities may also intentionally produce methanol as a product of these reactions. In these cases, the assumption that 100 percent of the carbon used in the process is converted to CO_2 and thus are direct CO_2 emissions from hydrogen production units is inaccurate.

As noted in section III.C of this preamble for subpart G (Ammonia Manufacturing), TFI has commented numerous times regarding its view of the lack of a true mass balance for subpart G. In several of their comments (specifically, TFI's Comments on the Proposed ''2013 Revisions to the Greenhouse Gas Reporting Rule and Proposed Confidentiality Determinations for New or Substantially Revised Data Elements,'' May 2, 2013, and Comments on the Proposed ''2015 Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule,'' March 30, 2016),[59 60] TFI stated that subpart P lacked a true mass balance because the emissions calculation methodology in 40 CFR 98.163 does not account for carbon that is bound in methanol or other by-products of the process and therefore is not emitted as CO_2. TFI pointed out that subpart P requires reporting of methanol that is intentionally produced and ''carbon other than CO_2'' that is transferred off site, but that the emissions calculation methodology in 40 CFR 98.163 still assumes that 100 percent of the carbon is emitted as CO_2 because the mass balance equations do not subtract out the carbon that leaves the facility as methanol or another product.

Syngas is used as a feedstock for chemical production, most commonly to produce methanol. Carbon transformed into methanol or other chemicals are not emitted as CO_2 unless the syngas is used directly as fuel. For fuel combustion units other than the hydrogen process units, and to which subpart C (General Stationary Fuel Combustion Sources) applies, the CO_2 emissions from syngas combustion would be reported under subpart C of part 98. In considering TFI comments, as noted in the preamble to the November 2013 amendments (78 FR 71935, November 29, 2013), we considered both the emissions from the production processes and consistency with the reporting requirements for other subparts. We note that subpart X (Petrochemical Production) uses a more direct mass balance approach in that carbon contained in produced products (*e.g.,* ethylene) is subtracted from the carbon contained in feedstocks to calculate CO_2 emissions. The EPA has tentatively concluded that requiring reporters subject to subpart P to report net CO_2 process emissions after subtracting out carbon contained in other products would provide a more accurate estimate of the direct GHG emissions from these processes and would provide consistency in our approach across the GHGRP. Therefore, the EPA is proposing to amend subpart P to allow the subtraction of carbon contained in products other than CO_2 (excluding methanol) and the carbon contained in methanol from the carbon mass balance used to estimate CO_2 emissions. The proposed revisions would add new paragraph 40 CFR 98.163(d) to allow facilities to adjust the calculated emissions from fuel and feedstock consumption to subtract the mass of both non-CO_2 carbon (excluding methanol) and carbon contained in the intentionally produced methanol in order to calculate net CO_2 process emissions. We are also proposing harmonizing revisions to the introductory paragraph of 40 CFR 98.163 and 40 CFR 98.163(b).

In conjunction with adding the new paragraph to 40 CFR 98.163(d), we are proposing a clarifying revision to the reporting requirements at 40 CFR 98.166(b)(1) to specify that the annual CO_2 emissions may be determined in accordance with either 40 CFR 98.163(b), the existing equations, or 40 CFR 98.163(d), the revision requiring the calculation of net CO_2 emissions using equation P–4. We are proposing to revise 40 CFR 98.166(d) to require reporting the mass of non-CO_2 carbon (excluding methanol) collected and transferred off-site for each process unit rather than for all process units combined, as currently reported. Reporters are already required to account for and report under 40 CFR 98.166(d) the mass of non-CO_2 carbon (excluding methanol) collected and transferred off-site for all process units combined and under 40 CFR 98.166(e) the mass of methanol produced for each process unit. This proposed revision would cause a slight increase in reporting burden, but the additional level of reporting is necessary to implement the requested change in the calculation method and facilitate report verification. The proposed revision would provide the same breadth of information that was previously reported to inform future policy decisions. Additionally, this data element may be determined using company records, which also should minimize the increased burden. We are proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

As a result of the new equation P–4, the EPA is proposing to add two new monthly recordkeeping elements as part of the verification software records required in 40 CFR 98.167(e): (1) monthly mass of carbon other than CO_2 or methanol collected and transferred off site; and (2) monthly mass of methanol intentionally produced as a desired product. This proposed change is not expected to result in a significant increase in burden because both elements are already being reported on an annual basis. For reporters that do not produce carbon other than CO_2 (excluding methanol) or methanol, the requirements for recordkeeping would remain unchanged. We are also clarifying that retention of the file required in 40 CFR 98.167(e) satisfies

[59] TFI's Comments on the Proposed ''2013 Revisions to the Greenhouse Gas Reporting Rule and Proposed Confidentiality Determinations for New or Substantially Revised Data Elements,'' Docket Id. No. EPA–HQ–OAR–2012–0934, May 2, 2013. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[60] TFI's Comments on the Proposed ''2015 Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule,'' Docket Id. No. EPA–HQ–OAR–2015–0526–0064, March 30, 2016. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

the recordkeeping requirements for each hydrogen production unit.

2. Proposed Revisions To Streamline and Improve Implementation for Subpart P

We are proposing several revisions to subpart P to streamline the requirements of this subpart and improve flexibility for reporters. First, we are proposing several revisions to address unconventional feedstocks being used for hydrogen production. For example, in RY2017, a new facility started reporting under subpart P that produced hydrogen via brine electrolysis. Additionally, we understand facilities are considering using anhydrous ammonia as a feedstock for hydrogen production. The test methods included in 40 CFR 98.164(b)(5) are generally not applicable for these feedstocks. Moreover, the reduced, annual measurement frequency allowances in 40 CFR 98.164(b)(2) and (3) are specific to ''*hydrocarbon* fuels and feedstocks having consistent composition'' [emphasis added].

To address the recent use of unconventional non-hydrocarbon feedstocks, and for the reasons described in section II.B.2 of this preamble, we are proposing to add an allowance in a new paragraph 40 CFR 98.164(b)(5)(xix) to use alternative methods if the methods currently in 40 CFR 98.164(b)(5) are not appropriate because the relevant compounds cannot be detected, the quality control requirements are not technically feasible, or use of the method would be unsafe. Similar provisions have been provided in other GHGRP subparts, such as subpart X. This proposed revision will ensure that subpart P will not mandate the use of inappropriate or unsafe methods for these unconventional feedstocks.

Additionally, we are proposing revisions to 40 CFR 98.164(b)(2) and (3) to allow the use of product specification information annually for non-hydrocarbon gaseous fuels and feedstocks that have carbon content less than or equal to 20 parts per million by weight (*i.e.,* 0.00002 kg carbon per kg of gaseous fuel or feedstock) rather than at least weekly sampling and analysis. Similarly, we are proposing revisions to 40 CFR 98.164(b)(3) to allow the use of product specification information annually for non-hydrocarbon liquid fuels and feedstocks that have a carbon content of less than or equal to 0.00006 kg carbon per gallon of liquid fuel or feedstock rather than monthly sampling and analysis. The value of 0.0006 kg/gallon was derived using 20 parts per million by weight and assuming the liquid that has a specific gravity of 0.8 (*i.e.,* a density of approximately 3.0 kg/gal). The current unconventional non-hydrocarbon fuels and feedstocks utilized in hydrogen production have very limited GHG emission potential and are currently an insignificant contribution to the GHG emissions from hydrogen production. Therefore, we consider it reasonable to provide a simple alternative of allowing use of product specification information on an annual basis for determining carbon content for these unconventional, non-hydrocarbon fuels and feedstocks.

We are also proposing revisions to 40 CFR 98.164(b)(5) to clarify that the methods in 40 CFR 98.164(b)(5) must be used for determining carbon content except for the newly proposed provisions for gaseous and liquid fuels and feedstocks that have a low carbon content as provided in paragraphs 40 CFR 98.164(b)(2) and (3). Additionally, we are proposing to revise paragraphs 40 CFR 98.164(b)(2) through (4) to specifically state that the carbon content must be determined ''. . . using the applicable methods in paragraph (b)(5) of this section.'' This proposed revision does not alter the existing requirements for fuels and feedstocks, it simply clarifies the linkage between the requirements in paragraphs 40 CFR 98.164(b)(2) through (4) and (5) of the current rule.

These proposed revisions to address unconventional hydrogen production feedstocks would increase flexibility for reporters and clarify requirements to reduce the number of reporters performing monthly sampling and analysis using potentially inappropriate methods. We expect that the proposed changes would allow reporters using unconventional non-hydrocarbon fuels and feedstocks to use the proposed product specifications provisions and reduce the need for sampling and analysis. Even if the reporter cannot use the product specifications provisions, the proposed revision to allow the use of modified or alternative methods would likely reduce the analytical burden of trying to use hydrocarbon-focused methods for a non-hydrocarbon stream. While the proposed revisions would provide significant relief for those reporters using unconventional non-hydrocarbon fuels or feedstocks, the proposed change is expected to only affect a small number of reporters due to the limited number of reporters that currently use these types of feedstocks.

In providing these alternatives, we also evaluated whether amendments to the recordkeeping and reporting requirements were necessary. There are no direct reporting requirements for the analytical method used to determine carbon content. The recordkeeping requirements are included in 40 CFR 98.167(b), which requires retention of ''. . . records of all analyses and calculations conducted as listed in 40 CFR 98.166(b), (c), and (d).'' In reviewing these requirements, we noted that these recordkeeping requirements were not revised when the EPA added reporting requirements at 40 CFR 98.166(e) (79 FR 63787, Oct. 24, 2014). Therefore, we are proposing to revise the recordkeeping requirements at 40 CFR 98.167(b) to refer to paragraphs (b) through (e) of 40 CFR 98.166. We note that, for facilities using the proposed alternatives at 40 CFR 98.164(b)(2), (3) or (5)(xix), these requirements include retention of product specification sheets, records of modifications to the methods listed in 40 CFR 98.164(b)(5)(i) through (xviii) that are used, and records of the alternative methods used, as applicable.

H. Subpart Q—Iron and Steel Production

1. Proposed Revisions To Improve the Quality of Data Collected for Subpart Q

For the reasons described in section II.A.4 of this preamble, we are proposing revisions to the reporting requirements for subpart Q of part 98 (Iron and Steel Production) to enhance the quality and accuracy of the data collected. Subpart Q currently requires calculation of CO_2 emissions using one of three methodologies: direct measurement using CEMS, carbon mass balance methodologies, or site-specific emission factors. Subpart Q requires that the CO_2 emissions be calculated and reported for the following types of units: taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, decarburization vessel, and direct reduction furnace. We are proposing to revise the existing reporting requirements at 40 CFR 98.176(g) for all unit types and all calculation methods to require that facilities report the type of unit, the annual production capacity, and the annual operating hours for each unit. The capacity of the unit as well as the level of operation have a significant influence on the emissions of that unit. Therefore, the annual production capacity in combination with annual operating hours would provide useful information for understanding variations in annual emissions and would provide useful information to verify reported data. We often contact facilities seeking to understand yearly variations in the emissions of a unit, and facilities explain that the variation was due to the unit not operating for a particular time period. If data on the capacity of the unit and the operating hours are included in the annual report, it could explain the variation and eliminate the need for correspondence with facilities. In addition, this data would provide useful information to understand trends across the sector and support analysis of these sources.

In general, we do not anticipate that the proposed data elements would require any additional monitoring or data collection by reporters. For facilities using the carbon mass balance method, this data is already included in the record keeping requirements described at 40 CFR 98.177(c) and (d). Although the record keeping requirement at 40 CFR 98.177(d) does not specify whether the data would be retained at the facility or unit level, we do not anticipate that reporting data at the unit level would present additional burden. For facilities using the CEMS method or the site-specific emission factor calculation method, we anticipate that this data would be readily available in company records. However, we seek comment on both these assumptions. We are proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

For the reasons described in section II.A.5 of this preamble, we are proposing to correct equation Q–5 in 40 CFR 98.173(b)(1)(v). An error appears to have been introduced in equation Q–5 in revisions to the equation in a final rule published in 2016 (81 FR 89188, December 9, 2016). Specifically, the final rule inadvertently published the equation such that it appeared that the total CO_2 emissions from EAFs are determined as a fraction of, rather than the total of, carbon mass emissions from inputs to the furnace. The proposed revisions would correct the equation to remove the unnecessary fraction symbol and would not add additional burden for the calculation or reporting requirements for subpart Q.

2. Proposed Revisions To Streamline and Improve Implementation for Subpart Q

For the reasons described in section II.B.2 of this preamble, we are proposing two revisions to subpart Q to streamline monitoring. First, we are proposing to revise 40 CFR 98.174(b)(2) to provide a new option for facilities to determine the carbon content of process inputs and outputs. Reporters are currently allowed to determine carbon content either through direct sampling using the methods provided in 40 CFR 98.174(b)(2) or from similar analyses provided by a supplier. We are proposing to allow reporters an additional third option to use analyses provided by material recyclers that manage process outputs for sale or use by other industries. Several of the process output materials used in iron and steel production are typically sent to recycling facilities (*e.g.,* secondary zinc recycling facilities), which process the material for supply to another entity. Such material recyclers conduct testing on their inputs and products to provide to entities using the materials downstream, and therefore perform carbon content analyses using similar test methods and procedures as suppliers. In the 2009 Final Rule, we determined that the use of carbon content analyses from a material supplier was appropriate because the carbon content does not vary widely at a given facility for the significant process inputs and outputs that contain carbon, and because the EPA continued to account for variations in emissions due to changes in production rate, which are more likely to be a significant source of variability (*i.e.,* the quantity of carbon-containing materials that are inputs and outputs to the process more directly influence emissions). For these same reasons, we anticipate that analyses received from a material recycling entity would be a reliable source of carbon content. The proposed change would add flexibility for reporters by allowing an additional option for obtaining measurements, in lieu of direct sampling. We are proposing a minor harmonizing change to 40 CFR 98.176(e)(2) to require reporters to indicate if the carbon content was determined from information supplied by a material recycler.

We are also proposing to revise 40 CFR 98.174(b)(2) to incorporate a new test method for carbon content analysis of low-alloy steel. The EPA has become aware that an additional method is available for analysis of carbon content, specifically, ASTM E415–17, *Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry* (2017). We have reviewed the method, which is targeted to this sector, and have tentatively concluded it is a valid method for the purposes of subpart Q monitoring and reporting. The EPA allows for the use of standard methods based on atomic emission spectrometry in other sections of the rule, including under 40 CFR 98.144(b) where it can be used to determine the composition of coal, coke, and solid residues from combustion processes by glass production facilities. Therefore, we are proposing to incorporate the method by reference in 40 CR 98.7 and cross-reference that incorporation in 40 CFR 98.174(b)(2) for use for steel, as applicable. The proposed test method would be an alternative method and would provide additional flexibility for reporters. We are also proposing a harmonizing change to the reporting requirements of 40 CFR 98.176(e)(2), to clarify that the carbon content analysis methods available to report are those methods listed in 40 CFR 98.174(b)(2).

I. Subpart S—Lime Manufacturing

For the reasons discussed in this section and section II.A of this preamble, we are proposing several revisions to subpart S of part 98 (Lime Manufacturing) to improve the quality of the data collected from this subpart. First, for the reasons described in this section and in section II.A.2 of this preamble, we are proposing to amend subpart S to improve the methodology for calculation of annual CO_2 process emissions from lime production. The proposed revisions would account for CO_2 that is captured from lime kilns and used on-site. Under subpart S, reporters currently calculate CO_2 emissions by either operating and maintaining a CEMS as specified in 40 CFR 98.193(a) or (b)(1), or by using the mass balance methodology under 40 CFR 98.193(b)(2). All lime kilns that are subject to 40 CFR 98.193(b) must calculate and report process and combustion CO_2 emissions by using the procedures in either 40 CFR 98.193(b)(1), for estimation of combined process and combustion emissions from all lime kilns, or 40 CFR 98.193(b)(2), for estimation of process and combustion CO_2 emissions from all lime kilns separately. For those lime kilns that use 40 CFR 98.193(b)(2), calculation of annual CO_2 process emissions from all lime kilns is estimated through summing the following three values (per 40 CFR 98.193(b)(2)(iv)): (1) the product of a monthly site-specific emission factor and weight or mass for each type of lime produced, (2) the product of a monthly site-specific emission factor and each type of calcined byproduct or waste that is sold, and (3) the annual CO_2 emissions from each type of calcined byproduct or waste that is not sold. There is currently no allowance for subtraction of CO_2 that may be captured and used in another process on-site (*e.g.,* for use in a purification process or the manufacture of another product such as refined beet sugars, precipitated calcium carbonate, etc.).

In response to the 2009 Proposed Rule, one subpart S reporter, Specialty

Minerals Inc., submitted a comment that stated that subpart S does not include a ''deduction for the carbon dioxide that is taken up as a raw material'' for use in another product, resulting in ''an overstatement of total carbon dioxide emissions'' from lime manufacturing.[61] In section III.C of this preamble, we describe similar comments received from TFI requesting changes that would allow sources to subtract from direct facility emissions CO_2 that is being used in the manufacturing of other products on-site.

Following review of these comments, the EPA has tentatively concluded that allowing reporters subject to subpart S to report net CO_2 process emissions after subtracting out CO_2 captured and used in other on-site processes would provide a more accurate estimate of the direct GHG emissions from the lime manufacturing process and would provide consistency in our approach across the GHGRP. Therefore, we are proposing to modify equation S–4 to subtract the CO_2 that is captured and used in on-site processes, with corresponding proposed revisions to the recordkeeping requirements in 40 CFR 98.197(c) (to record the monthly amount of CO_2 from the lime manufacturing process that is captured for use in all on-site processes). We are also proposing minor amendments to the reporting elements in 40 CFR 98.196(b)(17) to clarify that we only intend to collect data on CO_2 that is captured and used on-site (*i.e.,* reporters do not need to account for CO_2 that was not captured but was used on-site), and to clarify that reporters must account for CO_2 usage from all on-site processes, including for manufacture of other products, in the total annual amount of CO_2 captured. The proposed changes would also correct some instances where reporters have provided values of CO_2 used on-site that exceed facility emissions, where they have inadvertently included CO_2 that was not captured on-site (*e.g.,* CO_2 purchased for water treatment), which incorrectly implied that the facility's emissions were net negative. The proposed amendments would not change the reporting of emissions from manufacture of lime products, calcined lime by-products, or waste; this information would continue to be collected. As such, the proposed amendments would provide the same breadth of information that was previously reported to inform future policy decisions.

Second, for the reasons described in section II.A.4 of this preamble, we are proposing to add reporting requirements for reporters using the CEMS methodology in order to improve our understanding of source category emissions and our ability to verify reported data. Subpart S reporters who use CEMS collect CO_2 emissions data through direct measurement, and no data on the chemical composition of the products, byproducts, or wastes at CEMS facilities are collected through the GHGRP.[62] As such, there is currently limited data available to the EPA to evaluate process emissions for reporters using CEMS. As we noted for cement production facilities in section III.D of this preamble, CEMS facility emissions are different from non-CEMS emissions because combustion and process emissions are typically vented through the same stack, causing process and combustion emissions to be mixed and indifferentiable. In order to be able to differentiate process emissions, we are proposing to collect other data elements from CEMS reporters that are not currently reported, including annual average results of the chemical composition analysis of lime products, byproducts, or wastes. Collecting average chemical composition data for CEMS facilities will provide the EPA the ability to develop a process emission estimation methodology for CEMS reporters, which can be used to verify the accuracy of the reported CEMS emission data. The EPA is proposing to add data elements under 40 CFR 98.196(a) to collect annual averages of the chemical composition input data on a facility-basis. The proposed data elements include the annual arithmetic average calcium oxide content (metric tons CaO/metric tons lime) and magnesium oxide content (metric tons MgO/metric tons lime) for each type of lime produced, for each type of calcined lime byproduct and waste sold, and for each type of calcined lime byproduct and waste not sold. The proposed data elements would rely on an arithmetic average of the measurements rather than requiring reporters to weight by quantities produced in each month. In addition to improving verification and data quality for the GHGRP, the proposed data elements will also improve the U.S. GHG Inventory, which could use the proposed data elements to disaggregate process and combustion emissions that are reported by facilities using CEMS.

Similarly, in order to improve verification, we are proposing to collect additional data elements for reporters using the mass balance methodology (*i.e.,* reporters that comply using the requirements at 40 CFR 98.193(b)(2)). These proposed amendments would allow the EPA to build verification checks for the actual inputs entered (*e.g.,* MgO content). We currently rely on verification checks within the IVT to check the accuracy of inputs and reported emissions from non-CEMS reporters, however, these checks are of limited usefulness since we lack the information to develop specific anticipated ranges or references for the entered data. Reporters using the mass balance methodology are currently required to report the annual average results of chemical composition analysis of each type of lime product produced and calcined byproduct or waste sold, but do not supply data for byproducts or wastes not sold. The EPA is proposing to add data elements under 40 CFR 98.196(b) to collect the annual average results of the chemical composition analysis of all lime byproducts or wastes not sold (*e.g.,* a single facility average calcium oxide content calculated from the calcium oxide content of all lime byproduct types at the facility), and the annual quantity of all lime byproducts or wastes not sold (*e.g.,* a single facility total calculated as the sum of all quantities, in tons, of all lime byproducts at the facility not sold during the year). Because the proposed data elements rely on annual averages of the chemical composition measurements and an annual quantity of all lime byproducts or wastes at the facility, they are distinct from the data entered into the EPA's IVT. These proposed data elements would inform and improve the EPA's existing reference checks and allow the EPA to build additional checks for the data that are currently verified through IVT. The proposed amendments would improve the verification of entered data and confirm the veracity of reported emissions.

We do not anticipate that the proposed data elements would require any additional monitoring or data collection by reporters, as these data are likely already available in existing company records. However, we are requesting comment on whether any of

[61] Specialty Minerals Inc.'s Comments on the Proposed 2009 Greenhouse Gas Reporting Rule, Docket Id. No. EPA–HQ–OAR–2008–0508–0907, June 4, 2009. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[62] Subpart S reporters who use the mass balance methodology under 40 CFR 98.193(b)(2) currently estimate CO_2 emissions using monthly chemical composition data as inputs to calculate emissions factors for the lime produced, calcined byproducts and wastes sold, and calcined byproducts and wastes not sold. These data inputs are not collected by the EPA but are only entered into the EPA's Inputs Verification Tool, which conducts verification checks at the time of report submission but does not retain the data entered.

the above listed data elements would not be readily available to reporters. Reporters using the mass balance methodology are expected to have very minimal changes to reporting, as the chemical composition averages and quantities we are proposing can be calculated from the inputs that are currently entered into IVT. Finally, we are proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

J. Subpart W—Petroleum and Natural Gas Systems

We are proposing several revisions to subpart W (Petroleum and Natural Gas Systems). Section III.J.1 of this preamble presents proposed amendments that would improve the quality of data collected, including new requirements for reporting of additional emission sources, updated emission factors, new and revised reporting requirements, and clarification of reporting requirements that reporters have indicated are unclear, as described in section II.A of this preamble. We are also proposing revisions described in section III.J.2 of this preamble that would streamline and improve implementation, including removing redundant or unnecessary reporting requirements, and providing additional flexibility in the calculation methods and monitoring requirements for some emission sources, as described in section II.B of this preamble. We are proposing the miscellaneous technical corrections and clarifications described in section III.J.3 of this preamble. Finally, section III.J.4 of this preamble describes the provisions for which we propose subpart W reporters would be able to use best available monitoring methods (BAMM) for RY2023. We are also proposing related confidentiality determinations for new or revised data elements that result from these proposed amendments, as discussed in section VI of this preamble.

In addition, on November 15, 2021 (86 FR 63110), the EPA proposed under CAA section 111(b) NSPS for new, reconstructed, and modified oil and natural gas sources, *i.e.,* sources for which owners or operators commence construction, modification, or reconstruction after November 15, 2021 (40 CFR part 60, subpart OOOOb) (hereafter referred to as ''NSPS OOOOb''), as well as emissions guidelines under CAA section 111(d) for existing oil and natural gas sources, *i.e.,* sources for which owners or operators commence construction, modification, or reconstruction on or before November 15, 2021 (40 CFR part 60, subpart OOOOc) (hereafter referred to as ''EG OOOOc'') (the sources affected by these two proposed subparts are collectively referred to in this preamble as ''affected sources''). While the standards in NSPS OOOOb would directly apply to new, reconstructed, and modified sources when finalized, the final EG OOOOc would not impose binding requirements directly on sources; rather it would contain guidelines, including presumptive standards, for states to follow in developing, submitting, and implementing plans to establish standards of performance to limit GHGs (in the form of methane limitations) from existing oil and gas sources within their own states. If a state does not submit a plan to the EPA for approval in response to the final emission guidelines, or if the EPA disapproves a state's plan, then the EPA must establish a Federal plan that would apply to existing sources within that state that are not covered by a state plan. In addition, a Federal plan could apply to facilities located on tribal land that do not request approval to develop a tribal implementation plan similar to a state plan. Once the Administrator approves a state plan under CAA section 111(d), the plan is codified in 40 CFR part 62 (Approval and Promulgation of State Plans for Designated Facilities and Pollutants) within the relevant subpart for that state.[63] 40 CFR part 62 also includes all Federal plans promulgated pursuant to CAA section 111(d). Therefore, rather than referencing the presumptive standards in EG OOOOc, which would not directly apply to sources, the proposed amendments to subpart W reference 40 CFR part 62.

Similar to the 2016 amendments to align subpart W with certain requirements in 40 CFR part 60, subpart OOOOa (hereafter referred to as ''NSPS OOOOa'') (81 FR 86500, November 30, 2016), we are proposing revisions to certain requirements in subpart W relative to the requirements proposed for NSPS OOOOb and the presumptive standards proposed in the EG OOOOc (which would inform the standards to be developed and codified under 40 CFR part 62). Specifically, we are proposing amendments to the subpart W calculation methodologies for natural gas pneumatic devices and equipment leak surveys related to the proposed NSPS OOOOb and presumptive standards in EG OOOOc, and we are proposing new reporting requirements for ''other large release events'' as defined in subpart W that would reference the NSPS OOOOb and approved state plans or applicable Federal plan in 40 CFR part 62. These proposed amendments are described in sections III.J.1.a, k, and m, respectively. These proposed amendments, if finalized, would not apply to individual reporters unless and until their emission sources are required to comply with either the final NSPS OOOOb or an approved state plan or applicable Federal plan in 40 CFR part 62. In the meantime, reporters would comply with the applicable provisions of subpart W for sources not subject to NSPS OOOOb or 40 CFR part 62.

1. Proposed Revisions To Improve the Quality of Data Collected for Subpart W

As further described in section II.A of this preamble, the EPA is proposing amendments that would ensure that accurate data are being collected under the rule, improve the accuracy of emissions reported under part 98, and enhance the overall quality of the data collected under the GHGRP. Consistent with section II.A.1 of this preamble, we are proposing to incorporate recent data to update selected subpart W emission factors. Where emission factors are currently provided in subpart W for certain emission source types, those emission factors were based on the best available public data at the time that subpart W was promulgated. In the years since promulgation of subpart W, additional data have been collected for some source types as part of emissions studies, and the EPA has reviewed and evaluated the data in these studies. Based on those evaluations, the EPA is proposing to update selected subpart W population emission factors[64] for natural gas pneumatic device vents across a variety of industry segments and equipment leaks from the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution industry segments. The EPA is also proposing revisions to the leaker emission factors for all industry segments conducting equipment leak surveys to account for differences in the leak detection methodologies. Consistent with section II.A.2 of this preamble, the EPA is proposing amendments to improve calculation methodologies for emissions from natural gas pneumatic pumps,

[63] 40 CFR part 62 contains a subpart for each of the 50 states, District of Columbia, American Samoa, Puerto Rico, Virgin Islands, and Northern Mariana Islands.

[64] When the total emissions from all leaking sources of the same type are divided by the total count of that source type, then the resultant factor is referred to as a population emission factor. When the total emissions from all leaking sources of the same type are divided by the total count of leaking sources for that source type, then the resultant factor is referred to as a leaker emission factor.

centrifugal compressors, reciprocating compressors, equipment leak surveys, combustion units, and sources that use the acoustic leak detection method for leak detection. Consistent with section II.A.3 of this preamble, we are proposing to add calculation and reporting requirements for ''other large release events,'' which are emission events that are not sufficiently accounted for using the current subpart W methodologies, and emissions from uncombusted methane from compressor engines. We are also proposing to require facilities in the Onshore Natural Gas Processing industry segment to begin calculating and reporting emissions from natural gas pneumatic devices and proposing to require facilities in the LNG Import/Export industry segment to begin calculating and reporting emissions from acid gas removal vents. Consistent with section II.A.4 of this preamble, we are proposing to add or revise reporting requirements to better understand and characterize the emissions from acid gas removal units, glycol dehydrator vents, liquids unloadings, atmospheric storage tanks, associated gas flaring, flare stacks, and equipment leaks, as well as to better characterize facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment. Finally, consistent with section II.A.5 of this preamble, we are proposing to clarify calculation and reporting requirements for natural gas pneumatic devices, natural gas driven pneumatic pumps, blowdown vent stacks, atmospheric storage tanks (including requirements for open thief hatches), associated gas venting and flaring, centrifugal and reciprocating compressors, combustion devices, and facilities in the Onshore Natural Gas Transmission Pipeline industry segment, in part to address questions asked by reporters to the GHGRP Help Desk and in verification correspondence via e-GGRT.

a. Natural Gas Pneumatic Device Vents

Revisions to emission factors. Subpart W requires calculation of GHG emissions from natural gas pneumatic device venting using default population emission factors multiplied by the number of devices and the average time those devices are ''in-service'' (*i.e.,* supplied with natural gas). Subpart W provides two sets of pneumatic device emission factors, one for devices in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments and one for the Onshore Natural Gas Transmission Compression and Underground Natural Gas Storage industry segments. Each set of emission factors consists of emission factors for three different types of natural gas pneumatic devices: continuous low bleed devices, continuous high bleed devices, and intermittent bleed devices.[65]

The EPA has become aware of several studies on emissions from natural gas pneumatic device vents since subpart W was first promulgated. For example, in April 2015, the EPA reviewed three recently published studies on emissions from pneumatic devices (also referred to as ''pneumatic controllers'' within the studies as well as in NSPS OOOOa, NSPS OOOOb, and EG OOOOc) at onshore production facilities and evaluated those studies for use in the U.S. GHG Inventory.[66] As part of this proposed rulemaking, we have reviewed these and other available studies to evaluate the potential for revisions to the natural gas pneumatic device emission factors in subpart W. For more information regarding this review, see the document *Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Proposed Rule—Petroleum and Natural Gas Systems,* (hereafter referred to as ''subpart W TSD''), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

As part of our review, we found there are significantly more data available now by which to characterize pneumatic device emissions. Therefore, consistent with section II.A.1 of this preamble, we are proposing to amend the emission factors for the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, Onshore Natural Gas Transmission Compression, and Underground Natural Gas Storage industry segments. We are also proposing to add pneumatic device venting as an emission source for the Onshore Natural Gas Processing industry segment using the same emission factors we are proposing for the Onshore Natural Gas Transmission Compression and Underground Natural Gas Storage industry segments, consistent with section II.A.3 of this preamble.

Intermittent bleed pneumatic devices subject to surveys. As part of our review to characterize pneumatic device emissions, we found a significant difference in the emissions from intermittent bleed pneumatic devices that appeared to be functioning as intended (short, small releases during device actuation) and those that appeared to be malfunctioning (continuously emitting or exhibiting large or prolonged releases upon actuation). For natural gas intermittent bleed pneumatic devices, it is possible to identify malfunctioning devices through routine monitoring using optical gas imaging (OGI) or other technologies. As noted in the introduction to section III.J of this preamble, the EPA recently proposed NSPS OOOOb and EG OOOOc for oil and natural gas sources. Under the proposed standards in NSPS OOOOb and the proposed presumptive standards in EG OOOOc (which would inform the state plans or, if necessary, the Federal plan in 40 CFR part 62), nearly all covered pneumatic devices (continuous bleed and intermittent vent) would be required to have a methane and volatile organic compound (VOC) emission rate of zero. The only exception would be for pneumatic devices in Alaska at locations where on-site power is not available, in which case owners and operators would be required to use low bleed pneumatic devices in place of high bleed pneumatic devices (unless a high bleed device is needed for a functional need such as safety), and to verify that any intermittent bleed pneumatic devices operate such that they do not vent when idle by monitoring these devices during the fugitive emissions survey.

We envision relatively few intermittent bleed pneumatic devices under the proposed zero-emission standard and presumptive standard for these pneumatic devices, compliance with which would require the use of non-emitting devices. As noted in the previous paragraph, we proposed in NSPS OOOOb and EG OOOOc to require periodic monitoring of those few intermittent bleed pneumatic devices. In addition, as noted in section III.J of this preamble, the proposed amendments that would apply to sources subject to the NSPS OOOOb and approved state plans or applicable Federal plan in 40 CFR part 62 would not become effective for individual reporters unless and until their emission sources become subject to and are required to comply with either the final NSPS OOOOb or an

[65] The development of the current emission factors for natural gas pneumatic devices is described in *Greenhouse Gas Emissions Reporting from the Petroleum And Natural Gas Industry: Background Technical Support Document,* U.S. EPA, November 2010, (Docket Id. No. EPA–HQ–OAR–2009–0923–3610), also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[66] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: Potential Revisions to Pneumatic Controller Emissions Estimate (Production Segment).* April 2015. Available at *https://www.epa.gov/sites/production/files/2015-12/documents/ng-petro-inv-improvement-pneumatic-controllers-4-10-2015.pdf.*

approved state plan or applicable Federal plan in 40 CFR part 62. Prior to that time, a reporter may elect to conduct inspections or surveys of their intermittent bleed pneumatic devices. Therefore, similar to the 2016 amendments to subpart W (81 FR 4987, January 29, 2016), the EPA is proposing amendments to subpart W to provide an alternative methodology to calculate emissions from intermittent bleed pneumatic devices based on the results of inspections or surveys, consistent with section II.A.2 of this preamble. Specifically, for facilities that would be required to inspect their intermittent bleed pneumatic devices requirements under NSPS OOOOb or an approved state plan or the applicable Federal plan in 40 CFR part 62 (to the extent there are any) or facilities that elect to conduct routine monitoring surveys of their existing natural gas intermittent bleed pneumatic devices consistent with the methods in NSPS OOOOb prior to becoming subject to 40 CFR part 62, we are proposing to provide an alternative calculation methodology analogous to a ''leaker factor'' approach used for equipment leaks. Reporters using this calculation methodology would report the total number of natural gas intermittent bleed pneumatic devices at the facility, the frequency of monitoring, the number of devices found to be malfunctioning, and the average time the malfunctioning devices were malfunctioning. For more information regarding this proposed alternative calculation methodology for natural gas intermittent bleed pneumatic devices, see the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

Hours of operation of natural gas pneumatic devices and natural gas driven pneumatic pumps. In correspondence with the EPA via e-GGRT, reporters have indicated that there is confusion over the use of the term ''operational'' in the definition of variable ''T_t'' in equation W–1 in 40 CFR 98.233(a) and the term ''in operation'' in the reporting requirements in 40 CFR 98.236(b)(2). Both the current emission factors and the proposed updated emission factors described earlier in this section for natural gas pneumatic devices were developed by taking both periods of actuation and periods without actuation into account;[67] in other words, the emission factors are population emission factors. To calculate emissions accurately using a population emission factor, the average number of hours used in equation W–1 should be the number of hours that the devices of a particular type are in service (*i.e.,* the devices are receiving a measurement signal and connected to a natural gas supply that is capable of actuating a valve or other device as needed). Therefore, consistent with section II.A.5 of this preamble, we are proposing to revise the definition of variable ''T_t'' in equation W–1 and the corresponding reporting requirement in 40 CFR 98.236(b)(2) to use the term ''in service (*i.e.,* supplied with natural gas)'' rather than ''operational'' or ''in operation.''

Similarly, the population emission factor for natural gas driven pneumatic pumps was developed using measurements taken during actuations together with manufacturer data and observed operational data at facilities (*e.g.,* pump actuation rate).[68] In other words, the emission factor represents the average emissions over the period when the pump is operating, not just the emissions during periods when the pump was actuating. Therefore, we are also proposing to revise the definition of variable ''T'' in equation W–2 in 40 CFR 98.233(c)(1) for natural gas driven pneumatic pumps to use the term ''in service (*i.e.,* supplied with natural gas),'' and we are proposing to use that same term in the corresponding reporting requirement in proposed 40 CFR 98.236(c)(4).

b. Natural Gas Driven Pneumatic Pump Venting

The current procedures in subpart W for calculating and reporting emissions from natural gas driven pneumatic pump venting are specified in 40 CFR 98.233(c) and 40 CFR 98.236(c). The inputs to equation W–2 in 40 CFR 98.233(c) are the total number of natural gas driven pneumatic pumps and average estimated number of hours in the operating year the pumps were operational. Reporters then report these inputs along with the emissions under 40 CFR 98.236(c). As the calculated emissions are vented emissions from natural gas driven pneumatic pumps, the intent is that the total number of natural gas driven pneumatic pumps should include only those pumps that are vented directly to the atmosphere (*i.e.,* uncontrolled). However, based on contact with reporters, we understand that emissions from some natural gas driven pneumatic pumps are routed to controls, particularly flares or combustion units. Flared emissions from natural gas driven pneumatic pumps are not required to be calculated and reported separately from other flared emissions. Instead, emission streams from natural gas driven pneumatic pumps that are routed to flares are required to be included in the calculation of total emissions from the flare according to the procedures in 40 CFR 98.233(n) and reported as part of the total flare stack emissions according to the procedures in 40 CFR 98.236(n), in the same manner as emission streams from other source types that are routed to the flare. Similarly, emissions from natural gas driven pneumatic pumps that are routed to a combustion unit are required to be combined with other streams of the same fuel type and used to calculate total emissions from the combustion unit as specified in 40 CFR 98.233(z) and reported as part of the total emissions from the combustion unit as specified in 40 CFR 98.236(z).

In correspondence with the EPA via e-GGRT, some reporters have expressed confusion regarding the requirements for natural gas driven pneumatic pumps that are routed to flares or combustion devices, particularly between 40 CFR 98.236(c) (for vented emissions) and 40 CFR 98.236(n) or (z) (for flared or combusted emissions, respectively). Additionally, the counts of controlled natural gas driven pneumatic pumps currently are not reported separately from counts of vented natural gas driven pneumatic pumps under 40 CFR 98.236(c), and the emissions currently reported from flares and combustion units are not attributed specifically to natural gas driven pneumatic pumps. This lack of reported information leads to uncertainty in verification of reported data when there are significant changes in reported data at a facility from one year to the next, which can result in additional communication with the reporter to clarify whether or not the changes are an error. The lack of reported information also means changes in the trends related to implementation of such controls relative to trends in overall use of natural gas driven pneumatic pumps in the petroleum and natural gas systems source category would be difficult to track. In addition, there are other rules

[67] As noted previously, the development of the current emission factors for natural gas pneumatic devices is described in *Greenhouse Gas Emissions Reporting from the Petroleum And Natural Gas Industry: Background Technical Support Document,* U.S. EPA, November 2010, (Docket Id. No. EPA–HQ–OAR–2009–0923–3610), also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[68] The development of the emission factor for natural gas pneumatic pumps is described in *Greenhouse Gas Emissions Reporting from the Petroleum And Natural Gas Industry: Background Technical Support Document,* U.S. EPA, November 2010, (Docket Id. No. EPA–HQ–OAR–2009–0923–3610), also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

that require the control of pneumatic pumps (*e.g.,* NSPS OOOOa), so we expect that there will be an increase in the number of natural gas driven pneumatic pumps that are routed to controls as more facilities become subject to those rules.

Thus, consistent with section II.A.2 of this preamble, we are proposing to revise 40 CFR 98.233(c) to clarify requirements for calculating emissions from both natural gas driven pneumatic pumps that are vented to the atmosphere and controlled natural gas driven pneumatic pumps that are consistent with the intent of the current rule. Specifically, we are proposing to revise 40 CFR 98.233(c) introductory text and the definitions of the terms ''Count'' and ''T'' in equation W–2 to further clarify that the provisions of 40 CFR 98.233(c)(1) and (2) should only be used to calculate emissions from natural gas driven pneumatic pumps venting directly to the atmosphere. We are proposing to add 40 CFR 98.233(c)(3) to specify that if the emissions are flared, then flared emissions would be calculated using the method for flare stack emissions in 40 CFR 98.233(n) and reported as flare stack emissions under 40 CFR 98.236(n). If emissions are routed to a combustion device, then emissions would be calculated using the methods for combustion devices as specified in 40 CFR 98.233(z) and reported as specified in 40 CFR 98.236(z). Finally, if the emissions are routed to vapor recovery and are not subsequently routed to a combustion device, then we are proposing that reporters would not calculate or report emissions. If a natural gas driven pneumatic pump is vented directly to the atmosphere for part of the year and routed to a flare, combustion, or vapor recovery system during another part of the year, the reporter would calculate emissions using all applicable procedures and adjust the number of hours used in equation W–2 as needed. We request comment on whether pneumatic pumps are routed to vapor recovery systems and whether there are other controls that should be addressed with these new provisions. In addition, we request comment on whether flared emissions associated with natural gas driven pneumatic pumps should continue to be reported as flare stack emissions under 40 CFR 98.236(n) or should be reported in the natural gas driven pneumatic pumps emission source under 40 CFR 98.236(c).

We are also proposing to add new reporting elements in 40 CFR 98.236(c) to align with the proposed clarifications to the emission calculation procedures. Specifically, we are proposing to expand the current requirement to report the total count of natural gas driven pneumatic pumps to three separate counts: the number of natural gas driven pneumatic pumps that are vented directly to atmosphere (*i.e.,* uncontrolled); the number of natural gas driven pneumatic pumps that are routed to a flare, combustion, or vapor recovery (*i.e.,* controlled); and the total number of natural gas driven pneumatic pumps at the facility. The total count of pneumatic pumps is a proposed reporting element along with the counts of uncontrolled and controlled pneumatic pumps because the total count would not always be equal to the sum of the other two counts. For example, a reporter that switches from one scenario to another during a year for a particular pneumatic pump (*e.g.,* from vented to flared) would include that pneumatic pump in the count of pumps that vent directly to atmosphere and in the count of pumps that are routed to flares, but that pneumatic pump would only be counted once towards the total number of pneumatic pumps. The number of pneumatic pumps vented directly to the atmosphere would be equal to the ''Count'' in equation W–2 and would be used in the verification of annual reports to the GHGRP. The total count of pneumatic pumps at the facility and the number of pneumatic pumps that are routed to a flare, combustion, or vapor recovery would provide the EPA with information to better characterize emissions from this source, including how many pneumatic pumps are controlled across the industry, how often pneumatic pumps are both controlled and vented directly to the atmosphere in the same year, and how the use of controls for pneumatic pumps changes across multiple years.

c. Acid Gas Removal Vents

Acid Gas Removal Units at LNG Import/Export Facilities. Emissions from acid gas removal units are currently reported for three industry segments: Onshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, and Onshore Petroleum and Natural Gas Gathering and Boosting. However, prior to becoming LNG, natural gas is treated to specifications more stringent than pipeline quality natural gas to remove nearly all of the heavy hydrocarbons, mercury, CO_2, sulfur compounds, and other impurities to prevent problems with the liquefaction process (*e.g.,* CO_2 and hydrogen sulfide can cause freezing and plugging in downstream units once the gas is liquefied). Therefore, liquefaction plants at LNG export facilities may include acid gas removal units, and those emissions are not currently reported to the GHGRP if the acid gas removal unit vents are vented directly to the atmosphere. Emissions from acid gas removal unit vents that are routed to flares or thermal oxidizers that meet the subpart W definition of flare in 40 CFR 98.238 are reported under the flare stacks emission source, but they are not characterized as acid gas removal emissions. LNG export facilities may receive natural gas that has already been treated in a natural gas processing plant as well as raw material from dedicated gas fields, so the emissions from acid gas removal units at these facilities can comprise a significant portion of the facility's emissions if the gas received at an LNG export facility has a relatively high CO_2 content.[69]

Therefore, consistent with section II.A.3 of this preamble, the EPA is proposing to revise 40 CFR 98.232(h) and 40 CFR 98.236(a)(7) to add acid gas removal vents to the list of emission sources for which facilities in the LNG Import/Export industry segment must calculate and report emissions. Facilities in this industry segment with an acid gas removal unit would use one of the four calculation methods currently provided in 40 CFR 98.233(d) and report emissions as currently provided in 40 CFR 98.236(d). Facilities in this industry segment without an acid gas removal unit would only be required to indicate that in their report. We request comment on whether all four calculation methods currently provided in 40 CFR 98.233(d) are appropriate for facilities in the LNG Import/Export industry segment and if not, how specific calculation methods could be adjusted to be more applicable to this industry segment. In addition, we request comment on whether there are other emission sources at LNG Import/Export facilities with significant emissions that should be added to subpart W (*e.g.,* glycol dehydrators), as well as whether there are other industry segments with acid gas removal units that are not reported and make up a significant portion of facility emissions.

Calculation method 4 reporting. Reporters with acid gas removal units that elect to calculate emissions using Calculation Method 4 are required to report several data elements that are inputs to the simulation software package that is used to calculate

[69] American Petroleum Institute (API). *Liquefied Natural Gas (LNG) Operations Consistent Methodology for Estimating Greenhouse Gas Emissions.* Prepared for API by The LEVON Group, LLC. Version 1.0, May 2015. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

emissions. One of the required inputs to report is the solvent weight, in pounds per gallon (40 CFR 98.236(d)(2)(iii)(L)). A variety of different solvents may be used in an acid gas removal unit (*e.g.,* chemical solvents such as monoethanolamine (MEA) and methyl diethanolamine (MDEA), physical solvents such as Selexol™ and Rectisol®), and the solubility of CO_2 varies across the different types of solvent. Requiring reporters to provide solvent characteristics provides information about the type of solvent used so the emissions calculated by the modeling run could be verified. However, the ''solvent weight'' is the only data element related to the identification of the solvent that is currently collected, and the values reported across all reporters have been inconsistent over the last few years, indicating that this data element is likely not clear to reporters (*e.g.,* some reporters appear to be providing the density of the solvent and others appear to be providing the amine concentration in weight percent). In addition, the densities of common amine-based solvents are fairly close in value, so even among reporters that are providing values within the expected range of solvent densities, we have found it difficult to use this data element to identify the solvent type. Finally, the current requirement to report solvent weight does not specify how this value should be determined, but given the precise values being reported, it appears that reporters are either measuring the solvent or reporting a specific value provided by the vendor.

Therefore, we are proposing to replace the requirement to report solvent weight with a requirement to report the solvent type and, for amine-based solvents, the general composition. Reporters would choose the type/general composition option from a pre-defined list that most closely matches the solvent type and composition used in their acid gas removal unit. The standardized response options would include the following: ''Selexol™,'' ''Rectisol®,'' ''Purisol™,'' ''Fluor Solvent℠,'' ''Benfield™,'' ''20 wt% MEA,'' ''30 wt% MEA,'' ''40 wt% MDEA,'' ''50 wt% MDEA,'' and ''Other.'' We are proposing to use commercially available trade names in this list rather than chemical compositions, as the trade names are more commonly used among acid gas removal unit operators and therefore more readily available. This proposed amendment to collect standardized information about the solvent is expected to result in more useful data that would improve verification of reported data and better characterize acid gas removal vent emissions, consistent with section II.A.4 of this preamble. It would also improve the quality of the data reported compared to the apparently inconsistent application of the current requirements. In addition, the solvent type and composition rarely change from one year to the next, so once the data element is reported the first time, most reporters would be able to copy the response from the previous year's reporting form each year. Therefore, the proposal to require reporters to select a solvent type and composition from these standardized responses is also expected to streamline and improve implementation compared to the current requirement of reporting an exact value for solvent weight, consistent with section II.B.3 of this preamble.

d. Dehydrator Vents

Dehydrators are used to remove water from produced natural gas prior to transferring the natural gas into a pipeline or to a gas processing facility. Subpart W requires reporting of GHG emissions from dehydrator vents at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas processing facilities. Emissions are determined using one of the calculation methodologies for glycol dehydrators provided in 40 CFR 98.233(e) based on the unit's annual average daily natural gas throughput. For units with an annual average daily natural gas throughput less than 0.4 MMscf per day, reporters currently use population emission factors and equation W–5 to calculate volumetric CO_2 and CH_4 emissions per 40 CFR 98.233(e)(2). For units with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day, reporters must follow the provisions under 40 CFR 98.233(e)(1), which require modeling GHG emissions using a software program (*e.g.,* AspenTech HYSYS® [70] or GRI–GLYCalc™ [71]).

The EPA has reviewed the subpart W glycol dehydrator data and reporting requirements in 40 CFR 98.236(e) and has made a preliminary determination that additional information would help to more accurately characterize emissions from glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day. Specifically, the EPA's review found no strong correlations between glycol dehydrator emissions and the operating parameters currently reported under 40 CFR 98.236(e)(1). This assessment is consistent with the results of an analysis provided to the EPA by GPA Midstream, which indicated that the correlations between vent gas flow rate, glycol circulation rate, and glycol pump type provided the most accurate approximation of dehydrator emissions.[72] While subpart W does currently collect information on glycol pump type and circulation rate for each modeled glycol dehydrator with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day, reporters are not asked to report any characteristics of their units' flash tank and still vents, including vent gas flow rate. As such, the EPA is not able to review historical subpart W dehydrator data to verify GPA Midstream's suggested correlation between vent gas flow rate, glycol circulation rate, and glycol pump type. Therefore, the EPA is proposing to add new reporting requirements to 40 CFR 98.236(e)(1), consistent with section II.A.4 of this preamble. The following new data elements are proposed to be added to subpart W for glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day:

- Flash tank control technique
- Regenerator still vent control technique
- Flash tank vent gas flow rate (standard cubic feet per hour (scfh))
- Regenerator still vent gas flow rate (scfh)
- Concentrations of CH_4 and CO_2 in flash tank vent gas (mole fraction)
- Concentrations of CH_4 and CO_2 in regenerator still vent gas (mole fraction)
- Type of stripping gas used
- Flow rate of stripping gas (standard cubic feet per minute (scfm))

These proposed additional data elements are intended to allow the EPA to derive a correlation between vent flow rate and absorbent circulation rate and better characterize emissions from glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day. Further, the EPA is proposing to require separate reporting of emissions for a modeled glycol dehydrator's still vent and flash tank vent. These vents

[70] AspenTech HYSYS® software available from AspenTech website (*https://www.aspentech.com/*).

[71] GRI–GLYCalc™ software available from Gas Technology Institute website (*https://sales.gastechnology.org/*).

[72] GPA Midstream Association. Presentation slides regarding three alternatives for possible development of emission factors for large glycol dehydrators. November 20, 2019. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

often use different control techniques, so requiring the emissions from these vents to be reported separately would ensure that future analyses accurately characterize the emissions. The proposed data elements are included in the output files from the modeling software used for glycol dehydrators and are, therefore, not expected to be difficult for reporters to implement.

Additionally, in correspondence with the EPA via e-GGRT, some reporters have expressed confusion regarding the requirements for glycol dehydrators emissions that are routed to vapor recovery and subsequently routed to a flare or regenerator firebox/fire tubes. As such, the EPA is proposing edits to the vapor recovery calculation methodology of 40 CFR 98.233(e)(5) (proposed to be moved to 40 CFR 98.233(e)(4)) to clarify that unrecovered emissions that are not routed to flares or regenerator fireboxes/fire tubes should be reported as emissions vented directly to atmosphere, while emissions that are routed to flares or regenerator fireboxes/fire tubes should be reported as flared emissions from dehydrators. Along with the proposed amendments to 40 CFR 98.233(e)(6) (proposed to be moved to 40 CFR 98.233(e)(5)) for calculating emissions from flares or regenerator fireboxes/fire tubes (discussed in section III.J.1.i of this preamble), the EPA seeks to enhance the overall quality of the data collected under the GHGRP, consistent with section II.A.5 of this preamble.

e. Liquids Unloading

Subpart W currently requires reporting of emissions from well venting for liquids unloading. Facilities calculate emissions using measured flow rates under Calculation Method 1 (40 CFR 98.233(f)(1)) or engineering equations under Calculation Method 2 for unloadings without plunger lifts (40 CFR 98.233(f)(2)) and Calculation Method 3 for unloadings with plunger lifts (40 CFR 98.233(f)(3)). Under the reporting requirements of 40 CFR 98.236(f), facilities must report whether plunger lifts were used when using Calculation Method 1 and must report the data elements used in equations W–7A and W–7B. For Calculation Methods 2 and 3, however, reporters only report a subset of the data elements used to calculate emissions in equations W–8 and W–9. Specifically, for Calculation Methods 2 and 3, reporters must provide a plunger lift indicator (*i.e.,* whether plunger lifts were used), total number of wells with well venting for liquids unloading, the total number of unloading events, and the casing diameter (Calculation Method 2) or the tubing diameter (Calculation Method 3).

In a 2019 study, Zaimes *et al.*[73] evaluated various liquid unloading scenarios, and the results indicated that differentiating emissions only on the basis of type of unloading (plunger or non-plunger lift) may not accurately assess emissions from this source. In particular, Zaimes *et al.* noted that type of unloading should be further differentiated for plunger lift unloadings between automated and manual unloadings, suggesting further granularity is necessary to properly characterize emissions. In particular, there could be significant differences in the number and duration of unloadings and, hence, differences in emissions between manual and automated plunger lift unloadings and liquids unloading emissions.

The Zaimes *et al.* study did not evaluate manual and automated non-plunger lift unloadings separately, but further differentiating non-plunger lift unloadings between manual and automated unloadings in subpart W could also improve data quality. Correspondence with reporters via e-GGRT since subpart W reporting for the onshore production segment began in 2011 indicates potentially significant differences in the number of unloadings and emissions for manual versus automated non-plunger lift unloadings. When the EPA finalized the calculation methods and reporting requirements for well venting for liquids unloading, the reporting requirements did not differentiate between manual and automated non-plunger lift unloadings. However, reporters have clearly affirmed the use of automated non-plunger lift unloadings in response to multiple inquiries the EPA has made as part of the annual report verification process.

In addition, there are several data elements used to calculate emissions from liquids unloading in equations W–8 and W–9 for Calculation Methods 2 and 3 that are not currently required to be provided. Specifically, reporters do not report well depth (Calculation Method 2) or tubing depth (Calculation Method 3), the average flow-line rate of gas, the hours that wells are left open to the atmosphere during unloading events, and the shut-in, surface or casing pressure (Calculation Method 2) or the flow-line pressure (Calculation Method 3). Requiring reporting of these data elements would improve verification of annual reports to the GHGRP and would allow the EPA and the public to replicate calculations and more confidently confirm reported calculated emissions than is currently possible.

The EPA is, therefore, proposing to revise the reporting requirements in 40 CFR 98.236(f)(1) and (2) to require reporters to include the following data elements, consistent with section II.A.4 of this preamble. In 40 CFR 98.236(f)(1), for Calculation Method 1, the EPA is proposing that reporters would identify the type of unloading as an automated or manual unloading in addition to identifying whether the unloading is a plunger lift or non-plunger lift unloading. We are also proposing that reporters would report emissions from automated unloadings separately from manual unloadings. In addition, for each individual Calculation Method 1 well that was tested during the year, we are proposing that reporters would specify the type of unloading as an automated or manual unloading under 40 CFR 98.236(f)(1)(xi)(F) or 40 CFR 98.236(f)(1)(xii)(F), as applicable.

For non-plunger lift unloadings that use Calculation Method 2 in 40 CFR 98.233(f)(2), the EPA is proposing that reporters would identify the type of non-plunger lift unloading as an automated or manual non-plunger lift unloading and that reporters would report emissions and activity data separately for each unloading type. In addition, for all non-plunger lift unloadings, the EPA is proposing to add requirements in 40 CFR 98.236(f)(2)(ix) (proposed to be moved to 40 CFR 98.236(f)(2)(xi)) to report the average well depth for all wells in the sub-basin (WD_p) and the average shut-in pressure or surface pressure for wells with tubing production, or average casing pressure for wells with no packers for all wells in the sub-basin (SP_p).

For plunger lift unloadings that use Calculation Method 3 in 40 CFR 98.233(f)(3), the EPA is proposing that reporters would identify the type of plunger lift unloading as an automated or manual plunger lift unloading and that reporters would report emissions and activity data separately for each unloading type. In addition, for all plunger lift unloadings, the EPA is proposing to add requirements in 40 CFR 98.236(f)(2)(x) (proposed to be moved to 40 CFR 98.236(f)(2)(xii)) to report the average tubing depth to plunger bumper for all wells in the sub-basin (WD_p) and the average flow-line pressure for all wells in the sub-basin (SP_p). Finally, for all unloadings that use Calculation Method 2 or 3, the EPA is proposing to add requirements in 40

[73] Zaimes, G.G. *et al.* ''Characterizing Regional Methane Emissions from Natural Gas Liquid Unloading.'' *Environ. Sci. Technol.* 2019, 53, 4619–4629. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

CFR 98.236(f)(2)(ix) and (x) to report the average flow-line rate of gas for all wells in the sub-basin (SFR_p) and cumulative number hours that all wells in the sub-basin are left open to the atmosphere during unloading events ($HR_{p,q}$), respectively.

f. Blowdown Vent Stacks

Subpart W currently requires reporting of blowdowns either using flow meter measurements (40 CFR 98.233(i)(3)) or using unique physical volume calculations by equipment or event types (40 CFR 98.233(i)(2)). Stakeholders have indicated that there is some confusion regarding the reference to ''distribution'' pipelines in the descriptions of the ''facility piping'' and ''pipeline venting'' categories because compressor stations are not associated with distribution pipelines. Therefore, the EPA is proposing to revise the descriptions of the facility piping and pipeline venting categories to reduce confusion regarding which equipment or event type category is appropriate for each blowdown, consistent with section II.A.5 of this preamble. Our intent is that the ''facility piping'' equipment category is limited to unique physical volumes of piping (*i.e.,* piping between isolation valves) that are located entirely within the facility boundary. Conversely, the intent for the ''pipeline venting'' equipment category is that a portion of the unique physical volume of pipeline is located outside the facility boundary and the remainder, including the blowdown vent stack, is located within the facility boundary. The proposed revisions to the equipment type descriptions would clarify these distinctions. Additionally, we are proposing to remove the reference to ''distribution'' pipelines because we did not intend to limit the pipeline venting category to unique physical volumes that include such pipelines. We agree with the industry stakeholders that facilities subject to the blowdown vent stack reporting requirements typically are connected to other pipelines such as gathering pipelines or transmission pipelines, and on-site blowdowns from sections of these pipelines should be reported. Finally, we note that for the ''facility piping'' equipment category and the ''pipeline venting'' equipment category, the phrase ''located within a facility boundary'' generally refers to being part of the facility as defined by the existing provisions of subpart A or subpart W, as applicable. In other words, blowdowns from unique physical volumes of gathering pipeline that are entirely considered to be part of the ''facility with respect to onshore petroleum and natural gas gathering and boosting'' as defined in 40 CFR 98.238 would be assigned to the ''facility piping'' equipment category. The ''pipeline venting'' equipment category would only apply if the unique physical volume includes some sections of gathering pipelines that are not part of the ''facility with respect to onshore petroleum and natural gas gathering and boosting'' as defined in 40 CFR 98.238.

g. Atmospheric Storage Tanks

Open thief hatches. Facilities in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments are required to report CO_2 and CH_4 emissions (and N_2O emissions when flared) from atmospheric pressure fixed roof storage tanks receiving hydrocarbon liquids (hereafter referred to as ''atmospheric storage tanks''). The purpose of a thief hatch on an atmospheric storage tank is generally to allow access to the contents of the tank for sampling, gauging, and determining liquid levels. The thief hatch also works along with the vent valve to maintain pressure on the tank while preventing excessive vacuum from collapsing the tank. The EPA previously evaluated emissions from atmospheric storage tanks as part of the 2016 amendments to subpart W (81 FR 86500, November 30, 2016) and determined that the subpart W calculation methodology in 40 CFR 98.233(j) already includes emissions from thief hatches or other openings on atmospheric storage tanks in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. The subpart W calculation methodologies for controlled atmospheric storage tanks include procedures for determining emissions from storage tanks with a vapor recovery system (40 CFR 98.233(j)(4)) and storage tanks with a flare (40 CFR 98.233(j)(5)). The procedure for determining emissions from a tank with a vapor recovery system instructs reporters to adjust the storage tank emissions downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data (40 CFR 98.233(j)(4)(i)). The procedure for determining emissions from an atmospheric storage tank with a flare references 40 CFR 98.233(n), which instructs reporters to use engineering calculations based on process knowledge, company records, and best available data to determine the flow to the flare if the flare does not have a continuous flow measurement device. If a reporter sees emissions from a thief hatch or other opening on a controlled atmospheric storage tank during an equipment leak survey conducted using OGI, the reporter should consider that information as part of the ''best available data'' used to calculate emissions from that storage tank.

However, it appears that emissions from open thief hatches on atmospheric storage tanks may not be accurately portrayed in subpart W, as many reporters claim 100 percent capture efficiency from vapor recovery systems and flares. In order to alleviate any reporting confusion, the EPA is proposing several clarifying edits to 40 CFR 98.233(j)(4) and (5), consistent with section II.A.5 of this preamble. We are proposing to specifically state in each paragraph that emissions during times of reduced capture efficiency are required to be evaluated to determine if adjustments are needed to the calculated recovered mass from vapor recovery units or flare feed gas volumes. Reduced capture efficiency may occur during periods when the control device is not operating or is bypassed and at times when the control device is operating, such as open thief hatches. The emissions that are not captured by a vapor recovery system or sent to a flare must be considered when calculating emissions from atmospheric storage tanks vented directly to the atmosphere.

The EPA is also proposing revisions to the atmospheric storage tank reporting requirements in 40 CFR 98.236(j) with regard to open thief hatches. Specifically, the EPA is proposing to require reporting of the number of controlled tanks with open or unseated thief hatches within the reporting year, as well as the total volume of gas vented through the open or unseated thief hatches. With these new reporting elements, the EPA seeks to quantify the impact of open thief hatches on atmospheric storage tanks and enhance the overall quality of the data collected under the GHGRP, consistent with section II.A.4 of this preamble.

Malfunctioning dump valves and atmospheric storage tanks with flares. For Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting facilities with atmospheric storage tank emissions calculated using Calculation Method 1 (40 CFR 98.233(j)(1)) or Calculation Method 2 (40 CFR 98.233(j)(2)), reporters must also follow the procedures in 40 CFR 98.233(j)(6) and use equation W–16 to calculate emissions from occurrences of gas-liquid separator dump valves not closing properly. Equation W–16 estimates the annual volumetric GHG emissions at standard conditions from each storage tank resulting from the malfunctioning dump valve on the gas-liquid separator using a correction factor, the total time the dump valve did not close properly in the calendar year, and the hourly storage tank emissions. Per the definition of the variable ''E_n'' in equation W–16, the input hourly storage tank emissions should be those calculated using Calculation Methods 1 or 2 and should be adjusted downward by the magnitude of emissions recovered using a vapor recovery system, if applicable. However, the definition of the variable ''E_n'' in equation W–16 does not include the procedure to be used for emissions from malfunctioning dump valves and atmospheric storage tanks that are flared. In order to address any confusion for reporters, the EPA is proposing to amend the definition of the variable ''E_n'' in equation W–16 to include flared storage tank emissions as determined in paragraph 40 CFR 98.233(j)(5), consistent with section II.A.5 of this preamble. The EPA is also proposing to revise the equation variables (particularly the subscripts) in equation W–16 to clarify the intent of this equation. We are proposing to revise the variable ''E_n'' to ''$E_{s,i}$'' to further clarify that these are the volumetric atmospheric storage tank emissions determined using the procedures in 40 CFR 98.233(j)(1) through (5). We are also proposing to replace the ''n'' and ''p'' subscripts in the other variables with a ''dv'' subscript to indicate that these are the emissions from periods when the gas-liquid separator dump valves were not closed properly and that the emissions from these periods should be added to the emissions determined using the procedures in 40 CFR 98.233(j)(1) through (5).

Composition of hydrocarbon liquids. Under 40 CFR 98.236(j)(1)(vii) and (viii), reporters with atmospheric storage tank emissions calculated using Calculation Method 1 or Calculation Method 2 are required to provide the minimum and maximum concentrations (mole fractions) of CO_2 and CH_4 in the tank flash gas. Reporting of emissions and activity data for atmospheric storage tanks is aggregated at the sub-basin or county level, and the minimum and maximum flash gas concentrations were expected to provide the EPA with a broad characterization of the often-significant number of tanks reported for each sub-basin or county. However, through correspondence with reporters via e-GGRT, the EPA has found that the minimum and maximum flash gas concentrations do not accurately represent the majority of atmospheric storage tanks within the reported sub-basins and counties. Thus, the EPA is proposing to revise these two reporting requirements to request the flow-weighted average concentration (mole fraction) of CO_2 and CH_4 in the flash gas, rather than the minimum and maximum values. Consistent with section II.A.4 of this preamble, the EPA expects that these revisions would improve both the representative nature of the data collected and the process of verifying annual reported atmospheric storage tanks emissions data under the GHGRP.

h. Associated Gas Venting and Flaring

Associated gas venting. Associated gas venting or flaring is the venting or flaring of natural gas that 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. Venting associated gas involves directly releasing associated gas into the atmosphere at the well pad or tank battery. Flaring associated gas is a common, and usually preferred, alternative to venting for safety and environmental reasons. Subpart W requires reporters to calculate annual emissions from associated gas venting and flaring using equation W–18, which uses the gas-to-oil ratio (GOR), volume of oil produced, and volume of associated gas sent to sales to calculate the volume of gas vented. Associated gas venting emissions are then calculated using the results of equation W–18 and the gas composition determined using 40 CFR 98.233(u), and associated gas flaring emissions are calculated by applying the calculation method of flare stacks in 40 CFR 98.233(n) to the associated natural gas volume and gas composition determined for the associated gas stream routed to the flare.

As discussed further in section III.J.1.i of this preamble, the EPA is proposing several amendments to the calculation and reporting requirements for flare stacks that would impact associated gas flaring emissions. One of the proposed amendments would provide for the use of continuous flow measurement devices for the purposes of calculating flared emissions. Similarly, for associated gas venting emissions, we are proposing provisions to specify that if a continuous flow measurement device is present, it must be used to determine the volume of gas vented rather than equation W–18. We are proposing corresponding reporting requirements for associated gas venting emissions, including requiring an indication of whether a continuous flow monitor or continuous composition analyzer was used and the flow-weighted mole fractions. Finally, we are proposing to specify that if all of the volumetric emissions from associated gas venting and flaring in the sub-basin were determined using a continuous flow measurement device rather than equation W–18 (*i.e.,* equation W–18 was not used for any wells in the sub-basin), then reporting of the GOR, the volume of oil produced, and the volume of gas sent to sales for wells with associated gas venting or flaring is not required for that sub-basin.

Oil and gas volumes. As noted previously in this section, subpart W requires reporters to calculate annual emissions from associated gas venting and flaring using equation W–18. Two of the inputs in the equation are the volume of oil produced and volume of associated gas sent to sales for each well in the sub-basin during time periods in which associated gas was vented or flared. However, based on the values reported, there seems to be confusion among some reporters regarding the inputs to these equations. For example, for some reporters, when the reported volume of gas sent to sales during time periods in which associated gas was vented or flared under 40 CFR 98.236(m)(6) is summed across all sub-basins at the facility, the total is the same as the total volume of gas sent to sales for the facility reported under 40 CFR 98.236(aa)(1)(i)(B). If these reporters are accurately reporting the volume of gas sent to sales and using that volume in equation W–18, then the associated gas venting and flaring emissions are likely overstated, as it is unlikely that all wells are venting or flaring associated gas 100 percent of the time. If the reporters are using accurate volumes of gas sent to sales during time periods in which associated gas was vented or flared for their emissions calculations but reporting total gas sent to sales, then the activity data reported do not match the emissions, leading to an inconsistent data set. Therefore, the EPA is proposing to add the word ''only'' to the definitions of the terms $V_{p,q}$ and $SG_{p,q}$ in equation W–18 (40 CFR 98.233(m)(3)) and to the reporting requirements for those data elements in 40 CFR 98.236(m)(5) and (6). Consistent with section II.A.5 of this preamble, these proposed amendments would reduce reporter confusion regarding the volumes that should be used in the emissions calculations and the volumes that should be reported.

i. Flare Stack Emissions

Flare stacks are an emission source type subject to emissions reporting by facilities in seven of the ten industry segments in the Petroleum and Natural Gas Systems source category.[74]

Total CO_2, CH_4, and N_2O emissions from each flare are required to be calculated using the methodology specified in 40 CFR 98.233(n). In addition to calculating total emissions from a flare, reporters must also separately calculate the flared emissions from several types of emission sources.[75] The methodology for calculating source-specific flared emissions is specified in the applicable paragraph of 40 CFR 98.233 for each source type. The procedures in the source-specific paragraphs of the rule cross-reference the calculation procedures in 40 CFR 98.233(n), but they also specify that the volume and composition of the gas routed to the flare are required to be determined according to the procedures for estimating vented emissions from the specific source type. For example, 40 CFR 98.233(e)(6) specifies that the volume and gas composition to use in calculating flared emissions from dehydrators must be determined according to the procedures for calculating vented emissions from dehydrators as specified in 40 CFR 98.233(e)(1) through (5). Since source-specific flared emissions often are a portion of the total emissions from a flare, 40 CFR 98.233(n)(9) specifies that the total CO_2, CH_4, and N_2O for a particular flare must be adjusted downward by the amount of the source-specific emissions that are calculated for the same flare; this ensures that emissions from a flare are not double counted (*i.e.,* reported for both the flare stacks source type and another emission source type). The resulting CO_2, CH_4, and N_2O emissions to report for that flare according to 40 CFR 98.236(n)(9) through (11) should be only what is left after subtracting all of the source-specific flared emissions from the total emissions.

This calculation and reporting paradigm often means zero mass emissions are reported for the flare because all of the mass emissions are reported as flared emissions from other source types. However, even when the only streams routed to a flare are from source types that are subject to flared emissions reporting, the flare name or ID and all activity data related to the streams that are routed to the flare and the flare operating characteristics still must be reported under 40 CFR 98.236(n). These activity data include the volume of gas routed to the flare, average CO_2 and CH_4 mole fractions in the flared gas, flare combustion efficiency, fraction of flared gas routed to the flare when it was unlit, and indicators of whether a continuous flow measurement device and a continuous gas analyzer were used on the gas stream routed to the flare. These flare ID and activity data reporting requirements are specified in 40 CFR 98.236(n)(1) through (8). In the rare cases that a CEMS is used on the outlet of a flare, then according to 40 CFR 98.236(n)(12), only the flare ID and the measured CO_2 emissions must be reported.

Reporting requirements for flared emissions. Many reporters have provided information through the GHGRP Help Desk and in correspondence with the EPA via e-GGRT indicating that reporters are not interpreting the reporting requirements as written and as the EPA intended for flares that receive gas from sources that are subject to source-specific flared emissions reporting (*e.g.,* atmospheric tanks). A key misconception is that the adjustment requirement in 40 CFR 98.233(n)(9) applies to all flare data, not just the mass emissions (as intended). Thus, some reporters provide information for a flare only if some of the mass emissions from the flare are due to combustion of gas from source types that are not subject to source-specific flared emissions reporting (*i.e.,* miscellaneous flared sources). Although these reporters generally correctly report the mass emissions from the flare that are due to the miscellaneous flared sources, they incorrectly limit their activity data reporting to those same streams. The EPA has procedures in its verification process to identify such errors; if errors are identified, the EPA notifies the reporter, who can resolve the issue by correcting the data and resubmitting their annual GHG report. Some reporters have also indicated that it is confusing to report activity data for a flare in one table in the reporting form (*i.e.,* Table N.1), but to report the emissions in different tables; they suggest that it would be clearer to report all flare activity data and emissions related to a particular emission source type together in one location. One industry stakeholder, GPA Midstream, also suggested that flare activity data should be reported in the same manner that flared emissions are reported. In other words, instead of providing a single comprehensive record of the activity data per flare as is currently required by 40 CFR 98.236(n), the activity data for flared streams for a particular emission source (*e.g.,* associated gas or atmospheric storage tanks) should be reported with the flared emissions for the same emission source type. According to GPA Midstream, this reporting approach would be simpler and easier for reporters to follow than the current requirements.[76] We reviewed the flare reporting requirements based on this feedback, and we are proposing several revisions to the reporting requirements to improve the quality of the reported data, consistent with section II.A.4 of this preamble.

First, we are proposing to modify the reporting requirements so that the existing requirements in 40 CFR 98.236(n) would apply only to flares that receive gas from miscellaneous flared sources. The activity data to report would be limited to the streams from the miscellaneous flared sources, and the CO_2, CH_4, and N_2O emissions to report would be the emissions that are calculated from combustion of the same streams. In addition, we would add comparable activity data reporting requirements to the reporting required for all of the source types for which flared emissions reporting is currently required (*e.g.,* 40 CFR 98.236(e) for dehydrators, 40 CFR 98.236(g) for completions and workovers with hydraulic fracturing). The activity data reporting would be on the same basis as the emissions reporting. For example, activity data for glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day would be related to the flared streams from each dehydrator because flared emissions are reported per dehydrator. Activity data to be

[74] Flare stacks are an emission source type subject to emissions reporting by facilities in the following industry segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Import and Export Equipment, and LNG Storage.

[75] Facilities separately calculate the flared emissions from the following types of emission sources (if required for the applicable industry segment, per 40 CFR 98.232): dehydrator vents, well venting during completions and workovers with hydraulic fracturing, gas well venting during completions and workovers without hydraulic fracturing, onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, transmission storage tanks, well testing venting and flaring, and associated gas venting and flaring.

[76] Letter from Matt Hite, GPA Midstream Association, to Mark de Figueiredo, U.S. EPA, Re: Additional Information on Suggested Part 98, Subpart W Rule Revisions to Reduce Burden. September 13, 2019. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

reported for associated gas streams, on the other hand, would be aggregated over all associated gas streams routed to flares in a sub-basin because flared associated gas emissions are reported per sub-basin. In addition, for completions and workovers with hydraulic fracturing, flaring during the initial flowback period may not be possible; therefore, some of the wells that report as part of a ''flared'' well type combination because most of the gas is flared may also include emissions from gas that is vented before flaring begins. To improve our understanding of the characteristics of the ''flared'' emissions from completions and workovers with hydraulic fracturing, we are proposing that reporters would indicate in 40 CFR 98.236(g)(10)(i) whether the total emissions reported under 40 CFR 98.236(g)(8) and (9) include emissions from venting during the initial flowback period. These proposed amendments would better align the flared emissions and activity data for source types for which flared emissions reporting is currently required.

Second, in the current rule, 40 CFR 98.236(n)(7) and (8) require reporting of the CH_4 and CO_2 mole fractions in feed gas that are used in equations W–19 and W–20 to calculate total emissions from a flare. The intent was for reporters to provide the average values used to calculate total emissions from the flare. However, the rule language is not clear on this point, and it appears some reporters have interpreted these data elements in different ways. It appears that one common interpretation is to report the mole fraction for the emissions source type with the most flared emissions. Because that interpretation does not align with the EPA's intent, clarification of this reporting requirement is needed to improve the verification process. Thus, we are proposing to modify these reporting elements, both in 40 CFR 98.236(n) (proposed to be moved to 40 CFR 98.236(n)(1)(ix) and (x)) and for all the proposed activity data reporting elements for individual source types that are subject to source-specific flared emissions reporting as described above. Specifically, we are proposing to require the flow-weighted annual average mole fraction of CH_4 over all streams from a particular emission source type that are used in equation W–19 to calculate the reported flared CH_4 emissions from that emission source type (and used in equation W–20 to calculate CO_2 emissions). For example, if a flare receives gas from an acid gas removal vent and a blowdown vent stack, both of which are miscellaneous flared sources, then the CH_4 mole fraction to report should be the flow-weighted annual average value from the acid gas removal vent and each blowdown through the blowdown vent stack. The CO_2 mole fractions to report would also be a flow-weighted annual average determined in the same manner.

Third, reporters are required to use equation W–40 to calculate N_2O emissions from flares. Variables in the equation are the volume of gas routed to the flare and the HHV of the gas. The volume of gas routed to the flare must be reported, but the HHV is not reported. As a result, when reported N_2O emissions differ significantly from the amount that would be expected if using the default HHV, it can be difficult for the EPA to determine whether the reported emissions are an error or if the difference is due to the use of a site-specific HHV. To improve the verification process and potentially reduce the amount of communication with reporters via e-GGRT, we are proposing to add a reporting element that would require reporters to indicate whether each reported N_2O value is based on the default HHV, a site-specific HHV(s), or both the default and site-specific HHVs. The proposed reporting element would be added in 40 CFR 236(n)(4)(iv) for miscellaneous flared sources, and it would be included as one of the proposed activity data reporting elements for each of the other source types that are subject to source-specific flared emissions reporting. Providing an option to indicate that both types of HHVs are used is needed because some reported flared N_2O emissions are aggregated values over all flares in a sub-basin or county (*e.g.,* for atmospheric tanks), and a reporter may choose to use different methods for the flares in each sub-basin or county. In addition to improving the verification process, knowledge of site-specific HHVs would allow the EPA to assess how well the default HHV characterizes flared gas streams in different industry segments and basins.

Fourth, an additional finding from the currently reported data is that a number of facilities in the Onshore Petroleum and Natural Gas Production industry segment, the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, and the Onshore Natural Gas Processing industry segment report significant amounts of emissions from miscellaneous flared sources. It is not clear what sources are generating the large amount of gas that is routed to these flares. To help clarify the source types that are generating large amounts of flared gas, we are proposing in 40 CFR 98.236(n)(1)(v) to require reporting by facilities in these three industry segments of an estimate of the fraction of the gas burned in the flare that is obtained from other facilities specifically for flaring as opposed to being generated in on-site operations. As an example, if an owner or operator has an onshore petroleum and natural gas production and an onshore petroleum and natural gas gathering and boosting facility in the same basin and routes associated gas from wells in the onshore petroleum and natural gas production facility to a flare that is defined as part of the onshore petroleum and natural gas gathering and boosting facility, then the flared emissions would be reported by the onshore petroleum and natural gas gathering and boosting facility as emissions from ''other flare stacks'' sources under the current rule (or from miscellaneous flared sources under the proposed amendments). If the other gas streams routed to the flare are from sources at the onshore petroleum and natural gas gathering and boosting facility, then for this proposed reporting requirement, the onshore petroleum and natural gas gathering and boosting facility report would include an estimate of the fraction of the total gas burned in the flare that is associated gas from the onshore petroleum and natural gas production facility. We request comment on the types of sources that may be generating these large emissions and whether other reporting elements could be specified that would better achieve the EPA's objective of clearly characterizing the sources of flared emissions from facilities in the three industry segments identified above. For example, one potential additional reporting element could be a requirement to describe the primary source of miscellaneous flared emissions for any flare that reports CO_2 emissions greater than an amount that would be determined if such a reporting requirement were finalized.

Finally, one objective of the current flare reporting requirements is to obtain information on the total number of flares and their operating characteristics. If the proposed changes to flare activity data requirements as described previously in this section were finalized, then additional amendments to reporting requirements would be needed to continue collecting flare-specific information. Thus, we are proposing to require reporting of a list of all flare IDs per facility and add reporting for a series of flare-specific data elements. One of the proposed flare reporting elements is the total volume of gas routed to the flare. This information is consistent with current reporting requirements and would be helpful in conducting verification of other reported flare data because the sum of the total volume from all flares should be equal to the sum of the disaggregated volumes reported for all flared emissions source types. The total volumes per flare also would provide information on the range of flare sizes in different industry segments and would be useful in analyses for potential future policy decisions related to flares. Another of the proposed flare reporting elements is a list of the subpart W emission source types that routed emissions to the flare stack. This proposed data element would improve verification of other reported flare data as well as provide information regarding the types of sources that are combined and routed to the same flare. We are also proposing a few new flare-specific reporting elements to help us better understand the state of flaring in the industry, such as an indication of the type of the flare (*e.g.,* open ground-level flare, enclosed ground-level flare, open elevated flare, or enclosed elevated flare) and the type of flare assist (*e.g.,* unassisted, air-assisted (with indication of single-, dual-, or variable-speed fan), steam-assisted, or pressure-assisted). Further, researchers conducting remote sensing tests of emissions from flares have reported detecting much larger quantities of emissions from un-lit flares than is evident from the GHGRP data. To help us better understand the prevalence of emissions from un-lit flares, we are proposing to add requirements to report an indication of whether the flare has a continuous pilot or autoigniter, whether the presence of flame is continuously monitored if the flare has a continuous pilot, and an indication of how the reporter identifies periods when the flare is not lit if the flare does not have a continuous pilot. These proposed data elements would be added in 40 CFR 98.236(n). This paragraph of subpart W would be rearranged into two subparagraphs. The first subparagraph, 40 CFR 98.236(n)(1), would include the current activity data and emissions data reporting elements but would be revised to be specific to miscellaneous flared sources (as discussed previously), and the proposed flare-specific reporting elements would be added in the second subparagraph, 40 CFR 98.236(n)(2).

Definition of flare stack emissions. In response to a verification message in e-GGRT, one reporter noted that the definition of the term ''flare stack emissions'' in 40 CFR 98.238 does not include CO_2 that is in streams routed to the flare. The term is currently defined to mean ''CO_2 and N_2O from partial combustion of hydrocarbon gas sent to a flare plus CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in flares.'' Based on this definition, the reporter concluded that CO_2 in streams routed to the flare are not to be reported as flare stack emissions. However, the current definition, which was added to the 2010 Final Revisions Rule after consideration of comments on the 2010 re-proposal, does not clearly convey the EPA's intent that the CO_2 that enters a flare should be reported as flare stack emissions. This intent is evident from the fact that equation W–20 includes a term for the inlet gas volume times the CO_2 mole fraction in the inlet gas. Additionally, in a response to a comment on the 2010 proposed rule, the EPA clearly stated that the total quantity of CO_2, including both combusted CO_2 (*i.e.,* CO_2 created in the flare) and uncombusted CO_2 (*i.e.,* CO_2 that entered and simply passed through the flare), is to be calculated. Another issue with the current definition is that it implies N_2O emissions only result from partial combustion of hydrocarbons in the gas routed to the flare. This is likely the primary mechanism for generating N_2O emissions when combusting fuels that include nitrogen-containing compounds. However, natural gas and field gas have negligible amounts of fuel-bound nitrogen. For combustion of these fuels, it appears the N_2O is generated primarily from converting thermal NO_X under certain operating conditions in the flare. To eliminate the unintended inconsistency between the definition and the intent that CO_2 in gas routed to the flare is to be reported as emissions from the flare, to clarify the requirement to calculate and report total CO_2 that leaves the flare, and to clarify the source of flared N_2O emissions, we are proposing to revise the definition of the term ''flare stack emissions'' to mean CO_2 in gas routed to a flare, CO_2 from partial combustion of hydrocarbons in gas routed to a flare, CH_4 resulting from the incomplete combustion of hydrocarbons in gas routed to a flare, and N_2O resulting from operation of a flare.

Calculation methodology for flared emissions. In addition to proposing changes to the flare reporting requirements as discussed above, we are also proposing to clarify language in the emission calculation procedures of 40 CFR 98.233(n) that we believe may be ambiguous for flares that do not have CEMS, consistent with section II.A.5 of this preamble. The procedures for determining the volume and composition of gas routed to flares for use in the emission calculation equations for a particular emission source type are currently specified in two places for each source type. Each source type-specific paragraph in 40 CFR 98.233 specifies calculation methodologies for that emissions source type, as do 40 CFR 98.233(n)(1) and (2). The procedures in the source type-specific requirements specify only that the volume and composition of the flared gas are to be determined using the procedures for estimating vented emissions from that source type, but they also cross-reference the calculation method in 40 CFR 98.233(n) for determining the emissions from the flaring of that gas stream. However, 40 CFR 98.233(n)(1) and (2) specify that if continuous flow or composition measurement devices are used on the gas to the flare, then data from those devices must be used to calculate emissions; otherwise, estimates may be used. The intent is that the procedures in 40 CFR 98.233(n) should take precedence, but this may not be clear to all reporters. Additionally, the procedures for continuous measurement devices in 40 CFR 98.233(n)(1) and (2) refer to devices ''on the flare'' or ''on gas to the flare.'' The intent is that the procedures should apply to devices regardless of whether they are on a stream routed from a single emission source or on a stream routed to a flare that includes streams combined from multiple emission source types, but this is not explicitly described. A third potential ambiguity is that procedures in 40 CFR 98.233(n)(1) and (2) do not specify how to disaggregate data collected with a continuous measurement device when the device measures a combined stream from more than one emission source type.

To clarify these requirements, we are proposing to specify all of the potential options for determining volume and composition of gas to the flare(s) in the applicable sections of 40 CFR 98.233 for each of the emission source types that have flared emissions reporting requirements. In general, the volume of gas would be determined by a continuous flow measurement device, if available, or using the methods for determining vented emissions for the applicable emission source type. If the measured volume includes flow from multiple source types routed to the same flare, reporters would use process knowledge and best available data to determine the portion of the total flow from each emission source type.[77] Similarly, the composition of the gas from the emission source type would be determined by a continuous composition analyzer, if available, or using the methods for determining the composition of the vented emissions for the applicable emission source type. Alternatively, if multiple source types are routed to one flare and the gas routed to the flare from each of those source types is expected to have similar compositions, the reporter could measure the composition of the total gas to the flare using a continuous composition analyzer just upstream of the flare and apply the results to each of the applicable source types. The source-specific sections of 40 CFR 98.233 would then cross-reference only 40 CFR 98.233(n)(3) through (8) for the applicable calculation equations and procedures for determining combustion efficiency, converting volumetric emissions to mass emissions, and the separate procedures that apply if a CEMS is used on gases from the flare. As part of this proposed amendment, we would also remove 40 CFR 98.233(n)(9); with these proposed calculation methodology clarifications and the reporting clarifications described earlier in this section, a general direction to correct flare emissions to avoid double counting would no longer be necessary (however, a provision specifically to avoid double counting of CO_2 emissions from acid gas removal units that route emissions to a flare would still be needed, as discussed later in this section). We recognize that the proposed changes introduce some repetition to the regulatory text overall because the requirements for each emission source type are similar. However, clearly describing the applicable procedures for each source type separately rather than trying to generally describe a single set of consolidated procedures would make the rule easier for reporters to understand, and we request comment on whether the proposed changes achieve this goal.

Calculation methodologies for flared emissions from acid gas removal vents. We are also proposing source type-specific provisions for calculating and reporting emissions from acid gas removal vents routed to flares that are related to the proposed calculation methodology clarifications described earlier in this section, consistent with section II.A.5 of this preamble. Reporters are currently required to report the CO_2 removed from the natural gas as CO_2 emissions from acid gas removal vents, and that quantity is not affected (*i.e.,* the CO_2 is not converted to another compound) when the acid gas vent stream is routed to a flare, engine, or sulfur recovery plant. Therefore, the current rule does not require reporters to separate emissions vented directly to the atmosphere from emissions routed through a flare, engine, or sulfur recovery plant. Instead, as noted earlier in this section, 40 CFR 98.233(n)(9) specifies that the total CO_2 for a flare that receives gas from acid gas removal vents must be adjusted downward by the amount of the CO_2 emissions that are calculated for those acid gas removal vents. In other words, the CO_2 emissions that are calculated for the acid gas removal vents are reported under 40 CFR 98.236(d) and not under 40 CFR 98.236(n).

Because the reporting of emissions from acid gas removal vents routed to a flare is addressed differently in the current rule from the reporting of flared emissions for all other source types, we are proposing amendments for acid gas removal vents routed to flares that are slightly different than the proposed amendments for other sources. First, as noted previously in this section, we are proposing to remove 40 CFR 98.233(n)(9) because it would be unnecessary for other source types in light of the other amendments previously described. However, for acid gas removal vents routed to flares, an adjustment would still be necessary for CO_2 emissions. Therefore, we are proposing to add provisions in 40 CFR 98.233(d)(12) for calculating emissions from acid gas removal vents routed to flares (as described in more detail in the next paragraph) and proposing to add a clarification to the requirement to report CO_2 emissions from flare stacks (40 CFR 98.236(n)(9), proposed to be moved to 40 CFR 98.236(n)(1)(xi)) indicating that the reported CO_2 emissions should not include emissions from acid gas removal vents reported under 40 CFR 98.236(d)(1)(v) to prevent double counting of emissions.

Second, we reviewed the calculation methods for acid gas removal vents and flares, and we are proposing amendments to more closely align the methods for acid gas removal vents routed to flares. For acid gas removal vents, Calculation Method 1 (40 CFR 98.233(d)(1)) is required to be used if a vent has a CEMS installed, and Calculation Method 2 (40 CFR 98.233(d)(2)) is required to be used if a vent has a continuous flow monitor. If there is no CEMS or flow monitor installed, then reporters currently must use Calculation Methods 3 or 4 (40 CFR 98.233(d)(3) or (4), which are estimation methods based on the volume of natural gas treated and the acid gas contents of the inlet and outlet natural gas. However, because these are estimation methods rather than methods based on measurements, the EPA has found through the verification process and correspondence with reporters via e-GGRT that these methods can sometimes result in estimated volumetric CO_2 emissions from acid gas removal vents routed to a flare that are greater than the reported total volume of gas routed to that flare. Therefore, we are proposing new provisions in 40 CFR 98.233(d)(12) for reporters routing acid gas removal vents to flares. The first set of amendments would apply to acid gas removal vents that are routed to any dedicated flare as well as acid gas removal vents comingled with emissions from other source types and routed to flares with no continuous monitors for either the flow or composition of the comingled gas stream. In either of these cases, reporters would continue to calculate CO_2 emissions using one of the Calculation Methods 1 through 4, as applicable for the type of monitoring available, and would continue to report those emissions under 40 CFR 98.236(d) rather than 40 CFR 98.236(n). Reporters would also incorporate the flow rate and composition of the acid gas removal vent stream into the calculation of total flare emissions from miscellaneous flared sources. For acid gas removal vent streams comingled with emissions from other source types and routed to flares with continuous monitoring of the flow and/or composition of the comingled gas stream, we are proposing that reporters would first determine the total emissions from the flare stacks and then use site-specific engineering estimates based on best available data to estimate the portion of the total flared CO_2 emissions that is from the acid gas removal vents. In this case, we are proposing that reporters would select ''Routed to a flare [§ 98.233(d)(12)(ii)]'' as the calculation method. We are also proposing new reporting requirements for acid gas removal vents routed to flares; in addition to the current requirements to report the CO_2 emissions under 40 CFR 98.236(d)(1)(v),

[77] The proposed revisions to 40 CFR 98.233(n)(1) would remove ''company records'' from the existing list of information upon which engineering calculations may be based. In this instance, the use of ''company records'' was intended to refer generally to facility records rather than the specific type of records as defined in 40 CFR 98.3, and we expect that general facility records are covered by the proposed inclusion of process knowledge and best available data. Therefore, we are proposing to remove the defined term ''company records'' solely to avoid confusion for reporters; this amendment is not intended to indicate a change in the engineering calculations.

we are proposing to add the identification of the flare to which the acid gas removal vent is routed.

j. Compressors

Compressors are used across the petroleum and natural gas industry to raise the pressure of and convey natural gas or CO_2. The two main types of compressors used in the industry are centrifugal compressors and reciprocating compressors. Subpart W requires Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting facilities to calculate compressor emissions using population emission factors. Population emission factors are multiplied by the count of equipment, in this case compressors of a certain type, to calculate emissions. For the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Equipment industry segments, subpart W requires facilities to annually measure the emissions from the compressor sources applicable to the mode the compressor is in at the time of the measurement; facilities also have the option to continuously measure emissions from a compressor source. The annual measurements are called ''as found'' measurements because the compressors are to be measured in the mode in which they are found when the measurements are made. The ''as found'' measurements are required for each centrifugal and reciprocating compressor at least annually, but only for those compressor emission sources that have measurement requirements for the mode in which they are found (*i.e.,* the defined ''compressor mode-source combinations''), as described in the following paragraph.

Subpart W defines the following ''compressor sources'': wet seal degassing vent (for centrifugal compressors only); rod packing emissions (for reciprocating compressors only); blowdown valve leakage through the blowdown vent (for both centrifugal and reciprocating compressors) and unit isolation valve leakage through the open blowdown vent without blind flanges (for both centrifugal and reciprocating compressors). Subpart W also defines the following ''compressor modes'': operating-mode (for both centrifugal and reciprocating compressors), standby-pressurized-mode (for reciprocating compressors only [78]), and not-operating-depressurized-mode (for both centrifugal and reciprocating compressors). Some compressor sources may only release emissions during certain compressor modes. Therefore, subpart W uses the term ''compressor mode-source combination'' to refer to the specific compressor sources that must be measured based on the mode in which the compressor is found.

For centrifugal compressors, subpart W requires measurement in the following compressor mode-source combinations: wet seal oil degassing vents in operating-mode, blowdown valve leakage through the blowdown vent in operating-mode, and unit isolation valve leakage through an open blowdown vent without blind flanges in not-operating-depressurized-mode. For reciprocating compressors, subpart W requires measurement in the following compressor mode-source combinations: rod packing emissions in operating-mode, blowdown valve leakage through the blowdown vent in operating-mode, blowdown valve leakage through the blowdown vent in standby-pressurized-mode, and unit isolation valve leakage through an open blowdown vent without blind flanges in not-operating-depressurized-mode.

The EPA is proposing several amendments related to the ''as found'' measurement requirements to improve the quality of data collected for compressors. First, standby-pressurized-mode was not included as a mode for centrifugal compressors in the subpart W definition of ''compressor mode'' and no compressor mode-source combinations were defined for centrifugal compressors in standby-pressurized-mode. While centrifugal compressors are seldom in the standby-pressurized-mode, there have been several occasions when reporters have indicated through the GHGRP Help Desk that a centrifugal compressor was in this mode during the ''as found'' measurement. This has led to confusion from reporters regarding how to report the data from the measurements performed. To address this issue, we are proposing to add standby-pressurized-mode to the defined modes for centrifugal compressors (40 CFR 98.238) and require measurement of volumetric emissions from the wet seal oil degassing vent and volumetric emissions from blowdown valve leakage through the blowdown vent when the compressor is found in this mode (40 CFR 98.233(o)(1)(i)(C) as proposed), consistent with sections II.A.2 and II.A.5 of this preamble.

Second, dry seals on centrifugal compressors were not included in the subpart W definition of ''compressor source'' and no compressor mode-source combinations were defined for dry seals on centrifugal compressors. While emissions from wet seal oil degassing vents are expected to be larger than from dry seals, dry seals may still contribute to centrifugal compressor emissions. Additionally, the measurement crew will already be at the centrifugal compressor to make the ''as found'' measurement for blowdown valve leakage. Therefore, to better characterize the emissions from dry seal centrifugal compressors, we are proposing to add dry seal vents to the defined compressor sources for centrifugal compressors (40 CFR 98.238) and require measurement of volumetric emissions from the dry seal vents in both operating-mode and in standby-pressurized-mode (40 CFR 98.233(o)(2)(iii) as proposed), consistent with section II.A.2 of this preamble. Proposed measurement methods for the dry seal vents are similar to those provided for reciprocating compressor rod packing emissions and would include the use of temporary or permanent flow meters, calibrated bags, and high volume samplers. Screening methods may also be used to determine if a quantitative measurement is required. Acoustical screening or measurement methods are not applicable to dry seal vents because these emissions are not a result of through-valve leakage. These proposed revisions include a proposed new reporting requirement to report the number of dry seals on centrifugal compressors and the reporting of emission measurements made on the dry seals.

Third, we are proposing to revise 40 CFR 98.233(p)(1)(i) to require measurement of rod packing emissions for reciprocating compressors when found in the standby-pressurized-mode because recent studies indicate that rod packing emissions can occur while the compressor is in this mode.[79] The inclusion of this compressor mode-source combination would more accurately reflect compressor emissions, consistent with section II.A.2 of this preamble. Furthermore, the measurement crew will already be at the compressor to make the ''as found''

[78] Currently, subpart W does not require measurements for centrifugal compressors in standby-pressurized-mode and therefore does not define this mode for centrifugal compressors.

[79] Subramanian, R. *et al.* ''Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol.'' *Environ. Sci. Technol.* 49, 3252–3261. 2015. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

measurement for blowdown valve leakage and several reporters already make these measurements.

Fourth, we are proposing to revise the allowable methods for measuring wet seal oil degassing vents. Since the inception of subpart W, the only method provided in 40 CFR 98.233(o)(2)(ii) for measuring volumetric flow from wet seal oil degassing vents has been the use of a temporary or permanent flow meter. The limitation in methods allowed for wet seal oil degassing vents was due to the expectation that the volumetric flows may exceed the quantitative limits of these other methods. In reviewing the data reported for the wet seal oil degassing vent, we found that the measured flow rates using flow meters are often within the limits of other measurement methods allowed for other compressor sources. We also found that many reporters have overlooked the restriction on the methods allowed for wet seal oil degassing vents and often reported using other measurement methods (*e.g.,* high volume samplers). We have found that most of these measured flow rates appear to be within the capacity limits of a typical high volume sampler. In the small minority of cases in which flow rates would be outside of the capacity limit of the instrument, facilities can use an alternate method, consistent with the requirements for other compressor source measurements. Consequently, we concluded that the measurement methods allowed for wet seal oil degassing vents could be expanded to include the use of calibrated bags and high volume samplers. Therefore, we are proposing to revise 40 CFR 98.233(o)(2)(ii) to allow the use of calibrated bags and high volume samplers. However, we are not proposing to allow the use of screening methods because wet seal oil degassing vents are expected to always have some natural gas flow. Therefore, we are proposing to retain and clarify this unique limitation on the use of screening methods for wet seal oil degassing vent measurement methods. This proposed revision would provide greater flexibility and improved clarity of the wet seal oil degassing provisions consistent with section II.A.2 of this preamble.

Fifth, we are proposing to remove acoustic leak detection from the screening and measurement methods allowed for manifolded groups of compressor sources. As noted in 40 CFR 98.234(a)(5), acoustic leak detection is applicable only for through-valve leakage. The acoustic method can be applied to individual compressor sources associated with through-valve leakage (*i.e.,* blowdown valve leakage or isolation valve leakage), but it cannot be applied to a vent that contains a group of manifolded compressor sources downstream from the individual valves or other sources that may be manifolded together. The inclusion of this method for manifolded compressor sources was in error and we are proposing to remove it from 40 CFR 98.233(o)(4)(ii)(D) and (E) and 40 CFR 98.233(p)(4)(ii)(D) and (E) to improve accuracy of the measurements, consistent with section II.A.2 of this preamble.

Sixth, we are proposing a number of clarifications to the references to the allowed measurement methods to correct errors and improve the clarity of the rule, consistent with section II.A.5 of this preamble. These proposed revisions include: revising 40 CFR 98.233(o)(1)(i)(A) and (B) to reference 40 CFR 98.233(o)(2)(i) instead of specific subparagraphs of that paragraph that may be construed to limit the methods allowed for blowdown or isolation valve leakage measurements; revising 40 CFR 98.233(p)(1)(i)(A), (B) and (C) to reference 40 CFR 98.233(p)(2)(i) instead of specific subparagraphs of that paragraph that may be construed to limit the methods allowed for blowdown or isolation valve leakage measurements; revising 40 CFR 98.233(p)(1)(i)(A) and (C) (as proposed) to reference ''paragraph (p)(2)(ii) or (iii) of this section as applicable'' instead of only ''paragraph (p)(2)(ii)'' to clarify that measurement of rod packing emissions without an open-ended vent line are to be made according to 40 CFR 98.233(p)(2)(iii); and revising 40 CFR 98.233(p)(2)(ii)(C) and (iii)(A) to clarify that acoustic leak detection is not an applicable screening method for rod packing emissions (not a through-valve leakage).

In addition to these proposed revisions to the ''as found'' measurement requirements, we are also proposing to clarify the language at 40 CFR 98.233(o)(10) and (p)(10) for compressors at Onshore Petroleum and Natural Gas Production or Onshore Petroleum and Natural Gas Gathering and Boosting facilities, consistent with section II.A.2 of this preamble. The compressor emission factors for these industry segments are specific to uncontrolled wet seal oil degassing vents on centrifugal compressors and uncontrolled rod packing emissions for reciprocating compressors. The language in 40 CFR 98.233(o) and (p) clearly indicates that the provisions of 40 CFR 98.233(o)(10) and (p)(10) do not apply for controlled compressor sources. However, proposed revisions are necessary to provide clarity regarding the compressor sources for which emissions are required to be calculated under 40 CFR 98.233(o)(10) and (p)(10) and reported under 40 CFR 98.236(o)(5) and (p)(5). Specifically, we are proposing minor revisions to 40 CFR 98.233(o)(10) and the corresponding reporting requirements in 40 CFR 98.236(o)(5) to clarify that the compressor count used in equation W–25 should be the number of centrifugal compressors with atmospheric (*i.e.,* uncontrolled) wet seal oil degassing vents. Similarly, we are proposing minor revisions to 40 CFR 98.233(p)(10) and the corresponding reporting requirements in 40 CFR 98.236(p)(5) to clarify that the compressor count used in equation W–29D should be the number of reciprocating compressors with atmospheric (*i.e.,* uncontrolled) rod packing emissions. Finally, we are proposing to add requirements to report the total number of centrifugal compressors at the facility and the number of centrifugal compressors that have wet seals to 40 CFR 98.236(o)(5) and proposing to add a requirement to report the total number of reciprocating compressors at the facility to 40 CFR 98.236(p)(5). These additional data would provide the EPA with an improved understanding of the total number of compressors and the number of compressors that are controlled (*i.e.,* routed to flares, combustion, or vapor recovery systems) in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, consistent with section II.A.4 of this preamble.

k. Equipment Leak Surveys

Addition of leaker emission factors for survey methods other than method 21. Subpart W reporters are required to quantify emissions from equipment leaks using the calculation methods in 40 CFR 98.233(q) (equipment leak surveys) and/or 40 CFR 98.233(r) (equipment leaks by population count). The equipment leak survey method uses the count of leakers detected with one of the subpart W leak detection methods in 40 CFR 98.234(a), subpart W leaker emission factors, and operating time to estimate the emissions from equipment leaks. The current leaker emission factors applicable to onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities are found in Table W–1E of subpart W. These leaker emission factors are based on the EPA's *Protocol for Equipment Leak Emission Estimates* published in 1995 (Docket Id. No. EPA–HQ–OAR–2009–0927–0043), also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424. The leaker emission factors are provided for components in gas service, light crude service, and heavy crude service that are found to be leaking via several different screening methods. In addition to being component- and service-specific, subpart W currently provides two different sets of leaker emission factors: one based on leak rates for leaks identified by Method 21 (see 40 CFR part 60, appendix A–7) using a leak definition of 10,000 ppm and one based on leak rates for leaks identified by Method 21 using a leak definition of 500 ppm. Currently, the other leak screening methods provided in subpart W (OGI, infrared laser beam illuminated instrument, and acoustic leak detection device) use the leaker emission factors based on Method 21 data with a leak definition of 10,000 ppm.

In the years that have followed the adoption of these emission factors into subpart W, there have been numerous studies regarding emissions from equipment leaks that provide measurement data to quantify leaker emission factors for OGI screening methods at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities.[80] These studies found that OGI identifies fewer yet larger leaks than the EPA's Method 21. Specifically, the average leaker emission factor determined from OGI leak detection surveys is often a factor of two or more larger than leaker emission factors determined when using Method 21 leak detection surveys. Therefore, the application of the same leaker emission factor to leaking components detected with OGI and Method 21 with a leak definition of 10,000 ppm, as is currently done in subpart W, likely understates the emissions from leakers detected with OGI.

Based on our review of these studies, we are proposing to amend the leaker emission factors in Table W–1E for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities to include separate emission factors for leakers detected with OGI, consistent with section II.A.1 of this preamble. These emission factors were developed by combining the data from Zimmerle *et al.* (2020) and Pacsi *et al.* (2019) to provide OGI leaker emission factors by site type (*i.e.,* gas or oil). These studies were selected as the basis for the proposed OGI emission factors because they included recent measurements of subpart W-specified equipment leak components from both oil and gas production and gathering and boosting sites in geographically diverse locations. The precise derivation of the proposed emission factors is discussed in more detail in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

At onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities, very few facilities use infrared laser beam illuminated instruments or acoustic leak detection devices to conduct equipment leak surveys and there are no data available to develop leaker emission factors specific to these methods. Based on our understanding of these alternative methods, we expect that their leak detection thresholds would be most similar to OGI, so that the average emissions per leak identified by these alternative methods would be similar to the emissions estimated using the proposed OGI leaker factors. Therefore, we are proposing that, if these alternative methods are used to conduct leak surveys, the proposed OGI leaker emission factors would be used to quantify the emissions from the leaks identified using these other monitoring methods.

For onshore petroleum and natural gas gathering and boosting facilities, all components are considered to be in gas service consistent with the language in 40 CFR 98.233(q)(2)(iv); thus, the gas service factors from Table W–1E should be applied to all leakers. In order to make clear how onshore petroleum and natural gas production facilities should apply these revised emission factors, we are proposing to amend 40 CFR 98.233(q)(2)(iii) to state that onshore petroleum and natural gas production facilities must use the appropriate default whole gas leaker emission factors consistent with the well type, where components associated with gas wells are considered to be in gas service and components associated with oil wells are considered to be in oil service as listed in Table W–1E to this subpart.

As described previously, our analysis of measurement study data from onshore production and gathering and boosting facilities demonstrates that the OGI screening method finds fewer and larger leaks than Method 21. Consequently, the leaker emission factors derived using measurement data from the OGI screening method are larger than those derived using the measurement data from Method 21 screening method. We expect that the leaker emission factors for other industry segments that are based on measurements of Method 21-identified leaks may similarly underestimate the emissions from leaking equipment when OGI (or other alternative methods besides Method 21) are used to detect the leaks. Therefore, we are proposing to apply the ''OGI enhancement'' factor identified from measurement study data in the onshore production and gathering and boosting industry segments to the leaker emission factors for the other subpart W industry segments as a means to estimate an OGI emission factor set. Analogous to the proposed changes in Table W–1E for the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, this results in the addition of an emission factor set specific to OGI, infrared laser beam illuminated instrument, or acoustic leak detection device screening methods. The proposed emission factor sets are included in Tables W–2A, W–3A, W–4A, W–5A, W–6A, and W–7 for the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, LNG Import and Export Equipment, and Natural Gas Distribution industry segments, respectively. A detailed description of the proposed emission factors is discussed in more detail in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

As an alternative to the proposed revised default leaker emission factors, we are also proposing an option that would allow reporters to quantify emissions from equipment leak components in 40 CFR 98.233(q) by performing direct measurement of equipment leaks and calculating emissions using those measurement results, consistent with section II.A.2 of this preamble. The proposed amendments would provide that

[80] See, *e.g.,* ERG (Eastern Research Group, Inc.) and Sage (Sage Environmental Consulting, LP). *City of Fort Worth Natural Gas Air Quality Study: Final Report.* July 13, 2011, available at *https://www.fortworthtexas.gov/departments/development-services/gaswells/air-quality-study/final;* Allen, D.T., *et al.* ''Measurements of methane emissions at natural gas production sites in the United States.'' *Proceedings of the National Academy of Sciences of the United States of America,* Vol. 110, no. 44. pp. 17768–17773, October 29, 2013, available at *http://dept.ceer.utexas.edu/methane/study.* Docket Item No. EPA–HQ–OAR–2014–0831–0006; Pacsi, A.P., *et al.* ''Equipment leak detection and quantification at 67 oil and gas sites in the Western United States.'' *Elem Sci Anth,* 7: 29, available at *https://doi.org/10.1525/elementa.368.* 2019; Zimmerle, D., *et al.* ''Methane Emissions from Gathering Compressor stations in the U.S.'' *Environmental Science & Technology* 2020, 54(12), 7552–7561, available at *https://doi.org/10.1021/acs.est.0c00516.* The documents are also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

facilities with components subject to 40 CFR 98.233(q) can elect to perform direct measurement of leaks using one of the subpart W measurement methods in 40 CFR 98.234(b) through (d) such as calibrated bagging or a high volume sampler. To use this proposed option, all leaks identified during a ''complete leak detection survey'' must be quantified; in other words, reporters could not use leaker emission factors for some leaks and quantify other leaks identified during the same leak detection survey. For the Onshore Petroleum and Natural Gas Production industry segment, a complete leak detection survey would be the fugitive emissions monitoring of a well site conducted to comply with NSPS OOOOa, NSPS OOOOb, or the applicable EPA-approved state plan or the applicable Federal plan in 40 CFR part 62 or, if the reporter elected to conduct the leak detection survey, a complete survey of all equipment on a single well-pad. For the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, a complete leak detection survey would be the fugitive emissions monitoring of a compressor station to comply with NSPS OOOOa, NSPS OOOOb, or the applicable EPA-approved state plan or the applicable Federal plan in 40 CFR part 62 or, if the reporter elected to conduct the leak detection survey, a complete survey of all equipment at a gathering ''compressor station'' or at a ''centralized oil production site'' (and we are proposing to define these terms in 40 CFR 98.238, as described in section III.J.1.p of this preamble). For downstream industry segments (*e.g.,* Onshore Natural Gas Transmission Compression), a complete leak detection survey is facility-wide, and therefore, the election to perform direct measurement of leaks would also be facility-wide. In other words, this option would allow the use of measurement data directly when all leaks identified are quantitatively measured.

The proposed amendments rely specifically on quantitative measurement methods already provided in the rule. We are seeking comment on alternative methods for quantifying leaks for use for these equipment leak measurements (and for ''as found'' compressor measurements) along with supporting information and data. The supporting information should include description of the method, limitations on the applicability of the method, and calibration requirements. Supporting data should include accuracy assessments relative to other quantitative measurement methods provided in the rule.

Finally, as part of this overall amendment, we are also proposing to remove the additional Method 21 screening when a survey is conducted using a method other than Method 21. Currently, facilities using survey methods other than Method 21 to detect equipment leaks may then screen the equipment identified as leaking using Method 21 to determine if the leak measures greater than 10,000 parts per million by volume (ppmv) (see, *e.g.,* 40 CFR 98.234(a)(1)). If the Method 21 screening of the leaking equipment is less than 10,000 ppmv, then reporters may consider that equipment as not leaking. In the 2016 subpart W revisions, we added a leak detection methodology at 40 CFR 98.234(a)(6) (proposed to be moved to 40 CFR 98.234(a)(1)(ii)) for using OGI in accordance with NSPS OOOOa, which does not include an option for additional Method 21 screening. As noted in response to comments on the subpart W proposal regarding the absence of this optional additional Method 21 screening when using OGI in accordance with NSPS OOOOa, the additional screening of OGI-identified leaking equipment using Method 21 requires additional effort from reporters (81 FR 86500, November 30, 2016). Furthermore, as noted previously in this section, the average emissions of leakers identified by OGI are greater than leaks identified by Method 21. Directly applying the number of OGI-identified leaks to the subpart W leaker emission factor specific to that survey method would provide the most accurate estimate of emissions, while selectively screening OGI-identified leaks using Method 21 to reduce the number of reportable leakers would yield a low bias in the reported emissions. Therefore, we are proposing to require reporters to directly use the leak survey results for the monitoring method used to conduct the complete leak survey and are proposing to eliminate this additional Method 21 screening provision. In addition to providing more accurate emissions data consistent with section II.A.2 of this preamble, the removal of the additional monitoring step would streamline and improve implementation consistent with section II.B.2 of this preamble.

Amendments related to oil and natural gas standards and emissions guidelines in 40 CFR part 60. As noted in the introduction to section III.J of this preamble, the EPA recently proposed NSPS OOOOb and EG OOOOc for oil and natural gas new and existing affected sources, respectively. Under the proposed standards in NSPS OOOOb and the proposed presumptive standards in EG OOOOc, owners and operators would be required to implement a fugitive emissions monitoring and repair program for the collection of fugitive emissions components at well site and compressor station affected sources. In addition, the proposed NSPS OOOOb and EG OOOOc include a proposed appendix K to 40 CFR part 60, an OGI-based method for detecting leaks and fugitive emissions from all components that is not currently provided in subpart W. The EPA also proposed provisions in NSPS OOOOb and EG OOOOc for equipment leak detection and repair at onshore natural gas processing facilities. Similar to the 2016 amendments to subpart W (81 FR 4987, January 29, 2016), the EPA is proposing to revise the calculation methodology for equipment leaks in subpart W so that data derived from equipment leak and fugitive emissions monitoring conducted under NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62 would be used to calculate emissions, consistent with section II.A.2 of this preamble.

First, under these proposed amendments, facilities with certain fugitive emissions components at a well site or compressor station subject to NSPS OOOOb or an applicable approved state plan or applicable Federal plan in 40 CFR part 62 would use the data derived from the NSPS OOOOb or 40 CFR part 62 fugitive emissions requirements along with the subpart W equipment leak survey calculation methodology and leaker emission factors to calculate and report their GHG emissions to the GHGRP. Specifically, the proposed amendments would expand the cross-reference to 40 CFR 60.5397a to include the analogous requirements in NSPS OOOOb or 40 CFR part 62. Facilities with fugitive emissions components not subject to the standards in the proposed NSPS OOOOb or addressed by the presumptive standards in the proposed EG OOOOc and subject to 40 CFR part 62 would continue to be able to elect to calculate subpart W equipment leak emissions using the leak survey calculation methodology and leaker emission factors (as is currently provided in 40 CFR 98.233(q)). Therefore, reporters with other fugitive emission sources at subpart W facilities not covered by NSPS OOOOb or 40 CFR part 62 (*e.g.,* sources subject to other state regulations and sources participating in the Methane Challenge Program or other voluntarily implemented programs) would continue to have the opportunity to voluntarily use the proposed leak detection methods to calculate and report their GHG emissions to the GHGRP. To facilitate this proposed requirement, we are also proposing to clarify that fugitive emissions monitoring conducted to comply with NSPS OOOOa, NSPS OOOOb, or an applicable approved state plan or applicable Federal plan in 40 CFR part 62 is considered a ''complete leak detection survey,'' so that onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities can use NSPS OOOOb or 40 CFR part 62 fugitive emission surveys directly for their subpart W reports. In a corresponding amendment, we are also proposing to expand the current reporting requirement in 40 CFR 98.236(q)(1)(iii) to require reporters to indicate if any of the surveys of well sites or compressor stations used in calculating emissions under 40 CFR 98.233(q) were conducted to comply with the fugitive emissions standards in NSPS OOOOb or an applicable approved state plan or applicable Federal plan in 40 CFR part 62.[81] We request comment on these proposed amendments and whether there are other provisions or reporting requirements relative to NSPS OOOOb or EG OOOOc that we should consider for subpart W.

Second, we are proposing to revise 40 CFR 98.234(a) to clarify and consolidate the requirements for OGI and Method 21 in 40 CFR 98.234(a)(1) and (2), respectively. In the 2016 amendments to subpart W (81 FR 4987, January 29, 2016), the EPA added 40 CFR 98.234(a)(6) and (7) to provide OGI and Method 21 as specified in NSPS OOOOa as leak detection survey methods. In part, structuring the amendment this way allowed the EPA to provide the NSPS OOOOa leak detection methods as allowable methods under subpart W without affecting the requirements for facilities and industry segments not subject to NSPS OOOOa. However, as the EPA continues to propose additional standards with slightly different variations on OGI and Method 21, it would be unnecessarily convoluted to continue to add those methods and cross-references to each standard to the end of 40 CFR 98.234(a). Therefore, the EPA is proposing to move 40 CFR 98.234(a)(1) and 40 CFR 98.234(a)(6) to 40 CFR 98.234(a)(1)(i) and 40 CFR 98.234(a)(1)(ii), respectively, which would consolidate the OGI-based methods in 40 CFR 98.234(a)(1). Similarly, the EPA is proposing to revise 40 CFR 98.234(a)(2) such that 40 CFR 98.234(a)(2)(i) is Method 21 with a leak definition of 10,000 ppm and 40 CFR 98.234(a)(2)(ii) is Method 21 with a leak definition of 500 ppm. This proposed amendment would effectively move 40 CFR 98.234(a)(7) to 40 CFR 98.234(a)(2)(ii). The references to ''components listed in § 98.232'' would be replaced with a more specific reference to 40 CFR 98.233(q)(1). The references to specific provisions in 40 CFR 60.5397a in 40 CFR 98.234(a)(6) and (7) would be moved to 40 CFR 98.234(a)(1)(ii) and 40 CFR 98.234(a)(2), as applicable.

The EPA proposed in NSPS OOOOb and EG OOOOc that owners and operators would detect leaks using an OGI-based monitoring method following the concurrently proposed appendix K to 40 CFR part 60. We are proposing to include that same method in subpart W at 40 CFR 98.234(a)(1)(iii) to ensure that reporters would be able to comply with the proposed subpart W requirement to use data derived from the NSPS OOOOb or 40 CFR part 62 fugitive emissions requirements for purposes of calculating emissions from equipment leaks. As part of the proposal of NSPS OOOOb and EG OOOOc, the EPA proposed an alternative screening approach for fugitive emissions from well sites and compressor stations that would allow the use of advanced measurement technologies to detect large equipment leaks. If emissions are detected using one of these advanced technologies, facilities would be required to conduct monitoring using OGI or Method 21 to identify and repair specific leaking equipment. Additionally, even if no large emissions are identified, facilities using these advanced technologies would still be required to conduct annual fugitive emissions monitoring using OGI or Method 21. The EPA's intent in this proposed rule for subpart W is that the results of those NSPS OOOOb and 40 CFR part 62 OGI or Method 21 surveys would be used for purposes of calculating emissions for subpart W, as OGI and Method 21 are capable of identifying leaks from individual components and they are leak detection methods provided in subpart W. The EPA also requests comment on additional methods or advanced technologies that can identify individual leaking components. Based on the information received, the EPA would need to review the specific method and leak detection data collected using that method to determine what default leaker emission factors would apply for that method and whether any adjustments might be needed to the subpart W equipment leak survey calculation methodology when using that method. Following that review, the EPA may undertake a rulemaking process to include the additional leak detection method(s) in 40 CFR 98.234(a).

Third, we are proposing subpart W requirements for onshore natural gas processing facilities consistent with certain requirements for equipment leaks in the proposed NSPS OOOOb or EG OOOOc. Currently, onshore natural gas processing facilities must conduct at least one complete survey of all the components listed in 40 CFR 98.232(d)(7) each year, and each complete survey must be considered when calculating emissions according to 40 CFR 98.233(q)(2). Under the equipment leak detection and repair program included in proposed NSPS OOOOb and the EG OOOOc presumptive standards, different component types may be monitored on different frequencies, so all equipment at the facility is not always monitored at the same time. According to the current requirements in 40 CFR 98.233(q), surveys that do not include all of the applicable equipment at the facility are not considered complete surveys and are not used for purposes of calculating emissions. Therefore, we are proposing that for onshore natural gas processing facilities subject to NSPS OOOOb or an applicable approved state plan or the applicable Federal plan in 40 CFR part 62 would use the data derived from each equipment leak survey conducted as required by NSPS OOOOb or 40 CFR part 62 along with the subpart W equipment leak survey calculation methodology and leaker emission factors to calculate and report GHG emissions to the GHGRP, even if a survey required for compliance with NSPS OOOOb or 40 CFR part 62 does not include all the component types listed in 40 CFR 98.232(d)(7).

Under this proposed amendment, reporters would still have to meet the subpart W requirement to conduct at least one complete survey of all applicable equipment at the facility per year, so if there were components listed in 40 CFR 98.232(d)(7) not included in any NSPS OOOOb or 40 CFR part 62-required surveys conducted during the year (*e.g.,* connectors that are monitored only once every 4 years), reporters

[81] We are similarly proposing to revise the existing reporting requirement related to NSPS OOOOa, such that reporters would report whether any of the surveys of well sites or compressor stations used in calculating emissions under 40 CFR 98.233(q) were conducted to comply with the fugitive emissions standards in NSPS OOOOa (rather than simply reporting whether the facility has well sites or compressor stations subject to the fugitive emissions standards in NSPS OOOOa).

subject to NSPS OOOOb or 40 CFR part 62 would need to either add those components to one of their required surveys, making that a complete survey for purposes of subpart W, or conduct a separate complete survey for purposes of subpart W. We expect that reporters with onshore natural gas processing plants implementing traditional leak detection and repair programs are already making similar decisions regarding how to meet the requirement to conduct a complete survey for subpart W, and our intention with this proposed amendment is not to change those decisions. Rather, this amendment would specify that surveys conducted pursuant to NSPS OOOOb or 40 CFR part 62 that do not include all component types listed in 40 CFR 98.232(d)(7) would be used for calculating emissions along with each complete survey.

We are also proposing to add leaker emission factors for all survey methods for ''other'' components that would be required to be monitored under NSPS OOOOb or an approved state plan or applicable Federal plan in 40 CFR part 62 or that reporters elect to survey that are not currently included in subpart W. These proposed total hydrocarbon leaker emission factors are the same as the total hydrocarbon leaker emission factors for the Onshore Natural Gas Transmission Compression and the Underground Natural Gas Storage industry segments (Table W–3A and Table W–4A, respectively). For more information on the derivation of the original emission factors, see the TSD for the final subpart W standards,[82] and for more information on the derivation of the emission factors proposed to be added to Table W–2B, see the TSD for the 2016 amendments to subpart W.[83] In a corresponding amendment, we are also proposing to expand the reporting requirement in 40 CFR 98.236(q)(1)(iii) to require onshore natural gas processing reporters to indicate if any of the surveys used in calculating emissions under 40 CFR 98.233(q) were conducted to comply with the equipment leak standards in NSPS OOOOb or an applicable approved state plan or the applicable Federal plan in 40 CFR part 62. We request comment on the proposed amendments to subpart W for onshore natural gas processing facilities subject to the equipment leak provisions of NSPS OOOOb or 40 CFR part 62, as well as whether there are other provisions or reporting requirements for these facilities that we should consider.

Finally, in our review of subpart W equipment leak requirements for onshore natural gas processing facilities, we found that the leak definition for the Method 21-based requirements for processing plants in NSPS OOOOa (as well as proposed NSPS OOOOb and EG OOOOc presumptive standards) is not consistent with the leak definition in the Method 21 option in current 40 CFR 98.234(a)(1), which is the only Method 21-based method available to onshore natural gas processing facilities under subpart W. Based on this review, and to complement the proposed addition of default leaker emission factors for survey methods other than Method 21 (as described previously in this preamble), we are proposing several additions to the equipment leak survey requirements for the Onshore Natural Gas Processing industry segment, beyond those amendments already described related to the proposed NSPS OOOOb and EG OOOOc presumptive standards. First, we are proposing default leaker emission factors for Method 21 at a leak definition of 500 ppm in Table W–2A. As with the proposed ''other'' leaker emission factors, these proposed leaker emission factors are the same as the total hydrocarbon leaker emission factors for the Onshore Natural Gas Transmission Compression and the Underground Natural Gas Storage industry segments (Table W–3A and Table W–4A, respectively). For more information on the derivation of those emission factors, see the TSD for the 2016 amendments to subpart W.[84] In addition, we are proposing to add 40 CFR 98.233(q)(1)(v) to indicate that onshore natural gas processing facilities not subject to NSPS OOOOb or an approved state plan or the applicable Federal plan in 40 CFR part 62 may use any method specified in 40 CFR 98.234(a), including Method 21 with a leak definition of 500 ppm and OGI following the provisions of appendix K to 40 CFR part 60. This proposed amendment would ensure that equipment leak surveys conducted using any of the approved methods in subpart W would be available for purposes of calculating emissions, not just those surveys conducted using one of the methods currently provided in 40 CFR 98.234(a)(1) through (5).

l. Equipment Leaks by Population Count

As noted in section III.J.1.k of this preamble, subpart W reporters are required to quantify emissions from equipment leaks using the calculation methods in 40 CFR 98.233(q) (equipment leak surveys) and/or 40 CFR 98.233(r) (equipment leaks by population count), depending upon the industry segment. The equipment leaks by population count method uses the count of equipment components, subpart W emission factors (*e.g.,* Table W–1A for the Onshore Petroleum and Natural Gas Production industry segment), and operating time to estimate emissions from equipment leaks. For the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, the count of equipment components may be determined by counting each component individually for each facility (Component Count Method 2) or the count of equipment components may be estimated using the count of major equipment and subpart W default average component counts for major equipment (Component Count Method 1) in Tables W–1B and W–1C, as applicable. Reporters in other industry segments must count each applicable component at the facility. We are proposing several amendments to the calculation methodology provisions of 40 CFR 98.233(r) and the reporting requirements in 40 CFR 98.236(r) to improve the quality of the data collected, consistent with sections II.A.1, II.A.4, and II.A.5 of this preamble.

Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting population count method. The current population emission factors for the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments are found in Table W–1A of subpart W. The gas service population emission factors are based on the 1996 Gas Research Institute (GRI)/EPA study *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks* (available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424). The oil service population emission factors are based on the American Petroleum Institute's (API) Emission Factors for Oil

[82] *Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Systems Industry: Background Technical Support.* November 2010. Docket Id. No. EPA–HQ–OAR–2009–0923–3610; also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[83] *Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems.* November 1, 2016. Docket Id. No. EPA–HQ–OAR–2015–0764–0066; also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[84] *Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems.* November 1, 2016. Docket Id. No EPA–HQ–OAR–2015–0764–0066; also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

and Gas Production Operations, Publication 4615 published in 1995.

As noted previously in this section, when estimating emissions using the population count method, onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities have the option to use actual component counts (*i.e.,* Component Count Method 2) or to estimate their component counts using the count of major equipment (*e.g.,* wellhead) and default component counts per major equipment (*e.g.,* valves per wellhead) included in Tables W–1B and W–1C of subpart W (*i.e.,* Component Count Method 1). In reviewing subpart W data, we find that the vast majority (greater than 95 percent) of onshore production and natural gas gathering and boosting facilities use Component Count Method 1 to estimate the count of components.

It is important to note that both the population count emission factors and the default component counts per major equipment included in Tables W–1A, W–1B and W–1C are service-specific (*i.e.,* gas or oil) as well as region-specific (*i.e.,* eastern or western U.S.). The regional designations are provided by U.S. state in Table W–1D of subpart W such that a facility would determine the facility's region and select the appropriate region- and service-specific factors.

In the years that have followed the adoption of these emission factors into subpart W, there have been numerous studies regarding emissions from equipment leaks at onshore production and gathering and boosting facilities. Two recent field studies, Pacsi *et al.* (2019)[85] and Zimmerle *et al.* (2020),[86] have performed an equipment and component inventory alongside equipment leak screening and measurement results. Another recent study, Rutherford *et al.* (2021),[87] included synthesis and analysis of measurements from component-level field studies. These studies provide the necessary data to develop and compare study-estimated population emission factors as well as study-estimated default component counts per major equipment to those in subpart W. Comparison of the study-estimated default component counts per major equipment found that the subpart W values underestimate the count of components found on major equipment in the field (Zimmerle *et al.,* 2020; Pacsi *et al.,* 2019). Regarding a comparison of the population emission factors and component counts per major equipment between the subpart W eastern and western values, Zimmerle *et al.* (2020) was the only field study to include both eastern and western facilities, and the study values showed ''no statistically significant differences between eastern and western U.S. regions.'' Rutherford *et al.* (2021) also found their study-estimated population emission factors to be higher than those in subpart W, noting that one of the contributing factors to this difference was the use of the eastern factors in subpart W, which appear to significantly undercount emissions. Rutherford *et al.* (2021) noted that the impact of the use of the eastern factors has grown over time as the production in the eastern region of the U.S. has increased from less than 5 percent of gas produced to nearly 30 percent of the gas produced.

Based on our review of these studies, we are proposing to amend the population count method for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities using these more recent study data, consistent with section II.A.1 of this preamble. These proposed amendments include new population emission factors that are on a per major equipment basis rather than a per component basis. As mentioned previously, the vast majority of reporters estimate the component counts using Component Count Method 1. By providing emission factors on a major equipment basis instead of by component, we would eliminate the step to estimate the number of components. All facilities would be able to inventory their major equipment and consistently apply the same emissions factor to estimate emissions. This would reduce reporter burden and reduce the number of errors in the calculation of emissions, as we find that numerous facilities incorrectly estimate the number of components using Component Count Method 1 while providing consistently estimated emission results. The major equipment emission factors were developed by combining data from Zimmerle *et al.* (2020) and Pacsi *et al.* (2019) to provide population emission factors by major equipment and site type (*i.e.,* gas or oil). The emission factors were derived by summing the leaker emissions by major equipment type, including wellhead, separator, meters/piping, compressor, acid gas removal unit, dehydrator, header, heater treater, and storage vessel, by the reported site type and dividing those leaker emissions by the count of major equipment screened to yield an emission factor in units of scf whole gas/hour-equipment. Specific to meters/piping and consistent with current requirements related to meters/piping at 40 CFR 98.233(r)(2)(i)(A), we are proposing in 40 CFR 98.233(r)(2) to specify that one meters/piping equipment should be included per well-pad for onshore petroleum and natural gas production operations and the count of meters in the facility should be used for this equipment category at onshore petroleum and natural gas gathering and boosting facilities. As a consequence of the broader scope of equipment surveyed in the Pacsi/Zimmerle studies, the proposed emission factors include more pieces of major equipment than are currently included in subpart W. The derivation of the proposed emission factors is discussed in more detail in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424. The proposed major equipment emission factors would replace the component-based emission factors in the current Table W–1A. We are also proposing to revise the titles of Tables W–1B, W–1C, and W–1D to clarify that they apply to reporting years up to and including RY2022. These tables would not apply to subsequent reporting years as they provide activity data that would no longer be needed for the population count method for these industry segments. We are seeking comment on the approach of providing population count emission factors by major equipment.

We note that the application of these emission factors is by site type such that for onshore petroleum and natural gas production facilities, gas well sites should use the proposed gas service emission factors and oil well sites should use the proposed oil service emission factors. Similarly, for onshore petroleum and natural gas gathering and boosting facilities, we consider all equipment to be in gas service consistent with the language in 40 CFR 98.233(r)(2); thus, the proposed gas service factors from Table W–1A should be applied to all equipment counts. We

[85] Pacsi, A. P. et al. Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. Elementa (2019). *https://doi.org/10.1525/elementa.368.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[86] Zimmerle, D., et al. *Methane Emissions from Gathering Compressor Stations in the U.S.* Environmental Science & Technology *54* (12), 7552–7561 (2020). *https://doi.org/10.1021/acs.est.0c00516.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[87] Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. et al. *Closing the methane gap in US oil and natural gas production inventories.* Nat Commun 12, 4715 (2021). *https://doi.org/10.1038/s41467-021-25017-4.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

are proposing language clarifying the service-specific application of these emission factors specifically for onshore petroleum and natural gas production in 40 CFR 98.233(r)(2).

Natural Gas Distribution Emission Factors. Natural Gas Distribution companies quantify the emissions from equipment leaks from pipeline mains and services, below grade transmission distribution transfer stations, and below grade metering-regulating stations following the procedures in 40 CFR 98.233(r). This method uses the count of equipment, subpart W population emission factors in Table W–7 (proposed to be moved to Table W–8), and operating time to estimate emissions. The population emission factors for pipeline mains and services in Table W–7 (proposed to be moved to Table W–8) are based on information from the 1996 GRI/EPA study.[88] Specifically for plastic mains, additional data are sourced from a 2005 ICF analysis.[89] The population emission factors for pipeline mains are published per mile of main by pipeline material and emission factors for pipeline services are published per service by pipeline material. The population emission factors for below grade stations in Table W–7 (proposed to be moved to Table W–8) are based on information from the 1996 GRI/EPA study.[90] The population emission factors for below grade transmission-distribution transfer stations and below grade metering-regulating stations are published per station by three inlet pressure categories (>300 psig, 100–300 psig, <100 psig).

The EPA is proposing to update the population emission factors in Table W–7 (proposed to be moved to Table W–8) to subpart W using the results of studies and information that were not available when the rule was finalized in 2010. Notably, the EPA reviewed recent studies and updated the emission factors for several natural gas distribution sources, including pipeline mains and services and below grade stations, for the 2016 U.S. GHG Inventory.[91 92] The majority of the U.S. GHG Inventory updates were based on data published by Lamb *et al.* in 2015.[93] Since the time that the 2016 U.S. GHG Inventory updates were made, additional studies for pipeline distribution mains have been published and reviewed by the EPA, notably Weller *et al.* in 2020.[94] Our assessment of the studies published since subpart W was finalized supports revising the emission factors for pipelines in the Natural Gas Distribution industry segment of subpart W. For more information on the review and analysis of the various studies, see the subpart W TSD, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

The population emission factors for distribution mains and services are a function of the average measured leak rate (scf/hr) and the frequency of annual leaks observed (leaks/mile-year or leaks/service-year) by pipeline material (*e.g.,* protected steel, plastic). The Lamb *et al.* and Weller *et al.* studies utilized different approaches for quantifying leak rates and determining the pipeline material-specific frequency of annual leaks. The Lamb *et al.* study quantified leaks from distribution mains and services using a high volume sampling method and some downwind tracer measurements and estimated the frequency of leaks by pipeline material using company records and Department of Transportation (DOT) repaired leak records from six local distribution companies (LDCs). This methodology was consistent with the GRI/EPA study. The Weller *et al.* study quantified leaks from only distribution mains using the Advanced Mobile Leak Detection (AMLD) technique, which involves mobile surveying using high sensitivity instruments and algorithms that predict the leak location and size, attributed leaks to the pipeline material using geographic information system (GIS) data, and estimated the frequency of leaks using modeling.

During our assessment of the Lamb *et al.* and Weller *et al.* studies, we identified the method for leak quantification as being a key strength of the Lamb *et al.* study and the significantly larger sample size used in estimating the annual leak frequency as being a key strength of the Weller *et al.* study. In order to take advantage of the strengths of both studies, we are proposing to amend the subpart W emission factors for distribution mains using the measurements from Lamb *et al.* combined with the pipeline material specific leaks per mile data from Weller *et al.* We are proposing to amend the subpart W emission factors for distribution services using the measurements from Lamb *et al.* only, consistent with the emission factors used in the 2016 U.S. GHG Inventory, because services were not included in the Weller *et al.* study. See the subpart W TSD, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424) for more information on our assessment of both studies and the derivation of the proposed emission factors from the data published by Lamb *et al.* and Weller *et al.* We are seeking comments on the approach of combining data from both studies to update the distribution mains emission factors. As alternatives to the proposed amendments, we also considered updating the distribution mains emission factors using data from each study independently. Accordingly, we are also seeking comment on whether using data only from Lamb *et al.,* consistent with the emission factors used in the U.S. GHG Inventory, or only from Weller *et al.* to update the distribution mains emission factors would be preferable over the combined approach included in this proposal, and if so, which study is preferred and why.

For below grade stations, the 2016 U.S. GHG Inventory also began applying a new emission factor from the data published by Lamb *et al.* to the count of stations to estimate emissions from these sources. In order to assess the

[88] GRI/EPA. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines.* Prepared for Gas Research Institute and U.S. Environmental Protection Agency National Risk Management Research Laboratory by L.M. Campbell, M.V. Campbell, and D.L. Epperson, Radian International LLC. GRI–94/0257.2b, EPA–600/R–96–080i. June 1996. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[89] ICF. *Fugitive Emissions from Plastic Pipe,* Memorandum from H. Mallya and Z. Schaffer, ICF Consulting to L. Hanle and E. Scheehle, EPA. June 30, 2005. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[90] GRI/EPA. *Methane Emissions from the Natural Gas Industry, Volume 10: Metering and Pressure Regulating Stations in Natural Gas Transmission and Distribution.* Prepared for Gas Research Institute and U.S. Environmental Protection Agency National Risk Management Research Laboratory by L.M. Campbell and B.E. Stapper, Radian International LLC. GRI–94/0257.27, EPA–600/R–96–080j. June 1996. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[91] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: Revisions under Consideration for Natural Gas Distribution Emissions.* December 2015. Available at *https://www.epa.gov/sites/production/files/2016-02/documents/proposed_revisions_to_ng_distribution_segment_emissions.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[92] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2014: Revisions to Natural Gas Distribution Emissions.* April 2016. Available at *https://www.epa.gov/sites/production/files/2016-08/documents/final_revision_ng_distribution_emissions_2016-04-14.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[93] Lamb, B.K. *et al.* ''Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States.'' *Environ. Sci. Technol.* 2015, 49, 5161–5169. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[94] Weller, Z.D.; Hamburg, S.P.; and Von Fischer, J.C. 2020. ''A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems.'' *Environ. Sci. Technol.* 2020, *54*(1), 8958. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

appropriateness of incorporating this revision into the subpart W requirements for below grade stations (*i.e.,* replacing the set of below grade emission factors by station type and inlet pressure with one single emission factor), the EPA performed an analysis of the reported subpart W data for below grade stations compared to data from the recent studies (see the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424). We found that the subpart W reported station count combined with the current subpart W emission factors yields an average emission factor similar to the U.S. GHG Inventory emission factor; as such, using either set of emission factors would yield approximately the same emissions results for the GHGRP.

Therefore, we are proposing to amend the emission factors for below grade transmission-distribution transfer stations and below grade metering-regulating stations in Table W–7 (proposed to be moved to Table W–8) to a single emission factor without regard to inlet pressure. We are also proposing to amend the corresponding section header in Table W–7 (proposed to be moved to Table W–8) for below grade station emission factors and the references to Table W–7 (proposed to be moved to Table W–8) in 40 CFR 98.233(r)(6)(i) to clarify the emission factor that should be applied to both types of below grade stations (*i.e.,* transmission-distribution transfer and metering-regulating). This proposed amendment would impact the reporting requirements as well, as it would consolidate six emission source types to two emission source types (below grade transmission-distribution transfer stations and below grade metering-regulating stations, without differentiating between inlet pressures) for purposes of reporting under 40 CFR 98.236(r)(1). This proposed amendment would improve the data quality through use of more recent emission factors and would be consistent with changes made to the U.S. GHG Inventory. It would also result in reporting of fewer data elements, consistent with section II.B.3 of this preamble.

Gathering pipeline emission factors. Facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment quantify the emissions from equipment leaks from gathering pipelines following the procedures in 40 CFR 98.233(r). This method uses the count of equipment, subpart W population emission factors in Table W–1A, and operating time to estimate emissions. The population emission factors for gathering pipeline mains in Table W–1A are based on leak rates from natural gas distribution companies and gathering pipeline-specific activity data as provided in the 1996 GRI/EPA study.[95] The population emission factors for gathering pipelines are published per mile by pipeline material.

As noted previously in this section, the EPA is proposing to update the natural gas distribution population emission factors in Table W–7 (proposed to be moved to Table W–8) to subpart W using the results of studies and information that were not available when the rule was originally finalized. In particular, the EPA is proposing to update the leak rate portion of the emission factor based on data published by Lamb *et al.* in 2015.[96] The EPA has reviewed the recent studies published for onshore petroleum and natural gas gathering and boosting facilities as well as the additional studies for pipeline distribution mains, and none of the studies provide new emissions data or activity data specific to gathering pipelines. Therefore, consistent with the updates to the emission factors for distribution mains, and consistent with section II.A.1 of this preamble, we are proposing to revise the gathering pipeline population emission factors to use the leak rates from Lamb *et al.* (2015). We are not proposing to update the activity data (leaks per mile of pipeline) portion of the emission factors, as the information in the 1996 GRI/EPA study continues to be the best available data specific to gathering pipelines. For more information on the proposed updates to the gathering pipeline population emission factors, see the subpart W TSD, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

m. Other Large Release Events

We are proposing to add an additional emissions source, referred to as ''other large release events'' to capture abnormal emission events that are not fully accounted for using existing methods in subpart W, consistent with section II.A.3 of this preamble. Most of the emission sources and methodologies included in subpart W characterize emissions that routinely occur at oil and gas facilities as part of their normal operations. While some sources covered by subpart W methodologies, such as equipment leaks, may represent ''malfunctioning'' equipment, these sources are ubiquitous across the oil and gas sector, are generally small, and have been studied and characterized. On the other hand, there have been several large, atypical release events at oil and gas facilities over the last few years where it was difficult to sufficiently include these emissions in annual GHGRP reports. For example, a storage wellhead leak at Aliso Canyon released approximately 100,000 metric tons of CH_4 between October 2015 and February 2016 and a well blowout in Ohio released an estimated 40,000 to 60,000 tons of CH_4 in a 20-day period in 2018. The emissions from these types of releases were not well represented using the existing calculation methodologies in subpart W because these were not common or predictable events.[97] Because these events can significantly contribute to the total GHG emissions from this sector, we are proposing new calculation methods for estimating the GHG emissions from other large release events in 40 CFR 98.233(y) and requirements for reporting other large release events in 40 CFR 98.236(y). These proposed additional calculation and reporting requirements would apply to all subpart W industry segments and would improve the accuracy of emissions reported under subpart W and enhance the overall quality of the data collected under the GHGRP.

The new calculation requirements being proposed rely on measurement data or engineering estimates of the amount of gas released and measurement data, if available, or process knowledge (best available data) to estimate the composition of the released gas. The proposed requirement to calculate and report GHG emissions from other large release events would be limited to events that release at least 250 $mtCO_2e$ per event. This is equivalent to approximately 500,000 scf of pipeline quality natural gas. We selected this proposed threshold to capture reporting for large emission events, such as well blowouts, well releases, and large pressure relief venting. In order to establish this reporting threshold, we first assessed other emission sources that we considered large. Specifically,

[95] GRI/EPA. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines.* Prepared for Gas Research Institute and U.S. Environmental Protection Agency National Risk Management Research Laboratory by L.M. Campbell, M.V. Campbell, and D.L. Epperson, Radian International LLC. GRI–94/0257.2b, EPA–600/R–96–080i. June 1996. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[96] Lamb, B.K. *et al.* ''Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States.'' *Environ. Sci. Technol.* 2015, 49, 5161–5169. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[97] The EPA notes that the full emissions from this event were included in the U.S. GHG Inventory based on the results of multiple measurement studies.

we considered completions of hydraulically fractured wells that are not controlled (*i.e.,* not performed using reduced emission completions) to be large emissions events. Based on analysis of GHGRP data of wells that are not reduced emission completions and that vent, the U.S. GHG Inventory developed an average emission factor of about 360 $mtCO_2e$ for these events. Because this is an average emissions factor, some uncontrolled hydraulically fractured completions will be below this average and some above. From this assessment, we considered 250 $mtCO_2e$ to be a reasonable emissions threshold for a ''large'' event.

While 250 $mtCO_2e$ is much lower than the emissions from the Aliso Canyon or Ohio well blowout releases, we determined that a 250 $mtCO_2e$ threshold would be needed to capture most well blowouts. There are limited data to quantify an ''average'' well blowout, but the 2021 U.S. GHG Inventory uses an oil well blowout emission factor of 2.5 MMscf per event. As this is an average, many well blowouts will be less than this average value. The 250 $mtCO_2e$ threshold is approximately equivalent to 500,000 scf of natural gas, which compares reasonably well with the lower range of well blowouts expected based on the average emission factor of 2.5 MMscf per event.

We also find that the 250 $mtCO_2e$ threshold (approximately equivalent to 500,000 scf natural gas release) is a reasonable threshold for requiring individual assessments of releases. In subpart Y (Petroleum Refineries), we established event-specific emission calculation requirements for startup, shutdown, or malfunction releases to a flare exceeding 500,000 scf per day (40 CFR 98.253(b)(1)(iii)). While the subpart Y threshold is per day rather than per event, it is also specific to flared emissions. For flared emissions to exceed a 250 $mtCO_2e$ threshold, approximately 4 MMscf of natural gas would have to be released to the flare, which is well above the subpart Y ''per day'' threshold for flares. Thus, we conclude that the 250 $mtCO_2e$ per event threshold is an appropriate size threshold for requiring event-specific emission calculations to be performed. More information regarding our review and characterization of types of other large release events is included in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424. Emissions from smaller or routine release events would still be reported, as applicable, under the source-specific calculation and reporting requirements in subpart W.

We are proposing a definition of ''other large release events'' in 40 CFR 98.238 to clarify the types of releases that must be characterized for this new emissions source and specify that other large release events include, but are not limited to, well blowouts, well releases, releases from equipment rupture, fire, or explosions. Currently, there are no calculation methodologies or reporting requirements for these types of large releases in subpart W. The proposed definition would also include large pressure relief valve releases from process equipment other than onshore production and onshore petroleum and natural gas gathering and boosting storage tanks that are not included in the blowdown definition. While subpart W currently includes emission factors for pressure relief devices, these equipment leak emission factors only account for leaks past a pressure relief valve that is in the closed position, not releases from the complete opening of these valves. The proposed definition specifies that pressure relief valve releases from onshore production and onshore petroleum and natural gas gathering and boosting storage tanks would not be considered other large release events because the calculation methodology for these storage tanks currently assumes all flash gas will be emitted. As noted in section III.K.1.g of this preamble, pressure relief emission releases from onshore production and onshore petroleum and natural gas gathering and boosting storage tanks generally occur from the thief hatch and these releases must be accounted for when calculating the fraction of flash gas that is recovered or sent to a flare, if applicable. A more detailed discussion of certain other emissions events we have identified and expect to be subject to the ''other large release events'' proposed amendments is included in the subpart W TSD available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

As part of the proposed definition of ''other large release events'' in 40 CFR 98.238, we are also proposing that other large release events include releases from equipment for which the existing calculation methodologies in subpart W would significantly underestimate the episodic nature of these emissions. For example, subpart W contains population emission factors and leaker emission factors for estimating equipment leak emissions for storage wellheads. Thus, it is possible to argue that subpart W includes calculation methodologies for the equipment responsible for the Aliso Canyon release. However, the calculation methodologies in subpart W do not accurately estimate emissions from such an uncharacteristically large event because such events are so rare that they generally do not exist when measurement studies are conducted. Additionally, skewing the emission factors used to account for such an event would yield erroneously high emissions from normal operations for nearly all reporting facilities. Thus, we determined that it is more accurate for facility-specific reporting to account for these large releases on a per event basis. Therefore, if a single leak or event has emissions that exceed the emissions estimated by an applicable methodology included in subpart W by 250 $mtCO_2e$ or more, we are proposing that such releases would be included in the definition of ''other large release events'' and that reporters would be required to calculate and report the GHG emissions from these events using the proposed requirements for other large release events.

Further, we are proposing to define the terms ''well release'' and ''well blowout'' in 40 CFR 98.238 to assist reporting facilities with differentiating between these types of release events that could potentially occur at wells. We find that a well blowout is generally distinguished by a complete loss of well control for a long duration of time and a well release is characterized as a short period of uncontrolled release (not the controlled pre-separation stage of well flowback in a hydraulically fractured completion) followed by a period of controlled release in which control techniques were successfully implemented.

Finally, we are proposing a reporting requirement that would require subpart W reporters to indicate whether an ''other large release event'' was identified under any provisions of NSPS OOOOb or an applicable approved state plan or applicable Federal plan in 40 CFR part 62. As described in section III.J.1.k of this preamble, the EPA proposed a fugitive emissions monitoring program in NSPS OOOOb and EG OOOOc, including an alternative screening approach for fugitive emissions from well sites and compressor stations that would allow the use of advanced measurement technologies to detect emissions. As part of that proposal, the EPA also requested comment on how to evaluate and design a requirement for owners and operators to investigate and remediate large emission events, which could include the use of alternative screening techniques and advanced measurement technologies, all of which, if finalized, could potentially be used to identify ''other large release events'' under subpart W. While some methods that could be used to identify and estimate the magnitude of these ''other large release events,'' such as monitors installed on mobile vehicles or aircraft or methane satellite imagery, would not be specifically included as measurement methods in subpart W, these methods may be used to quantify the emissions release for ''other large release events'' under the ''engineering estimates'' and ''best available data'' provisions of the proposed calculation methodology. To improve the EPA's understanding of the technologies and methods used to identify reported ''other large release events,'' including the impact of periodic screenings with advanced measurement technologies on the identification of large release events, we are proposing reporting provisions that would require reporters to indicate whether each ''other large release event'' was identified as part of compliance with NSPS OOOOb or the applicable state plan or applicable Federal plan in 40 CFR part 62.

n. Combustion

Methane slip from compressor engines. All facilities reporting under subpart W except those in the Onshore Natural Gas Transmission Pipeline industry segment must include combustion emissions in their annual report. Facilities in the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution industry segments calculate emissions in accordance with the provisions in 40 CFR 98.233(z) and report combustion emissions per 40 CFR 98.236(z). Reporters in the other industry segments calculate and report combustion emissions under subpart C (General Stationary Fuel Combustion Sources). The authors of several recent studies have examined combustion emissions at Onshore Petroleum and Natural Gas Gathering and Boosting facilities and have demonstrated that a significant portion of emissions can result from unburned methane entrained in the exhaust of natural gas compressor engines (also referred to as ''combustion slip'' or ''methane slip''). These studies contend that emissions from natural gas compressor engines included in the GHGRP are significantly underestimated because they do not account for combustion slip.[98] The EPA performed a review of each of these studies and the U.S. GHG Inventory to determine whether and how combustion slip emissions have been incorporated into published data and how the incorporation of combustion slip would affect the emissions from the petroleum and natural gas system sector reported to the GHGRP (see the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).

Based on the EPA's review and analysis, there appears to be combustion slip for all compressor engine types at oil and gas facilities. In addition, while the recent studies are focused on the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, the EPA's literature review found the presence of combustion slip in different industry segments, so it appears that combustion slip is dependent on the type of engine and not the application (*i.e.,* we expect combustion slip from compressor engines regardless of the industry segment). Therefore, the EPA is proposing to revise the methodologies for determining combustion emissions from compressor engines to account for combustion slip, consistent with section II.A.3 of this preamble. For the three subpart W industry segments that calculate combustion emissions per 40 CFR 98.233(z), we are proposing to accomplish this with two amendments to the calculation methods and the addition of one new reporting requirement. For compressor engines in those subpart W industry segments that combust natural gas and qualify to determine emissions using the subpart C calculation methodologies per 40 CFR 98.233(z)(1) and proposed new 98.233(z)(2),[99] we are proposing that reporters would use subpart-W specific emission factors by engine design class (*e.g.,* 2-stroke lean-burn, 4-stroke lean-burn, 4-stroke rich-burn, or other) in proposed new Table W–9 rather than the emission factors in Table C–2. For compressor engines that combust natural gas and determine emissions per 40 CFR 98.233(z)(2) (proposed to be moved to 40 CFR 98.233(z)(3)), we are proposing updated combustion efficiency value(s) (η) by engine design class to be used in equations W–39A and W–39B that would reflect combustion slip. We are also proposing to add a reporting requirement to 40 CFR 98.233(z)(2) to specify the design class of reported internal combustion units that are compressor-drivers to facilitate verification of the selected emission factors and efficiencies, as applicable, and the resulting emissions.

In an analogous amendment for the reporters in the other subpart W industry segments that calculate and report combustion emissions under subpart C, we are proposing that they also use subpart W-specific emission factors rather than the emission factors in Table C–2. Currently, these facilities use either equation C–8, C–8a, C–8b, C–9, C–9a, C–9b, or C–10 in 40 CFR 98.33(c), as it corresponds to the Tier methodology selected to estimate their CO_2 emissions, to estimate CH_4 emissions. These equations rely on the use of a default CH_4 emission factor from Table C–2 to estimate emissions. As described in section III.B of this preamble, the emission factor term definition in each of these equations is proposed to be amended to reference Table W–9 rather than Table C–2 specifically for quantifying emissions from compressor-drivers. We are also proposing to add a footnote to Table C–2 to specify that the default CH_4 emission factor should only be used for combustion devices that are not compressor-drivers.

Clarifications of calculation methodologies. As noted previously in this section, Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution facilities report combustion emissions calculated in accordance with 40 CFR 98.233(z) instead of reporting under subpart C. Stakeholders (*e.g.,* GPA Midstream) have identified several concerns with the requirements in 40 CFR 98.233(z). First, GPA Midstream has indicated that for fuels using the existing provisions of 40 CFR 98.233(z)(2) to calculate emissions, the requirements for determining the gas composition could result in inaccurate calculations of emissions for some facilities.[100] In particular, 40 CFR 98.233(z)(2)(ii) currently specifies that to determine the concentrations of

[98] Zimmerle *et al., Characterization of Methane Emissions from Gathering Compressor Stations: Final Report* (October 2019 Revision) and Vaughn *et al.,* ''Methane Exhaust Measurements at Gathering Compressor Stations in the United States,'' *Environmental Science & Technology.* 2021, *55* (2), 1190–1196, both available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[99] See section III.J.2.f of this preamble for information on the proposed amendments to 40 CFR 98.233(z) to increase the flexibility for reporters to use the subpart C calculation methodologies.

[100] See Letter from GPA Midstream Association to Mark de Figueiredo, U.S. EPA, providing information in response to EPA questions during the meeting on March 23, 2016. May 18, 2016. See also Letter from Matt Hite, GPA Midstream Association, to Mark de Figueiredo, U.S. EPA, Re: Additional Information on Suggested Part 98, Subpart W Rule Revisions to Reduce Burden. September 13, 2019. Both letters are available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

hydrocarbon constituents in the flow of gas to the unit, reporters must either use a continuous gas composition analyzer (if one is present) or the procedures in the applicable paragraph in 40 CFR 98.233(u)(2) of this section. For onshore petroleum and natural gas gathering and boosting facilities, 40 CFR 98.233(u)(2) specifies use of the annual average gas composition based on the most recent available analysis of the gas received at the facility. However, GPA Midstream explained that onshore petroleum and natural gas gathering and boosting facilities do not necessarily use the gas received at their facility for combustion. For example, if the gas received at the facility is not suitable for combustion, they may mix the gas with purchased natural gas. In that case, the annual average composition of gas received at the facility would not be representative of the gas sent to the combustion unit (as required by 40 CFR 98.233(z)(2)), which could result in inaccurate emissions. Therefore, the EPA is proposing to revise the language in 40 CFR 98.233(z)(2)(ii) (proposed to be moved to 40 CFR 98.233(z)(3)(ii)(B)) to allow the use of engineering estimates based on best available data to determine the concentration of gas hydrocarbon constituent in the flow of gas to the unit. This proposed amendment would allow reporters to use the best information available to determine the gas composition while maintaining the option for reporters to use 40 CFR 98.233(u)(2) if they do not have other stream-specific information. In addition to improving the accuracy of the emissions calculated and therefore the quality of data collected, consistent with section II.A.2 of this preamble, this proposed amendment is expected to provide additional flexibility for reporters, consistent with section II.B.2 of this preamble.

Second, GPA Midstream indicated that the existing provisions of 40 CFR 98.233(z)(1)(ii) are unclear and that some member companies have been interpreting those provisions to mean that reporters with combustion sources at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities must use the calculation methodologies in subpart W rather than subpart C (even given the provisions in 40 CFR 98.233(z)(1) that reference subpart C for certain fuels).[101]

The existing provisions of 40 CFR 98.233(z)(1)(ii) are intended to refer only to the reporting requirements and are not intended to define which calculation methodologies can be used. In the current rule, the provisions in the 40 CFR 98.233(z)(1) introductory text define which calculation methodologies can be used, and 40 CFR 98.233(z)(1)(ii) simply indicates that all reporters with combustion sources at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities must report those emissions in the e-GGRT system under subpart W rather under subpart C. As part of the amendments described in this section, consistent with section II.A.5 of this preamble, 40 CFR 98.233(z)(1)(ii) is proposed to be moved to 40 CFR 98.233(z)(4), and we are proposing wording changes to be clear that this paragraph refers only to reporting. We are also proposing to add a reference to this new paragraph 40 CFR 98.233(z)(4) in both 40 CFR 98.233(z)(1)(ii) and 98.233(z)(2)(ii) (as proposed to be amended).

o. Leak Detection and Measurement Methods

Acoustic leak detection. For emission source types for which measurements are required, subpart W specifies the methods that may be used to make those measurements in 40 CFR 98.234(a). To improve the quality of the data when an acoustic leak detection device is used, consistent with section II.A.2 of this preamble, we are proposing two revisions to the acoustic measurement requirements in 40 CFR 98.234(a)(5). First, for stethoscope type acoustic leak detection devices (*i.e.,* those designed to detect through-valve leakage when put in contact with the valve body and that provide an audible leak signal but do not calculate a leak rate), we are proposing that a leak is detected if an audible leak signal is observed or registered by the device. Second, we are proposing that if a leak is detected using a stethoscope type device, then that leak must be measured using one of the quantification methods specified in 40 CFR 98.234(b) through (d) and that leak measurement must be reported regardless of the volumetric flow rate measured. These proposed revisions would improve the accuracy of emissions reported for compressors and transmission tanks when an acoustic leak detection device is used.

High volume samplers. We are proposing two revisions to the high volume sampler methods to improve the quality of the data when high volume samplers are used for flow measurements, consistent with section II.A.2 of this preamble. First, we are proposing to add detail to 40 CFR 98.234(d)(3) to clarify the calculation methods associated with high volume sampler measurements. Generally, high volume samplers measure methane flow, not whole gas flow. However, the current calculation methods in 40 CFR 98.234(d)(3) treat the measurement as a whole gas measurement. Therefore, we are clarifying the calculation methods needed if the high volume sampler outputs methane flow in either a mass flow or volumetric flow basis. Specifically, we are proposing methods to determine natural gas (whole gas) flows based on measured methane flows.

Second, we are proposing to add a paragraph at 40 CFR 98.234(d)(5) to clarify how to assess the capacity limits of a high volume sampler. Currently, 40 CFR 98.234(d) simply states to ''Use a high volume sampler to measure emissions within the capacity of the instrument''; there is no other information provided to clarify what ''within the capacity of the instrument'' means or how it is determined. We understand that there are different manufacturers, but most common high volume samplers report maximum sampling rates of 10 to 11 cubic feet per minute (cfm) and maximum methane flow quantitation limits of 6 to 8 cfm. Based on our review of reported high volume sampler measurements, we found that 2 to 5 percent of high volume sampler measurements for all types of compressor sources (for both centrifugal and reciprocating compressors) are likely at or beyond the expected capacity limits of the high volume sampler instrument. Considering actual sampling rates, gas collection efficiencies near the sampling rates, and reported methane quantitation limits relative to maximum sampling rates, we determined that whole gas flow rates exceeding 70 percent of the device's maximum rated sampling rate is an indication that the device will not accurately quantify the volumetric emissions, which we deem to exceed the capacity of the device. Therefore, we are proposing to specify that methane flows above the manufacturer's methane flow quantitation limit or total volumetric flows exceeding 70 percent of the manufacturer's maximum sampling rate indicate that the flow is beyond the capacity of the instrument and that flow meters or calibrated bags must be used to quantify the flow rate. For more information on our review, see the subpart W TSD, available in the

[101] Letter from GPA Midstream Association to Mark de Figueiredo, U.S. EPA, providing information in response to EPA questions during the meeting on March 23, 2016. May 18, 2016. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

docket for this rulemaking (Docket Id. No EPA–HQ–OAR–2019–0424).

p. Onshore Petroleum and Natural Gas Gathering and Boosting Compressor Stations

The EPA received feedback from GPA Midstream that a count of compressor stations per Onshore Petroleum and Natural Gas Gathering and Boosting facility would provide the EPA with improved data on the number and type of equipment at gathering and boosting stations, which could help to better inform future rulemakings.[102] In addition, the EPA could use information on the count of compressor stations to improve the process of verifying annual reports to the GHGRP. As an example, a facility with high emissions for a particular source type compared to other facilities in the same basin might currently be identified as a potential outlier. However, if the report also indicated that the facility has a large number of compressor stations compared to other facilities, the EPA could use that information during report verification to confirm the high emissions without needing to contact the facility owner or operator. Therefore, the EPA is proposing to add a requirement in 40 CFR 98.236(aa)(10)(v) to report the count of compressor stations for facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, consistent with section II.A.4 of this preamble. Additionally, the count of compressor stations per facility would allow for refinements to the activity data used by the U.S. GHG Inventory. In particular, the calculated national-level compressor station activity data used by the U.S. GHG Inventory could be informed by reported compressor station counts for Onshore Petroleum and Natural Gas Gathering and Boosting facilities subject to subpart W, which improves the U.S. GHG Inventory estimate of total national emissions. The EPA is also proposing a definition of ''compressor station'' in 40 CFR 98.238 to be used for the purposes of this reporting requirement to reduce any potential reporter confusion.

Based on the definition of Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, this industry segment also includes ''centralized oil production sites.'' These are sites that collect oil from multiple well pads but that do not have compressors (*i.e.,* are not ''compressor stations''). Therefore, we are proposing to add a requirement in 40 CFR 98.236(aa)(10)(vi) to report the count of centralized oil production sites for facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, consistent with section II.A.4 of this preamble. We are also proposing to add a definition of ''centralized oil production site'' in 40 CFR 98.238 to be used for the purposes of this reporting requirement. These proposed additional data elements would enhance the overall quality of the data collected under the GHGRP.

q. Onshore Natural Gas Transmission Pipeline Throughput Information

Similar to Natural Gas Distribution facilities, Onshore Natural Gas Transmission Pipeline facilities are currently required to report five throughput volumes under subpart W, as specified in 40 CFR 98.236(aa)(11). These five data reporting elements include: the quantity of natural gas received at all custody transfer stations; the quantity of natural gas withdrawn from in-system storage; the quantity of gas added to in-system storage; the quantity of gas transferred to third parties; and the quantity of gas consumed by the transmission pipeline facility for operational purposes. As noted in section III.J.2.g of this preamble, the EPA has received stakeholder comments on the reporting elements for Natural Gas Distribution facilities, including questions submitted to the GHGRP Help Desk, regarding the term ''in-system storage.'' Although the questions were specific to Natural Gas Distribution facilities, the term ''in-system storage'' is also included in the throughput reporting elements for Onshore Natural Gas Transmission Pipeline facilities at 40 CFR 98.236(aa)(11)(ii) and (iii). After consideration of the stakeholder comments, the EPA is proposing to clarify the term ''in-system.'' Specifically, we are proposing to amend 40 CFR 98.236(aa)(11)(ii) and (iii) to clarify that ''in-system'' withdrawals/additions of natural gas from storage are specifically referring to Underground Natural Gas Storage and LNG Storage facilities that are owned and operated by the onshore natural gas transmission pipeline owner or operator that do not report under subpart W as direct emitters themselves. These amendments are expected to improve data quality consistent with section II.A.5 of this preamble.

2. Proposed Revisions to Streamline and Improve Implementation for Subpart W

As further described in section II.B of this preamble, we are also proposing amendments to remove, reduce, or simplify requirements that would streamline and improve implementation while maintaining the quality of the data collected under part 98. To determine which reporting requirements and data elements of subpart W to propose amending, the EPA reviewed correspondence with reporters during the annual verification of GHGRP data, questions submitted to the GHGRP Help Desk and the responses provided, and the specific regulatory language of subpart W. As a result of that process, the EPA is proposing to eliminate, clarify, or otherwise amend select calculation methodologies and reporting requirements as described in this section. Consistent with section II.B.2 of this preamble, some of the proposed amendments would add monitoring or reporting flexibility for certain calculation methodologies. Other proposed revisions would remove reporting requirements that are redundant with data already reported to the EPA or no longer being used at this time, as further described in section II.B.3 of this preamble.

a. Dehydrator Vents

Removal of requirements for desiccant dehydrators. Subpart W currently requires reporting of desiccant dehydrators as a subcategory of dehydrator vents. Based on the data reported to date, the emissions from these sources are less than 0.1 percent of total reported emissions from dehydrator vents (in RY2020, desiccant dehydrators contributed 760 $mtCO_2e$ of the total 3.35 million $mtCO_2e$ from all dehydrator vent emissions). In addition, it appears that a significant percentage of the emissions reported to date may be from molecular sieve dehydrators; however, we never intended to require reporting of emissions from such units, and based on the definition of ''dehydrator'' in 40 CFR 98.6, we do not read the rule to require such reporting. In RY2015 through RY2020, about 60 percent of the facilities that reported counts of desiccant dehydrators also reported emissions of 0 $mtCO_2e$ (516 out of 897 reporters), and more than one-quarter of the reported desiccant dehydrators were at facilities that reported 0 emissions from desiccant dehydrators (1,888 out of 7,139 units). Furthermore, facilities that report emissions from desiccant dehydrators in a given year may not have depressurized every one of their desiccant dehydrators

[102] Letter from Matt Hite, GPA Midstream Association, to Mark de Figueiredo, U.S. EPA, Re: Additional Information on Suggested Part 98, Subpart W Rule Revisions to Reduce Burden. September 13, 2019. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

in that year, but this cannot be determined from the reported data because emissions are reported at the facility level instead of per dehydrator. This pattern of emissions reporting is consistent with the expected results for molecular sieve dehydrators because such units typically are opened (depressurized) only once every few years. Thus, a significant percentage of the reported emissions from desiccant dehydrators may be from units that are not subject to reporting, meaning that the actual emissions from desiccant dehydrators would be less than the reported 0.1 percent of the total dehydrator emissions. Therefore, we are proposing to remove requirements for desiccant dehydrators from 40 CFR 98.233(e)(3) and (4) and 40 CFR 98.236(e)(3) of subpart W, consistent with section II.B.2 and II.B.3 of this preamble.[103] As a corollary to the proposed removal of the desiccant dehydrator requirements, we are also proposing to remove the definition of ''desiccant'' and to revise the definition of ''dehydrator'' in 40 CFR 98.6, as discussed in section III.A of this preamble.

As an alternative to removing the requirements for all desiccant dehydrators, we considered revising 40 CFR 98.233(e)(3) to clarify that only devices with desiccant that absorb water (as opposed to those containing materials that adsorb water) are subject to the GHGRP. That change would be consistent with the original intent, as evidenced by the definitions of ''desiccant'' and ''dehydrator'' in 40 CFR 98.6, and it would clarify that molecular sieve units (which contain material that adsorbs water) are not subject to subpart W. That change also would reduce the number of reporters. However, we are not proposing that option because the reported emissions would be extremely small relative to other dehydrator emissions. We request comment on other advantages and disadvantages of this option relative to the proposed plan of deleting requirements for desiccant dehydrators and whether commenters think there are potential benefits of this option that outweigh potential drawbacks.

Although this proposal would remove the desiccant dehydrator requirements from subpart W, other requirements in subpart W may then apply instead. Currently, 40 CFR 98.233(e)(3) and 40 CFR 98.233(i) specify that desiccant dehydrator emissions calculated using equation W–6 do not have to be calculated separately under the blowdown vent stacks provisions in 40 CFR 98.233(i). However, because we are proposing to remove the desiccant dehydrator provisions, the EPA is also proposing to remove the exception at the end of the 40 CFR 98.233(i) introductory paragraph. Thus, the blowdown provisions in 40 CFR 98.233(i) would apply, provided that the volume of space in a desiccant dehydrator that is depressurized to atmosphere is greater than 50 cubic feet. Similarly, in the absence of desiccant dehydrator provisions, if the emissions from depressurizing desiccant dehydrators are routed to a flare, then the emissions would be subject to the requirements for flare stack emissions in 40 CFR 98.233(n). We note that while these emissions may still be reported to the EPA if the proposal to remove the desiccant dehydrator provisions is finalized, they would no longer be required to be calculated and reported separately, which would still streamline implementation for reporters.

Clarification of Count for Glycol Dehydrators with Annual Average Daily Natural Gas Throughput Less Than 0.4 MMscf per Day. As noted in section III.J.1.d of this preamble, for glycol dehydrators with an annual average daily natural gas throughput less than 0.4 MMscf per day, reporters currently use population emission factors and equation W–5 to calculate volumetric CO_2 and CH_4 emissions per 40 CFR 98.233(e)(2) and report emissions per 40 CFR 98.236(e)(2). Under these current requirements, the count of glycol dehydrators with annual average daily natural gas throughput less than 0.4 MMscf per day could include dehydrators with annual average daily natural gas throughput of 0 MMscf per day (*i.e.,* glycol dehydrators that were not operated during the reporting year). As a result, some annual reports include a nonzero count of dehydrators per 40 CFR 98.236(e)(2)(i) without any corresponding CO_2 and CH_4 emissions. In these cases, it is not clear if the reporter did not report emissions because emissions are not expected, the emissions data were inadvertently omitted, or the nonzero count represents the total count of all dehydrators with annual average daily natural gas throughput less than 0.4 MMscf per day, including those that were not in use.

Therefore, the EPA is proposing to clarify in 40 CFR 98.233(e)(2) that the dehydrators for which emissions are calculated should be those with annual average daily natural gas throughput greater than 0 MMscf per day and less than 0.4 MMscf per day (*i.e.,* the count should not include dehydrators that did not operate during the year). Similarly, the EPA is proposing to clarify that the count of dehydrators in 40 CFR 98.236(e)(2)(i) should also be those with annual average daily natural gas throughput greater than 0 MMscf per day and less than 0.4 MMscf per day. These amendments are expected to streamline and improve implementation, consistent with section II.B.3 of this preamble.

b. Blowdown Vent Stacks

Blowdown equipment types. Subpart W currently requires reporting of blowdowns either using flow meter measurements (40 CFR 98.233(i)(3)) or using unique physical volume calculations by equipment or event types (40 CFR 98.233(i)(2)). When the Onshore Natural Gas Transmission Pipeline industry segment was added to subpart W in 2015, public commenters indicated that the existing equipment or event types were not appropriate for the new segment, so the EPA developed new equipment or event types that apply only for the Onshore Natural Gas Transmission Pipeline industry segment (80 FR 64275, October 22, 2015). The new equipment or event types were added to the introductory paragraph of 40 CFR 98.233(i)(2), where the existing equipment or event types were already located, resulting in a complex introductory paragraph. Also, both the third sentence and last sentence in 40 CFR 98.233(i)(2) currently read as follows: ''If a blowdown event resulted in emissions from multiple equipment types and the emissions cannot be apportioned to the different equipment types, then categorize the blowdown event as the equipment type that represented the largest portion of the emissions for the blowdown event.'' According to this provision, when a blowdown event consists of emissions from two or more equipment types, the emissions must be apportioned to each applicable equipment type, unless such apportionment is not possible.

The EPA is proposing to move the listings of event types and the apportioning provisions to a new 40 CFR 98.233(i)(2)(iv) so that the introductory paragraph in 40 CFR 98.233(i)(2) would be more concise and provide clearer information regarding which requirements are applicable for each blowdown. Proposed 40 CFR 98.233(i)(2)(iv) includes separate paragraphs for each set of equipment and event type categories and would also provide clearer information

[103] We are also proposing to move the specifications for calculating mass emissions from volumetric emissions for glycol dehydrators with an annual average of daily natural gas throughput that is less than 0.4 MMscf per day from 40 CFR 98.233(e)(4) to 40 CFR 98.233(e)(2), which would consolidate the requirements for those dehydrators.

regarding the applicable requirements for each industry segment.

Blowdown Temperature and Pressure. In the 2015 amendments to subpart W (80 FR 64262, October 22, 2015), the EPA added the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment and the Onshore Natural Gas Transmission Pipeline industry segment and specified that both industry segments are required to report emissions from blowdown vents. Stakeholders representing the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment provided comments on the proposed rule stating that the proposed definition of facility would make equipment geographically dispersed, and blowdowns may occur without personnel on-site or nearby, which would make it difficult to collect the information needed to calculate emissions from each blowdown (80 FR 64271, October 22, 2015). As a result of those comments, the EPA also specified in the final amendments to equation W–14A that for emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities, engineering estimates based on best available information may be used to determine the actual temperature and actual pressure.

Since that time, the EPA has received questions through the GHGRP Help Desk indicating that facilities in the Onshore Natural Gas Transmission Pipeline industry segment also have unmanned blowdown vents. Given that a ''facility with respect to the onshore natural gas transmission pipeline segment'' is the total mileage of natural gas transmission pipelines owned and operated by an onshore natural gas transmission pipeline owner or operator, all of the blowdown vents at that facility would be outside the fenceline of a transmission compression station and would be geographically dispersed. The EPA considers it reasonable to assume that those blowdown vents may also be unmanned. Therefore, we are proposing to extend the provisions in equation W–14A of 40 CFR 98.233(i)(2)(i) that allow use of engineering estimates based on best available information to determine the temperature and pressure of an emergency blowdown to the Onshore Natural Gas Transmission Pipeline segment, which would align the requirements for the two geographically dispersed industry segments (Onshore Natural Gas Transmission Pipeline and Onshore Petroleum and Natural Gas Gathering and Boosting) and increase flexibility for Onshore Natural Gas Transmission Pipeline reporters, consistent with section II.B.2 of this preamble.

In addition, similar provisions to allow use of engineering estimates based on best available information to determine the temperature and pressure of an emergency blowdown were not added to equation W–14B of 40 CFR 98.233(i)(2)(i) in 2015 (80 FR 64262, October 22, 2015). We have reviewed this equation and have determined that this omission was inadvertent. Therefore, we are proposing to add provisions to equation W–14B to allow use of engineering estimates to determine the temperature and pressure of an emergency blowdown for both the Onshore Natural Gas Transmission Pipeline and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, consistent with equation W–14A.

c. Atmospheric Storage Tanks

Calculation methods 1 and 2 reporting. For facilities reporting atmospheric storage tank emissions calculated using Calculation Method 1 or Calculation Method 2, 40 CFR 98.236(j)(1) requires reporting of counts of the total number of atmospheric storage tanks within the sub-basin or county, the number of atmospheric storage tanks that are controlled by a vapor recovery system, the number of atmospheric storage tanks that are controlled by a flare, and the number of atmospheric storage tanks that are not controlled by either a vapor recovery system or a flare. As atmospheric storage tanks are typically controlled by both a vapor recovery system and a flare, these counts allow for overlap and cause confusion among reporters. Additionally, atmospheric storage tanks may be included in multiple categories of counts if the facility elects to add an emissions control partway through the reporting year.

Therefore, the EPA is proposing to reorganize the reporting requirements in 40 CFR 98.236(j)(1) to reduce overlap between several of the current data elements that are reported by control methodology. Specifically, the EPA is proposing to collect only the total number of tanks within the sub-basin or county, the count of atmospheric tanks that routed emissions to vapor recovery and/or flares at any point during the reporting year, and the count of atmospheric tanks that vented gas directly to the atmosphere and did not control emissions using a vapor recovery system or flares at any point during the reporting year.

For consistency with the revisions to the atmospheric storage tank count data elements, the EPA is proposing to require separate reporting of emissions for tanks that did not control emissions using a vapor recovery system or flares at any point during the reporting year and for tanks that routed emissions to vapor recovery and/or flares at any point during the reporting year. For tanks that do not control emissions using a vapor recovery system or flares at any point during the reporting year, facilities would report CO_2 and CH_4 emissions resulting from venting gas directly to the atmosphere. For tanks that rout emissions to vapor recovery and/or flares at any point during the reporting year, facilities would report CO_2, CH_4, and N_2O emissions from flares and the total mass of CO_2 and CH_4 that was recovered using a vapor recovery system in addition to the CO_2 and CH_4 emissions resulting from venting gas directly to the atmosphere. With this reorganization of the emissions reporting requirements for atmospheric storage tanks, the EPA expects to streamline reporting and reduce redundancy between data elements, consistent with section II.B.3 of this preamble.

Additionally, the EPA is proposing to remove the requirement to report an estimate of the number of atmospheric storage tanks that are not on well-pads and that are receiving the facility's oil (40 CFR 98.236(j)(1)(xi)), consistent with section II.B.3 of this preamble. This reporting requirement is redundant because all Onshore Petroleum and Natural Gas Production facilities reporting atmospheric storage tank emissions calculated using Calculation Method 1 or Calculation Method 2 must also report the total number of atmospheric tanks in the sub-basin per 40 CFR 98.236(j)(1)(x).

Calculation method 3 reporting. For hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks with throughput less than 10 barrels per day, reporters follow the Calculation Method 3 methodology specified in 40 CFR 98.233(j)(3) and equation W–15. Equation W–15 uses population emission factors and the count of applicable separators, wells, or non-separator equipment to determine the annual total volumetric GHG emissions at standard conditions. The associated reporting requirements in 40 CFR 98.236(j)(2)(i)(E) through (F) require reporters to delineate the count used in equation W–15 into the number of wells with gas-liquid separators in the basin and those without gas-liquid separators. The EPA has received feedback through correspondence with reporters via e-GGRT that these reporting requirements are unclear.

After consideration of this feedback, the EPA has made a preliminary determination that these reporting requirements are not consistent with the language used in the definition of the ''Count'' variable in equation W–15, nor are they inclusive of all equipment to be included in the count.

Therefore, the EPA is proposing to revise 40 CFR 98.236(j)(2)(i)(E) to completely align the requirement with the total ''Count'' input variable in equation W–15. The EPA proposes to amend the language in 40 CFR 98.236(j)(2)(i)(E) to request the total number of separators, wells, or non-separator equipment in the basin used to calculate Calculation Method 3 storage tank emissions. The current language in 40 CFR 98.236(j)(2)(i)(E) requests the number of wells with gas-liquid separators in the basin, which is only a subset of the equipment included in the ''Count'' variable. Further, the EPA is proposing to remove the reporting requirement in 40 CFR 98.236(j)(2)(i)(F), which requires reporting of the number of wells without gas-liquid separators in the basin. Both of the current data elements in 40 CFR 98.236(j)(2)(i)(E) and 40 CFR 98.236(j)(2)(i)(F) have been determined to be no longer as useful for present program or policy purposes, as they do not correlate with the calculated Calculation Method 3 atmospheric tank emissions. These changes would streamline the requirements for all facilities reporting atmospheric storage tanks emissions using Calculation Method 3. Consistent with section II.B.3 of this preamble, reporters would no longer be required to determine two separate counts that may not be representative of the inputs used in equation W–15.

In addition, the provisions in 40 CFR 98.236(j)(2)(ii) and (iii) require facilities to separately report Calculation Method 3 emissions from atmospheric storage tanks that did not control emissions with flares and those that controlled emissions with flares, respectively. Using the calculation procedures provided in 40 CFR 98.233(j)(3) through (5), when a facility adds a flare control to an atmospheric storage tank in the middle of a reporting year, facilities are required to separately calculate emissions that are not flared from emissions that are flared from that tank, sum these emissions values, and report all emissions from the tank as part of the sub-basin or county flared tanks total per the requirements of 40 CFR 98.236(j)(2)(iii). In an effort to streamline and improve implementation consistent with section II.B.2 of this preamble, the EPA is proposing to clarify that for storage tanks using Calculation Method 3, reporters would calculate either flared or vented emissions for a tank, but not both. Specifically, the EPA is proposing to add language in 40 CFR 98.233(j)(5) that specifies that if the flare captured flash gas from at least half of the annual hydrocarbon liquids received by the tank for which emissions were calculated using Calculation Method 3, flared emissions would be calculated according to 40 CFR 98.233(j)(5) (*i.e.,* as if all flash gas generated from a tank during the entire reporting year is sent to a flare). The EPA is also proposing to amend 40 CFR 98.236(j)(2)(iii) to specify that the reporting requirements in that section only apply to tanks whose emissions were calculated using Calculation Method 3 that used flares to control emissions from at least half the annual hydrocarbon liquids received. The EPA is proposing a corresponding change to 40 CFR 98.236(j)(2)(ii), which would require reporting of the Calculation Method 3 emissions from the remaining atmospheric storage tanks that either used flares to control emissions from less than half the annual hydrocarbon liquids received or did not control any emissions with a flare. The emissions from these remaining atmospheric storage tanks would be calculated as venting directly to the atmosphere for the entire year (*i.e.,* emissions from tanks that flared for less than half of the year would not be calculated using the flare procedures provided in 40 CFR 98.233(j)(5)).

d. Flared Transmission Storage Tank Vent Emissions

Reporters in the transmission compression industry segment currently are required to report flared emissions specific to their transmission storage tanks separately from other flare stack emissions. In the years RY2015 through RY2020, between one and six facilities per year reported having a transmission tank vent stack routed to a flare, and each of these facilities reported no leaks. As a result, the reported flared emissions from transmission storage tank vent stacks in each of the last 6 years have been 0 metric tons of CO_2, CH_4, and N_2O. Based on these results, the EPA has made a preliminary determination that continued reporting of source-specific flared emissions from transmission tanks would not likely provide new insights or knowledge of the industry sector, emissions, or trends. Therefore, consistent with section II.B.3 of this preamble, the EPA is proposing that transmission tanks be classified as a miscellaneous flared source such that any flared emissions from the tanks in the future would be reported collectively with flared emissions from all miscellaneous flared sources as specified in 40 CFR 98.236(n)(1). The EPA is proposing to retain the current requirements in 40 CFR 98.233(k)(1) and (2) to monitor the tank vent stack annually for leaks and to quantify the leak rate if a leak is detected. As an alternative to these source-specific requirements, a reporter also would be allowed to continuously measure either total flow from the transmission tank vent stack or the comingled total flow into the flare, consistent with the existing requirement in 40 CFR 98.233(n)(1). Flow data determined by either of these methods would still be needed to calculate total flared emissions from the miscellaneous flared sources. Reporting requirements would remain essentially the same except that flared mass emissions would no longer be reported under 40 CFR 98.236(k)(3). Note that if we decide not to finalize the proposed changes described in this section after considering public comment, then we alternatively propose that we would finalize flare activity data reporting requirements for flared emissions from transmission storage tank vent stacks consistent with the activity data reporting for other source types that have source-specific flared emissions reporting requirements as described in the ''Calculation Methodology for Flared Emissions'' subsection in section III.J.1.i of this preamble. The proposed rule language under this alternative would be added to 40 CFR 98.233(k)(5), and it would be similar to proposed language for other flared sources (*e.g.,* well testing in 40 CFR 98.233(l)(6) and associated gas flaring in 40 CFR 98.233(m)(5)). One difference is that an option to continuously measure combined streams into a flare would not be allowed for transmission tanks because it would not be possible to tell if there were any scrubber dump valve leaks if only a combined emissions stream is measured. We request comment on the advantages and disadvantages of both approaches we are considering relative to the current requirements.

e. Compressors

As noted in section III.J.1.j of this preamble, reporting requirements for compressors in the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Equipment industry segments include requirements to conduct ''as found'' measurements for the compressor mode-source combination in which the compressor is found. In addition, if a given compressor was not measured in not-operating-depressurized-mode during the ''as found'' measurements for three consecutive years, a measurement in not-operating-depressurized-mode is currently required to be taken during the next planned scheduled shutdown of the compressor, per 40 CFR 98.233(o)(1)(i)(C) and (p)(1)(i)(D). This provision requires reporters to schedule an extra ''as found'' measurement to make this required measurement if the compressor was not found in this mode when the regularly scheduled ''as found'' measurements were taken.

We are proposing to eliminate this requirement to conduct a measurement in not-operating-depressurized-mode at least once every three years, consistent with section II.B.2 of this preamble. We originally included this requirement in subpart W in order to obtain a sufficient amount of data for this mode (75 FR 74458, November 30, 2010). However, based on data collected under subpart W thus far, many compressors are in not-operating-depressurized-mode for 30 percent of the time or more. As such, the extra measurements are unnecessary, and we are proposing to eliminate this requirement and make the annual ''as found'' measurements true ''as found'' measurements. We are also proposing to remove the reporting requirement to indicate if the compressor had a scheduled depressurized shutdown during the reporting year (40 CFR 98.236(o)(1)(xiv) and 40 CFR 98.236(p)(1)(xiv)) because that information is only collected to verify compliance with the requirement to conduct a measurement in not-operating-depressurized-mode at least once every three years.

In addition, centrifugal and reciprocating compressors are the only sources for which capture for fuel use and thermal oxidizers are specifically listed as dispositions for emissions that would otherwise be vented. The EPA's intent with the provisions is to differentiate flares, which are combustion devices that combust waste gases without energy recovery (per 40 CFR 98.238), from combustion devices with energy recovery, including for fuel use. However, some thermal oxidizers combust waste gases without energy recovery and therefore may instead meet the subpart W definition of flare. To avoid confusion, and to clarify that the EPA's intent is generally to treat emissions routed to flares and combustion devices other flares consistently, we are proposing to remove the references to fuel use and to thermal oxidizers in 40 CFR 98.233(o) and (p) and 40 CFR 98.236(o) and (p). Instead, we are proposing to define ''routed to combustion'' in 40 CFR 98.238 to specify the types of non-flare combustion equipment for which reporters would be expected to calculate emissions. In particular, for the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution industry segments, ''routed to combustion'' means the combustion equipment specified in 40 CFR 98.232(c)(22), (i)(7), and (j)(12), respectively (*i.e.,* the combustion equipment for which emissions must be calculated per 40 CFR 98.233(z)). For all other industry segments, ''routed to combustion'' means the stationary combustion sources subject to subpart C. The proposed definition of ''routed to combustion'' would apply for all subpart W emission sources for which that term appears (*e.g.,* natural gas driven pneumatic pumps).

Finally, we are proposing to remove some data elements that are redundant between 40 CFR 98.236(o)(1) and (2) for centrifugal compressors and between 40 CFR 98.236(p)(1) and (2) for reciprocating compressors. Specifically, 40 CFR 98.236(o)(1)(vi) and 40 CFR 98.236(p)(1)(vi) require reporters to indicate which individual compressors are part of a manifolded group of compressor sources, and 40 CFR 98.236(o)(1)(vii) through (ix) and 40 CFR 98.236(p)(1)(vii) through (ix) require reporters to indicate whether individual compressors have compressor sources routed to flares, vapor recovery, or combustion. However, 40 CFR 98.236(o)(2)(ii)(A) and 40 CFR 98.236(p)(2)(ii)(A) require the same information for each compressor leak or vent rather than by compressor. The information collected for each leak or vent is more detailed and is the information used for emissions calculations. Therefore, the EPA is proposing to remove the redundant reporting requirements in 40 CFR 98.236(o)(1)(vi) through (ix) and 40 CFR 98.236(p)(1)(vi) through (ix), consistent with section II.B.3 of this preamble.

f. Combustion

Subpart W refers reporters in the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution industry segments to the calculation methodologies in subpart C to determine combustion emissions for certain fuels. Specifically, 40 CFR 98.233(z)(1) specifies that reporters may use any tier of subpart C if the fuel combusted is listed in Table C–1; the paragraph further specifies that the subpart C methodologies may only be used for fuel meeting the definition of ''natural gas'' in 40 CFR 98.238 if it is also of pipeline quality specification and has a minimum HHV of 950 Btu per standard cubic foot (Btu/scf). If the fuel is natural gas that does not meet these criteria, field gas, process vent gas, or a blend containing field gas or process vent gas, 40 CFR 98.233(z)(1) specifies that the procedures in 40 CFR 98.233(z)(2) should be used to calculate combustion emissions. Stakeholders (*e.g.,* GPA Midstream) have identified several concerns with these requirements. In general, they have stated that the ability to use subpart C calculation methodologies is unclear and too restrictive. We are proposing several amendments to these provisions to address these concerns and increase the flexibility of the calculation methods, consistent with section II.B.2 of this preamble.

First, GPA Midstream has indicated that it is not clear whether field gas that is of pipeline quality meets the criteria to use the subpart C methodologies under 40 CFR 98.233(z)(1),[104] and ''field gas'' is not defined within subpart W or subpart A (General Provisions). The terms ''field gas'' and ''field quality'' are frequently used interchangeably by the industry, but the EPA also recognizes that some streams in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment that industry would generally call ''field gas'' can be natural gas (as defined in 40 CFR 98.238) of pipeline quality with a minimum HHV of 950 Btu/scf. GPA Midstream stated that the procedures in 40 CFR 98.233(z)(2) are more burdensome than the subpart C methodologies and asked that the EPA clarify that ''field gas'' streams of pipeline quality can use the subpart C methodologies. After review of these comments, the EPA is proposing to revise 40 CFR 98.233(z)(1) to remove the references to field gas and process vent gas and include only the characteristics for the fuels that can use subpart C methodologies. The EPA's intent is to clarify that a stream colloquially referred to as ''field gas'' that otherwise meets the three criteria to use the subpart C methodologies for combustion emissions (*i.e.,* (1) meets the definition of ''natural gas'' in 40 CFR 98.238; (2) is of pipeline quality specification; and (3) has a minimum HHV of 950 Btu/scf) may use subpart C methodologies. The

[104] Letter from GPA Midstream Association to Mark de Figueiredo, U.S. EPA, providing information in response to EPA questions during the meeting on March 23, 2016. May 18, 2016. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

EPA is also proposing conforming edits to 40 CFR 98.233(z)(2) (proposed to be moved to 40 CFR 98.233(z)(3)) for consistency.

Second, reporters have indicated in questions submitted to the GHGRP Help Desk that the term ''pipeline quality'' is also not defined in subpart W, leading to confusion over whether some fuel streams meet the criteria to use the subpart C calculation methodologies per 40 CFR 98.233(z)(1). In addition, GPA Midstream has opined that the emissions calculated using subpart C and subpart W calculation methodologies are similar for many fuel streams that are not natural gas of pipeline quality specification with a minimum HHV of 950 Btu/scf. Therefore, they have suggested that the EPA should allow subpart C calculation methodologies to be used for a wider variety of fuels (if not all fuels in the segments that report combustion emissions under subpart W).[105]

We have reviewed the analysis in GPA Midstream's May 18, 2016 letter and conducted our own analysis of additional hypothetical fuel compositions. In general, we observed that the agreement of emissions as calculated using subpart C calculation methodologies for natural gas and using subpart W calculation methodologies varies based on the composition, with the largest differences resulting for fuel streams with high CO_2 content. We also observed that for these fuels, emissions calculated using subpart W calculation methodologies generally showed better agreement with emissions calculated using the subpart C calculation methodology for natural gas when using a site-specific HHV (Tier 2) than with emissions calculated using the subpart C calculation methodology that uses a default HHV (Tier 1). For more information on our fuel composition analysis and the comparison of emissions using various composition thresholds, see the subpart W TSD, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

Based on our analysis, we are proposing to add numeric composition thresholds for natural gas to a new paragraph in 40 CFR 98.233(z)(2) that define the fuels for which an owner or operator may use subpart C methodologies. In particular, we are proposing that subpart C methodologies Tier 2 or higher may be used for fuel meeting the definition of ''natural gas'' in 40 CFR 98.238 if it has a minimum HHV of 950 Btu/scf, a maximum CO_2 content of 1 percent by volume, and a minimum CH_4 content of 85 percent by volume. We are not proposing to amend the existing provisions in 40 CFR 98.233(z)(1) that allow the use of any subpart C calculation methodology for natural gas of pipeline quality specification with a minimum HHV of 950 Btu/scf (with the clarifications noted earlier in this section). We are also proposing to move the existing provisions for fuels that do not meet the specifications to use subpart C methodologies from 40 CFR 98.233(z)(2) to a new paragraph 40 CFR 98.233(z)(3). This proposed amendment would allow reporters to use subpart C methodologies for a wider variety of fuel streams while still ensuring data quality. We request comment on the natural gas specifications included in proposed 40 CFR 98.233(z)(2), including the values proposed for the maximum CO_2 content and minimum CH_4 content, as well as whether additional specification criteria should be included (*e.g.,* a maximum HHV).

Third, we are proposing amendments to clarify that emissions may be calculated in 40 CFR 98.233(z)(3)(ii) for groups of combustion units. The current provisions of 40 CFR 98.233(z)(2) (proposed to be moved to 40 CFR 98.233(z)(3)(ii)) could be interpreted to specify that emissions must be calculated for each individual combustion unit. However, because combustion emissions and activity data are reported as combined totals for each type of combustion device and fuel, it is not necessary to calculate emissions for each individual unit before aggregating the total emissions. For example, if the volume of fuel combusted is determined at a single location upstream of several combustion units with similar combustion efficiencies, emissions may be determined for that combined volume of fuel (*i.e.,* for that group of combustion units). In other words, it is not necessary in this case to apportion a volume of fuel to each unit, calculate emissions separately, and then combine them again. If the combustion units downstream of this shared measurement point are a mix of combustion device types, the emissions and the volume of fuel would still need to be apportioned between those combustion device types for reporting purposes; however, reporters may elect to perform that apportioning either before or after emissions are calculated, as appropriate, as long as the group of combustion units does not include any natural gas-driven compressor drivers. If any of the combustion units downstream of this shared measurement point are natural gas-driven compressor drivers, the volumes of fuel for those units would have to be separated from the total before emissions are calculated to account for the differences in combustion efficiency, as described in section III.J.1.n of this preamble.

g. Onshore Natural Gas Processing and Natural Gas Distribution Throughput Information

Onshore Natural Gas Processing plants are required to report seven facility-level throughput-related items under subpart W, as specified in 40 CFR 98.236(aa)(3). These seven data reporting elements include: quantities of natural gas received and processed gas leaving the gas processing plant, cumulative quantities of NGLs received and leaving the gas processing plant, the average mole fractions of CH_4 and CO_2 in the natural gas received, and an indication of whether the facility fractionates NGLs. Natural Gas Distribution companies are also required to report seven throughput volumes under subpart W, as specified in 40 CFR 98.236(aa)(9). These seven data reporting elements include: the quantity of gas received at all custody transfer stations; the quantity of natural gas withdrawn from in-system storage; the quantity of gas added to in-system storage; the quantity of gas delivered to end users; the quantity of gas transferred to third parties; the quantity of gas consumed by the LDC for operational purposes; and the quantity of gas stolen.

The EPA has received stakeholder comments, including from the American Gas Association (AGA),[106] related to some of these reporting elements. Stakeholders have commented that the reporting elements included in subpart W are redundant with data reported elsewhere within the GHGRP, specifically under subpart NN (Suppliers of Natural Gas and Natural Gas Liquids). Subpart NN requires NGL fractionators and LDCs to report the quantities of natural gas and natural gas

[105] See Letter from GPA Midstream Association to Mark de Figueiredo, U.S. EPA, providing information in response to EPA questions during the meeting on March 23, 2016. May 18, 2016. See also Letter from Matt Hite, GPA Midstream Association, to Mark de Figueiredo, U.S. EPA, Re: Additional Information on Suggested Part 98, Subpart W Rule Revisions to Reduce Burden. September 13, 2019. Both letters are available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[106] See Docket Id. Nos. EPA–HQ–OA–2017–0190–46726, EPA–HQ–OA–2017–0190–1958, EPA–HQ–OA–2017–0190–2066 available in *Compilation of Comments Related to the Greenhouse Gas Reporting Program submitted to the Department of Commerce under Docket ID No. DOC–2017–0001 and the Environmental Protection Agency under Docket ID No. EPA–HQ–OA–2017–0190* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

liquid products supplied downstream and their associated emissions. For example, for natural gas processing plants, both subparts require reporting of the volume of natural gas received and the volume of NGLs received. Subpart W also requires reporting of total NGLs leaving the processing plant, while subpart NN requires reporting of the volume of each individual NGL product supplied. For LDCs, some duplicative reporting is required as well. For example, both subparts require reporting of the volume of natural gas received, volume placed into and out of storage each year, and volume transferred to other LDCs or to a pipeline as well as some other duplicative data. In addition, commenters stated that the reporting elements included in subparts W and NN for LDCs are redundant with data reported to the U.S. Energy Information Administration (EIA) on Form EIA–176, the Annual Report of Natural and Supplemental Gas Supply and Disposition.[107] The commenters explained that subpart W and subpart NN collect nearly the same data, and discrepancies between the data sets are due to the use of inconsistent terminology. Commenters also suggested that due to the redundancy and availability of data reported to the EIA for LDCs, the EPA should remove the throughput-related reporting requirements for the Natural Gas Distribution industry segment from the GHGRP altogether. Commenters added that if the requirements are maintained, the EPA should reconcile the terminology used within the GHGRP and clarify the reporting elements.

The EIA report is submitted in the spring of each year and covers the previous calendar year. After completing internal audits of the reports, EIA publishes the data for each LDC on its website in the fall. The EIA data provides detailed information on the volume of gas received, gas stored, gas removed from storage, gas deliveries by sector, and HHV data. The EPA previously reviewed the possibility of obtaining data by accessing existing federal government reporting and ''decided not to modify the final rule because collecting data directly in a central system will enable the EPA to electronically verify all data reported under this rule quickly and consistently, to use the information for non-statistical purposes, and to handle confidential business information in accordance with the Clean Air Act.'' [108] In the specific case of subpart NN, in the 2009 Final Rule, the EPA also ''determined that it could not rely on EIA data to collect facility-level data from fractionators and company-level data from LDCs.'' Additionally, the EPA sought ''data that is beyond what EIA collects, such as quality assurance information, verification data, and information on odorized propane'' and ''data on site-specific HHV and carbon content from those sites that choose to sample and test products rather than use default emission factors.''

After further review of the data available through EIA, the stakeholder comments described earlier in this section, and the reporting requirements in subpart W and subpart NN, the EPA is proposing to eliminate duplicative elements from subpart W for facilities that report to subpart NN, consistent with section II.B.3 of this preamble. The EPA is proposing to amend the reporting requirements in 40 CFR 98.236(aa)(3) for Onshore Natural Gas Processing plants that fractionate NGLs (approximately 100 of the 450 subpart W natural gas processing plants) and also report as a supplier under subpart NN. For this subset of facilities, the EPA reviewed the data from subpart W and subpart NN and determined that there are no gas processing plants that report as fractionators under subpart W that do not also report under subpart NN without supplying a valid explanation.[109] During this review, the EPA found that some of the data elements included in subpart W overlap with data elements in subpart NN. Specifically, the data elements in 40 CFR 98.236(aa)(3)(i), (iii) and (iv) of subpart W overlap with data elements in subpart NN as specified in 40 CFR 98.406(a)(3), 98.406(a)(1) and (2), 98.406(a)(4)(i) and (ii), respectively.[110]

To eliminate reporting redundancies, the EPA is proposing6 several amendments to 40 CFR 98.236(aa)(3). First, to clarify which facilities have data overlap between subparts W and NN, the EPA is proposing to add a reporting element for natural gas processing plants at 40 CFR 98.236(aa)(3)(viii) to indicate whether they report as a supplier under subpart NN. Next, the EPA is proposing that facilities that indicate that they both fractionate NGLs and report as a supplier under subpart NN would no longer be required to report the quantities of natural gas received or NGLs received or leaving the gas processing plant as specified in 40 CFR 98.236(aa)(3)(i), (iii) and (iv). These facilities would, however, be required to continue reporting the data elements specified in 40 CFR 98.236(aa)(3)(ii) and (v) through (viii), as these reporting elements do not overlap with subpart NN reporting elements. Natural gas processing plants that do not fractionate or that fractionate but do not report as a supplier under subpart NN would continue to report all of the reporting elements for natural gas processing plants as specified in 40 CFR 98.236(aa)(3).

The EPA is also proposing to remove the reporting elements for throughput for LDCs in 40 CFR 98.236(aa)(9). The EPA reviewed the data from subpart W and subpart NN and determined that there are no LDCs that report under subpart W that do not also report under subpart NN. In fact, an average of 385 LDCs report under subpart NN, while 170 LDCs report under subpart W. Subpart NN therefore provides more comprehensive coverage of the Natural Gas Distribution industry segment. Additionally, subpart NN has been in effect for LDCs since RY2011 while subpart W throughput information has only been collected since RY2015; thus, subpart NN has a more robust historical data set. During this review, the EPA determined that the data elements found in 40 CFR 98.236(aa)(9)(i) through (v) of subpart W overlap with data elements in subpart NN as specified in 40 CFR 98.406(b)(1) through (3), 98.406(b)(5) and (6), and 98.406(b)(13). To eliminate reporting redundancies, the EPA is proposing to remove these reporting elements from subpart W.

[107] Form EIA–176 is available at the U.S. EIA website at *https://www.eia.gov/survey/form/eia_176/form.pdf;* the Form EIA–176 Instructions are available at *https://www.eia.gov/survey/form/eia_176/instructions.pdf.*

[108] See page 7 of *EPA Response to Public Comment Vol. 39 Subpart NN* at *https://www.epa.gov/ghgreporting/ghgrp-2009-final-rule-response-comments-documents,* also available in the docket for this rulemaking, Docket Id. No EPA–HQ–OAR–2019–0424.

[109] One such explanation is that the gas processing plant fractionates NGLs to supply fuel for use entirely on-site (*i.e.,* the fuel is not supplied downstream). Due to definitional differences between the two subparts, this facility is defined as a fractionator for purposes of subpart W but is not a supplier that must report under subpart NN.

[110] While it is the EPA's intention that the reported quantity of natural gas received at the facility in 40 CFR 98.236(aa)(3)(i) should be the quantity of natural gas received for processing, consistent with the requirement to report the annual volume of natural gas received for processing in 40 CFR 98.406(a)(3), some reporters have indicated in correspondence with the EPA via e-GGRT that they are including gas that is received at but not processed by the onshore natural gas processing facility (*i.e.,* gas that was processed elsewhere and passes through the onshore natural gas processing facility). Therefore, to clarify the EPA's intention and reinforce the consistency of the subpart W and subpart NN quantities, the EPA is proposing to revise 40 CFR 98.236(aa)(3)(i) to indicate that that reported quantity should be natural gas received at the gas processing plant for processing in the calendar year.

The EPA is also proposing to remove the reporting elements for the volume of natural gas used for operational purposes and natural gas stolen specified in 40 CFR 98.236(aa)(9)(vi) and (vii). These reporting elements are unique to subpart W and have caused confusion for subpart W reporters, require additional burden to estimate, and have not been used for the EPA's analyses of the subpart W data. As a result of removing these data elements, the EPA proposes to reserve paragraph 40 CFR 98.236(aa)(9). Table 2 of this preamble shows all the duplicative data elements that the EPA is proposing to remove from subpart W for facilities that also report to subpart NN.

TABLE 2—LIST OF PROPOSED SUBPART W DATA ELEMENTS TO BE REMOVED WHERE ANALOGOUS SUBPART NN DATA ELEMENTS ARE REPORTED

Subpart W data elements proposed to be eliminated		Analogous subpart NN data elements	
Citation	Description	Citation	Description
Local Distribution Companies.			
§ 98.236(aa)(9)(i)	Quantity of natural gas received at all custody transfer stations.	§ 98.406(b)(1) § 98.406(b)(5)	Annual volume of natural gas received by the LDC at its city gate stations and Annual volume natural gas that bypassed the city gate(s).
§ 98.236(aa)(9)(ii)	Quantity of natural gas withdrawn from in-system storage.	§ 98.406(b)(3)	Annual volume natural gas withdrawn from on-system storage and annual volume of vaporized LNG withdrawn from storage.
§ 98.236(aa)(9)(iii)	Quantity of natural gas added to in-system storage.	§ 98.406(b)(2)	Annual volume of natural gas placed into storage or liquefied and stored.
§ 98.236(aa)(9)(iv)	Quantity of natural gas delivered to end users.	§ 98.406(b)(13)(i) through (iv)	Annual volume of natural gas delivered by the LDC to residential consumers, commercial consumers, industrial consumers, electricity generating facilities.
§ 98.236(aa)(9)(v)	Quantity of natural gas transferred to third parties.	§ 98.406(b)(6)	Annual volume of natural gas delivered to downstream gas transmission pipelines and other local distribution companies.
Natural Gas Processing Plants that Fractionate NGLs.			
§ 98.236(aa)(3)(i)	Quantity of natural gas received.	§ 98.406(a)(3)	Annual volume of natural gas received for processing.
§ 98.236(aa)(3)(iii)	Cumulative quantity of all NGLs (bulk and fractionated) received.	§ 98.406(a)(2) § 98.406(a)(4)(i)	Annual quantity of each NGL product received and annual quantities of y-grade, o-grade and other bulk NGLs received.
§ 98.236(aa)(3)(iv)	Cumulative quantity of all NGLs (bulk and fractionated) leaving.	§ 98.406(a)(1) § 98.406(a)(4)(ii)	Annual quantity of each NGL product supplied and annual quantities of y-grade, o-grade and other bulk NGLs supplied.

h. Onshore Natural Gas Processing Industry Segment

According to 40 CFR 98.230(a)(3), the Onshore Natural Gas Processing industry segment currently includes all facilities that fractionate NGLs. The industry segment also includes all facilities that separate NGLs from natural gas or remove sulfur and CO_2 from natural gas, provided the annual average throughput at the facility is 25 MMscf per day or greater. The industry segment also includes all residue gas compression equipment owned or operated by natural gas processing facilities that is not located within the facility boundaries.

GPA Midstream has expressed concern that the current definition of the Onshore Natural Gas Processing industry segment applies to some compressor stations simply because they have an amine unit that is used to remove sulfur and CO_2 from natural gas. According to GPA Midstream, it would be more appropriate for such facilities to be in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment. GPA Midstream also explained that the 25 MMscf per day threshold creates additional burden and uncertainty for these compressor station facilities because they do not know until the end of the year whether they will be above or below the threshold. Thus, they need to collect the applicable data for both the Onshore Natural Gas Processing industry segment and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment so that they will have the required data for whichever industry segment ultimately applies to them. To resolve this issue and to promote consistency among regulatory programs, GPA Midstream recommended replacing the onshore natural gas processing definition in subpart W with the natural gas processing plant definition in NSPS OOOOa.[111]

After review of these comments, we are proposing to replace the definition of ''Onshore natural gas processing'' in 40 CFR 98.230(a) with language similar to the definition of ''natural gas processing plant'' in NSPS OOOOa. NSPS OOOOa defines ''natural gas processing plant (gas plant)'' as any processing site engaged in the extraction of NGLs from field gas, fractionation of mixed NGLs to natural gas products, or both. The definition specifies that a Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant. There are two minor editorial differences between

[111] Letter from Matt Hite, GPA Midstream Association, to Mark de Figueiredo, U.S. EPA, Re: Additional Information on Suggested Part 98, Subpart W Rule Revisions to Reduce Burden. September 13, 2019. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

the proposed definition in 40 CFR 98.230(a) and the definition in NSPS OOOOa. First, instead of defining a natural gas processing ''plant,'' as in the definition in NSPS OOOOa, we are proposing to describe what is meant by ''natural gas processing'' so that the structure of 40 CFR 98.230(a)(3) is consistent with the structure of all of the other industry segment definitions in 40 CFR 98.230(a). Second, the definition in NSPS OOOOa refers to ''extraction'' of NGLs from natural gas, but this term is not defined. Thus, we are proposing to retain the term ''forced extraction'' in the current provisions of 40 CFR 98.230(a)(3) and revise the definition of this term slightly in 40 CFR 98.238. The current definition of ''forced extraction'' specifies that forced extraction does not include ''portable dewpoint suppression skids.'' We are proposing to revise the definition to indicate instead that forced extraction does not include ''a Joule-Thomson valve, a dewpoint depression valve, or an isolated or standalone Joule-Thomson skid.'' These changes would make the definition of ''forced extraction'' in subpart W consistent with the language in the definition of a natural gas processing plant in NSPS OOOOa. This proposed amendment would provide reporters with certainty about the applicable industry segment for the reporting year, reducing the monitoring data they must collect to only the information needed for the applicable industry segment, consistent with section II.B.2 of this preamble.

This proposed amendment is not expected to decrease overall coverage of the GHGRP for the petroleum and natural gas systems industry, although we anticipate that some facilities would report under a different industry segment going forward. Based on reported data for RY2020, about 19 percent of facilities reporting in the Onshore Natural Gas Processing industry segment do not fractionate NGLs and report zero NGLs received and leaving the facility. These facilities meet the current definition of natural gas processing because they are separating CO_2 and/or hydrogen sulfide. These facilities would not meet the proposed revised definition for natural gas processing and instead, their emissions would be reported as part of either existing or new onshore petroleum and natural gas gathering and boosting facilities. In most cases, we anticipate that operations at a former gas processing facility would be incorporated into an existing gathering and boosting facility that has been subject to reporting, and the total emissions from the expanded gathering and boosting facility would be similar to the emissions that would have been reported by the separate facilities under the existing industry segment definitions. In cases where a former gas processing facility is located in a basin where the owner or operator does not have an existing reporting gathering and boosting facility, we expect that a new gathering and boosting facility including the former gas processing facility would be created because the emissions from the former gas processing facility alone would exceed the reporting threshold of 25,000 mtCO_2e. If the same owner or operator has other gathering and boosting operations in the same basin that have emissions less than 25,000 mtCO_2e, then the new gathering and boosting facility could result in increased coverage of the industry segment and greater total reported emissions than would be reported under the current industry segment definitions.

The proposed revised definition for natural gas processing also does not include the 25 MMscf per day threshold for facilities that do not fractionate NGLs. Under the current definition of onshore natural gas processing, processing plants that do not fractionate gas liquids and generally operate close to the 25 MMscf per day threshold do not know until the end of the year whether they will be above or below the threshold, so they must be prepared to report under whichever industry segment is ultimately applicable. The two potentially applicable segments report emissions from different sources and with different calculation methods. For example, facilities in the Onshore Natural Gas Processing industry segment are not required to report emissions from atmospheric storage tanks and are required to measure leaks from individual compressors, while facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment are required to report emissions from atmospheric storage tanks but may use emission factors to calculate emissions from compressors rather than conducting measurements. These sites would meet the revised proposed definition of natural gas processing regardless of their throughput level, so they would have the certainty of knowing they would be subject to reporting as natural gas processing facilities every year, and as a result, removing the 25 MMscf per day threshold is expected to increase the number of facilities that report under the Onshore Natural Gas Processing industry segment. We request comment on the impact the proposed change would have on the number of reporting facilities and emissions from both the Onshore Natural Gas Processing and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. We also request comment on any other advantages or disadvantages to finalizing the proposed change.

Finally, we note that the definition of natural gas processing plant in NSPS OOOOa does not specifically include residue gas compression equipment. Residue gas compression is defined in 40 CFR 98.238 as the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline. Per 40 CFR 98.230(a)(3), the Onshore Natural Gas Processing industry segment includes all residue gas compression equipment owned or operated by the natural gas processing plant. We are requesting comment on whether to remove the existing requirement to include residue gas compression equipment owned or operated by the natural gas processing facility from 40 CFR 98.230(a)(3) and 40 CFR 98.231(b). If this change were finalized, we anticipate that residue gas compression equipment would then be part of the Onshore Natural Gas Transmission Compression industry segment, which would require reporters with residue gas compression equipment that currently only report under the Onshore Natural Gas Processing industry segment to begin reporting under both the Onshore Natural Gas Processing and Onshore Natural Gas Transmission Compression industry segments in order to fully report their facility emissions. As part of the request for comment on this issue, we request comment on the expected impact on the level of reported emissions that would result if this change were finalized. We also request comment on other rationale for or against finalizing this change.

3. Other Proposed Minor Revisions or Clarifications

See Table 3 of this preamble for the miscellaneous minor technical corrections not previously described in this preamble that we are proposing throughout subpart W, consistent with section II.A.5 of this preamble.

TABLE 3—PROPOSED TECHNICAL CORRECTIONS TO SUBPART W

Section (40 CFR)	Description of proposed amendment
98.232(b), 98.233(s), 98.236(s)	Update the outdated acronym "BOEMRE" to the current acronym "BOEM."
98.232(b), 98.233(s)	Update the cross references to the BOEM requirements from "30 CFR 250.302 through 304" to "30 CFR 550.302 through 304."
98.233(a)(1)	Revise the definition of the equation variable "EF_t" to consolidate the list of applicable industry segments and tables into one sentence.
98.233(e)(1)(x)	Add "at the absorber inlet" to the end of the paragraph to clarify the location for the wet natural gas temperature and pressure to be used for modeling.
98.233(g)(4)(ii)	Revise the instance of "formation on N_2O" in the second sentence to read "formation of N_2O" to correct a typographical error.
98.233(j), 98.236(j)	Revise the instances of "oil," "oil/condensate," and "liquid" to read "hydrocarbon liquids" for consistency with the requirement in 40 CFR 98.233(j) to calculate emissions from "atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids," as noted in the 2015 amendments to subpart W (80 FR 64272, October 22, 2015).
98.233(n)(5)	Correct the cross reference in the definition of the equation variable "Y_j" from paragraph (n)(1) to (n)(2).
98.233(o) introductory text and (p) introductory text.	Moved the last sentence in each paragraph to be the second sentence to clarify that the calculation methodology for compressors routed to flares, combustion, and vapor recovery apply to all industry segments.
98.233(p)(1)(i)	Correct the internal cross reference from paragraph (o) to paragraph (p).
98.233(p)(4)(ii)(C)	Add missing "in" to read "according to methods set forth in § 98.234(d)."
98.233(r) introductory text	Revise the instance of "CH" in the third sentence to read "CH_4" to correct a typographical error.
98.233(r), equations W–32A and W–32B	Correct the cross reference in the definition of the equation variable "$_{Es,MR,i}$" and the equation variable "$Count_{MR}$" from paragraph (q)(9) to (q)(2)(xi).
98.233(r)(6)(ii)	Add reference to components listed in 40 CFR 98.232(i)(3), for consistency with proposed amendments to 40 CFR 98.233(r)(6)(i).
98.233(s)	Remove the outdated references to "GOADS."
98.233(t)(2)	Revise the definition of equation variable "Z_a" to include the sentence following the definition of that variable to correct a typographical error.
98.233(u)(ii)	Format the heading to be in italicized text.
98.233(z)	Revise the instances of "high heat value" to read "higher heating value" to correct inconsistency in the term.
98.233(z), equations W–39A and W–39B	Remove unnecessary "constituent" from "CO_2 constituent" and "methane constituent" and remove "gas" from "gas hydrocarbon constituent." Add missing "the" to read "to the combustion unit" in several variable definitions.
98.236 introductory text	Add missing "than" to read "report gas volumes at standard conditions rather than the gas volumes at actual conditions."
98.236(e)(2)	Revise the instances of "vented to" a control device, vapor recovery, or a flare to read "routed to" to correct inconsistency in the phrases "vented to" and "routed to."
	Revise the instances of "vapor recovery device" to read "vapor recovery system" to correct inconsistency in the term.
98.236(j)(2)	Clarify that the reported information in paragraphs (j)(1)(i) through (xvi) should only include those atmospheric storage tanks with emissions calculated using Calculation Method 3.
98.236(l)(1), (2), (3), and (4) introductory text	Revise the instances of "vented to a flare" to read "routed to a flare" to correct inconsistency in the phrases "vented to" and "routed to."
98.236(p)(3)(ii)	Add a missing period at the end of the sentence.
98.236(bb)	Clarify that reporting for missing data procedures includes the procedures used to substitute an unavailable value of a parameter (per 40 CFR 98.235(h)).
98.236(cc)	Correct the cross references from paragraph (l)(1)(iv), (l)(2)(iv), (l)(3)(iii), and (l)(4)(iii) to (l)(1)(v), (l)(2)(v), (l)(3)(iv), and (l)(4)(iv), respectively.
98.238	Remove the second definition of "Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements" to eliminate an inadvertent identical duplicative definition.
Table W–1A, Table W–3B, and Table W–4B to subpart W of part 98.	Change "Low Continuous Bleed Pneumatic Device Vents" to "Continuous Low Bleed Pneumatic Device Vents" and change "High Continuous Bleed Pneumatic Device Vents" to "Continuous High Bleed Pneumatic Device Vents" to be consistent with the terms used throughout the rest of subpart W.
Table W–3B and Table W–4B to subpart W of part 98.	Change table headings and footnotes to clarify that the population emission factors for pneumatic device vents are whole gas emission factors rather than total hydrocarbon emission factors.

4. Best Available Monitoring Methods

The EPA is proposing that facilities would be allowed to use BAMM on a short-term transitional basis for the proposed amendments for the 2023 reporting year for only the specific industry segments and emission sources for which new monitoring or data collection requirements are being proposed. These industry segments and emission sources include calculating and reporting emissions from natural gas pneumatic devices at onshore natural gas processing facilities, natural gas intermittent bleed pneumatic devices for which the reporter conducts routine monitoring surveys, acid gas removal vents at LNG import/export facilities, other large release events at all facilities, miscellaneous flared sources, glycol dehydrators and atmospheric storage tanks routed to vapor recovery systems, compressor sources and mode-source combinations for which new measurements would be required, and measurements taken using a high volume sampler. We are also proposing that reporters of an onshore natural gas processing facility that becomes part of an onshore petroleum and natural gas gathering and boosting facility, or vice versa, solely due to the proposed change in the definition of 40 CFR 98.230(a)(3) would be allowed to use BAMM for the emission sources for which measurements were not required under the previous industry segment. This proposal would allow reporters to use best available methods to estimate inputs to emission equations for the newly proposed emission sources using their best engineering judgment for cases where the monitoring of these inputs would not be possible beginning on January 1, 2023.

These reporters would have the option of using BAMM from January 1, 2023, to December 31, 2023, without seeking prior EPA approval for certain parameters that cannot reasonably be measured according to the monitoring and quality assurance/quality control (QA/QC) requirements of 40 CFR 98.234. This additional time for reporters to comply with the monitoring methods for new emission sources in subpart W would allow facilities to install the necessary monitoring equipment during other planned (or unplanned) process unit downtime, thus avoiding process interruptions. The EPA is not proposing to allow the use of BAMM beyond RY2023 and does not anticipate that BAMM would be needed beyond 2023 for the specific industry segments and emissions sources with proposed amendments in this rule. The EPA is also not proposing to allow the use of BAMM for industry segments and emission sources for which no amendments have been proposed that would require additional data collection because reporters should already be collecting the measurements and activity data needed to meet the requirements of the current rule.

K. Subpart X—Petrochemical Production

We are proposing several amendments to subpart X of part 98 (Petrochemical Production) to improve the quality of data reported and to clarify the calculation, recordkeeping, and reporting requirements for the reasons described in this section and in section II.A of this preamble.

For the reasons described in section II.A.3 of this preamble, we are proposing to add a reporting element in 40 CFR 98.246(b)(7) and (c)(3) for each flare that is reported under the CEMS and optional ethylene combustion methodologies. These sections of subpart X currently require reporting of the total emissions from each flare that burns off-gas from a petrochemical process unit for which emissions are determined under the CEMS or optional ethylene combustion methodologies. We are proposing that reporters also report estimated fractions of the total CO_2, CH_4, and N_2O emissions from these flares that are due to combusting petrochemical off-gas because the current requirements result in an overestimate of emissions attributed to a petrochemical process unit when the flare is not dedicated to a petrochemical process unit, particularly if the flare is also used to combust off-gas from non-petrochemical process units. The proposed requirement would allow the fractions attributed to each petrochemical process unit that routes emissions to the flare to be estimated using engineering judgment. This proposed change would allow more accurate quantification of emissions both from individual petrochemical process units and from the industry sector as a whole.

For the reasons described in section II.A.4 of this preamble, we are proposing to add a requirement in 40 CFR 98.246(c)(6) to report the names and annual quantity (in metric tons) of each product produced in each ethylene production process under the optional ethylene combustion methodology. Subpart X currently requires reporting of only the quantity of ethylene produced. The proposed change would make product reporting under the optional ethylene combustion methodology consistent with product reporting requirements under the CEMS and mass balance reporting options. Data on the quantities of all products will improve the EPA's ability to verify reported emissions from these process units, and the data will be useful in informing future policy decisions.

For the reasons described in section II.A.5 of this preamble, we are proposing two changes to clarify emissions calculation requirements for flares. Currently, 40 CFR 98.243(b)(3) and (d)(5) cross-reference the calculation procedures in 40 CFR 98.253(b)(1) through (b)(3) of subpart Y. We are proposing to revise these sections to cross-reference all of 40 CFR 98.253(b) to clarify that the provisions added in past amendments and in this amendments package to the introductory paragraph in 40 CFR 98.253(b) also apply to flares that are subject to reporting under subpart X. This proposed change would clarify that subpart X reporters are not required to report emissions from combustion of pilot gas and, as discussed in section III.L of this preamble, that gas released during SSM events of <500,000 scf/day are excluded from equation Y–3.

Additionally, we are proposing five amendments to clarify subpart X rule language pertaining to reporting of required data elements. In previous rule amendments, we added requirements to report the annual quantity of each petrochemical product produced from each process unit. In making the changes, we inadvertently introduced some overlapping reporting requirements. First, to clarify the reporting requirements and eliminate confusion for facilities that use the mass balance approach, we are proposing to amend 40 CFR 98.246(a)(2) to remove the requirement to report feedstock and product names. The rule currently specifies in two places that a reporter using the mass balance methodology must report the feedstock and product names for a subject process unit. The requirement in 40 CFR 98.246(a)(2) is to report the ''names of products, and names of carbon-containing feedstocks.'' The requirement in 40 CFR 98.246(a)(12) is to report the ''(n)ame (. . .) of each carbon-containing feedstock included in equations X–1, X–2, and X–3 of § 98.243.'' The requirement in 40 CFR 98.246(a)(13) is to report the ''(n)ame (. . .) of each product included in equations X–1, X–2, and X–3.'' Although the language in 40 CFR 98.246(a)(2) is slightly different from the language in 40 CFR 98.246(a)(12) and (13), the scope of 40 CFR 98.246(a)(2) is identical to the collective scope of 40 CFR 98.246(a)(12) and (13). For example, all gaseous carbon-containing feedstocks must be entered in the equation X–1 calculation, all liquid carbon-containing feedstocks must be entered in the equation X–2 calculation, and all solid carbon-containing feedstocks must be entered in the equation X–3 calculation. Thus, the current requirement in 40 CFR 98.246(a)(12) to report the name of each carbon-containing feedstock used in any of the equations means all carbon-containing feedstocks must be reported, which is identical to the requirement in 40 CFR 98.246(a)(2) to report the names of carbon-containing feedstocks. A similar analysis applied to the products results in the conclusion that the current requirement in 40 CFR 98.246(a)(13) to report the name of each product used in any of the equations means all products must be reported, which is identical to the requirement in 40 CFR 98.246(a)(2) to report the names of products. Note that the rule does not specify reporting of ''carbon-containing'' products; this is unnecessary because the term ''product'' is defined in 40 CFR 98.248 to mean ''. . .carbon-containing outputs. . .'' To eliminate the redundancy, we are proposing to delete the requirement to report names of products and the names of carbon-containing feedstocks from 40 CFR 98.246(a)(2) because the same requirements are also included in 40 CFR 98.246(a)(12) for feedstocks and 40 CFR 98.246(a)(13) for products.

The second amendment to the mass balance reporting requirements is to revise 40 CFR 98.246(a)(5) and 40 CFR 98.246(a)(13) to clarify the petrochemical and product reporting requirements for integrated ethylene dichloride/vinyl chloride monomer (EDC/VCM) process units. In a letter received from Occidental Chemical Company titled ''Request to Consider IPCC Balanced EDC/VCM Process Studies and Data for the Elimination of e-GGRT Validation Messages at VCM Production Facilities Reporting Under Subpart X,'' dated July 10, 2015 (available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424), industry representatives indicated that an integrated EDC/VCM process unit is a continuous process in which the EDC is produced as an intermediate that is used in the production of VCM; purified EDC circulates to the VCM production portion of the process, and multiple recovery loops recycle unconverted EDC from the VCM operations to the EDC operations for purification. These streams that pass back and forth between the EDC and VCM portions of the integrated unit are not isolated and are not measured in a manner that would allow for accurate calculation of the amount of intermediate EDC produced. Since the amount of EDC produced as an intermediate in such process units may not be measured, subpart X was previously amended to allow reporters to consider the entire integrated EDC/VCM process unit to be the petrochemical process unit (proposal at 81 FR 2536, January 15, 2016; final at 81 FR 89188, December 16, 2016). At the same time, 40 CFR 98.246(a)(5) was amended to specify that the amount of intermediate EDC produced in such units and included in the total reported amount of EDC petrochemical produced could be based on either measurements or an estimate. In subsequent years, data reported under subpart X of the GHGRP indicated that some facilities with an integrated EDC/VCM process unit withdraw small amounts of the EDC as a separate product stream. The amendments in 2016 were silent on how to report the amount of any EDC that is withdrawn as a separate product from the integrated unit. The intent of the proposed changes is that the amount of EDC product not used as an intermediate would continue to be determined as it would be for a standalone EDC process unit, this amount of EDC product would be added to the amount of intermediate EDC, and the total would be reported under 40 CFR 98.246(a)(5) as the amount of EDC petrochemical produced by the integrated EDC/VCM process unit. To clarify this intent we are proposing to revise 40 CFR 98.246(a)(5) to specify that the portion of the total amount of EDC produced that is an intermediate in the production of VCM may be either a measured quantity or an estimate, the amount of EDC withdrawn from the process unit as a separate product (*i.e.,* the portion of EDC produced that is not utilized in the VCM production) is to be measured in accordance with 40 CFR 98.243(b)(2) or (3), and the sum of the two values is to be reported under 40 CFR 98.246(a)(5) as the total quantity of EDC petrochemical from an integrated EDC/VCM process unit. We are also proposing a harmonizing change in 40 CFR 98.246(a)(13) to clarify that the amount of EDC product to report from an integrated EDC/VCM process unit should be only the amount of EDC, if any, that is withdrawn from the integrated process unit and not used in the VCM production portion of the integrated process unit. Reporting as a product only the quantity of EDC not used in the VCM process is consistent with the boundary of the mass balance being around the integrated EDC/VCM process unit.

For facilities that use CEMS, we are proposing a third amendment to 40 CFR 98.246(b)(8) to clarify the reporting requirements for the amount of EDC petrochemical when using an integrated EDC/VCM process unit. In previous amendments (81 FR 89188, December 16, 2016), reporting requirements related to the quantity of intermediate EDC for an integrated EDC/VCM process unit were added to the petrochemical quantity reporting requirements at 40 CFR 98.246(b)(8) for CEMS-monitored units that were identical to the reporting requirements added to 40 CFR 98.246(a)(5) that are discussed above for mass balance units. This 2016 language was added so that the reporting requirements would be the same under both the mass balance methodology and the CEMS methodology. However, an EDC manufacturer does not need to consider an integrated EDC/VCM process unit to be the petrochemical process unit when using CEMS since vent streams are directly monitored and thus recycle streams from the VCM to EDC process are not required to be quantified as with a mass balance unit. Under the mass balance option, the amount of product must be a measured value because the quantity is used in the emissions calculation equation; thus, we allowed the entire integrated unit to be considered the petrochemical process unit so the amount of VCM product could be the primary reported product, and it would be measured. Under the CEMS option, the product quantity is used only in data verification procedures and other data analyses, and the EPA has tentatively determined that, for these purposes, reporting an estimated value is an acceptable alternative to incurring the expense of modifying an integrated unit process unit so that measurements can be taken. Thus, we are proposing to revise 40 CFR 98.246(b)(8) by removing language related to considering the petrochemical process unit to be the entire integrated EDC/VCM process unit.

For facilities that use the optional ethylene combustion methodology to determine emissions from ethylene production process units, we are proposing a fourth amendment to 40 CFR 98.246(c)(4) to clarify that the names and annual quantities of feedstocks that must be reported would be limited to feedstocks that contain carbon. This proposed change will make the feedstock reporting requirement under the optional ethylene combustion methodology consistent with the feedstock reporting requirements under the mass balance and CEMS options.

The fifth proposed change to clarify the reporting requirements under subpart X consists of clarifying changes to 40 CFR 98.246(a)(15). Currently, this paragraph specifies that the annual average molecular weight must be reported for each gaseous feedstock and product. The proposed revision would more clearly specify that molecular weight must be reported for gaseous feedstocks and products only when the quantity of the gaseous feedstock or product used in equation X–1 is in standard cubic feet; the molecular weight does not need to be reported when the quantity of the gaseous feedstock or product is in kilograms. This change would be consistent with statements in the definitions of the terms for volume or mass in equation X–1. We are also proposing to rearrange the text in 40 CFR 98.246(a)(15) and split the paragraph into two sentences to improve clarity.

These proposed clarifying changes would pose no new monitoring, reporting, or recordkeeping requirements. We are also proposing related confidentiality determinations for the new or revised data elements, as discussed in section VI of this preamble.

L. Subpart Y—Petroleum Refineries

1. Proposed Revisions To Improve the Quality of Data Collected for Subpart Y

We are proposing several amendments to subpart Y of part 98 (Petroleum Refineries) to improve data collection, clarify rule requirements, and correct an error in the rule.

For the reasons described in section II.A.2 and II.A.4 of this preamble, we are proposing to amend some of the requirements for DCUs to improve data collection and our ability to perform verification of reported data for these emission sources. During the verification of DCU emissions, we noted a disproportionate number of facilities were messaged with potential emission errors that used mass measurements from company records to estimate the dry coke at the end of the coking cycle (as an alternative to estimating this quantity using Eq. Y–18a) in 40 CFR 98.257(b)(41). Through correspondence with facilities regarding these potential emission errors, we found that the some of the errors were due to reporters incorrectly determining the mass of coke at the end of the coking cycle on a wet basis rather than on a dry basis. This led to an erroneously high value being used for the M_{coke} input parameters to equation Y–18b, resulting in an unusually low value of M_{water} and subsequently lower-than-expected methane emissions. We also found that some of the errors were explained by the use of a facility-specific bulk density of coke that was sufficiently different from the default value used in EPA-estimated emissions to generate a potential error message. Finally, we found that some facilities indicated the coke may not be completely submerged by water due to initiating draining prior to atmospheric venting. Such activities undermine some of the underlying assumptions of the steam generation model being used to estimate DCU emissions. In order to improve the quality of data collected and our ability to ensure the reported data are accurate, we are proposing two amendments to the DCU provisions.

The first proposed amendment is designed to enhance the reporting and recordkeeping specifically for facilities using mass measurements from company records to estimate M_{coke}. Currently, facilities using mass measurements have less recordkeeping requirements than those facilities using equation Y–18a to estimate the quantity. Facilities using equation Y–18a are required to keep records of the drum outage, drum height, and the drum diameter as specified in 40 CFR 98.257(b)(42) through (44), while facilities using mass measurements from company records for M_{coke} do not have any related reporting or recordkeeping other than the recordkeeping requirement of the M_{coke} quantity in 40 CFR 98.257(b)(41). Therefore, we have limited data available by which to verify the reported dry mass of coke at the end of the cycle, M_{coke}. In order to perform more robust and consistent verification of all of these reported quantities in future years, we are proposing to add reporting requirements for facilities using mass measurements from company records to estimate the amount of dry coke at the end of the coking cycle in 40 CFR 98.256(k)(6)(i) and (ii). These new subparagraphs would require these facilities to additionally report, for each DCU: (1) the internal height of the DCU vessel; and (2) the typical distance from the top of the DCU vessel to the top of the coke bed (*i.e.,* coke drum outage) at the end of the coking cycle (feet). These new elements will allow the EPA to estimate and verify the reported mass of dry coke at the end of the cooling cycle as well as the reported DCU emissions, ensuring the most consistent and accurate data are provided. We do not anticipate that the proposed data elements would require any additional monitoring or data collection by reporters, as these data are likely already available in existing company records. We are proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

The second amendment for DCUs we are proposing is to amend equation Y–18b in 40 CFR 98.253(i)(2) to include a new variable ''f_{coke}'' and revise the existing descriptions of the ''M_{water}'' output and ''H_{water}'' variable. As noted in the discussion, some of the facilities messaged for potential emission errors explained that the coke was not completely submerged at the time the vessel is vented to the atmosphere, which contradicts assumptions underlying the calculation methodology. First, we are proposing to revise the definitions of ''M_{water}'' and ''H_{water}'' to add the phase ''or draining'' to specify that these parameters reflect the mass of water and the height of water, respectively, at the end of the cooling cycle just prior to atmospheric venting or draining. The steam generation model requires a complete accounting of the heat within the unit prior to venting or draining since steam generation will occur if superheated water is drained from the unit prior to venting. We are also proposing similar revisions to the recordkeeping requirements at 40 CFR 98.257(b)(45) and (46) to add the phrase ''or draining'' to the description of the records. We are also proposing to add a new variable ''f_{coke}'' to equation Y–18b to allow facilities that do not completely cover the coke bed with water prior to venting or draining to accurately estimate the mass of water in the drum. The ''f_{coke}'' variable would be defined as the fraction of coke-filled bed that is covered by water at the end of the cooling cycle just prior to atmospheric venting or draining, where a value of 1 represents cases where the coke is completely submerged in water. The second term in equation Y–18b represents the volume of coke in the drum. It is subtracted from the water-filled coke bed volume to determine the volume of water. If the coke bed is not completely submerged in the water, subtracting the entire volume of coke from the water-filled coke bed volume will underestimate the actual volume of water in the coke drum vessel, resulting in an underestimate of the methane emissions. Adding the ''f_{coke}'' variable to the second term in equation Y–18b would make the equation universally applicable in cases where the coke bed is not fully submerged when the coke drum is first vented or drained. We are also proposing to add a corresponding recordkeeping requirement at 40 CFR 98.257(b)(53).

We are proposing several clarifying changes, for the reasons described in section II.A.5 of this preamble. We are proposing to add clarifying language to 40 CFR 98.253(c) and 98.253(e) to reiterate the language from 40 CFR 98.252(b) that the emissions being quantified in these paragraphs are coke burn-off emissions rather than emissions that may occur from other venting events. The language at 40 CFR 98.252(b) clearly indicates that the emissions to be reported are ''. . . *coke burn-off* emissions from each catalytic cracking unit, fluid coking unit, and catalytic reforming unit . . . '' [emphasis added]. However, the language at to 40 CFR 98.253(c) and 98.253(e) could be construed to apply to other vented emissions. We have received a GHGRP Help Desk question concerning the applicability of the calculation methodology to other venting events. To help clarify that the calculation methodologies in 40 CFR 98.253(c) and 98.253(e) are specific to coke burn-off emissions, we are proposing to add ''from coke burn-off'' immediately after the first occurrence of ''emissions'' in the introductory text of 40 CFR 98.253(c) and 40 CFR 98.253(e).

We are proposing a clarifying change to correct an inconsistency introduced into subpart Y by the amendments published on December 9, 2016 (81 FR 89188). The introduction to the flare emission calculation requirements at 40 CFR 98.253(b) was revised in 2016 to state that all gas discharged through the flare stack must be included in the calculations except for pilot gas. The intent of this provision was to require inclusion of purge and sweep gas in addition to SSM events. However, because equation Y–3 excludes SSM events less than 500,000 scf/day, the new provision created an apparent inconsistency about whether to include or exclude SSM events less than 500,000 scf/day in equation Y–3. Some reporters have interpreted that such SSM events must be included. We are proposing to clarify in 40 CFR 98.253(b) that SSM events less than 500,000 scf/ day may be excluded, but only if reporters are using the calculation method in 40 CFR 98.253(b)(1)(iii). This proposed clarification corrects the 2016 amendment, which was not intended to eliminate the exclusion when reporters use equation Y–3, and would reduce repeated verification and correction of errors submitted in reports.

We are proposing a correction to an erroneous cross-reference in 40 CFR 98.253(i)(5) for the reasons described in this section and section II.A.5 of this preamble. The section inaccurately defines the term M_{stream} in equation Y–18f for DCUs. Currently, M_{stream} is defined as, ''Mass of steam generated and released per decoking cycle (metric tons/cycle) as determined in paragraph (i)(3) of this section.'' The correct cross-reference is paragraph (i)(4) instead of (i)(3). The proposed change would not have any impact on burden.

Finally, we are proposing a change to correct an inconsistency introduced into subpart Y by the amendments published on December 9, 2016 (81 FR 89188). The DCU emission calculations were updated in 2016, and, as part of that update, 40 CFR 98.253(j) was revised to remove the option to calculate CH_4 emissions from DCUs using the process vent method (equation Y–19). However, the DCU recordkeeping requirements for the process vent method at 40 CFR 98.257(b)(53) through (56) were inadvertently not removed from the rule. We are proposing to revise 40 CFR 98.257(b)(53) to include recordkeeping requirement for the ''f_{coke}'' variable, as previously discussed in this section, and to remove and reserve the recordkeeping requirements in paragraphs 98.257(b)(54) through (56) since equation Y–19, the process vent calculation method, is no longer used to calculate DCU emissions.

2. Proposed Revisions To Streamline and Improve Implementation for Subpart Y

For the reasons described in this section and in section II.B.2 of this preamble, we are proposing to allow the use of mass spectrometer analyzers to determine gas composition and molecular weight without the use of a gas chromatograph. Currently, the methods for determining gas composition in 40 CFR 98.254(d) rely on gas chromatography. Advances in data analytics have made it easier for mass spectrometer analyzers to determine concentrations of individual compounds from a mixture of hydrocarbons without the need for pre-separation of the compounds using gas chromatography. Direct analysis using mass spectrometer analyzers greatly reduces the cycle time between sample analyses, allowing improved process control. As such, some refinery owner/ operators use direct mass spectrometer analyzers to determine gas stream composition. The proposed inclusion of direct mass spectrometer analysis as an allowable gas composition method in 40 CFR 98.254(d) would allow these reporters to use the same analyzers used for process control or for compliance with continuous sampling required under the National Emissions Standards for Hazardous Air Pollutants from Petroleum Refineries (40 CFR part 63, subpart CC) to comply with GHGRP requirements in subpart Y. Currently, these reporters have to conduct separate periodic sampling of these gas streams for analysis using gas chromatography to comply with GHGRP requirements in subpart Y. Thus, the proposed inclusion of mass spectrometer analyzers for determining gas composition will reduce the burden for these reporters. It is also expected to provide more accurate data due to the use of continuous analyzers rather than periodic sampling.

M. Subpart BB—Silicon Carbide Production

For the reasons described in section II.A.4 of this preamble, we are proposing revisions to the reporting requirements for subpart BB of part 98 (Silicon Carbide Production) to improve the quality of the data collected under the GHGRP.

The original 2009 GHG Reporting Rule for silicon carbide production required reporting CH_4 emissions by measuring petroleum coke consumption and applying a default CH_4 emission factor of 10.2 kilograms of CH_4 per metric ton of coke consumed (see 74 FR 56260). However, in 2013, we removed the requirement for silicon carbide production facilities to report CH_4 emissions from silicon carbide process units or furnaces and the CH_4 calculation methodology because we determined that the then-current CH_4 calculation methodologies in subpart BB overestimated the emissions of CH_4 from silicon carbide facilities. At the time we determined the following: the equations did not take into consideration the destruction of CH_4 emissions, the CH_4 emissions from these facilities were typically controlled, the CH_4 emissions from these facilities were minimal, and the requirement to report CH_4 emissions was not necessary to understand the emissions profile of the industry (see 78 FR 19802, April 2, 2013, and 78 FR 71904, November 29, 2013). The determination to not require reporting of CH_4 emissions was predicated on the conclusion that because CH_4 emissions are typically controlled, CH_4 emissions from these facilities are minimal. Although our understanding is still that CH_4 emissions are typically controlled, we are proposing to amend the rule in order to gather more information on CH_4 control practices at silicon carbide production facilities to better understand the extent of those control practices and their impact on CH_4 emissions. Specifically, we are interested in how the CH_4 emissions are controlled, the efficiency of the control technologies, and to what extent these technologies are operated throughout the year. As such, we are proposing adding new reporting requirement 40 CFR 98.286(c) such that if CH_4 abatement technology is used at silicon carbide production facilities, then facilities must report: (1) the type of CH_4 abatement technology used, and the date of installation for each; (2) the CH_4 destruction efficiency (percent destruction) for each CH_4 abatement technology; and (3) the percentage of annual operating hours that CH_4 abatement technology was in use for all silicon carbide process units or production furnaces combined. The proposed reporting requirements would be used to confirm the operation and efficiency of CH_4 abatement at silicon carbide facilities and would enable us to determine whether the EPA's 2013 determination that CH_4 emissions are typically controlled (and therefore minimal) remains accurate. Although silicon carbide facilities would continue to not be required to estimate CH_4 emissions from their processes for their GHGRP annual report, providing data on CH_4 abatement technology and usage would allow the EPA to assess the potential for unabated CH_4 emissions that may influence the industry's emission profile under the GHGRP. We also anticipate that we could use this kind of information to better understand methane emission control practices at silicon carbide facilities, to improve the EPA's knowledge of CH_4 emissions that may be useful for other CAA programs, or to support future climate change policies, non-regulatory initiatives, or regulations under the CAA. The proposed data could also be used to help estimate CH_4 emissions from silicon carbide facilities at the national level, and thereby inform and improve the U.S. GHG Inventory by allowing for more accurate estimates that account for CH_4 removal.

We are also proposing that for each CH_4 abatement technology, reporters must either use the manufacturer's specified destruction efficiency or the destruction efficiency determined via a performance test; if the destruction efficiency is determined via a performance test, reporters must also provide the name of the test method that was used during the performance test. We note that the collection of data elements related to GHG abatement and methane destruction are consistent with other subparts such as subparts E (Adipic Acid Production), I (Electronics Manufacturing), V (Nitric Acid Production), HH (Municipal Solid Waste Landfills), and FF (Underground Coal Mines) of part 98. For these subparts, reporters are typically provided an option to account for the destruction of methane in their estimated emissions (*e.g.,* fluorinated gases abated in electronics manufacturing processes or collection and destruction of methane at MSW facilities) and provide similar information on the type of abatement technology, hours of operation, and destruction or control efficiencies. This data is typically used for verification of emissions estimates and to confirm where process technologies or control measures result in minimal emissions. The collection of abatement data from silicon carbide facilities would be consistent with this practice. Finally, we are proposing that upon reporting this information once in an annual report, reporters would not be required to report this information again unless the information changed during another reporting year, in which case, the reporter would update the information in the submitted annual report. However, if it appeared that operational practices change at facilities such that CH_4 emissions are not consistently controlled from year to year or that unabated CH_4 emissions may be a more substantive contributor to industry emissions, then the EPA may consider whether it would be beneficial to reintroduce CH_4 calculation methodology and reporting requirements. We are proposing adding recordkeeping requirement 40 CFR 98.287(d) for facilities to maintain a copy of the reported data.

Based on review of available permits, we anticipate that reporters could obtain the proposed data elements from data that is collected and readily available to facilities as part of their standard operation. For example, as part of normal operations, we assume facilities would keep records of any time that the CH_4 abatement technology was not in use; therefore, the facility could then calculate the percent of total operating hours that the abatement technology was not in use. We are soliciting comment on whether this assumption is correct. We are also proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

We are also seeking comment on alternative methods for determining destruction efficiency (*i.e.,* methods other than using either the manufacturer's specified destruction efficiency or the destruction efficiency determined via a performance test). For example, we are considering whether it would be more reasonable to allow for the ''lesser of manufacturer's specified destruction efficiency and 0.99,'' as is required in subpart HH.

N. Subpart DD—Electrical Transmission and Distribution Equipment Use

1. Proposed Revisions To Improve the Quality of Data Collected for Subpart DD

For the reasons discussed in section II.A.3 of this preamble, we are proposing several revisions to subpart DD of part 98 (Electrical Transmission and Distribution Equipment Use) to improve the quality of the data collected from this subpart. These include adding F–GHGs other than SF_6 and PFCs to the monitoring, calculation, and reporting requirements of subpart DD (at 40 CFR 98.302, 98.303, 98.304, 98.305, and 98.306), clarifying the definition in 40 CFR 98.308 for ''facility,'' adding definitions for ''energized,'' ''insulating gas,'' ''new equipment,'' and ''retired equipment,'' and specifying procedures in 40 CFR 98.303(b) for establishing user-measured nameplate capacity values for new and retiring equipment.

Currently, this subpart includes all electric transmission and distribution equipment and servicing inventory insulated with or containing SF_6 or PFCs used within an electric power system. We are proposing to revise the existing calculation, monitoring, and reporting requirements of subpart DD to require reporting of additional F–GHGs as defined under 40 CFR 98.6. At the time of the 2010 Final Rule for Additional Fluorinated GHGs, SF_6 was the most commonly used insulating gas in the electrical power industry, and PFCs were occasionally used as dielectrics and heat transfer fluids in power transformers. During the implementation of the reporting program, electrical power systems equipment manufacturers and F–GHG suppliers have introduced alternative technologies and replacements for SF_6 with lower GWPs, including fluorinated gas mixtures, such as fluoronitriles or fluoroketones mixed with carrier gases (*e.g.,* CO_2 and O_2), as a replacement for dielectric insulation gases. The GWPs of these gases are generally much lower than the GWP of SF_6; the GWPs of fluoronitrile mixtures are typically estimated to fall between 300 and 500, whereas the GWPs of fluoroketone mixtures are usually estimated to be less than 1. The EPA is aware that some electric power systems are currently using or considering use of these alternative gas mixtures; Therefore, we are proposing revisions to the reporting requirements in order to capture emissions from equipment using these alternative gases that are not currently accounted for. While the use of alternative insulation gases will generally result in lower GHG emissions, we would expect that that increased usage of these alternative technologies, particularly fluoronitrile mixtures, could still significantly contribute to the total GHG emissions from this sector if used in large quantities. The proposed reporting of these additional F–GHGs would improve the accuracy and completeness of the emissions reported under subpart DD and enhance the overall quality of the data collected under the GHGRP.

To implement these revisions, we are proposing at 40 CFR 98.300(a) to redefine the source category to include equipment containing ''fluorinated GHGs (F–GHGs), including but not limited to sulfur-hexafluoride (SF_6) and perfluorocarbons (PFCs).'' As discussed in section III.N.2 of this preamble, the proposed changes would also apply to the threshold in 40 CFR 98.301. Under the proposed rule, both electric power systems and electric generating units with insulated equipment would also consider any additional F–GHGs, including those in F–GHG mixtures, used at the facility in the nameplate capacity used for estimating the threshold. At this time, we are unaware of any facilities that currently use the alternative gas mixtures exclusively or in large quantities that would render them newly subject to the subpart; therefore, we expect the minimal burden from the proposed requirements would fall on existing reporters, who would only be required to account for the additional F–GHGs in their gas-insulated equipment (GIE) and inventory.

The proposed revisions to subpart DD include minor revisions to equation DD–1 (which would be redesignated as equation DD–3 at 40 CFR 98.303(a) under this proposed rule) to incorporate the estimate of emissions from all F–GHGs within the existing calculation methodology, including F–GHG mixtures. Equation DD–3 would maintain the facility-level mass balance approach of tracking and accounting for decreases, acquisitions, disbursements, and net increase in total nameplate capacity for the facility each year, but would require applying the weight fraction of each F–GHG to determine the user emissions by gas. It is our understanding that facilities receive gas in equipment pre-mixed and do not mix the gas themselves; therefore, the proposed revisions assume that facilities will track the mixtures received, and rely on supplier data to obtain the weight fraction of each F–GHG within equipment containing a gas mixture. Facilities would need to track mixtures with unique weight fractions of individual F–GHGs separately. However, we are seeking comment on whether the weight fraction of individual F–GHGs is readily available from supplier data. We are also seeking comment on whether there are facilities that mix gas in equipment on site, or that expect to mix gas in equipment at the facility in the future, and whether we should account for this mixing in the current equation. Since we assumed that gases are typically received pre-mixed, the proposed changes include reporting of an ID number or descriptor for each insulating gas and the name and weight percent of each fluorinated gas of each insulating gas reported. To simplify references to F–GHGs and F–GHG mixtures throughout the subpart (especially in equation DD–3), we are proposing to introduce the term ''insulating gas'' and to define it as follows: ''*Insulating gas,* for the purposes of this subpart, means any fluorinated GHG or fluorinated GHG mixture, including but not limited to SF_6 and PFCs, that is used as an insulating and/or arc quenching gas in electrical equipment.'' The proposed changes also include updating the monitoring and quality assurance requirements at 40 CFR 98.304(b) to account for emissions from additional F–GHGs, and harmonizing revisions to the term ''facility'' in the definitions section at 40 CFR 98.308, and the requirements at 40 CFR 98.302, 40 CFR 98.305, and 40 CFR 98.306 such that reporters would account for the mass of each F–GHG for each electric power system. The proposed changes would not significantly revise the existing calculation, monitoring, or reporting requirements; therefore, we expect only a minimal increase in burden due to the collection of data for any equipment containing F–GHGs that are not SF_6 or PFCs. We are proposing related confidentiality determinations for the revised data elements that incorporate additional F–GHGs, as discussed in section VI of this preamble. We are proposing one additional change to remove an outdated monitoring provision at 40 CFR 98.304(a), which reserves a prior requirement for use of BAMM that applied solely for RY2011.

For the reasons described in section II.A.5 of this preamble, we are also proposing to add new definitions to clarify the existing provisions of the rule. The mass balance methodology in 40 CFR 98.303 (used for calculating facility emissions) uses the terms ''new'' and ''retired'' to describe equipment added to or removed from active use, and reporters are required to report nameplate capacity and the number of F–GHG containing pieces of any new and retired equipment. We have previously received questions from reporters regarding what equipment should be included as new or retired equipment each year, and we developed interpretations of these terms for our list of Frequently Asked Questions.[112] We are proposing to adopt the previous interpretations into the rule's requirements in order to help ensure that reporters correctly estimate emissions, which would improve the quality of the data collected. The proposed revisions would also reduce time spent searching the list of Frequently Asked Questions or responding to questions through the GHGRP Help Desk.

First, we are proposing a definition at 40 CFR 98.308 of ''energized'' to more clearly designate what equipment is considered to be installed and functioning as opposed to being in storage. The proposed definition clarifies that energized equipment includes gas-insulated equipment (including hermetically-sealed pressure switchgear) that is connected through busbars or cables to an electrical power system or that is fully-charged, ready for service, and being prepared for connection to the electrical power system, and does not include spare GIE (including hermetically-sealed pressure switchgear) in storage that has been acquired by the facility, and is intended for use by the facility, but that is not being used or prepared for connection to the electrical power system. Consistent with our previous interpretation, we are proposing to add a definition for ''new equipment'' to mean any GIE, including hermetically-sealed pressure switchgear, that is not energized at the beginning of the reporting year, but is energized at the end of the reporting year. Similarly, we are proposing a definition for ''retired equipment'' to mean any GIE, including hermetically-sealed pressure switchgear, that is energized at the beginning of the reporting year, but is not energized at the end of the reporting year. Finally, we are clarifying that (1) new equipment may also include equipment that has been transferred while in use, meaning it has been added to the facility's inventory without being taken out of active service (*e.g.,* when the equipment is sold to or acquired by the facility while remaining in place and continuing operation), and (2) retired equipment may also include equipment that has been transferred while in use, meaning it has been removed from the facility's inventory without being taken out of active service (*e.g.,* when the equipment is acquired by a new facility while remaining in place and continuing operation).

The proposed definitions of ''energized,'' ''new equipment,'' and ''retired equipment'' are intended to clarify how these terms should be interpreted for purposes of the equation used to estimate emissions for annual reporting (*i.e.,* the current equation DD–1, which we are proposing to redesignate as equation DD–3). This equation uses a mass-balance approach that assesses annual net gas consumption (based on the decrease in gas inventory and gas acquisitions and disbursements) and accounts for gas used or freed up, respectively, by equipment installations and

[112] U.S. EPA. ''*Q852. What equipment should be included as new or retired equipment each year for Subpart DD?*'' April 6, 2020. *https://ccdsupport.com/confluence/pages/viewpage.action?pageId=721715270.*

retirements.[113] The nameplate capacity of new equipment is subtracted from the total, reflecting the fact that some of the insulating gas consumed is used to fill the new equipment, while the nameplate capacity of retiring equipment is added to the total, reflecting the fact that the gas formerly used to fill the retiring equipment, unless emitted, would either be added to the gas inventory or disbursed (*e.g.,* to an SF_6 recycling company). Implicit in this approach are the assumptions that ''new'' equipment is filled with insulating gas during the same year that it is considered ''new,'' and that ''retired'' equipment is emptied of insulating gas during the same year that it is considered ''retired.'' [114] We request comment on whether new equipment is typically filled with gas during the same year that it is ''energized'' under the proposed definition of ''energize,'' and on whether retiring equipment is typically emptied of gas during the same year that it ceases to be ''energized'' under the proposed definition. If gas is added to or removed from ''new'' and/ or ''retired'' equipment in a year different from the year that the equipment is energized or ceases to be energized, respectively, it may be clearer to directly tie the terms ''new'' and ''retired'' to the filling and emptying of the equipment (for closed-pressure equipment).

In 40 CFR 98.303(b) we are proposing to require users of electrical equipment to follow certain procedures when they elect to measure the nameplate capacities (in units of mass of insulating gas) of new and retiring equipment rather than relying on the rated nameplate capacities provided by equipment manufacturers. This option would be available only for closed-pressure equipment with a voltage capacity greater than 38 kV, not for hermetically sealed pressure equipment or smaller closed-pressure equipment. The procedures are intended to ensure that the nameplate capacity values that equipment users measure match the full and proper charges of insulating gas in the electrical equipment. These procedures are also intended to be similar to and compatible with the procedures for measuring nameplate capacity adopted by the California Air Resources Board (CARB) in its Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear (effective January 1, 2022).[115]

As discussed above, the nameplate capacities of new and retiring electrical equipment are used in the current equation DD–1 of subpart DD (which would be redesignated as equation DD–3 under this proposed rule), which calculates annual GHG emissions from the equipment. In the equation, nameplate capacity is defined as referring to ''the full and proper charge of equipment rather than to the actual charge, which may reflect leakage.'' With each piece of electrical equipment, electrical equipment manufacturers typically provide a rated nameplate capacity in pounds of SF_6 (or other insulating gas) on a nameplate affixed to the equipment and/or in the product specifications. When the EPA promulgated subpart DD, we expected that users of electrical equipment would be able to use these rated nameplate capacities in their emissions calculations without introducing any errors. Experience has shown, however, that even when users of electrical equipment follow industry-accepted equipment filling and gas measuring methods, the mass of insulating gas contained in the equipment when it is filled to the manufacturer-specified density can sometimes differ from that specified on the nameplate. That is, the actual nameplate capacity of the equipment (the full and proper charge) can differ from the rated nameplate capacity of the equipment.[116]

Differences between the actual and rated nameplate capacities may result in either under- or over-estimates of emissions in the short run, depending on: (1) whether the actual nameplate capacity is greater than the rated nameplate capacity or vice versa; and (2) whether the equipment is being commissioned or retired. For example, if the actual nameplate capacity of new equipment is larger than the rated nameplate capacity of that equipment, emissions will be overestimated, because some of the gas that was actually used to fill the new equipment will be assumed to have been emitted. On the other hand, if the actual nameplate capacity of retiring equipment is larger than the rated nameplate capacity of the equipment, emissions will be underestimated (and may even be calculated as negative), because the quantity of gas recovered or emitted from the retiring equipment will be larger than is accounted for by the equation. (More scenarios are described in the document *Technical Support for Proposed Revisions to Subpart DD (2021)* included in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.)

As the above example shows, these underestimates and overestimates from a piece of equipment would cancel out over the lifetime of the equipment. To some extent, they may also cancel out in any given year because rated nameplate capacities can be either larger or smaller than the actual nameplate capacities, and most electrical equipment users are likely to both install and retire several pieces of equipment during the year. However, if a large piece of electrical equipment (or several smaller pieces of electrical equipment) is installed or retired in a given year, an error in the rated nameplate capacity of that equipment could potentially have a significant impact on the calculated emissions from the electrical equipment user in that year.

For this reason, when electrical equipment users have asked the EPA via the Helpdesk whether they may use a nameplate capacity value different from the rated nameplate capacity value in their calculations and reporting under subpart DD, we have responded [117] that

[113] This particularly applies to closed-pressure equipment. Closed-pressure equipment is typically delivered to the facility without a full and proper charge of insulating gas and therefore must be filled to the full and proper charge before it is energized. Similarly, closed-pressure equipment is typically emptied of insulating gas before it is sent off-site for recycling or disposal. Hermetically sealed-pressure equipment, on the other hand, is generally expected to be fully charged upon delivery unless it has leaked en route. Hermetically sealed-pressure equipment is also often sent off-site (*e.g.,* returned to the equipment manufacturer) with its charge intact unless it has leaked over its lifetime.

[114] Note that this logic does not necessarily apply to equipment that is ''new'' or ''retired'' because it is transferred to or from another owner while it remains energized. In this case, we are assuming that insulating gas is not generally added to or removed from equipment upon transfer, and that both the transferring and receiving facilities would presume that the equipment is transferring with its full and proper charge, meaning that the transfer of such equipment would not affect the emissions calculated under the mass-balance equation. We request comment on whether this assumption is correct.

[115] State of California Air Resources Board, ''Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear.'' Available at *https://ww2.arb.ca.gov/rulemaking/2020/sf6?utm_medium=email&utm_source=govdelivery.*

[116] Electrical equipment manufacturers indicate that this is because the rated nameplate capacity was historically only intended to indicate the approximate mass of gas required to fill equipment. The full and proper charge for a given model of equipment can vary from year to year and even from one piece of equipment to the next due to minor design changes and manufacturing variability. To ensure that the equipment functions correctly, manufacturers provide precise instructions for filling to the proper density. (The Electric Transmission & Distribution SF_6 Coalition (administered by NEMA), *SF_6 Reporting Challenges,* undated. Accessed at *https://www.nema.org/docs/default-source/products-document-library/sf6-reportingchallenges.pdf* on June 3, 2021.)

[117] See documents ''HELPDESK–64899'' and ''HELPDESK–30364'', available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

they may use the nameplate capacity value that corresponds to the full and proper charge of the equipment, which is determined based on density (*e.g.,* the temperature-corrected pressure of the equipment) per the manufacturer's filling instructions. We have also noted that subpart DD does not currently specify a method for calculating nameplate capacity values, but for the mass-balance approach to yield correct results, the nameplate capacity value should reflect any shipping charge contained in the equipment upon delivery, and the same nameplate capacity value should be used throughout the life of the equipment. Finally, we have noted that paragraph 98.3(g)(2) requires equipment users to keep records of the method used to calculate the nameplate capacity value.

The process that we are proposing in this action would elaborate on and adopt this guidance into the rule's requirements. It is designed to avoid a number of potential errors by equipment users that can result in inaccuracies in the nameplate capacities that they measure. Such errors can occur when:

- Equipment is deliberately overfilled or underfilled;
- Shipping charges are accounted for incorrectly or not at all;
- Inaccurate weigh scales, flowmeters, pressure gauges, or thermometers are used to fill equipment;
- The temperature of the insulating gas is not measured accurately when the equipment is filled or emptied (*e.g.,* the temperature of the gas is incorrectly equated to the ambient temperature);
- The insulating gas in equipment (especially retiring equipment) is not completely recovered (or the gas remaining in the equipment is not accounted for);
- Previous leakage from equipment (especially retiring equipment) is not accounted for; or
- Insulating gas in hoses and gas carts is not accounted for.

To avoid these potential errors, the EPA is proposing certain requirements at 40 CFR 98.303(b) for when electrical equipment users measure the nameplate capacity of new equipment that they install. These proposed requirements for new equipment would help ensure that electrical equipment users:

- Correctly account for the mass of insulating gas contained in equipment upon delivery from the manufacturer (*i.e.,* the holding charge);
- Use flowmeters or weigh scales that meet certain accuracy and precision requirements to measure the mass of insulating gas added to the equipment;
- Use pressure-temperature charts and pressure gauges and thermometers that meet certain accuracy and precision requirements to fill equipment to the density specified by the equipment manufacturer, allowing appropriate time for temperature equilibration; and
- Ensure that insulating gas remaining in hoses and gas carts is correctly accounted for.

The EPA is also proposing certain requirements at 40 CFR 98.303(b) for when electrical equipment users measure the nameplate capacity of retiring equipment. These proposed requirements for retiring would help ensure that electrical equipment users:

- Correctly account for the mass of insulating gas contained in equipment upon retirement, measuring the actual temperature-adjusted pressure and comparing that to the temperature-adjusted pressure that reflects the correct filling density of that equipment;
- Use flowmeters or weigh scales that meet certain accuracy and precision requirements to measure the mass of insulating gas recovered from the equipment;
- Use pressure-temperature charts and pressure gauges and thermometers that meet certain accuracy and precision requirements to recover the insulating gas from the equipment to the correct blank-off pressure, allowing appropriate time for temperature equilibration; and
- Ensure that insulating gas remaining in the equipment, hoses and gas carts is correctly accounted for.

We are proposing at 40 CFR 98.303(b)(6) that instead of measuring the nameplate capacity of electrical equipment when it is retired, users may measure the nameplate capacity of electrical equipment earlier during maintenance activities that require opening the gas compartment. In this case, the equipment user would still be required to follow the measurement procedures required for retiring equipment at 40 CFR 98.303(b)(5) to measure the nameplate capacity, and the measured nameplate capacity would be recorded but would not be used in equation DD–3 until that equipment was actually retired.

As previously mentioned, only closed-pressure equipment with a voltage capacity greater than 38 kV would be eligible for nameplate capacity measurement and correction. This is because the quantities of insulating gas that are typically inside hermetically sealed-pressure equipment and in closed pressure equipment with smaller voltage capacities are individually and collectively less significant than those in closed-pressure equipment with voltage capacities at or above 38 kV. Consequently, any errors in the rated nameplate capacities of smaller equipment are not likely to have a significant impact on the calculated emissions of equipment users, and efforts to correct the nameplate capacity values of smaller equipment do not appear to be justified by the improvement in accuracy that would result. CARB has established eligibility criteria similar to those we are proposing based on their finding that the criteria would cover ''approximately 23 percent of California's GIE [gas insulated equipment] and approximately 80 percent of the SF_6 used in the State.'' [118] In addition, users rarely add or remove gas to or from hermetically sealed-pressure equipment, by design. We request comment on the proposed eligibility criteria.

We are proposing a scheme in 40 CFR 98.303(b) that would require all eligible new and retiring equipment to be treated consistently with respect to the measurement and adoption of nameplate capacities. To avoid biases that could result from measuring and adopting nameplate capacities for some pieces of eligible new or retiring equipment but not others, electrical equipment users electing to measure the nameplate capacities of any new or retiring equipment would be required at 40 CFR 98.303(b)(1) to measure the nameplate capacities of all eligible new and retiring equipment in that year and in all subsequent years. For each piece of equipment, the electrical equipment user would be required to calculate the difference between the user-measured and rated nameplate capacities, verifying that the rated nameplate capacity was the most recent available from the equipment manufacturer. Where a user-measured nameplate capacity differed from the rated nameplate capacity by two percent or more, the electrical equipment user would be required at 40 CFR 98.303(b)(2) to adopt the user-measured nameplate capacity for that equipment for the remainder of the equipment's life. Where a user-measured nameplate capacity differed from the rated nameplate capacity by less than two percent, the electrical equipment user would have the option at 40 CFR 98.303(b)(3) to adopt the user-measured nameplate capacity, but if they chose to do so they would be required to adopt the user-measured nameplate capacities for all new and retiring equipment

[118] State of California Air Resources Board, ''Notice of Public Availability of Modified Text: Proposed Amendments to the Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear,'' May 5, 2021, pp. 17–18.

whose user-measured nameplate capacity differed from the rated nameplate capacity by less than two percent. As is the case for the proposed requirement to consistently measure or not measure the nameplate capacities of all new and retiring equipment, the proposed requirement to consistently adopt or not adopt the user-measured nameplate capacities where they differ from the rated nameplate capacity by less than two percent is intended to avoid bias that could result from adopting only a subset of the user-measured nameplate capacities that fall into this category.

We are proposing the two-percent tolerance for differences between the user-measured and rated nameplate capacities because, given the precisions and accuracies that we are proposing for the measuring devices (scales, gauges, etc.) used to calculate nameplate capacities (as discussed further in this section), differences of one percent or less are not expected to be mathematically meaningful. We request comment on the value of two percent and on whether the percentage tolerance should be supplemented by an absolute tolerance, such as 100 pounds of SF_6 (equivalent to 1,034 $mtCO_2e$). In the latter case, differences equal to or greater than the lesser of two percent or 100 pounds would trigger the requirement to use the user-measured nameplate capacity. The drawback of using a separate absolute tolerance is that this tolerance may not be mathematically meaningful if the full and proper charge of the equipment exceeded 10,000 pounds.

Our proposal to allow electrical equipment users to adopt the user-measured nameplate capacity even when the difference between that capacity and the rated capacity is less than two percent is based on our desire to maintain as much consistency as possible between GHGRP requirements and the proposed requirements of CARB. Our understanding is that CARB is proposing [119] to require electrical equipment users in California to measure the nameplate capacity of all newly installed closed pressure equipment with a voltage capacity greater than 38 kV and to adopt the measured value irrespective of the magnitude of the difference between the measured value and the manufacturer-supplied value.

When electrical equipment is retired, the quantity of the gas remaining in the equipment may reflect leakage that has occurred since the last time the equipment was serviced or re-filled. In this case, we are proposing at 40 CFR 98.303(b)(5) to allow equipment users to account for the leakage using one of two approaches. In both approaches, equipment users would: (1) measure the temperature-compensated pressure of the equipment before they removed the insulating gas from that equipment; and (2) compare the measured temperature-compensated pressure to the temperature-compensated pressure corresponding to the full and proper charge of the equipment (the design operating pressure). If the measured temperature-compensated pressure was different from the temperature-compensated pressure corresponding to the full and proper charge of the equipment, the equipment user could either (a) add or remove insulating gas to or from the equipment until the equipment reached its full and proper charge, recover the gas until the equipment reached a pressure of 0.068 pounds per square inch, absolute (psia) (3.5 Torr) or less,[120] and weigh the recovered gas (charge adjustment approach), or (b) if the measured temperature-compensated pressure was at least 90 percent of the temperature-compensated design operating pressure, recover the gas that was already in the equipment, weigh it, and account mathematically for the difference between the quantity of gas recovered from the equipment and the full and proper charge (mathematical adjustment approach). In the mathematical adjustment approach, proposed as equation DD–4, the equipment user would calculate the mass of the full and proper charge by scaling up the mass recovered by the ratio of pressures (in absolute terms) corresponding to the full and proper charge and the actual charge, respectively, accounting for any insulating gas remaining in the equipment (if the final pressure of the equipment exceeded 0.068 psia).[121] We are proposing to limit the mathematical adjustment approach to situations where the measured temperature-compensated pressure is equal to or greater than 90 percent of the design operating pressure to ensure that nameplate capacity measurements and calculations remain precise. If smaller fractions of the full charge are scaled up to calculate the nameplate capacity, the uncertainty of the calculation begins to approach (and ultimately exceed) two percent given the precision and accuracy requirements we are proposing for pressure gauges and other measurement devices. We request comment on the expected accuracy of the mathematical adjustment approach, and whether it should be enhanced to account for non-linearities in the relationship between pressure and density. Our analysis of this issue, discussed in the Technical Support Document, indicates that such non-linearities can lead to systematic errors in the results of the mathematical adjustment approach under some circumstances. One way of addressing such non-linearities would be to include a compressibility factor (often termed a ''Z'' factor) in the calculation, as we have done for gas measurements for other subparts (see, *e.g.,* equation I–25 of subpart I (Electronics Manufacturing) and equation L–33 of subpart L (Fluorinated Gas Production) of part 98). A version of equation DD–4 including compressibility factors is included in the Technical Support Document.

The mathematical adjustment approach would accommodate situations where it may not be possible to fully recover the insulating gas from the equipment, *e.g.,* where the equipment has leaks through which air would be drawn into the equipment and subsequently into the recovery equipment or gas cart if the equipment were drawn into a deep vacuum. However, as discussed further in the Subpart DD TSD, an inability to pull the equipment into a vacuum may lead to inaccurate nameplate capacity measurements unless the accuracy and precision requirements for pressure gauges are tightened beyond those in the proposed rule. We request comment on this issue and on alternative methods for addressing nameplate capacity measurements for equipment with large leaks. For example, CARB has adopted an exception to its nameplate capacity measurement requirements for equipment with ''compromised integrity.'' The mathematical adjustment approach would also avoid some of the disadvantages of the charge adjustment approach, which, compared to the mathematical adjustment approach, would be more time-consuming and risks emitting more insulating gas and

[119] Attachment A: Modifications to the Proposed Regulation Order, California Air Resources Board, available at *https://ww3.arb.ca.gov/board/15day/sf6/15dayatta.pdf.*

[120] 3.5 Torr is a common ''blank-off pressure'' to which gas carts are designed to recover insulating gas from electrical equipment. At 3.5 Torr, the EPA estimates that 0.1 percent of the full and proper charge of insulating gas would remain in the equipment, assuming that a full and proper charge has a pressure of 5 atmospheres (3800 Torr). We are therefore proposing to treat quantities of gas remaining at pressures of 3.5 Torr and below as negligible in nameplate capacity calculations.

[121] Equipment users could also use a hybrid approach wherein they would top up the equipment but account mathematically for any gas remaining in equipment at a pressure above 0.068 psia.

contaminating the insulating gas used to top up the equipment with impurities in the gas that remains in the equipment.

To ensure that the mass-balance method is based on consistent nameplate capacity values throughout the life of the equipment, we are proposing at 40 CFR 98.303(b)(9) that electrical equipment users would be allowed to measure and revise the nameplate capacity value of any given piece of equipment only once, unless the nameplate capacity itself is likely to have changed due to changes to the equipment (*e.g.,* replacement of the equipment bushings).

Currently, subpart DD requires that scales used to measure cylinders of gas be accurate and precise to within 2 pounds of true weight and be periodically recalibrated per the manufacturer's specifications. Subpart DD does not include accuracy or precision requirements for other measuring devices, such as flow meters, pressure gauges, or thermometers. To help ensure that electrical equipment users obtain accurate measurements of their equipment's nameplate capacities, we are therefore proposing at 40 CR 98.303(b)(10) that electrical equipment users use measurement devices that meet the following accuracy and precision requirements when they measure the nameplate capacities of new and retiring equipment.

(1) Flow meters must be certified by the manufacturer to be accurate and precise to within one percent of the largest value that the flow meter can, according to the manufacturer's specifications, accurately record.

(2) Pressure gauges must be certified by the manufacturer to be accurate and precise to within 0.5 percent of the largest value that the gauge can, according to the manufacturer's specifications, accurately record.

(3) Temperature gauges must be certified by the manufacturer to be accurate and precise to within ±1.0 °F; and

(4) Scales must be certified by the manufacturer to be accurate and precise to within one percent of the true weight.

These requirements are the same as those proposed by CARB in its May 5, 2021 and June 17, 2021 documents,[122] except we are clarifying that the measurement devices must be precise as well as accurate. The measurement devices listed here would be subject to the general GHGRP calibration requirements at 40 CFR 98.3(i).

Even if electrical equipment users use an accurate thermometer, they may under- or overestimate the temperature of the gas being filled into the equipment or recovered from it, for example if they assume that the gas is at the same temperature as the area surrounding the equipment. This is because gas that is filled into equipment from a container may be cooler or warmer than the ambient temperature depending on the method used to transfer the gas. Where the insulating gas is pulled from the container in the liquid phase, an evaporator is generally used between the container and the equipment to ensure that only gas is transferred into the electrical equipment. A representative of a gas cart manufacturer indicated that the gas transferred using this method is often slightly warmer than the ambient temperature. In this case, the density of the gas will be lower than the density calculated using the ambient temperature. Where the insulating gas is pulled from the container in the gas phase, the container (and the gas inside) tends to cool as the gas boils off from a reservoir of liquid insulating gas in the container. Heating blankets are often used to warm the container and gas in this case, but they may not compensate for the temperature loss associated with the phase change. In this case, the gas will be cooler than the ambient temperature, and its density will be higher than the density calculated using the ambient temperature. To at least partly address these issues, we are proposing to require that equipment users measure the temperature of the electrical equipment rather than relying on the ambient temperature when making nameplate capacity measurements. However, even measurements on the surface of the electrical equipment may not reflect the temperatures inside, at least not right away. To ensure that the temperature of the gas is not under- or overestimated, we are considering requiring a minimum temperature equilibration time following the gas filling procedure. We request comment on this option, including on what appropriate waiting times would be for temperature equilibration for equipment of different sizes and on whether manufacturer filling directions adequately address temperature measurement issues. Temperature equilibration times that we are considering range from 30 minutes for relatively small equipment to 8 to 24 hours for large equipment.

We also request comment on whether it would be sufficient to require that any gas inside hoses is ''accounted for'' both before and after equipment filling or emptying processes, or whether we should specify a more detailed procedure for evacuating hoses before and after equipment filling and emptying. A representative of a gas cart manufacturer who commonly provides training on use of its gas carts described the following procedure to the EPA: Any gas in the hoses should be pulled back into the gas cart/cylinders before the filling or emptying process begins, and the baseline measurements on scales and/or flow meters should be taken at that point. Then the equipment should be filled or emptied, the hoses should be isolated from the equipment, and any remaining gas in the hoses should be pulled back into the gas cart/cylinders. At that point the final measurements on scales and/or flow meters should be taken. We request comment on whether we should require use of this procedure or whether there may be other acceptable procedures for ensuring that any gas in hoses is accounted for in nameplate capacity measurements.

We are proposing at 40 CFR 98.307(b) to require equipment users to keep records of certain identifying information for each piece of equipment for which they measure the nameplate capacity: the rated and measured nameplate capacities, the date of the nameplate capacity measurement, the measurements and calculations used to obtain the measured nameplate capacity (including the temperature-pressure curve and/or other information used to derive the initial and final temperature-adjusted pressures of the equipment), and whether or not the measured nameplate capacity value was adopted for that piece of equipment. In addition, we are proposing at 40 CFR 98.306(o) and (p) to require equipment users who measure and adopt nameplate capacity values to report the total rated and measured nameplate capacities across all the equipment whose nameplate capacities were measured and for which the measured nameplate capacities have been adopted in that year. Collecting this information would help enable us to ascertain the average magnitude of nameplate capacity adjustments at both the facility and U.S. level, providing insight into the extent to which manufacturer-assigned nameplate capacities may err and alerting us to situations where adjustments are unusually large, which may indicate

[122] State of California Air Resources Board, ''Notice of Public Availability of Modified Text: Proposed Amendments to the Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear,'' May 5, 2021, and State of California Air Resources Board, ''Notice of Public Availability of Modified Text: Proposed Amendments to the Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear,'' June 17, 2021. Available at *https://ww2.arb.ca.gov/rulemaking/2020/sf6?utm_medium=email&utm_source=govdelivery.*

that equipment users are not following the procedures specified in the rule to ensure that they measure nameplate capacity values accurately.

2. Proposed Revisions To Streamline and Improve Implementation for Subpart DD

In alignment with our proposed revisions to include additional F–GHGs in the source category, and for the reasons described in section II.B.1 of this preamble, we are proposing to revise the applicability threshold of subpart DD at 40 CFR 98.301. Subpart DD currently requires reporting from facilities with a total nameplate capacity of SF_6 and PFC-containing equipment located within the facility or under common ownership or control exceeding 17,820 pounds. The EPA established the nameplate capacity threshold [123] of 17,820 pounds in the 2010 Final Rule for Additional Sources of Fluorinated GHGs(75 FR 74774) as an ''equivalent threshold'' that approximated the 25,000 metric tons of CO_2 threshold for emissions. Emissions of SF_6 and PFC from the source category include emissions from equipment leaks and venting from gas-insulated substations and switch gear. The insulating gas can also be released during equipment manufacturing, installation, normal operation and maintenance, and disposal. We initially chose a nameplate capacity-based threshold because nameplate capacity is strongly correlated with SF_6 emissions, and a capacity-based threshold allows potential sources to determine whether they are above or below the threshold more quickly and with less effort than through estimating emissions.[124] The threshold of 17,820 pounds was estimated using the GWP of SF_6 that was applicable at the time and historical leakage data reported by industry owners and operators who are partners in EPA's SF_6 Emission Reduction Partnership for Electric Power Systems.

To help ensure that the GHGRP data collected better reflects the emission rates and insulating gases that prevail in the current electric power system industry, we are proposing to replace the existing nameplate capacity threshold with an emissions threshold of 25,000 metric tons CO_2e per year of F–GHGs. To calculate their F–GHG emissions for comparison with the threshold, electrical equipment users would use one of two new equations in subpart DD at 40 CFR 98.301, proposed equations DD–1 and DD–2. The proposed equations explicitly include not only the nameplate capacity of the equipment but also an updated default emission factor and the GWP of each insulating gas. The equations would therefore account for additional fluorinated gases (including GHG mixtures) now being marketed to the industry as well as lower reported emission rates within the industry.[125] The current nameplate-capacity based threshold was based on the historical emission rate, which was estimated at approximately 13 percent, and the GWP for SF_6. For small facilities (total nameplate capacity between 17,000 and 50,000 lbs), the largest emission rate reported since 2013 (based on beginning of year capacity) was 10.3 percent.[126] Additionally, some facilities within this industry sector may have begun to use lower GWP F–GHGs, which is not reflected when using only nameplate capacity of the equipment to determine applicability. Therefore, the current nameplate capacity threshold may require facilities with annual subpart DD emissions below 25,000 $mtCO_2e$ per year to report. Revising the reporting threshold to account for lower emission rates and the use of F–GHGs with lower GWPs would reduce burden for those electric power systems and facilities that have decreased their reliance on SF_6-insulated equipment and would maintain a threshold equivalent to the 25,000 $mtCO_2e$ threshold.

As discussed in section III.N.1 of this preamble, we are proposing to revise the existing calculation, monitoring, and reporting requirements of subpart DD to require reporting of additional F–GHGs beyond SF_6 and PFCs. Therefore, the proposed new equations DD–1 and DD–2 that we are proposing for the applicability threshold would require potential reporters to account for the total nameplate capacity of all F–GHG containing equipment (located on-site and/or under common ownership or control), including equipment containing F–GHG mixtures, and multiply by the weight fraction of each F–GHG (for gas mixtures), the GWP for each F–GHG, and an emission factor of 0.10 (representing an emission rate of 10 percent). We have determined that the proposed threshold methodology is more appropriate because it represents the actual fluorinated gases used by a reporter, accounts for gas mixtures, and updates the contemporaneous emission rate performance for the industry.[127] Finally, we are proposing harmonizing changes in multiple subsections to renumber existing equation DD–1 and maintain cross-references to the equation.

The proposed revisions would also streamline the reporting requirements to focus Agency resources on the substantial emission sources within the sector and would exclude new electric power systems and other new facilities from subpart DD when their emissions of insulating gas were estimated to be below 25,000 $mtCO_2e$ per year. The proposed changes would revise the existing threshold in 40 CFR 98.301 and Table A–3 to subpart A (General Provisions). Reporters would continue to determine the applicability of subpart DD under 40 CFR 98.2(a)(1), which applies to source categories listed in Table A–3, such that only total estimated emissions from F–GHGs would be accounted for in determining whether the applicability threshold is met. Therefore, facilities would continue to determine the applicability of subpart DD without consideration of the combined emissions from stationary fuel combustion sources (subpart C), miscellaneous use of carbonates (subpart U), and other applicable source categories towards the threshold.

Due to the definition of ''facility'' for electric power systems that is different from the definition of ''facility'' (in subpart A of part 98) that covers facilities in other subparts, electric power systems always report to the GHGRP as unique facilities (*i.e.,* emissions from other sources covered by the GHGRP that may have overlap in location with a subpart DD facility are reported under a different e-GGRT identifier due to the different definition of ''facility''). Thus, placement of subpart DD in Table A–3 or Table A–4 of subpart A has no effect on the emissions considered when determining applicability for electric power systems if an equivalent threshold is used.

[123] The current threshold is based on the total nameplate capacity of SF_6 or PFC containing equipment located within the facility and SF_6 or PFC containing equipment that is not located within the facility but is under common ownership or control.

[124] See U.S. EPA. *Subpart DD Technical Support Document—Use of Electric Transmission and Distribution Equipment,* November 2010. Available at *https://www.epa.gov/sites/production/files/2015-03/documents/subpartdd-tsd-electricpowerequip.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[125] *Id.* The leak rate was originally based on 1999 weighted leak rates from 42 entities reporting to the EPA's SF_6 Emission Reduction Partnership for Electric Power Systems.

[126] Calculated based on beginning of year nameplate capacity and total reported emissions to subpart DD of 40 CFR part 98, Use of Electric Transmission and Distribution Equipment, Envirofacts, downloaded from *https://www.epa.gov/enviro/greenhouse-gas-customized-search* on July 8, 2020.

[127] For more information see, *Technical Support for Proposed Revisions to Subpart DD (2021),* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

However, for other facilities that use electrical equipment, it is possible to add emissions under subpart DD to those from other subparts as they use the standard definition of ''facility'' in Subpart A. We are currently proposing to maintain subpart DD in Table A–3 of subpart A. By keeping subpart DD in Table A–3, we expect to continue to capture the majority of annual emissions from the use of electrical transmission and distribution equipment (approximately 65 percent in 2019; down from a high of 73 percent due to some facilities becoming eligible to exit the program [128]) while not significantly increasing burden. Moving subpart DD to Table A–4 of subpart A would likely have a significant impact on the number of reporters subject to subpart DD but is unlikely to result in a significant increase to the proportion of emissions covered by the GHGRP, because moving subpart DD to Table A–4 would only affect facilities that are not electric power systems. Facilities that are not electric power systems have historically reported emissions significantly below 25,000 $mtCO_2e$ even when the total nameplate capacity at the facility was over the current threshold of 17,820 lbs.[129] One option that we are considering is to move use of electrical equipment to Table A–4 of subpart A, which would require facilities that used electrical equipment but that were not electric power systems to determine applicability according to 40 CFR 98.2(a)(2). Under this option, facilities that used electrical equipment but that were not electric power systems would be required to add their total estimated F–GHG emissions from electrical equipment to their combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all other applicable source categories that are listed in Table A–3 and Table A–4 to determine whether the facility emits 25,000 $mtCO_2e$ or more per year in combined emissions and whether they were required to report under part 98. In other words, if the result of this calculation exceeded 25,000 $mtCO_2e$, they would be required to report their emissions from electrical equipment even if the F–GHG emissions from such equipment, by themselves, were below 25,000 $mtCO_2e$. We are considering requiring more comprehensive reporting of emissions from users of electrical equipment other than electric power systems because comparisons between the consumption of SF_6 reported to the GHGRP by SF_6 suppliers have generally exceeded the consumption reported by (or estimated by the EPA for) SF_6 users. It is possible that SF_6 consumption by users of electrical equipment with nameplate capacities under the current threshold (and therefore with SF_6 emissions that are likely to fall under the 25,000 $mtCO_2e$ threshold) could account for some of this gap, and therefore it is possible that reporting by these facilities would at least partially explain the gap. However, we recognize that if we move subpart DD to Table A–4, numerous facilities that are subject to this part because of emissions from another source category would potentially be newly required to report under subpart DD with only a few pieces of gas-insulated equipment. One option for addressing this concern would be not to require reporting when emissions from the facility's electrical equipment, as calculated using equation DD–2, fell below a threshold, such as 1,000 $mtCO_2e$. We request comment on these options.

[128] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019* (EPA 2021), available at: *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019.*

[129] See *Technical Support for Proposed Revisions to Subpart DD (2021),* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

O. Subpart FF—Underground Coal Mines

The EPA is proposing two technical corrections to subpart FF of part 98 (Underground Coal Mines), for the reasons described in section II.A.5 of this preamble. First, we are proposing to correct the term ''MCF_i'' in equation FF–3 of subpart FF to revise the term ''$1-(fH_2O)_1$'' to ''$1-(fH_2O)_i$.'' The proposed change would correct an error inadvertently introduced in the November 29, 2013 final rule (78 FR 71967). Second, we are proposing a revision to 40 CFR 98.326(t). Facilities are required to report the Mine Safety and Health Administration (MSHA) identification number to the EPA. The technical correction would add the word ''number'' after the word ''identification'' to clarify the reporting requirement.

P. Subpart GG—Zinc Production

We are proposing one revision to subpart GG of part 98 (Zinc Production) that would improve the quality of the data collection under the GHGRP. For the reasons described in section II.A.4 of this preamble, we are proposing to add a reporting requirement at 40 CFR 98.336(a)(6) and (b)(6) for the total amount of EAF dust annually consumed by all Waelz kilns at zinc production facilities. EAF dust and other scrap materials are primary inputs at certain zinc production and recycling facilities from which zinc is recovered. The EPA is proposing to collect this data in order to improve verification of reported data under the GHGRP. This data would also improve emissions estimates developed as part of the U.S. GHG Inventory. Collection of this data would be useful for verification of data reported through the GHGRP by assisting with data validation. The amount of EAF dust consumed by facilities strongly correlates with process CO_2 emissions. Therefore, the total amount of EAF dust consumed by all Waelz kilns could be used for comparison to emissions estimates and would be useful for verifying consistency in emissions over time. Additionally, the U.S. GHG Inventory uses Tier 1 methods from the 2006 IPCC Guidelines to estimate emissions from zinc produced. For primary zinc production, the inventory uses a Waelz kiln emission factor based on zinc production for non-EAF dust consuming facilities, and a Waelz kiln emission factor based on EAF dust consumption for EAF-dust consuming facilities. Currently, the EPA is only able to obtain EAF dust consumed for a small number of facilities using Waelz kilns, which increases the uncertainty of these emission factors. Further, for Waelz kiln-based production, the IPCC recommends the use of emission factors based on EAF dust consumption, since the amount of carbonaceous materials (*e.g.,* coal or coke) used (which drives process CO_2 emissions) is more directly dependent on the amount of EAF dust consumed, rather than the amount of zinc produced. Collecting the total annual EAF dust consumed for all Waelz kilns at facilities would allow the EPA to develop a more accurate emission factor for facilities using Waelz kilns for the Inventory.

Reporters currently estimate emissions using either a CEMS direct measurement methodology or calculate process CO_2 emissions by determining annually the total mass of carbon-containing input materials (including zinc-bearing material, flux, electrodes, and any other carbonaceous materials) introduced into each kiln and furnace and the carbon content of each material. Of these materials, the proposed data element would only require segregation and reporting of the mass of EAF dust consumed for all kilns. Reporters currently collect information on the EAF dust consumed on a monthly basis as part of their existing operations; reporters using the mass balance methodology collect this data as a portion of the inputs to equation GG–1. We are not proposing any changes to the mass calculation methodology; reporters would only be required to sum all EAF dust consumed on a monthly basis for each kiln and then for all kilns at the facility for reporting and entering the information into e-GGRT. Therefore, we do not anticipate that the proposed data elements would require any additional monitoring or data collection by reporters. The proposed data requirement would be required for reporters using either the CEMS direct measurement or mass balance calculation methodologies. We are also proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

Q. Subpart HH—Municipal Solid Waste Landfills

For the reasons described in section II.A.1 of this preamble, we are proposing revisions to subpart HH of part 98 (Municipal Solid Waste Landfills) that would improve the quality of the data collection under the GHGRP. First, we are proposing to update the factors used in modeling CH_4 generation from waste disposed at landfills to reflect the increased amount of inert materials that are disposed at landfills that do not contribute to CH_4 generation. The updated factors would allow MSW landfills to more accurately model their CH_4 generation.

Subpart HH uses a first order decay model to estimate CH_4 generation from MSW landfills. This model considers the quantity of MSW landfilled, the degradable organic carbon (DOC) content of that MSW, and the first order decay rate (k) of the DOC. Table HH–1 of subpart HH contains DOC and k values that a reporter must use to calculate their CH_4 generation based on the different categories of waste disposed at that landfill and the climate in which the landfill is located. The options available under the current rule can generally be summarized as follows:

- The Bulk Waste option assumes a single stream of waste coming into the facility that contains a mixture of organic and inorganic wastes. The current default DOC for this waste stream is 0.20, and the default decay rate values for this bulk waste stream are dependent on precipitation rates: 0.02 for <20 inches of rainfall per year; 0.038 for 20–40 inches of rainfall per year; and 0.057 for >40 inches of rainfall per year.
- The Modified Bulk MSW option allows facilities to break out their waste into three different streams: bulk MSW excluding inert and construction and demolition (C&D) wastes (effectively ‘‘organic MSW''); C&D waste; and inert waste. The decay rates for the ‘‘organic MSW'' stream are the same as those listed for the Bulk Waste option, however the default DOC is a higher value of 0.31. This value was calculated from the waste quantities reported in the EPA's ‘‘Municipal Solid Waste in the United States: 2007 Facts and Figures'' report [130] specifically for the GHGRP considering only the organic containing portions of MSW.
- The Waste Composition option provides defaults for DOC and k for several subcategories of waste including food waste, garden waste, paper waste, wood waste, inert waste, etc. The DOC and k values for different subcategories of wastes are based on the values recommended in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5 Waste, Chapters 2 and 3.[131] Reporters are allowed to use the waste composition option for those waste streams for which compositional data are available and use the bulk waste defaults (DOC and k values as described in the Bulk Waste option above) for waste streams where compositional data are not available.

The EPA has received comments from stakeholders in the waste industry (*i.e.,* Waste Management, Republic Services, National Waste & Recycling Association, Solid Waste Association of North America, SCS Engineers, and Weaver Consulting Group) related to the values for DOC and k for both the Bulk Waste and Modified Bulk Waste Options listed under Table HH–1 to subpart HH. These comments [132] were received during the expert and public comment review period for the U.S. GHG Inventory. The U.S. GHG Inventory for solid waste uses directly reported emissions values from subpart HH to estimate national CH_4 emissions from MSW landfills throughout the entire United States, and the commenters noted that, in order to implement these suggested revisions to the U.S. GHG Inventory, revisions must first be made to subpart HH. Commenters argued, based on alleged fundamental shifts in the characterization of waste disposed in landfills and research conducted by state agencies and the Environmental Research and Education Foundation (EREF),[133] that: (1) the default DOC values for Bulk Waste and Modified Bulk Waste overestimate the organic fraction of waste in U.S. landfills and therefore overestimate emissions from this source; and (2) that the EPA should perform an analysis of data reported to subpart HH and update the default k values as necessary based on the results of this analysis. Commenters noted that the default values for k currently listed in Table HH–1 of subpart HH for both the Bulk Waste and Modified Bulk Waste options are based on data from the EPA's 2008 draft AP–42: Compilation of Air Emissions Factors [134] (which is still in draft form) and stated these default values are likely out-of-date considering changes in waste disposal trends in the past two decades.

In response, the EPA performed a multivariate analysis to minimize the difference between CH_4 generation estimates back-calculated from the reported values of equation HH–7 and the CH_4 generation predicted using equation HH–1, while optimizing k and DOC simultaneously for each landfill included in the analysis cohort. Six years of GHGRP data for 355 landfills were ultimately analyzed in this cohort. These 355 landfills were subpart HH reporters that reported a gas collection system (GCS) installed on-site for all reporting years, reported a consistent waste categorization option for all reporting years, and reported the same DOC and decay rate values for all reporting years. Details of this analysis are available in the memorandum from Meaghan McGrath, Kate Bronstein, and Jeff Coburn, RTI International, to Rachel Schmeltz, EPA, *Multivariate analysis of data reported to the EPA's Greenhouse Gas Reporting Program (GHGRP), Subpart HH (Municipal Solid Waste Landfills) to optimize DOC and k values,* (June 11, 2019), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

After consideration of the comments received and the multivariate analysis

[130] U.S. EPA, Municipal Solid Waste in the United States: 2007 Facts and Figures, 2007. *https://archive.epa.gov/epawaste/nonhaz/municipal/web/pdf/msw07-rpt.pdf.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[131] IPCC. Guidelines for National Greenhouse Gas Inventories, Volume 5 Waste, 2006. *https://www.ipcc-nggip.iges.or.jp/public/2006gl/.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[132] See Waste Management, Republic Services, National Waste & Recycling Association, Solid Waste Association of North America, SCS Engineers, and Weaver Consulting Group. Comments on the 1990–2017 Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks EPA–HQ–OAR–2018–0853. March 14, 2019. These and other similar comments are in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[133] The Environmental Research & Education Foundation (2019). Analysis of Waste Streams Entering MSW Landfills: Estimating DOC Values & the Impact of Non-MSW Materials. Retrieved from *www.erefdn.org.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[134] U.S. EPA. 2008. AP–42: Compilation of Air Emissions Factors, Fifth Edition, Volume 1, Chapter 2.4: Municipal Solid Waste Landfills. *https://www3.epa.gov/ttn/chief/ap42/ch02/index.html.* Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

performed, we are proposing to amend subpart HH to provide revised DOC and k values that would more accurately estimate GHG emissions from the MSW landfills. We are proposing to amend the bulk waste DOC value in Table HH–1 from 0.20 to 0.17, which was the average optimal DOC value for all landfills reporting under the Bulk Waste option (n=239) in the multivariate analysis. This value is similar to the proposed bulk waste DOC value of 0.161 the waste industry has cited within their comments as a result of study produced by the EREF (2016). We are proposing to use the results of the multivariate analysis in lieu of using the EREF recommended DOC value because the multivariate analysis is more nationally representative. EREF develop their recommended DOC value using state-level data for a single year (2013) for 14 states. The multivariate analysis based on subpart HH reported data uses facility-level data covering 41 states over the course of 6 years (2012–2017).

It was not possible to use the multivariate analysis to develop an optimal DOC value for bulk MSW waste without inerts and (C&D) waste for the Modified Bulk Waste option due to a lack of reporters that used this option meeting the criteria developed and noted above for the multivariate analysis. Instead, we reanalyzed the DOC value for this option using the same approach used to develop this factor initially but with updated MSW composition data from 2011 to 2015 as reported by the EPA.[135] The average DOC value across the 5-year period considering all MSW landfilled is 0.17, which agrees well with our optimized DOC value for bulk MSW from the multivariate analysis. After subtracting out inerts, the average DOC for MSW excluding inerts is 0.27.[136] The percent reduction of the DOC value for MSW excluding inerts is similar to the percent reduction in the average DOC for bulk MSW as determined from the multivariate analysis. Therefore, we are also proposing to revise the DOC value for the Modified Bulk MSW option in Table HH–1 from 0.31 to 0.27.

The EPA is also proposing to include a DOC value for ''Uncharacterized MSW'' within the Waste Composition option in Table HH–1. Currently, reporters using this option use the DOC provided for the Bulk Waste option for these uncharacterized waste streams as provided in 40 CFR 98.343(a)(2). A multivariate analysis of the facilities that use a hybrid approach of the Waste Composition option and the Bulk Waste option indicates that the optimal DOC value for uncharacterized MSW is much greater than the value for bulk DOC. The multivariate analysis indicates an optimal DOC value for uncharacterized DOC when using the waste composition option of 0.32. Therefore, we are proposing to include within Table HH–1 a DOC for uncharacterized MSW of 0.32 and proposing to revise 40 CFR 98.343(a)(2) to reference using this uncharacterized MSW DOC value rather than the bulk MSW value for waste materials that could not be specifically assigned to the streams listed in Table HH–1 for the Waste Composition option. Details of this analysis are available in the memorandum, *Multivariate analysis of data reported to the EPA's Greenhouse Gas Reporting Program (GHGRP), Subpart HH (Municipal Solid Waste Landfills) to optimize DOC and k values,* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

We note that DOC and k values are linked. Appropriate k values are primarily dependent on the composition of the waste and on the moisture content of the waste within the landfill (2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5 Waste, Chapter 3), which is why subpart HH includes different k values based on annual precipitation rates. The multivariate analysis we conducted determined the optimal values for DOC and k values when varying both parameters. The optimal DOC value for bulk waste would have been higher if we had conducted a single variable analysis and had used only the k values currently provided in Table HH–1. Because of this linkage between the DOC and k values, the EPA is also proposing to revise the default decay rate values in Table HH–1 for both the Bulk Waste option and the Modified Bulk MSW option and add k value ranges for uncharacterized MSW for the Waste Composition Option as shown in Table 4 of this preamble. The proposed defaults represent the average optimal k values for the cohort of landfills within each precipitation category. The proposed k values are larger than the current defaults but provide a more accurate estimate of the landfill's emissions based on the results of the multivariate analysis. We also reviewed the k values used in other countries' inventories as well as those recommended in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. We found that the current k values in Table HH–1 were low compared to those used in other countries with climates similar to that in the U.S. We also found that the k values we are proposing more closely align with those used in countries with similar climates to the U.S. and with the defaults for moderately decaying bulk waste provided in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.[137] Because our review of other inventory k values and our multivariate analysis indicate that the current k values in Table HH1 are too low, we are proposing to revise these k values consistent with the results of our multivariate analysis and consistent with our revision to the default DOC for bulk waste.

TABLE 4—PROPOSED DEFAULT K VALUES

Factor	Current subpart HH default	Proposed subpart HH default	Units
k values for Bulk Waste option and Modified Bulk MSW option			
k (precipitation plus recirculated leachate <20 inches/year)	0.02	0.055	yr − 1
k (precipitation plus recirculated leachate 20–40 inches/year)	0.038	0.111	yr − 1
k (precipitation plus recirculated leachate >40 inches/year)	0.057	0.142	yr − 1

[135] U.S. EPA. 2015. Advancing Sustainable Materials Management—2015 Tables and Figures: Assessing Trends in Material Generation, Recycling, Composting, Combustion with Energy Recovery and Landfilling in the United States July 2018, available at: *https://www.epa.gov/facts-and-figures-about-materials-waste-and-recycling/advancing-sustainable-materials-management.* Data set from 1960 to 2015 (see ''Materials_Municipal_Waste_Stream_1960_to_2015.xlsx'') available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).

[136] See memorandum from Jeff Coburn, RTI International, to Rachel Schmeltz, EPA, *Modified Bulk MSW Option Update,* June 18, 2019, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).

[137] See memorandum from Kate Bronstein and Meaghan McGrath, RTI International to Rachel Schmeltz, EPA, *Comparison of U.S. Inventory Waste Model Decay Rate (k) Values to Other UNFCCC Annex 1 Country Defaults and Country-specific Waste Models* (June 18, 2019), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

TABLE 4—PROPOSED DEFAULT K VALUES—Continued

Factor	Current subpart HH default	Proposed subpart HH default	Units
k value range for Waste Composition option k (uncharacterized MSW)	Not applicable	0.055 to 0.142	yr^{-1}

Altering both the default DOC and k values for subpart HH reporters would affect closed and open landfills in different ways. Implementing the recommended, and higher, k values will serve to increase the emissions calculated from equation HH–1 and equation HH–5 for open, active landfills. The higher k values imply that the organic material that is placed in the landfill will degrade more quickly than predicted when using lower k-values. This tends to lead to greater calculated emissions from active landfills (landfills actively receiving waste during a reporting year). The higher k values also tend to predict that less degradable waste will be in the landfill once the landfill closes (*i.e.,* no longer receives wastes) and the degradable waste that is present in the closed landfill will decompose more quickly. This tends to reduce the emissions calculated for closed landfills, which may allow closed landfills to more quickly phase-out of the reporting program (*i.e.,* when reported emissions fall below the 25,000 $mtCO_2e$ threshold for 5 years consecutive years). Thus, the proposed k values are expected to increase the calculated emissions from active landfills, reduce calculated emissions from closed landfills, and potentially reduce burden associated with the reporting requirements for closed landfills (due to having fewer years of reported emissions above the reporting threshold once the landfill is closed). We also note that the emissions from the landfill over its entire life (active and closed periods) is dependent only on the amount of degradable organic material placed in the landfill, which is dependent only on the DOC value. Thus, the lower DOC value should reduce the cumulative emissions reported for a given landfill over all reporting years; however, it may increase the emissions reported during the years the landfill is actively receiving wastes.

To determine an estimate of the effect of these changes on overall subpart HH emissions reporting, equation HH–1 methane generation from six landfills in the final analysis cohort, three closed landfills (one in each precipitation range) and three open landfills (one in each precipitation range), were recalculated (as an illustrative example) with the recommended DOC value of 0.17 and the recommended k value corresponding to the landfill's precipitation zone.[138] On average, the selected closed landfills had a 21 percent decrease in methane generation while the selected open landfills saw a 55 percent increase. These are illustrative examples and not a quantitative nationwide assessment of the impact of the proposed revisions to DOC and k values, but they confirm our expectations. The nationwide impact of these changes will likely be limited to a large extent because the large majority (approximately 90 percent) of the emissions reported under subpart HH are from facilities with GCS. Facilities with GCS use two different calculation methodologies to determine methane emissions: equation HH–6, which used the predicted methane generation from equation HH–1 and the amount of methane recovered, and equation HH–8, which is based solely on the quantity of methane recovered. Per 40 CFR 98.346(i)(13), facilities with GCS may then choose the equation result that best represents emissions from the landfill to use as their total methane emissions reported for subpart HH. About 71 percent of subpart HH facilities in RY2020 used equation HH–8 to estimate their methane emissions and the proposed revisions would not impact the emissions reported for these facilities. Thus, the proposed revisions would impact only the emissions from landfills without GCS and landfills with GCS that elect to report emissions using equation HH–6, which is a smaller fraction (about 35 to 40 percent) of the total methane emissions reported subpart HH. While methane emissions reported by active landfills not using equation HH–8 are expected to increase, the methane emissions reported by closed landfills are expected to decrease, and the total amount of methane reported to be generated by a given landfill over its entire life is expected to decrease (based on the proposed lower DOC value).

For the reasons described in section II.A.4 of this preamble, we are proposing a reporting requirement for landfills with gas collection and control systems to inform the development of GHG policies and programs by providing information on the proportion of landfill gas used in energy recovery projects. There is no anticipated significant change in burden due to this reporting requirement because key data in estimating the annual amount of recovered CH_4 from data reported by measurement location and destruction device are already reported. Specifically, we are proposing to require landfills with gas collection and control systems to indicate the percentage of recovered CH_4 that is sent to a flare or sent to a landfill gas to energy project for each measurement location.

For landfills with gas collection and control systems, we currently collect the following information under 40 CFR 98.346(i) related to the gas collection and control system at the facility: total volumetric flow of landfill gas collected for destruction, the annual average CH_4 concentration of landfill gas for destruction, and an indication of whether destruction occurs at the landfill facility, off-site, or both. For landfills where destruction occurs at the facility, we also ask for information about the measurement location(s) and destruction device(s) at the facility. This information includes the number of destruction devices associated with each measurement location, the annual operating hours of each measurement location and its associated destruction devices, and the annual quantity of recovered CH_4 using equation HH–4 for each measurement location. We do not collect specific information about destruction devices located off-site and therefore cannot collect the annual quantity of CH_4 recovered using equation HH–4 at the destruction device level for all facilities subject to subpart HH. Therefore, we are proposing to collect information at the measurement location level about the proportion of landfill gas that is flared versus sent to a landfill gas to energy project. Specifically, we are proposing at 40 CFR

[138] Meaghan McGrath, Kate Bronstein, and Jeff Coburn, RTI International, to Rachel Schmeltz, EPA, *Multivariate analysis of data reported to the EPA's Greenhouse Gas Reporting Program (GHGRP), Subpart HH (Municipal Solid Waste Landfills) to optimize DOC and k values,* (June 11, 2019), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

98.346(i)(6)(i) to require landfills with gas collection and control systems to indicate the percentage of recovered CH_4 that is flared or sent to a landfill gas to energy project for each measurement location. We understand that a facility owner or operator may not know the exact quantity of recovered CH_4 sent off-site for destruction by a flare or landfill gas to energy project. Facilities that indicate off-site destruction in e-GGRT and do not know whether the recovered gas sent to the off-site destruction device is sent to a flare or landfill gas to energy project would be allowed to allocate the off-site portion of recovered gas into an ''unknown'' option along with an optional text description.

This information would help inform the development of GHG policies and programs under the CAA by providing information on the amount of recovered CH_4 that is beneficially used in energy recovery projects and will assist in verification of net CH_4 emissions from landfills with gas collection and control systems. This new requirement will also assist with QA/QC of required inputs into the U.S. GHG inventory for MSW landfills and will inform EPA, state, and local government officials on progress towards renewable energy targets and GHG emission inventories. Additionally, researchers have requested this information under the U.S. national solid waste inventory. We are also proposing related confidentiality determinations for the new data element, as discussed in section VI of this preamble.

R. Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids

For the reasons discussed in section II.B.3 of this preamble, the EPA is proposing to streamline reporting requirements by eliminating some duplicative reporting between subpart NN (Suppliers of Natural Gas and Natural Gas Liquids) and subpart W (Petroleum and Natural Gas Systems) by eliminating the duplicative elements from subpart W, as discussed in section III.J.2.f of this preamble.

S. Subpart OO—Suppliers of Industrial Greenhouse Gases

For the reasons provided in section II.A.4 of this preamble, we are proposing revisions to subpart OO of part 98 (Suppliers of Industrial Greenhouse Gases) that would improve the quality of the data collection under the GHGRP. First, we are proposing to add a requirement for bulk importers of F–GHGs to include, as part of the information required for each import in the annual report, the customs entry summary number. The customs entry summary number is provided as part of the U.S. Customs and Border Protection (CBP) Form 7501: Entry Summary [139] and is assigned for each filed CBP entry for each shipment. We are proposing to gather this data, which is already available in supplier records, to verify and compare the data submitted to the GHGRP with other available customs data. The proposed customs entry summary number would provide a means to cross-reference the data submitted and would help to ensure the accuracy and completeness of the information reported under the GHGRP. The proposed changes would modify 40 CFR 98.416(c)(7). Because the information collected is readily available in supplier records and is similar to the identifying information currently collected (*i.e.,* date of import, port of entry, country, commodity code, and importer number), there is no anticipated significant change in burden.

Additionally, the EPA is proposing to require at 40 CFR 98.416(k) that suppliers of N_2O, saturated PFCs, and SF_6 identify the end uses for which the N_2O, SF_6, or PFC is used and the aggregated annual quantities of N_2O, SF_6, or each PFC transferred to each end use, if known. This requirement, which is patterned after a similar requirement under subpart PP (Suppliers of Carbon Dioxide) of part 98, would help to inform the development of GHG policies and programs by providing information on N_2O, SF_6, and PFC uses and their relative importance. We are proposing the requirement for N_2O, SF_6, and PFCs in particular because: (1) the GWP-weighted quantities of these compounds that are supplied annually to the U.S. economy are relatively large; and (2) the identities and magnitudes of the uses of these compounds are less well understood than those of other industrial GHGs such as HFCs. For example, most N_2O is believed to be used for anesthetic applications, but the exact share used for these applications is not known. SF_6 is known to be used in electrical equipment, magnesium production and processing, and electronics manufacturing, but the total quantity of SF_6 that is estimated to be consumed by these applications has sometimes fallen significantly below the total quantity of SF_6 supplied annually to the U.S. economy from 2011 through 2019, indicating that significant uses of SF_6 may not be accounted for. Collecting information from suppliers of these compounds on how their customers use the compounds, and in what quantities, would help to resolve these questions.

To inform the revision of the subpart OO electronic reporting form in the event that this proposed amendment is finalized, we request comment on the end use applications for which N_2O, SF_6, and saturated PFCs are used and their relative importance. The EPA is aware of the following end uses of N_2O:

(1) Analgesia or anesthesia, including medical, dental, and veterinary uses,
(2) Oxidizer in fuel,
(3) Foaming agent (*e.g.,* for use in aerosol whipped cream),
(4) Propellant in aerosol sprays,
(5) Electronics manufacturing, including manufacturing of semiconductors (including light-emitting diodes), micro-electro-mechanical systems, liquid crystal display, and photovoltaic cells.

The EPA is aware of the following end uses of SF_6:

(1) Electrical equipment use (*i.e.,* by electric transmission and distribution systems),
(2) Electrical equipment manufacturing,
(3) Electronics manufacturing, including manufacturing of semiconductors (including light-emitting diodes), micro-electro-mechanical systems, liquid crystal display, and photovoltaic cells,
(4) Magnesium production and processing,
(5) Dielectrics for particle accelerators, including university and research particle accelerators, industrial particle accelerators, and medical particle accelerators,
(6) Radar systems,
(7) Adiabatic uses, including use in shoe soles and car tires,
(8) Sound-proof windows,
(9) Tracer gas, including leak detection,
(10) Waterproofing (*e.g.,* of textiles and/or circuit boards),
(11) Other medical applications.

The EPA is aware of the following end uses of saturated PFCs:

(1) Electronics manufacturing, including manufacturing of semiconductors (including light-emitting diodes), micro-electro-mechanical systems, liquid crystal display, and photovoltaic cells,
(2) Heat transfer fluids,
(3) Electrical equipment use,
(4) Electrical equipment manufacturing,
(5) Adiabatic uses, including use in shoe soles and car tires,
(6) Cosmetic applications,
(7) Medical applications,

[139] CBP Form 7501 is available at the U.S. Customs and Border Protection website (*https://www.cbp.gov/trade/programs-administration/entry-summary/cbp-form-7501*).

(8) Waterproofing (*e.g.,* of textiles and/or circuit boards).

We request comment on the above list and any additional end-uses of GHGs that should be considered for inclusion in the reporting form.

Finally, we are proposing a clarification to the reporting requirements for importers and exporters of F–GHGs, F–HTFs, or N_2O, for the reasons provided in section II.A.5 of this preamble. We are proposing to revise the required reporting of ''commodity code,'' which is required for importers at 40 CFR 98.416(c)(6) and for exporters at 40 CFR 98.416(d)(4), to clarify that reporters should submit the Harmonized Tariff System (HTS) code for each F–GHG, F–HTF, or N_2O shipped. Importers and exporters currently provide the commodity code as part of the annual summary information provided for each import or export at the corporate level. The majority of reporters provide a commodity code based on codes assigned through the HTS, which assigns 10-digit codes to identify products that are unique to U.S. markets. HTS codes start with a 6-digit code specifying a chapter, heading, and subheading, and in full include a specific 10-digit code including a subheading for duty and a statistical suffix. However, in some cases the requirement has apparently been unclear to and misread by reporters, and reporters may identify shipments using other commodity code systems, such as the abbreviated 6-digit codes assigned by the international Harmonized System (HS) or Standard Industrial Classification System (SIC), or may enter other unidentifiable data into the ''commodity code'' field. Reporters may also enter the data in different formats (*e.g.,* with or without decimals). This has resulted in cases in which the data provided in some annual reports is unclear or unable to be compared to outside data sources for verification. In order to reduce confusion for reporters and standardize the data received we are proposing to replace ''commodity code'' with ''Harmonized Tariff System code'' in 40 CFR 98.416(c)(6) and 40 CFR 98.416(d)(4). Reporters would enter the full 10-digit HTS code with decimals, to extend to the statistical suffix, as it was entered on related customs forms. For example, in 2020, the entry for ''1,1,1,2-Tetrafluoroethane (HFC–134a)'' would be ''2903.39.20.20''.[140] The proposed clarifications would reduce the uncertainty associated with the reported data elements and improve data verification.

We are also proposing related confidentiality determinations for the new and revised data elements, as discussed in section VI of this preamble.

T. Subpart PP—Suppliers of Carbon Dioxide

For the reasons discussed in section II.A.3 of this preamble, the EPA is proposing several revisions to subpart PP of part 98 (Suppliers of Carbon Dioxide) to improve the quality of the data collected from this subpart. Subpart PP is intended to identify and quantify supplies of CO_2 to commercial applications, underground injection, or geologic sequestration. Subpart PP currently requires reporting of the annual quantities of CO_2 supplied by pipeline and in containers from natural sources (*i.e.,* extraction wells), capture sources, and importers/exporters. Capture sources include natural gas processing plants, ethanol manufacturing facilities, and other types of facilities where CO_2 is captured and supplied for commercial applications or to inject or sequester underground.

Direct air capture (DAC) is a new, innovative approach to capturing CO_2 from ambient air. Unlike conventional capture sources where CO_2 is separated during the manufacturing or treatment phase of product stream, DAC captures CO_2 from ambient air. CO_2 is separated from air using aqueous or solid sorbents and then processed into a concentrated stream for utilization or injection underground. Historically a niche or experimental technology, interest in deploying DAC technology has grown significantly in recent years as a technology to address climate change.

We are proposing to add a new paragraph 40 CFR 98.420(a)(4), to explicitly include DAC as a capture option. In addition, we are proposing to amend 40 CFR 98.6, to include a definition for DAC. Specifically, we are proposing that DAC, with respect to a facility, technology, or system, means that the facility, technology, or system uses carbon capture equipment to capture carbon dioxide directly from the air. DAC does not include any facility, technology, or system that captures carbon dioxide (1) that is deliberately released from a naturally occurring subsurface spring or (2) using natural photosynthesis. The definition is taken directly from the definition of DAC in the CAA at 42 U.S.C. 7403(g)(6)(B)(III).[141] We believe these clarifications will benefit owner/operators of DAC facilities, the public, and other stakeholders by removing any questions or uncertainty about the applicability of subpart PP to DAC. Moreover, the proposed amendments will improve data quality by clarifying applicability of subpart PP, thereby ensuring the GHGRP accounts for a growing and potentially large component of the CO_2 supply chain.

To ensure consistency among definitions applicable to subpart PP, we are also proposing to amend the definition of ''Carbon dioxide stream'' in 40 CFR 98.6 to include DAC in the definition. Specifically we are proposing to add ''captured from ambient air (*e.g.,* Direct air capture)'' to the definition so that it reads, ''Carbon dioxide stream means carbon dioxide that has been captured from an emission source (*e.g.,* a power plant or other industrial facility), captured from ambient air (*e.g.,* direct air capture), or extracted from a carbon dioxide production well plus incidental associated substances either derived from the source materials and the capture process or extracted with the carbon dioxide.''

We are also proposing to amend other sections of subpart PP to explicitly include DAC as a capture source for consistency with the proposed changes to 40 CFR 98.420 and 40 CFR 98.428. Specifically, we are proposing to amend the following sections to add references to DAC: 40 CFR 98.422; 40 CFR 98.423; 40 CFR 98.426; and 40 CFR 98.427.

In addition to these changes, we are proposing one additional reporting requirement in 40 CFR 98.426 to improve data quality with respect to DAC facilities. Life Cycle Analysis (LCA) has become a very important tool in determining the net impact of DAC projects. DAC processes potentially require substantial quantities of energy to capture, process and supply CO_2; therefore, we believe it is important for the public and the EPA to understand the sources and amounts of energy used by DAC facilities to power the DAC plant from air intake at the facility through custody transfer of captured CO_2 or, if the CO_2 does not leave the facility, injection of captured CO_2. We are proposing to add a new requirement at 40 CFR 98.426(i) to require DAC facilities to report the amounts of on-site and off-site sourced electricity, heat and combined heat and power used to power the DAC plant from air intake at

[140] A complete list of codes and current HTS Chapters can be found at *https://hts.usitc.gov/current.*

[141] The definition of DAC was added to the CAA as part of the Utilizing Significant Emissions with Innovative Technologies Act (USE IT Act), which was included in Section 102 of Division S of the Consolidated Appropriations Act, 2021, available at *https://www.congress.gov/116/bills/hr133/BILLS-116hr133enr.pdf.*

the facility through the point of compressed CO_2 stream ready for supply for commercial applications or, if maintaining custody of the CO_2 stream, sequestration or injection of the CO_2. In addition, for on-site sourced electricity, heat and combined heat and power, we are proposing that DAC facilities indicate whether flue gas is also captured by the DAC process unit. We are additionally proposing related confidentiality determinations for the new data elements, as discussed in section VI of this preamble.

U. Subpart SS—Electrical Equipment Manufacture or Refurbishment

1. Proposed Revisions To Improve the Quality of Data Collected for Subpart SS

For the reasons discussed in section II.A of this preamble, we are proposing several revisions to subpart SS of part 98 (Electrical Equipment Manufacture or Refurbishment) to improve the quality of the data collected from this subpart. Currently, this subpart requires reporting of emissions from manufacturing and refurbishing processes that include SF_6 and PFCs. We are proposing to revise the existing calculation, monitoring, and reporting requirements of subpart SS (at 40 CFR 98.452, 98.453, 98.454, and 98.456) to require reporting of additional F–GHGs as defined under 40 CFR 98.6. As discussed in section III.N of this preamble, although SF_6 and PFCs have been the most commonly used insulating gases in the electrical power industry, over the implementation of the reporting program the EPA has become aware of alternative technologies and replacements for SF_6, including fluorinated gas mixtures. Therefore, we expect that electrical equipment manufacturers and refurbishment operations, in addition to electric power systems and facilities, include equipment or are anticipated to include equipment containing these alternative gas mixtures (*e.g.,* fluoronitrile or fluoroketone mixtures). As such, we are proposing revisions to subpart SS in order to capture emissions from equipment using these alternative gases that are not currently accounted for. The proposed reporting of these additional F–GHGs would improve the accuracy of emissions reported under subpart SS and enhance the overall quality of the data collected under the GHGRP.

To implement these revisions, we are proposing to redefine the source category at 40 CFR 98.450 to include equipment containing ''fluorinated GHGs (F–GHG), including but not limited to sulfur-hexafluoride (SF_6) and perfluorocarbons (PFCs).'' The proposed changes would also apply to the threshold in 40 CFR 98.451. Under the proposed rule, facilities would also consider additional F–GHGs purchased by the facility in estimating emissions for comparison to the threshold. There are no known facilities that currently use the alternative gas mixtures exclusively or in large quantities that would render them newly subject to the subpart; therefore, we expect the proposed changes would result in minimal burden for reporters.

The proposed revisions to subpart SS include minor revisions to equations SS–1 through SS–6 (which we are proposing be renumbered SS–2 through SS–7 to accommodate a new equation SS–1 as discussed in section III.U.2 of this preamble) to incorporate the estimation of emissions from all F–GHGs within the existing calculation methodology, updating the monitoring and quality assurance requirements to account for emissions from additional F–GHGs, and harmonizing revisions to the reporting requirements such that reporters account for the mass of each F–GHG at the facility level. We are also proposing a definition of ''insulating gas'' and proposing to add reporting of an ID number or descriptor for each insulating gas and the name and weight percent of each insulating gas reported. The proposed changes do not significantly revise the existing calculation requirements. Although the revisions do require additional monitoring and reporting requirements (including, but not limited to, the tracking of alternative gases in a facility's inventory, purchases of alternative gases, and the delivery of equipment containing alternative gases), there are no known facilities that currently manufacture large quantities of electrical transmission and distribution equipment that use alternative gas mixtures in the U.S.; therefore, we expect only a minimal increase in burden due to the collection of data for any equipment containing F–GHGs that are not SF_6 or PFCs. However, we expect that the use of alternative gases will continue to increase and collection of this data is important to both understand emission trends and account for total emissions from the sector. Finally, we are proposing related confidentiality determinations for the revised data elements that incorporate additional F–GHGs, as discussed in section VI of this preamble.

2. Proposed Revisions to Streamline and Improve Implementation for Subpart SS

For the reasons described in section II.B.1 of this preamble, we are proposing to revise the applicability threshold of subpart SS. The proposed revisions would remove the consumption-based threshold at 40 CFR 98.451 and instead require facilities to estimate total annual GHG emissions for comparison to the 25,000 metric tons of CO_2 threshold by introducing a new equation, equation SS–1. To accommodate this new equation, we are also proposing minor harmonizing changes to renumber existing equations SS–1 through SS–6 and related cross-references. Subpart SS currently requires facilities that have total annual purchases of SF_6 and PFCs that exceed 23,000 pounds to report. The EPA established the annual consumption-based threshold of 23,000 pounds in the 2010 Final Rule for Additional Sources of Fluorinated GHGs (75 FR 74774) as an ''equivalent threshold'' that approximated the 25,000 metric tons of CO_2 threshold. Emissions of SF_6 and PFC from the source category include emissions from the testing, manufacturing, and installation or commissioning of equipment, but can also occur when equipment is decommissioned at a manufacturing facility. The current threshold was based on an average emission rate estimated at approximately 10 percent [142] and the GWP for SF_6 referenced in the 2009 Final Rule from the IPCC Second Assessment Report. Since that time, the GWP for SF_6 has been updated in the GHGRP to a lower value (78 FR 71904, November 29, 2013). Further, some facilities within this industry sector have begun to use lower GWP F–GHGs, which are currently not accounted for in subpart SS. Therefore, we are proposing to revise the applicability threshold to align with the proposed revisions to require reporting of additional F–GHG beyond SF_6 and PFCs. The proposed equation SS–1 would continue to be based on the total annual purchases of insulating gases, but would establish an updated comparison to the threshold, and would account for the additional

[142] The 10 percent emission rate was based on the average of ''ideal'' and ''realistic'' manufacturing emission rates (4 percent and 17 percent, respectively) identified in a paper prepared under the auspices of the International Council on Large Electric Systems (CIGRE) in February 2002 (O'Connell, P., F. Heil, J. Henriot, G. Mauthe, H. Morrison, L. Neimeyer, M. Pittroff, R. Probst, J.P. Tailebois (2002) SF_6 in the Electric Industry, Status 2000, Cigre. February 2002.), available at *https://www.epa.gov/sites/default/files/2016-02/documents/conf02_pittroff.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424. This method for estimating OEM emissions was the same method used in EPA's Inventory of Greenhouse Gas Emissions and Sinks:1990–2006 (EPA 2008). Available at: *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2006* (accessed September 15, 2021).

fluorinated gases reported by industry. Potential reporters would be required to account for the total annual purchases of all insulating gases, and multiply by the GWP for each F–GHG and the emission factor of 0.10 (or 10 percent). We have determined that the proposed threshold methodology is more appropriate because it represents the actual fluorinated gases used by a reporter. The proposed revisions would also streamline the reporting requirements to focus Agency resources on the substantial emission sources within the sector. Additionally, the proposed changes would revise the inclusion of subpart SS in the existing Table A–3 to subpart A. Because we are proposing to provide a method for direct comparison to the 25,000 $mtCO_2e$ threshold, we are proposing to remove subpart SS from Table A–3 and include the subpart in Table A–4 of subpart A. Including subpart SS in Table A–4 is consistent with other GHGRP subparts that use the 25,000 $mtCO_2e$ threshold included under 40 CFR 98.2(a)(2) to determine applicability. Currently reporters determine the applicability of subpart SS under 40 CFR 98.2(a)(1), which applies to source categories listed in Table A–3. Therefore, facilities determine the applicability of subpart SS on the basis of the current consumption-based threshold without consideration of the combined emissions from stationary fuel combustion sources (subpart C), miscellaneous use of carbonates (subpart U), and other applicable source categories towards the threshold. Moving this subpart to Table A–4 of subpart A would require facilities to determine applicability according to 40 CFR 98.2(a)(2) and consider the combined emissions from stationary fuel combustion sources (subpart C), miscellaneous use of carbonates (subpart U), and other applicable source categories. The change from Table A–3 to Table A–4 is not expected to result in additional reporters under subpart SS. Although most facilities subject to subpart SS also report under subpart C, the reported subpart C emissions are typically less than 1000 $mtCO_2e$ and are not a significant portion of the total facility emissions.

V. Subpart UU—Injection of Carbon Dioxide

The EPA is proposing one amendment to subpart UU to ensure consistency with new proposed subpart VV (Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916). Subpart VV is described further in section III.W of this preamble. The proposed rule change adds language to 40 CFR 98.470, Definition of the source category, to clarify that reporters who report under subpart VV for a well or group of wells are not required to report under subpart UU for that well or group of wells. Proposed new 40 CFR 98.470(c) is similar to existing language in 40 CFR 98.470(b) which provides that reporters to the Geologic Sequestration of Carbon Dioxide source category of the GHGRP (subpart RR) for a well or group of wells are not required to report under subpart UU for that well or group of wells.

We are proposing this revision to reduce the reporting burden on subpart VV reporters by eliminating duplicative reporting requirements. This proposed rule change also improves data quality by avoiding double counting of the quantities of CO_2 received and injected at EOR and enhanced gas recovery facilities that use the CSA/ANSI ISO 27916:2019 standard and choose to report under subpart VV. This avoidance of double counting would allow the EPA and the public to better track and document the flow of CO_2 through the economy.

In proposing this change, we are also proposing to renumber existing 40 CFR 98.470(c) to 40 CFR 98.470(d); however, we are not proposing any rule language changes to this paragraph.

W. Subpart VV—Geologic Sequestration of Carbon Dioxide With Enhanced Oil Recovery Using ISO 27916

The GHGRP is proposing to add a new subpart—subpart VV—as an option for quantifying geologic sequestration in association with EOR operations using the ISO standard designated as CSA/ANSI ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2–EOR).* Although the title of the standard references only EOR, Clause 1.1 of CSA/ANSI ISO 27916:2019 indicates that the standard can apply to enhanced gas recovery as well. Thus, throughout subpart VV, as proposed, any reference to EOR also applies to enhanced gas recovery.

Carbon capture, utilization, and sequestration (or storage) (CCUS) refers to a set of technologies that remove CO_2 from the emissions of point sources or the atmosphere, and transport it, compress it, and inject it deep underground, or transform it for utilization in industrial processes or as feedstock for products. Geologic sequestration is feasible in different types of geologic formations including deep saline formations (formations with high salinity formation fluids) or in oil and gas formations, where CO_2 can be injected to increase oil production through a process referred to as EOR.

Subpart RR (Geologic Sequestration of Carbon Dioxide) is currently the only source category within the GHGRP that provides an accounting framework to report to the EPA the amount of CO_2 geologically sequestered on an annual basis. The GHGRP's geologic sequestration data are integral to providing transparent information to the EPA and the public to track the value chain of CO_2 supply and disposition.

The definition of the source category for subpart RR includes a well or group of wells that inject a CO_2 stream for long-term containment in subsurface geologic formations. It also includes wells permitted by the UIC Program as Class VI wells. Facilities that conduct EOR are not required to report under subpart RR unless the owner or operator chooses to opt-in to subpart RR, or the well is permitted as a Class VI well. An operator that does not choose to opt into subpart RR must report under subpart UU (Injection of Carbon Dioxide) of the GHGRP.

Facilities subject to subpart RR are required to develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan. The major elements of the MRV plan include: (1) delineation of active and maximum monitoring areas; (2) identification of potential surface leakage pathways for CO_2; (3) a strategy for detecting and quantifying surface leakage of CO_2; (4) a strategy for establishing the expected baseline for monitoring CO_2 leakage; and (5) definition of site-specific variables that will be used for estimating leakage. Once the facility has an approved MRV plan, reporters are required to report annually the amount of CO_2 received, the data used to calculate this amount, the source of the received CO_2 (if known), the mass balance equation inputs (amounts of CO_2 injected, CO_2 produced, CO_2 emitted by surface leakage, CO_2 emitted from equipment leaks and vented CO_2 emissions), the data used to calculate the inputs, and the amount of CO_2 sequestered. Facilities are also required to submit an annual monitoring report which implements the reporting requirements set forth in the MRV plan.

Like subpart RR, subpart UU requires facilities to report the quantity of CO_2 received, the data used to calculate this amount, and the source of the received CO_2 (if known). However, subpart UU does not require an MRV plan or the submission of an annual monitoring report. Nor does it require monitoring or reporting of the fate of the CO_2 after the custody transfer meter, and thus does not provide an accounting framework of the amount of CO_2 sequestered.

In January 2019, ISO published a new international standard for CO_2 storage using EOR. The standard was subsequently endorsed by the CSA and ANSI and is designated as CSA/ANSI ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2–EOR)*''.[143] The standard establishes a protocol for documenting the containment of CO_2 injected in an EOR operation and quantifying the amount of CO_2 that is stored in association with that operation.

As part of the Bipartisan Budget Act of 2018, Congress revised the Internal Revenue Code (IRC) section 45Q tax credit for carbon oxide sequestration (45Q).[144] If a taxpayer meets the applicability requirements, section 45Q provides tax credits for disposal of qualified carbon oxide in secure geological storage or utilization. The amount of the tax credit for disposal of qualified carbon oxide in secure geological storage depends on whether the qualified carbon oxide is used as a tertiary injectant in a qualified enhanced oil or natural gas recovery project.

Under a rule finalized by the Treasury Department and Internal Revenue Service (IRS),[145] qualified carbon oxide is considered disposed of by the taxpayer in secure geological storage such that the qualified carbon oxide does not escape into the atmosphere if the qualified carbon oxide is either: (1) injected into a well that complies with applicable UIC or other regulations, is located onshore or offshore under submerged lands within the territorial jurisdiction of states or federal waters, and is not used as a tertiary injectant in a qualified enhanced oil or natural gas recovery project; and is stored in compliance with applicable requirements under subpart RR; or (2) injected into a well that complies with applicable UIC or other regulations, is located onshore or offshore under submerged lands within the territorial jurisdiction of states or federal waters, and is used as a tertiary injectant in a qualified enhanced oil or natural gas recovery project and stored in compliance with applicable requirements under subpart RR or CSA/ANSI ISO 27916:2019.

For EOR facilities that choose CSA/ANSI ISO 27916:2019 for purposes of demonstrating secure geological storage for the IRC section 45Q tax credit, the IRS regulations require that documentation be provided to a qualified independent engineer or geologist, who then must certify that the documentation provided, including the mass balance calculations as well as information regarding monitoring and containment assurance, is accurate and complete. Under existing GHGRP requirements, reporters that choose CSA/ANSI ISO 27916:2019 for purposes of the section 45Q tax credit continue reporting under subpart UU of the GHGRP if they choose not to report under subpart RR.

Both subpart RR and CSA/ANSI ISO 27916:2019 require an assessment and monitoring of potential leakage pathways; quantification of inputs, losses, and storage through a mass balance approach; and documentation of steps and approaches used to establish these quantities. However, the inputs of the mass balance equations differ as between subpart RR and CSA/ANSI ISO 27916:2019. Specifically, the subpart RR mass balance equation for quantifying the amount of CO_2 that is geologically sequestered includes variables on injected CO_2; equipment leaks and vented CO_2 emissions from surface equipment between the flow meters and the wellhead; CO_2 produced and/or remaining with produced oil, gas, or other fluids; and CO_2 leakage to the surface. In contrast, under CSA/ANSI ISO 27916:2019, the mass of CO_2 stored is determined as the total mass of CO_2 received minus the total mass of CO_2 lost from project operations and the mass of CO_2 lost from the EOR complex. The CSA/ANSI ISO 27916:2019 standard defines the EOR complex as the project reservoir, trap, and such additional surrounding volume in the subsurface as defined by the operator within which injected CO_2 will remain in safe, long-term containment. Specific losses that are determined under the CSA/ANSI ISO 27916:2019 standard include those from leakage from production, handling, and recycling facilities; from infrastructure (including wellheads); from venting/flaring from production operations; and from entrainment within produced gas/oil/water when this CO_2 is not separated and reinjected. Thus, a primary difference between subpart RR and CSA/ANSI ISO 27916:2019 relates to the terms in their respective mass balance equations.

There are other noteworthy differences between subpart RR and CSA/ANSI ISO 27916 as well. One is how they determine ''leakage.'' Subpart RR quantification is based on leakage of CO_2 to the surface, that is, emissions of CO_2 to the atmosphere. In contrast, CSA/ANSI ISO 27916:2019 considers leakage to be CO_2 that migrates outside of the EOR complex.

Another difference is the time when facilities may discontinue reporting. Under subpart RR, a facility may discontinue reporting if it demonstrates that current monitoring and model(s) show that the injected CO_2 stream is not expected to migrate in the future in a manner likely to result in surface leakage. Under CSA/ANSI ISO 27916:2019, the operator must demonstrate that the CO_2–EOR project is completed, based on (1) the cessation of CO_2 injection, (2) the cessation of hydrocarbon production from the project reservoir, and (3) the plugging and abandoning of wells, unless otherwise required by the appropriate regulatory authority.

Another, and, for present purposes, perhaps the most salient difference between subpart RR and CSA/ANSI ISO 27916:2019 is related to public transparency. The EPA publishes final decisions under subpart RR on its website, such as whether to approve an MRV plan or request for discontinuation of reporting. Any interested person can appeal subpart RR final decisions to the EPA's Environmental Appeals Board. In addition, the EPA also verifies the data submitted in annual GHGRP reports, including annual monitoring reports submitted under subpart RR, and publishes non-confidential data on the EPA website. In contrast, facilities that follow CSA/ANSI ISO 27916:2019 are not currently subject to requirements related to public reporting and transparency of amounts stored and associated documentation.

In comments to the IRS on the proposed IRC section 45Q regulations, several commenters supported the IRS's adoption of the CSA/ANSI ISO 27916:2019 ISO pathway, but were concerned that the ISO standard itself, as relied on by the IRS, does not contain the requirements for public disclosure and transparency of information necessary to allow the public to review the adequacy of the demonstration of secure geologic storage. Commenters also emphasized the importance and need for credible third-party audits and certifications, and government oversight and enforcement.[146] The IRS responded

[143] Available at *https://www.iso.org/standard/65937.html* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[144] See 26 CFR 1.45Q–0 through 26 CFR 1.45Q–5.

[145] Internal Revenue Service, Treasury Department, Credit for Carbon Oxide Sequestration, Final Regulations (88 FR 4728, January 15, 2021), available at *https://www.govinfo.gov/content/pkg/FR-2021-01-15/pdf/2021-00302.pdf* (accessed September 7, 2021).

[146] See 85 FR 34050, 34055 (June 20, 2020).

that it is constrained by law concerning the public disclosure of information submitted by taxpayers.

Some stakeholders recommended that the EPA promulgate a new subpart to the part 98 regulations for GHGRP that would establish procedures for documenting and reporting the amount of carbon oxide securely stored using the CSA/ANSI ISO 27916:2019 methodology.[147] The reporting of this information to the EPA would ensure that the public has access to the relevant information in the same manner that the public currently has access to the information reported to the EPA under subpart RR. This reporting would also provide the EPA with complete data (that is, data from reporting under both subpart RR and CSA/ANSI ISO 27916:2019) to fully understand the amounts of CO_2 that are geologically sequestered for EOR.

Therefore, the EPA is proposing a new source category—subpart VV—related to the option for reporting of incidental CO_2 storage associated with EOR based on the CSA/ANSI ISO 27916:2019 standard. Specifically, facilities that conduct EOR would be required to report basic information on CO_2 received under subpart UU, or they could choose to opt-in to either subpart RR or the new subpart to quantify amounts of CO_2 that are geologically sequestered. The EPA seeks comment on this new proposed subpart VV.

The EPA is proposing that facilities would report the amount of CO_2 stored, inputs included in the mass balance equation used to determine CO_2 stored using the CSA/ANSI ISO 27916:2019 methodology, and documentation providing the basis for that determination as set forth in CSA/ANSI ISO 27916:2019. Specifically, the reporting of documentation under subpart VV would involve providing the CSA/ANSI ISO 27916:2019 EOR Operations Management Plan (OMP), which is required to specify: (1) a geological description of the site, the procedures for field management and operational containment during the quantification period; (2) the initial containment assurance plan to identify potential leakage pathways; (3) the plan for monitoring of potential leakage pathways; and (4) the monitoring methods for detecting and quantifying losses and how this will serve to provide the inputs into site-specific mass balance equations. The EOR OMP sets forth the operator's approaches for containment assurance and monitoring and provides the level of detail on operations and reporting that are comparable to an MRV plan submitted under subpart RR. Thus, annual reporting under subpart VV should specify any changes made to containment assurance and monitoring approaches and procedures in the EOR OMP made within the reporting year.

In addition, the EPA is proposing that reporters annually report the following information per CSA/ANSI ISO 27916:2019: (1) the quantity of CO_2 stored during the year; (2) the formula and data used to quantify the storage, including the quantity of CO_2 delivered to the CO_2–EOR project and losses during the year; (3) the methods used to estimate missing data and the amounts estimated; (4) the approach and method for quantification utilized by the operator, including accuracy, precision and uncertainties; (5) a statement describing the nature of validation or verification, including the date of review, process, findings, and responsible person or entity; and (6) the source of each CO_2 stream quantified as storage.

The EPA is proposing to require that reporters to subpart VV provide a copy of the independent engineer or geologist's certification as part of reporting to subpart VV, if such a certification has been made. The EPA notes that regulations under IRC section 45Q require the EOR OMP and the data in the annual report be provided to a qualified independent engineer or geologist, who then must certify that the documentation, including the mass balance calculations as well as information regarding monitoring and containment assurance, is accurate and complete. However, the EPA is not proposing EPA approval of a third-party approved and certified EOR OMP and documentation. In contrast, subpart RR requires EPA approval of subpart RR MRV plans.

Under CSA/ANSI ISO 27916:2019, monitoring and reporting and associated recordkeeping is required to continue until the CO_2–EOR project is terminated, at which time the monitoring, reporting, and recordkeeping may cease. CSA/ANSI ISO 27916:2019 provides that CO_2–EOR project termination is completed when all of the following occur: CO_2 injection has ceased, hydrocarbon production from the project reservoir has ceased, and wells have been plugged and abandoned unless otherwise required by a regulatory authority. The EPA proposes that the time for cessation of reporting under subpart VV be the same as under CSA/ANSI ISO 27916:2019, and that the operator notify the Administrator of its intent to cease reporting and provide a copy of the CO_2–EOR project termination documentation.

Currently under the GHGRP, if an owner or operator chooses to opt in to reporting under subpart RR for a CO_2–EOR project, that owner/operator is no longer required to report under subpart UU for that CO_2–EOR project, in light of the fact that CO_2 received is reported under both subparts. Because CO_2 received would be an element in the mass balance equation under subpart VV for the mass of CO_2 input, the EPA proposes that if and when an operator begins reporting under subpart VV, that operator will no longer be required to report under subpart UU for that CO_2–EOR project.

IV. Additional Requests for Comment

The EPA is considering future revisions to the GHG Reporting Rule to potentially expand existing source categories or develop other new source categories that would add calculation, monitoring, reporting, and recordkeeping requirements related to energy consumption; ceramics production; calcium carbide production; glyoxal, glyoxylic acid, and caprolactam production; coke calcining; and CO_2 utilization. Based on our recent review of the data collected under the GHGRP and in consideration of data that are needed to continue to inform the EPA's understanding of GHG data and better inform future EPA policy and programs, we are considering revising part 98 to include these newly identified source categories. Therefore, the EPA is specifically requesting comment related to the potential expansion of existing source categories or development of new source categories described in this section. If the Agency decides that sufficient information is available to support a rule revision, the EPA may consider undertaking a future action to expand or add these new source categories.

In the development of the GHGRP, the EPA considered its authorities under CAA sections 114 and 208 and the information that would be relevant to the EPA's carrying out a wide variety of CAA provisions when considering source categories. As part of the process in selecting the original list of source

[147] See, *e.g.,* Comments by Carbon Utilization Research Council, Clean Air Task Force, ClearPath, Environmental Defense Fund, Oxy Low Carbon Ventures, Shell Oil Company, and The Nature Conservancy on the Proposed "Credit for Carbon Oxide Sequestration," Docket Id. No. IRS–2020–0013–0057, August 3, 2020; Comments by Clean Air Task Force on the Proposed "Credit for Carbon Oxide Sequestration," Docket Id. No. IRS–2020–0013–0035, August 3, 2020; Comments by Shell Oil Company on the Proposed "Credit for Carbon Oxide Sequestration," Docket Id. No. IRS–2020–0013–0046, August 4, 2020. These comments are in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

categories to include in the GHG Reporting Rule in 2010, the EPA considered the language of the Appropriations Act, which referred to reporting ''in all sectors of the economy,'' and the accompanying explanatory statement, which directed the EPA to include ''emissions from upstream production and downstream sources to the extent the Administrator deems it appropriate'' (74 FR 16465, April 10, 2009). To develop the list of source categories, we followed a four-step process: (1) we first considered all anthropogenic sources of GHG emissions or supply; (2) we considered all of the source categories in the U.S. GHG Inventory; (3) we reviewed the 2006 IPCC Guidelines for National Greenhouse Gas Inventories for source categories that may be relevant for the United States; and (4) once the list was completed, we systematically reviewed those source categories to ensure that they included the most significant sources of GHG emissions and the most significant suppliers of GHG-emitting products. We also confirmed that the reported GHGs can be measured with an appropriate level of accuracy.[148] As described in sections IV.A through F of this preamble, we are requesting comment on expanding existing source categories or developing other new source categories based on the EPA's current understanding of U.S. GHG trends and where we have identified that additional data may be necessary to better understand GHG data from these specific sectors to inform future policy.

The addition of these source categories would provide data that would help eliminate data gaps, improve the coverage of the GHGRP, and inform the development of GHG policies and programs under the CAA. The GHGRP data continues to additionally be used as a resource for the U.S. GHG Inventory, providing not only annual emissions information, but also other annual information such as activity data and emission factors that can improve and refine national emission estimates and trends over time. Including these additional source categories would also allow the EPA to gather data that could improve the completeness of the emissions estimates presented in the U.S. GHG Inventory. For example, we are requesting comment on whether the EPA should collect data on energy consumption, a source category for which part 98 does not currently require reporting and which would support data analyses related to informing voluntary energy efficiency programs, providing information on industrial sectors where currently little data is reported to GHGRP, and informing QA/QC of the U.S. GHG Inventory. Inclusion of certain of these source categories would reduce potential data gaps in the GHGRP by incorporating emission sources that are recommended by (and for which there are existing calculation methodologies available in) the 2006 IPCC Guidelines used to prepare the U.S. GHG Inventory. Specifically, the IPCC 2006 Guidelines currently identify ceramics production, calcium carbide production, and glyoxal, glyoxylic acid, and caprolactam production as potential sources of GHG emissions. However, emissions from these processes are not currently estimated in the GHGRP or the U.S. GHG Inventory. The collection of data from these source categories (*e.g.,* ceramic production, calcium carbide production, and glyoxal, glyoxylic acid, and caprolactam production) would improve the coverage of the GHGRP and provide for more accurate estimates of U.S. GHG emissions that could then be used to inform development of EPA policies and programs.

The EPA is requesting comment on some source categories, such as coke calciners, that we have identified because they may potentially contribute significant emissions that are not currently reported. In other cases, through implementation of the program, the EPA has identified facilities representative of these source categories that are currently reporting under another part 98 source category, and relying on that other source category's calculation, monitoring, and reporting requirements for the purposes of estimating total facility GHG emissions. However, these facilities may not in fact be reporting complete or accurate estimates of emissions because appropriate estimation methods are currently unavailable for the source category. We are also requesting comment on source categories where we have identified emerging industries that utilize captured carbon emissions, and as a result would improve our knowledge of carbon utilization.

Inclusion of specific requirements for these source categories in part 98 would provide a means for the EPA to better estimate and understand U.S. GHG emissions and trends that could inform future policies. Therefore, we are soliciting comment on these source categories and the appropriate accounting methodologies, monitoring, and associated reporting requirements that should be considered in development of a future proposed rulemaking. Sections IV.A through IV.F of this preamble provide additional information on the EPA's consideration of including these source categories in the GHGRP and the information we are seeking.

The EPA is also considering proposing future amendments to subpart F of part 98 (Aluminum Production) to include reporting for additional sources of emissions, to update the cell technology types reflected in the rule, and to revise or replace the measurement and calculation methodologies with newer, improved methodologies. These updates are being considered based on new information and methodologies identified from the *2019 Refinement.* Section IV.G of this preamble provides additional information on the EPA's consideration of these amendments and the information we are seeking.

A. Energy Consumption

Indirect GHG emissions can result from on-site energy consumption, primarily the use of purchased electricity and thermal energy products. In this preamble we refer broadly to purchased electricity and thermal energy products such as steam, heat (in the form of hot water), and cooling (in the form of chilled water) as ''purchased energy'' or as ''purchased energy products.'' These terms expressly exclude the purchase of fuels associated with direct emissions.

In the 2009 GHGRP proposal, the EPA sought comment on, but did not propose, reporting related to electricity consumption. See 74 FR 16479, April 10, 2009. Comments received, as well as our responses to those comments, are summarized in the 2009 final rule. See 74 FR 56288–56289, October 30, 2009. We note that in 2009 some commenters expressed concerns regarding the collection of data on purchased electricity for several reasons. Primarily, they said it would constitute double counting if direct emissions were collected from electric utilities and the EPA also collected electricity consumption from facilities and estimated emissions attributable to the facilities' electricity consumption. Others stated that collecting information on electricity purchases was outside the scope of the rule, that it is not useful information in attempting to quantify emissions, that it would be burdensome for facilities, and that it is CBI that companies are not able to share with the EPA. In 2009, we responded to these concerns stating that collection of electricity purchase data under the GHGRP is consistent with the

[148] Refer to the preamble to the April 10, 2009 proposal (74 FR 16465) for further discussion of the EPA's rationale for its original section of source categories to include.

Consolidated Appropriations language,[149] and provides valuable information to the EPA and stakeholders in the development of climate change policy and programs. We still believe this to be true today. Ultimately, the EPA decided at that time not to propose requirements for facilities to report either their electricity purchases or indirect emissions from electricity consumption. In the 2009 final rulemaking, we stated that acquiring such data may be important in the future, and we were exploring options for possible future data collection on electricity purchases and indirect emissions and the uses of such data. We also said that such a future data collection on indirect emissions would complement the EPA's interests in energy efficiency and renewable energy.

In this action, we are requesting comment on whether the EPA should expand the GHGRP so that facilities that are subject to the GHGRP would be required to submit new, summary data elements quantifying their consumption of purchased energy products and characterizing associated markets and products (*e.g.,* regulated or de-regulated electricity markets and renewable attributes of purchased products). Under this approach, facilities would not be required to quantify indirect emissions, and indirect emissions would not count towards GHGRP applicability. However, the EPA could estimate indirect emissions using the purchased energy data. We solicit comment on this potential approach and on advantages and disadvantages of limiting the scope of any new reporting requirements to compiling and reporting purchased energy records.

The EPA is seeking comment on how an energy consumption source category should be defined, whether it should include purchased thermal energy products, and whether or not associated reporting requirements should differentiate purchased thermal energy products from purchased electricity.

The EPA also seeks comment on the approach of limiting applicability of an energy consumption source category to facilities that are currently subject to the GHGRP. For example, should the EPA consider adding new sector-specific requirements for operators of EAFs or other operations that may meet all their energy needs with purchased power and that may not trigger applicability under the GHGRP? The EPA is seeking comment on specific industrial sectors or technologies that may not be completely represented within the GHGRP but that should be considered when evaluating the performance of GHGRP sources (including usage of purchased energy) within discrete sectors.

The EPA also seeks comment on measures that would minimize the burden of reporting parameters related to purchased energy transactions. The EPA understands that cogeneration contracts between host facilities and energy producers are governed by clear metering and billing requirements. Accordingly, the EPA is seeking comment on our understanding that monitoring and recordkeeping systems are already in place for purchased energy transactions, and the incremental reporting burden would be minimal. We are also seeking comment on existing industry standards for assessing the accuracy of the monitoring systems used for purchased energy transactions.

B. Ceramics Production

The ceramics manufacturing industry comprises a variety of products manufactured from nonmetallic, inorganic materials, many of which are clay-based. The major sectors of ceramic products include bricks and roof tiles, wall and floor tiles, table and ornamental ware, sanitary ware, refractory products, vitrified clay pipes, expanded clay products, inorganic bonded abrasives, and technical ceramics (*e.g.,* aerospace, automotive, electronic, or biomedical applications). The general process of manufacturing ceramic products consists of raw material processing (grinding, calcining, and drying), forming, firing, and final processing (which may include grinding, polishing, surface coating, annealing, and/or chemical treatment).

GHG emissions are produced during the calcination process in the kiln or dryer and from any combustion sources. According to the IPCC 2006 Guidelines,[150] CO_2 emissions result from the calcination of the raw material (particularly clay, shale, limestone, dolomite, and witherite) and the use of limestone as a flux. Carbonates are heated to high temperatures in a kiln or dryer, producing oxides and CO_2. Additionally, CO_2, CH_4, and N_2O emissions are produced during combustion in the kiln or dryer and from other combustion sources on site.

The EPA is considering future amendments to the GHGRP to add a source category related to ceramics production or to incorporate ceramics into an existing subpart. Currently, under the GHGRP, ceramic production facilities report their GHG emissions from stationary fuel combustion sources if those emissions exceed the 25,000 $mtCO_2e$ reporting threshold. Some ceramic production facilities should also report miscellaneous uses of carbonate if they meet applicability requirements of subpart U of part 98 (Miscellaneous Uses of Carbonate).[151] Addition of a ceramics production source category would likely include process emissions and would improve the EPA's understanding of facility-level emissions from this source category by adding to the completeness of the data collected under the GHGRP, and better inform future EPA policy. Additionally, such data would be available to inform estimates and improve completeness of the U.S. GHG Inventory, consistent with methodological guidance and completeness principle outlined in the 2006 IPCC guidelines.

According to the 2018 United States Census Bureau, 815 corporations produce ceramic products;[152] however, only sixteen facilities owned by nine of these corporations reported under subpart C of the GHGRP (General Stationary Fuel Combustion Sources) for RY2019. No ceramics manufacturers currently report under subpart U of part 98. While some ceramics manufacturers may use some carbonates directly, it is likely the majority of the carbonates used are those contained in clay rather than pure carbonates. Additionally, some ceramic tile kilns may not heat to temperatures sufficient for calcination to occur, and therefore would not meet the applicability requirements of subpart U. For these reasons, emissions from ceramics manufacturers may not be appropriately captured by the current part 98. Although the nine corporations reported nearly 1 million $mtCO_2e$ from combustion under subpart C for RY2019, we estimate, using United States Geological Survey (USGS) reports[153] on the tons of clays sold or

[149] Consolidated Appropriations Act, 2008, Public Law 110–161, 121 Stat. 1844, 2128. Congress reaffirmed interest in a GHG Reporting Rule, and provided additional funding, in the 2009 Appropriations Act (Consolidated Appropriations Act, 2009, Pub. L. 110–329, 122 Stat. 3574–3716).

[150] IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Industrial Processes and Product Use, Mineral Industry Emissions. 2006. *https://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_2_Ch2_Mineral_Industry.pdf.*

[151] Subpart U of part 98 includes any equipment that uses the carbonates limestone, dolomite, ankerite, magnesite, siderite, rhodochrosite, or sodium carbonate and emits CO_2. Facilities are considered to emit CO_2 if they consume at least 2,000 tons per year of carbonates heated to a temperature sufficient to allow the calcination reaction to occur.

[152] See U.S. Census Bureau website *(https://www.census.gov/naics/)*, accessed March 2021.

[153] USGS 2020 Mineral Commodity Summaries. Clay. U.S. Department of the Interior, U.S. Geological Survey, February 2020. *https://*

used in the United States and IPCC default emission factor values, that the total process CO_2 emissions from carbonates for all ceramic production facilities in the United States is an additional 1.16 million $mtCO_2e$. We are considering whether adding a ceramic production source category, as a separate source category or combined with either the existing subpart N of part 98 or subpart U of part 98, would provide a more accurate estimation methodology for these emissions.

Methods for calculating GHG emissions from ceramic production are available in the 2006 IPCC Guidelines,[154] including methods based on: (1) default emission factors that assume limestone and dolomite are the only carbonates contained in clay and that 85 percent of carbonates consumed are limestone and 15 percent of carbonates consumed are dolomite; (2) facility-specific data on the quantity of limestone versus dolomite consumed; and (3) a carbonate input approach that accounts for all carbonates (species and amounts) and which mirrors the methodology used for estimating CO_2 emissions from glass production in subpart N of part 98. We are considering whether emissions could be estimated for the ceramics production source category by modifying these methodologies to consider facility-specific inputs. Facilities could potentially also use a CEMS to monitor CO_2 emissions from the kiln or dryer and use the CEMS data to report GHG emissions. More information about these potential methods can be found in the document, *Technical Support Document for Ceramics: Proposed Rule for The Greenhouse Gas Reporting Program,* available in the docket for this rulemaking (Docket Id. No EPA–HQ–OAR–2019–0424).

The EPA seeks comment on whether it should add a source category related to ceramics production, and if so, seeks information that could be related to source category definitions, calculation methodologies, and reporting requirements. For example, we are soliciting comment on how the source category should be defined, and whether it should be included as a separate category or as part of an existing category, either subpart N (Glass Production) or subpart U (Miscellaneous Uses of Carbonate). We also seek comment on which IPCC calculation methodologies or other methodologies, including those listed in the document, *Technical Support Document for Ceramics: Proposed Rule for the Greenhouse Gas Reporting Program,* should be used, with consideration of what information is readily available to reporters. Finally, we are requesting input on available monitoring methodologies or quality assurance requirements that should be used, including what data is readily available for reporting that would help to support emissions estimates.

C. Calcium Carbide Production

Calcium carbide (CaC_2) is used in production of acetylene (for cutting and welding) and calcium cyanamide (for industrial agricultural fertilizers). CaC_2 is manufactured from lime and carbon-containing raw materials (usually petroleum coke), by heating the mixture to approximately 2,000 degrees Celsius in an EAF. Use of carbon-containing raw materials in the production process results in CO_2 and CO emissions. In addition, any presence of hydrogen-containing volatile compounds and sulfur in the carbon-containing raw materials may cause formation of CH_4 and SO_2 emissions. Also, production of acetylene from CaC_2 results in CO_2 emissions.

The EPA is considering future amendments to the GHGRP to add a source category related to CaC_2 production (which may potentially also include acetylene production if a facility produces acetylene at their CaC_2 production facility). The IPCC 2006 Guidelines currently identify both silicon carbide production and calcium carbide production as potential sources of GHG emissions.[155] Although the GHGRP currently accounts for emissions from silicon carbide production processes, and the GHGRP collects data from silicon carbide production under subpart BB, emissions from CaC_2 production are not explicitly accounted for. Addition of a CaC_2 production source category to the GHGRP would better align with intergovernmental approaches to estimating emissions, improve the completeness of the data collected under the GHGRP, add to the EPA's understanding of the GHG data, and better inform future EPA policy. Further, such data would be available to improve the estimates provided in the U.S. GHG Inventory, by improving completeness and comparability of the estimates consistent with the 2006 IPCC guidelines.

The EPA has identified a CaC_2 production facility currently operating in the United States that is voluntarily reporting GHG emissions under subpart K (Ferroalloy Production) of part 98. Annual emissions from the reporting facility range between less than 10,000 and 50,000 $mtCO_2e$. We are considering whether adding the calcium carbide source category, either as a separate source category or combined with the existing silicon carbide production category under subpart BB of part 98, would provide more accurate applicability requirements and emissions estimation methodologies for these types of facilities. We are also considering, where acetylene production from CaC_2 occurs at the same facility, whether we should account for emissions from these sources.

We are considering several options for how emissions could be estimated for CaC_2 production at a facility-level based on methods available in the 2006 IPCC Guidelines, including methods based on: (1) default emission factors applied to activity data on petroleum coke consumption or CaC_2 production; (2) a carbon consumption methodology that assumes a stoichiometric conversion where two-thirds of the carbon consumed is in the CaC_2 product and one-third is emitted as CO_2 (similar to the estimation methods used for the silicon carbide production source category in subpart BB); and (3) a carbon balance method that uses measured quantities of carbon consumed in the process and carbon contained in the CaC_2 product. Facilities could potentially also estimate CO_2 emissions using CEMS. More information about these potential methods and the production of CaC_2 can be found in the document, *Technical Support Document for Calcium Carbide: Proposed Rule for the Greenhouse Gas Reporting Program,* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

The EPA seeks comment on whether it should add a source category related to CaC_2 production, and if so, seeks information related to source category definitions, calculation methodologies, and reporting requirements. For example, we solicit comment on how the source category should be defined, and whether it should be included as a separate category or, due to similarity in estimation methods, as part of the existing silicon carbide production category. We also request comment on whether additional CaC_2 production facilities (other than Carbide Industries

www.usgs.gov/centers/nmic/mineral-commodity-summaries.

[154] IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Industrial Processes and Product Use, Mineral Industry Emissions. 2006. *https://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_2_Ch2_Mineral_Industry.pdf.*

[155] IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Industrial Processes and Product Use, Mineral Industry Emissions. 2006. *https://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_2_Ch2_Mineral_Industry.pdf.*

LLC in Louisville, KY) are currently operating in the United States. In addition, we seek comment on which tier calculation methodology as well as the monitoring or measurement methodologies should be used, particularly the methodology(s) for which facilities would have information readily available. Furthermore, we seek comment on whether any CaC_2 production facility currently operating in the United States uses the CaC_2 product to produce acetylene at the same facility, and whether emissions from acetylene production should be accounted for in the emission estimate methodology. Finally, we seek input on available monitoring methodologies that should be used, as well as input on what data are readily available for reporting that would help to support emissions estimates.

D. Glyoxal, Glyoxylic Acid, and Caprolactam Production

Glyoxal ($C_2H_2O_2$) is used in a variety of applications including as a crosslinking agent in various polymers for paper coatings, textile finishes, adhesives, leather tanning, cosmetics, and oil-drilling fluids; as a sulfur scavenger in natural gas sweetening processes; as a biocide in water treatment; as a chemical intermediate in the production of pharmaceuticals, dyestuffs, glyoxylic acid, and other chemicals; and to improve moisture resistance in wood treatment. Glyoxal is also being used as a less toxic substitute for formaldehyde in some applications such as wood adhesives and embalming fluids. Glyoxal is commercially manufactured by either: (1) the gas-phase catalytic oxidation of ethylene glycol with air in the presence of a silver or copper catalyst (the LaPorte process); or (2) the liquid-phase oxidation of acetaldehyde with nitric acid. Glyoxylic acid ($C_2H_2O_3$) is used mainly in the synthesis of vanillin, allantoin, and several antibiotics like amoxicillin, ampicillin, and the fungicide azoxystrobin. Glyoxylic acid is exclusively produced by the oxidation of glyoxal with nitric acid. Caprolactam ($C_6H_{11}NO$) is a monomer used in carpet manufacturing. The addition of hydroxylamine sulphate to cyclohexanone produces cyclohexanone oxime, which can then be converted to caprolactam.

The production of any of these organic compounds (glyoxal, glyoxylic acid, and caprolactam) results in N_2O and CO_2 emissions. N_2O emissions are created from either oxidation or reduction steps that occur in each process. Our knowledge of the mechanisms that generate CO_2 emissions from glyoxal and glyoxylic acid production is less understood. The IPCC 2006 Guidelines state that CO_2 emissions generated from caprolactam production are unlikely to be significant in well-managed plants.[156]

The EPA is considering future amendments to the GHGRP to add a source category related to glyoxal, glyoxylic acid, and caprolactam production to improve the completeness of the data collected under the GHGRP, add to the EPA's understanding of the GHG data and better inform future EPA policy. Emissions from these processes are not currently estimated in U.S. GHG Inventory. Therefore, once collected, such data would be available to and improve on the estimates provided in the U.S. GHG Inventory, by incorporating the recommendations of the 2006 IPCC guidelines, which currently identify glyoxal, glyoxylic acid, and caprolactam production as potential sources of GHG emissions.[157] Grouping these three organic compounds together into one source category for GHGRP purposes would be reasonable because the 2006 IPCC guidelines methodology for estimating GHG emissions from the production of these compounds does the same.[158]

We are unsure whether there are any glyoxal and/or glyoxylic acid production facilities currently operating in the United States. Based on available 2015 data reported under the Toxic Substances Control Act (TSCA), four facilities could be domestic manufacturers of glyoxal.[159] [160] Also, although four facilities reported glyoxylic acid data under the TSCA, each of these facilities reported no domestically manufactured glyoxylic acid. We note that more recent data for 2016 through 2019 are expected to be published by the TSCA, but these data were not available at the time of writing this proposal. Nevertheless, it is possible that there are other glyoxal and glyoxylic acid production facilities operating in the United States, but that are not reporting under the TSCA because their total production volume is less than 25,000 pounds per year, or they are exempt from reporting because they are a small manufacturer based on their total company sales revenue. Currently, two caprolactam production facilities report GHG emissions under subpart C of part 98 (General Stationary Fuel Combustion Sources) (each facility reported RY2019 combustion emissions of approximately 600,000 to 800,000 $mtCO_2e$).

Methods for calculating N_2O emissions from glyoxal, glyoxylic acid, and caprolactam production are available in the 2006 IPCC Guidelines, including methods based on: (1) total nationwide production quantities using default uncontrolled emission factors; (2) plant-specific production quantities using plant-specific or default N_2O generation and control emission factors; and (3) plant-specific production quantities and direct measurement of emissions to calculate plant-specific emission factors.[161] Although the 2006 IPCC Guidelines do not provide methods for calculating CO_2 emissions from glyoxal and glyoxylic acid production,[162] we are considering use of either a default emission factor approach for N_2O and a mass balance approach for CO_2, or development of site-specific factors for both N_2O and CO_2. In the first approach, N_2O emissions would be calculated using production and the IPCC default factors, and for CO_2, the mass balance procedures would be similar to mass balances required for existing subparts in the GHGRP such as petrochemical production (subpart X). Specifically, site-specific quantities of all carbon-containing feedstocks and products would be determined, and CO_2 emissions would be calculated assuming all carbon from the feedstock that does not end up in product is emitted as CO_2. We recognize that if the N_2O is controlled using something other than thermal or catalytic destruction (that would not convert hydrocarbons to CO_2), then this mass balance approach would not work for CO_2. Alternatively, N_2O and CO_2 emissions could be calculated using site-specific production and site-specific emission factors that are developed based on flow measurement and periodic sampling and compositional analysis of the

[156] IPCC 2006. IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Industrial Processes and Product Use. Chapter 3, Chemical Industry Emissions. 2006. *https://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_3_Ch3_Chemical_Industry.pdf.*

[157] *Id.*

[158] *Id.*

[159] ChemView. Compilation of data submitted under TSCA in 2012 and 2016. *https://chemview.epa.gov/chemview.* Accessed April 2021.

[160] In 2015, four facilities indicated that their glyoxal production status (*i.e.,* as a domestic manufacturer or as an importer) and their quantities domestically manufactured and/or imported, were CBI. Thus, it is possible that one or more of these four glyoxal production facilities could be a domestic manufacturer.

[161] IPCC 2006. IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Industrial Processes and Product Use. Chapter 3, Chemical Industry Emissions. 2006. *https://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_3_Ch3_Chemical_Industry.pdf.*

[162] As previously mentioned, the 2006 IPCC Guidelines, CO_2 emissions generated from $C_6H_{11}NO$ production are likely to be insignificant.

streams to the control and exiting the control. These emission factors would be multiplied by the site-specific production quantity to calculate emissions. More information about these N_2O and CO_2 emission calculation methods and the production of glyoxal, glyoxylic acid, and caprolactam can be found in the document, *Technical Support Document for Glyoxal, Glyoxylic Acid, and Caprolactum Production: Proposed Rule for The Greenhouse Gas Reporting Program,* available in the docket for this rulemaking (Docket Id. No EPA–HQ–OAR–2019–0424).

The EPA seeks comment on whether it should add a source category related to glyoxal, glyoxylic acid, and caprolactam production, and if so, seeks information that could be related to source category definitions, calculation methodologies, and reporting requirements. For example, we solicit comment on how the source category should be defined. In addition, as previously mentioned, although we are aware of at least two caprolactam production facilities, we are unsure whether there any glyoxal and/or glyoxylic acid production facilities currently operating in the U.S.; therefore, we seek information about whether these types of facilities are currently operating in the U.S. We request comment on whether facilities have installed abatement equipment. We also solicit comment on which tier calculation methodologies or other methodologies, including those outlined in the document *Technical Support Document for Glyoxal, Glyoxylic Acid, and Caprolactum Production: Proposed Rule for The Greenhouse Gas Reporting Program,* available in the docket for this rulemaking (Docket Id. No EPA–HQ–OAR–2019–0424), should be used to determine GHG emissions from these types of facilities and which information or inputs for these methodologies is readily available. Furthermore, as previously mentioned, although we are considering a mass balance approach to determine CO_2 emissions from these types of facilities, our knowledge of the mechanisms that generate CO_2 emissions from glyoxal and glyoxylic acid production are not fully understood; therefore, we request information on this subject. Finally, we seek input on available monitoring methodologies and quality assurance procedures that should be used; and input on what data are readily available for reporting that would help to support emissions estimates.

E. Coke Calcining

Calcined petroleum coke is a nearly pure carbon material used primarily to make anodes for the aluminum, steel, and titanium smelting industries. The process used to produce calcined petroleum coke is called coke calcination and is commonly performed in coke calciners that are rotary kilns or rotary furnaces equipped with an afterburner. Coke calcining uses ''green'' petroleum coke with low metals content (commonly called ''anode grade petroleum coke'') as a feed material. The coke is then heated to high temperatures in the absence of air or oxygen for the purpose of removing impurities or volatile substances in the green coke. Auxiliary fuel is needed to start-up the kiln or furnace, but once the desired calcining temperature is reached, process gas consisting of volatile organics and sulfur-containing compounds driven from the coke are used as the primary fuel to maintain calciner temperatures. Similarly, the coke calciner afterburner combusts primarily the process off-gas and requires little, if any, auxiliary fuel except during start-up. The afterburner is used to convert excess process gas to CO_2 and SO_2, and a waste heat boiler may be used to recover energy from this combustion process. The afterburner will also likely release trace amounts of CH_4 and N_2O, similarly to other stationary combustion devices. The afterburner off-gas is emitted to the atmosphere and is the primary source of GHG emissions from this process.

Coke calcining processes may be co-located with petroleum refineries or may be independent facilities. Currently, coke calcining processes co-located at petroleum refineries must calculate and report emissions from coke calciners following the methodologies specified in subpart Y of part 98 (Petroleum Refineries). Several coke calciners not co-located at petroleum refineries report emissions that are calculated using the calculation methodologies under subpart C of part 98 (General Stationary Fuel Combustion Sources). The calculation methodologies in subparts C and Y, for facilities not using CEMS, are substantially different, resulting in inconsistent characterization of emissions between the two populations of sources. Specifically, the subpart C emission calculations assume that the carbon content of the fuel burned is represented by the default carbon content of petroleum coke and that the carbon in the petroleum coke is fully combusted and converted to CO_2 whereas the subpart Y calculation uses a mass balance approach to account for the fact that the carbon content in the final product is higher than the carbon content in the petroleum coke fed to the unit, thereby more accurately accounting for the carbon content in the process gas actually combusted. The EPA is considering future amendments to the GHGRP to add a coke calcining source category to require specific calculation methodologies and reporting requirements for coke calciners not co-located with petroleum refineries, in order to improve the completeness of the data collected under the GHGRP and better inform future EPA policy. Incorporating a new source category would improve the consistency of emission calculation methodologies for coke calcining processes units regardless of whether nor not they are co-located with a petroleum refinery. The EPA seeks comment on whether a separate source category for coke calcining facilities should be added to the GHGRP.

The EPA identified 15 coke calcining facilities operating 29 coke calcining process units in the United States. Most coke calcining facilities are located at or near a petroleum refinery. Three of the facilities report GHG emission under subpart Y. The remaining facilities either do not report coke calcining emissions or report emissions under subpart C. Based on data reported to the GHGRP for RY2019, the typical coke calcining facility emits 150,000 $mtCO_2e$ per year. With 15 operating facilities in the U.S., it is estimated that these facilities emit 2.2 million $mtCO_2e$ per year. The EPA seeks information on the total number of facilities currently operating coke calciners in the United States.

There are four possible calculation methodologies for determining GHG emissions from coke calciners, shown in order of most accurate to least: (1) use of CEMS; (2) a mass balance using the carbon content of the green and calcined coke; (3) a mass balance using a fixed methane content in the coke and using a mass reduction in the quantity of coke fed to the process and the quantity of coke leaving the process; and (4) using either default high heat values and CO_2 emission factors or assuming the reduction in the mass of coke is solely due to the combustion of green coke fed to the calciner. More information about these methods and the coke calcining process can be found in the memorandum, *Technical Support Document for Coke Calcining: Proposed Rule for The Greenhouse Gas Reporting Program,* available in the docket for this rulemaking (Docket Id. No EPA–HQ–OAR–2019–0424).

Subpart Y allows the use of CEMS (methodology (1), as noted above). If CEMS are not used, subpart Y requires the use of a carbon mass balance approach using equation Y–13 (methodology (2), as noted above). Facilities using equation Y–13 must measure the mass of petroleum coke in and out of the process and the carbon content of the coke in and out of the process. Subpart Y also requires estimating CH_4 and N_2O emissions based on the CO_2 emissions, and the ratio of the CH_4 or N_2O emission factor for ''petroleum products'' in Table C–2 of subpart C and the CO_2 emission factor for petroleum coke in Table C–1 of subpart C of part 98. If a new subpart for coke calcining is developed, the EPA seeks comment on the appropriate calculation method(s) to require. The EPA is also seeking comment on whether coke calcining facilities are already collecting the necessary information to estimate GHG emissions using methodologies (2), (3), and (4), as described in this section. We are also seeking comment on appropriate monitoring for the four methodologies described in the *Technical Support Document for Coke Calcining: Proposed Rule for The Greenhouse Gas Reporting Program,* available in the docket for this rulemaking (Docket Id. No EPA–HQ–OAR–2019–0424). Finally, we are seeking input on appropriate missing data and quality assurance procedures.

F. CO_2 Utilization

As mentioned in the previous section, CCUS refers to a set of technologies that capture CO_2 from the emissions of large point sources or ambient air, transport it, compress it, and either utilize it or inject it in deep underground for safe and secure storage. CO_2 utilization is a quickly growing area of interest among stakeholders and there is currently a lack of publicly available and nationally consistent GHG data regarding CO_2 utilization. As technologies scale up and markets develop for CO_2 utilization, the potential for GHG mitigation through CO_2 utilization is expected to greatly expand. There are a broad range of CO_2 utilization pathways (*i.e.,* technological approaches for carbon utilization), with each utilization pathway having its own set of specific characteristics in terms of products manufactured, technical maturity, market potential, economics, potential to displace existing products or sources of CO_2, and lifecycle GHG impact.

The EPA is considering amendments to part 98 to add a source category related to CO_2 utilization. While part 98 has source categories related to Suppliers of Carbon Dioxide (subpart PP), Injection of Carbon Dioxide (subpart UU) and Geologic Sequestration of Carbon Dioxide (subpart RR), it does not have a source category that is solely related to CO_2 utilization. The inclusion of CO_2 utilization as a source category in part 98 could fill a critical informational gap and inform future policy and programs under the CAA.

The EPA seeks comment on whether we should add a source category related to CO_2 utilization, and if so, seeks information related to source category definition; calculation, monitoring and QA/QC methodologies; and reporting requirements.

The EPA seeks comment on how the source category would be defined. In order to define the source category, the EPA seeks information to contextualize potential reporters and understand how this reporting would relate to other source categories of the GHGRP. For example, the EPA seeks comment on different types of end products that utilize CO_2 (currently and potentially), the amount of captured CO_2 used per unit of production or manufacture (gallons, metric tons, etc.) for different processes (currently and potentially), including processes that do not result in manufacture of marketable product (*e.g., ex-situ* mineralization for storage only). Additionally, the EPA seeks comment on the total amount of captured CO_2 being used in the end use per year for different manufacturing processes or utilization pathways (currently and potentially),[163] whether there should be a threshold for reporting, and if so, how that threshold should be defined. The EPA seeks information on the total number of facilities (currently and potentially), and how many facilities would be reporting under different potential thresholds. The EPA requests comment on whether particular CO_2 utilization pathways should be included in the source category, and if so, how should those pathways be defined. The EPA also requests comment on whether the source category should include reporting of not only CO_2, but also other greenhouse gases.

The EPA seeks comment on what calculation methodologies should be used for purposes of part 98 reporting. For example, most source categories reporting under part 98 focus on reporting of direct emissions. Taking a similar approach for CO_2 utilization would exclude emissions associated with the end use of the CO_2 in the product. A full accounting of all GHGs from cradle to grave, including the potential to displace an existing product or other existing source of CO_2, would be needed to understand the product's life cycle and total GHGs emitted. To that end, the EPA seeks input regarding whether a GHG LCA should be required, and if so, what information, protocols, guidance, and/or models would be required to conduct the LCA, who should validate it, what information would need to be reported to support the LCA validation, and to what extent LCA information is already reported through other GHGRP subparts.

In addition to calculation methodologies, the EPA seeks comment on what monitoring requirements should be in place and what methodologies are recommended for monitoring and QA/QC. LCA is also relevant with regard to monitoring, as CO_2 can be stored and emitted at various stages of the product's lifecycle, and the length of CO_2 storage varies between CO_2 utilization pathways and end products. The EPA also seeks comment on how permanence of the CO_2 storage should be defined and addressed if LCA were not required. Similarly, the EPA seeks comment on information that could be used for, and the feasibility of developing, sequestration lifetimes for various products that result from different utilization pathways. For both calculation and monitoring of CO_2 utilization under part 98 reporting, the EPA seeks comment on QA/QC practices to ensure consistent and accurate estimates.

Finally, the EPA requests comment on the reporting requirements related to CO_2 utilization. CO_2 utilization technologies can vary widely (*e.g.,* biological, chemical, or physical processes), and many technologies are still emerging. The EPA seeks input on how to manage reporting of these highly variable and emerging technologies. For example, we are seeking comment on whether different technology categories should have different calculation, monitoring, and reporting requirements. Additionally, the EPA requests comment regarding specific data elements to be reported. This includes the amount of CO_2 utilized, types of greenhouse gases to be reported (*i.e.,* reporting of not only CO_2, but also other greenhouse gases), and end uses of the CO_2. It also includes emissions of greenhouse gases throughout the lifecycle of a product, and more specifically emissions of greenhouse gases during the utilization process, the ultimate fate of the CO_2 used, and the

[163] The EPA notes that aggregated totals of primary end uses for CO_2 captured and produced are available on the GHGRP website at *https://www.epa.gov/ghgreporting/supply-underground-injection-and-geologic-sequestration-carbon-dioxide.*

sequestration lifetime of the utilized CO_2. EPA also seeks comment on whether the source of CO_2 used in the utilization process should be reported, and if so, what information on the source should be reported (*e.g.,* captured versus extracted, sector or type of facility from which the CO_2 was captured and sourced, and/or facility-specific information for where CO_2 was captured and sourced).

G. Aluminum Production

The EPA is considering proposing to amend subpart F of part 98 (Aluminum Production) to add reporting of low voltage emissions and cell-start-up emissions. The EPA is also considering updating cell technology categories to be consistent with the *2019 Refinement.* The EPA is also considering updating or replacing the 2008 Protocol [164] (used for development of the current emissions measurement methodology) based on the 2020 International Aluminium Institute (IAI) ''Good Practice Guidance: Measuring Perfluorocarbons'' [165] (hereafter referred to as ''2020 IAI Good Practice Guidance'') and the 2008 U.S. EPA/IAI ''Protocol for Measurement of Tetrafluoromethane (CF_4) and Hexafluoroethane (C_2F_6) Emissions from Primary Aluminum Production'' [166] developed by the IAI. Low voltage anode effects (LVAEs), where the cell voltage does exceed the voltage threshold, have been identified as a source of CF_4 emissions and can be a significant portion of the emissions in modern high-amperage cells with many large anodes. Emissions from LVAEs would be better characterized by measuring emission factors specifically for low voltage emissions. Emissions of CF_4 from LVAEs have not previously been included due to a lack of data and methodology for their estimation. However, the *2019 Refinement* provides several methods for estimating LVAE emissions. The *2019 Refinement* also provides methods for potentially more accurately characterizing cell start-up emissions and high voltage anode effect emissions (HVAEs) through the addition of new non-linear Tier 3 methods. The 2020 IAI Good Practice Guidance provides additional guidance on measurement frequency, calculation of emission factors using new Tier 3 calculation methods available in the *2019 Refinement* and updating methods to account for both low voltage and high voltage emissions of PFCs. In addition to improving the accuracy of emissions reported the GHGRP and adding to the EPA's understanding of facility-level emissions from this source category, the collection of low voltage and start-up emissions data would also improve emissions estimates for the U.S. GHG Inventory and better inform future EPA policy. Currently the U.S. GHG Inventory uses a Tier 1 emission factor to estimate LVAE emissions, based on production technology and high voltage emission estimates, which may overestimate low voltage emissions. However, the LVAE data is still somewhat limited. Additional studies would help to assess how frequently measurements must be made to maintain an accurate accounting of smelter emissions, including low voltage emissions. Studies are also needed to assess the relative advantages in robustness and accuracy of the non-linear method for calculating HVAE PFC emissions. The EPA requests comment on the extent to which low voltage emissions have been characterized and if data is available to develop guidance on low voltage emission measurements needed to develop robust LVAE emission factors. The EPA also requests comment on the use of the non-linear method as an alternative to the slope coefficient and overvoltage methods currently allowed in subpart F. The EPA is also requesting comment on the methods and protocols in the 2020 IAI Good Practice Guidance.

V. Schedule for the Proposed Amendments

The EPA is planning to consider the comments on these proposed changes, and, if any of the proposed amendments are finalized, to respond to the comments and publish any amendments before the end of 2022. We are proposing that these amendments would become effective on January 1, 2023 and that reporters would implement the changes beginning with reports prepared for RY2023 and submitted April 1, 2024.

We have determined that it would be feasible for existing reporters to implement the proposed changes for RY2023 because the revisions primarily include improvements to the rule that are consistent with the current data collection and calculation methodologies. Some of the proposed amendments would clarify and improve the existing rule in order to enhance the quality and accuracy of the data collected. These revisions primarily provide additional clarifications or flexibility regarding the existing regulatory requirements, do not add new monitoring or sampling requirements, and do not substantially affect the information that must be collected (*i.e.,* require new data collection). In the limited cases where we are proposing to require the collection of additional data, such as from subpart W (Petroleum and Natural Gas Systems) facilities, we are proposing to allow reporters to use BAMM for the first annual report submitted for RY2023 (as discussed in section III.J of this preamble), which would provide additional time for facilities to adapt to new monitoring requirements and, for example, install the appropriate equipment. Where calculation equations are proposed to be modified, the changes clarify equation terms or simplify the calculations, and do not require any additional data monitoring. In these cases, we anticipate that facilities would have any additional inputs for calculations available in company records or could easily calculate the required input from existing process knowledge and engineering estimates, or from available company records. Therefore, these types of changes are not anticipated to add significant burden for reporters. Although we are proposing one change to require additional reporting under subpart C (for separate reporting of biogenic emissions from the combustion of tires), because we are simultaneously proposing removal of the ''less than 10 percent'' restriction on using the default biogenic CO_2 factor to estimate biogenic emissions in 40 CFR 98.33(e)(3)(iv), the new reporting would not require any additional monitoring or data collection. As such, all reporters who combust tires would be able to use the default biogenic CO_2 factor, and would not need to conduct quarterly flue-gas testing, to establish the biogenic fraction of emissions.

In several instances we are proposing to require reporting of additional data elements to improve verification of annual reports, provide a more complete picture of GHG emissions or supply, or develop factors that may inform the U.S. GHG Inventory. As provided in section III of this preamble, in these instances we anticipate that the data is already available in company records (*e.g.,* production or material use data, or data on product or equipment type). In most

[164] U.S. Environmental Protection Agency & International Aluminium Institute. (2008). Protocol for Measurement of Tetrafluoromethane (CF_4) and Hexafluoroethane (C_2F_6) Emissions from Primary Aluminum Production. Available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

[165] Available at *https://international-aluminium.org/resource/good-practice-guidance-measuring-perfluorocarbons/* and in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

[166] Available at *https://international-aluminium.org/resource/good-practice-guidance-measuring-perfluorocarbons/* and in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

cases the data we are requesting can be calculated using data that is already required to be entered into the EPA's reporting system, is already maintained in keeping with existing facility data permits (*e.g.,* hours of operation an abatement device was not in use), or may be estimated using emission factors or engineering judgment. For example, where we are proposing to add reporting of unit specific data for subpart C (General Stationary Fuel Combustion Sources) reporters using the aggregation of units or common pipe configurations, facilities already collect data on the maximum rated heat input capacity of individual units in each aggregation of units or common pipe configuration (greater than or equal to 10 mmBtu/hr) to determine the reported cumulative maximum rated heat input capacity, and would be able to determine the other data elements requested (*i.e.,* unit type and estimate of the fraction of annual heat input) from their existing company records.

Additionally, although we are proposing the addition of calculation and reporting requirements under new subpart VV (Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916), we do not anticipate that the new subpart would expand the existing coverage of facilities subject to the GHGRP, but would only apply to those reporters that currently report under subpart UU (Injection of Carbon Dioxide) and that choose to report amounts of CO_2 stored under the proposed subpart VV. It is anticipated that these facilities already follow the calculation requirements and data gathering prescribed under CSA/ANSI ISO 27916:2019 (*e.g.,* as discussed in section III.W of this preamble, to quantify storage for the IRC section 45Q tax credit); would not perform any additional calculation, monitoring, or quality assurance procedures under the proposed requirements; and that the information submitted to the GHGRP would be obtained and provided from readily available data. These facilities will also retain the option to continue to report under existing subpart UU with no changes. Therefore, we have determined that it would be feasible for facilities who opt to report under proposed subpart VV to implement the proposed changes for RY2023.

Other proposed changes streamline and improve implementation by simplifying or clarifying calculation, monitoring, and recordkeeping, or reporting. These types of changes are intended to simplify or provide flexibility in the requirements that reporters must meet and do not require additional data collection. For these reasons, we believe that a proposed effective date of January 1, 2023 is reasonable. Reporters are not required to submit RY2023 reports until April 1, 2024, which is over a year after we expect a final rule based on this proposal to be finalized, if finalized, thus providing an opportunity for reporters to adjust to any finalized amendments. The proposed effective date would also allow ample time for the EPA to implement the changes into e-GGRT.

We are proposing one change that would impact the date of submittal of a non-annual report. For subpart I, we are proposing to revise the frequency of submittal of the technology assessment reports required under 40 CFR 98.96(y). The proposed change would revise the frequency of submittal from three years to five years. Under the current rule, semiconductor manufacturing facilities are required to submit their next technology assessment report by March 31, 2023 (concurrent with their RY2022 annual report). The proposed change would affect the due date of the following technology assessment report, moving the due date from March 31, 2023 to March 31, 2025. Because the proposed change would decrease the frequency of submissions and extend the timeframe for reporters to collect and compile data for the next submittal, we have determined that the proposed changes would be feasible to implement by this date.

We are likewise proposing that the proposed CBI determinations discussed in section VI of this preamble would become effective on January 1, 2023. The majority of the determinations are for new or revised data elements that would be included in annual GHG reports prepared for RY2023 and submitted April 1, 2024. However, there are some circumstances, discussed in detail in section VI of this preamble, where the proposed determinations cover data included in annual GHG reports submitted for prior years. In either case, the proposed determinations for the data that the EPA has already received for these prior years or receives going forward for any reporting year would become effective on January 1, 2023.

VI. Proposed Confidentiality Determinations for Certain Data Elements

A. Overview and Background

Part 98 requires reporting of numerous data elements to characterize, quantify, and verify GHG emissions and related information. Following proposal of part 98 (74 FR 16448, April 10, 2009), the EPA received comments addressing the issue of whether certain data could be entitled to confidential treatment. In response to these comments, the EPA stated in the preamble to the 2009 Final Rule (74 FR 56387, October 30, 2009), that through a notice and comment process, we would establish those data elements that are entitled to confidential treatment. This proposal is one of a series of rulemakings dealing with confidentiality determinations for data reported under part 98. For more information on previous confidentiality determinations for part 98 data elements, see the following documents:

- 75 FR 39094, July 7, 2010. Describes the data categories and category-based determinations the EPA developed for the part 98 data elements.
- 76 FR 30782, May 26, 2011; hereafter referred to as the ''2011 Final CBI Rule.'' Assigned data elements to data categories and published the final CBI determinations for the data elements in 34 part 98 subparts, except for those data elements that were assigned to the ''Inputs to Emission Equations'' data category.
- 77 FR 48072, August 13, 2012. Finalized confidentiality determinations for data elements reported under nine subparts I, W, DD, QQ, RR, SS, UU; except for those data elements that are inputs to emission equations. Also finalized confidentiality determinations for new data elements added to subparts II and TT in the November 29, 2011 Technical Corrections document (76 FR 73886).
- 78 FR 68162; November 13, 2013. Finalized confidentiality determinations for new data elements added to subpart I.
- 78 FR 69337, November 29, 2013. Finalized determinations for new and revised data elements in 15 subparts, except for those data elements assigned to the ''Inputs to Emission Equations'' data category.
- 79 FR 63750, October 24, 2014. Revised recordkeeping and reporting requirements for ''inputs to emission equations'' for 23 subparts and finalized confidentiality determinations for new data elements in 11 subparts.
- 79 FR 70352, November 25, 2014. Finalized confidentiality determinations for new and substantially revised data elements in subpart W.
- 79 FR 73750, December 11, 2014. Finalized confidentiality determinations for certain reporting requirements in subpart L.
- 80 FR 64262, October 22, 2015. Finalized confidentiality determinations for new data elements in subpart W.
- 81 FR 86490, November 30, 2016. Finalized confidentiality determinations

for new or substantially revised data elements in subpart W.

• 81 FR 89188, December 9, 2016. Finalized confidentiality determinations for new or substantially revised data elements in 18 subparts and for certain existing data elements in 4 subparts.

In this document, we are proposing confidentiality determinations or ''emission data'' designations for:

• New or substantially revised reporting requirements (*i.e.,* the proposed change requires additional or different data to be reported);

• Existing reporting requirements for which the EPA did not previously finalize a confidentiality determination or ''emission data'' designation; and

• Existing reporting requirements for which the EPA is proposing to amend existing confidentiality determinations. This includes cases where the EPA is proposing to amend confidentiality determinations to align with determinations established in 40 CFR part 84 under the American Innovation and Manufacturing Act of 2020 (AIM Act).

We are also aware that a few confidentiality determinations finalized in a previous rulemaking were not clear, and we are now clarifying the previous determinations. Further, we propose to designate certain new or substantially revised data elements as ''inputs to emission equations'' falling within the definition of ''emission data'' (see section VI.C of this preamble for a discussion of ''inputs to emission equations''), and we are proposing to require reporting of those data elements. Table 5 of this preamble provides the number of affected data elements and the affected subparts for each of these proposed actions.

Table 5 of this preamble also describes the effective date of these proposed actions. The majority of the determinations would apply at the same time as the proposed schedule described in section V of this preamble. In the cases where the EPA is proposing a determination for existing data elements where one was not previously made, or where the EPA is clarifying an existing determination, the proposed determination would be effective on January 1, 2023 for RY2023 as well as all prior years that the data was collected. For the data elements where we are proposing to amend previous determinations to align with rulemakings establishing 40 CFR part 84 under the AIM Act, the proposed confidentiality determinations would apply only prospectively, starting with RY2022 for the reasons described in section VI.D of this preamble.

TABLE 5—SUMMARY OF PROPOSED ACTIONS RELATED TO DATA CONFIDENTIALITY

Proposed actions related to data confidentiality	Number of data elements [a]	Subparts	Effective year
New or substantially revised reporting requirements for which the EPA is proposing a confidentiality determination or "emission data" designation.	283	C, G, H, I, N, P, Q, S, W, X, Y, BB, DD, GG, HH, OO, PP, SS, VV.	RY2023.
Existing reporting requirements for which the EPA is proposing a confidentiality determination or "emission data" designation because the EPA did not previously make a confidentiality determination or "emission data" designation.	33	A, I, K, W, HH	RY2023, and all prior years the data was collected.
Existing reporting requirements for which the EPA is proposing to amend an existing confidentiality determination.	33	A, RR, UU	RY2023.
Existing reporting requirements for which the EPA is clarifying the current confidentiality determination.	12	A, L, MM, NN	RY2023, and all prior years the data was collected.
New or substantially revised reporting requirements that the EPA is proposing be designated as "inputs to emission equations" and for which the EPA is proposing reporting determinations.	125	C, I, W, DD, SS	RY2023.
Existing reporting requirements for which the EPA is proposing to amend an existing confidentiality determination to align with determinations under the AIM Act.	9	OO	RY2022.

[a] These data elements are listed in the memoranda: (1) *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule,* (2) *Proposed Reporting Determinations for Data Elements Assigned to the Inputs to Emission Equations Data Category in Proposed Revisions to the Greenhouse Gas Reporting Rule,* and (3) *Proposed Determinations that would Align the Greenhouse Gas Reporting Program with the Determinations Made under the AIM Act Regulations,* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

Finally, we are confirming that, except for the cases discussed in detail in this proposal, part 98 data elements previously determined to be entitled to confidential treatment through rulemaking will continue to be treated as such under the standard for confidentiality set forth in *Food Marketing Institute* v. *Argus Leader Media,* 139 S. Ct. 2356 (2019).

B. Proposed Confidentiality Determinations and Emissions Data Designations

1. Proposed Approach

The EPA's past approach for evaluating reporting requirements for confidentiality was established in the 2011 Final CBI Rule (76 FR 30782, May 26, 2011). This approach was based on the requirements of 40 CFR part 2, which included an assessment of whether disclosure of the data would cause a likelihood of substantial competitive harm. As set forth in the 2011 Final CBI Rule, the EPA categorized all reporting requirements into 22 data categories and reviewed them for confidentiality as follows:

- 12 data categories were established and designated as either ''CBI'' or ''not CBI'' (hereafter referred to as ''categorical confidentiality determinations''), and all data elements assigned to one of these 12 data categories were also assigned the confidentiality determination of ''CBI'' or ''not CBI'' for that category;
- 5 data categories were established that were not assigned any categorical confidentiality determinations; instead, for each data element in these categories, the EPA made individual determinations through rulemaking for each data element;
- 4 data categories were established and designated as ''emission data'' (as defined in 40 CFR 2.301(a)(2)(i)) and all data elements assigned to these four data categories were assigned a categorical designation of ''emission data,'' which under CAA section 114 are not entitled to confidential treatment;[167] therefore, no data assigned to these four categories were further evaluated for confidentiality; and
- 1 data category, ''Inputs to Emission Equations,'' was proposed on July 7, 2010 (75 FR 39094) to be ''emissions data.'' Evaluation of data elements assigned to this data category was first conducted in the October 24, 2014 final rule (79 FR 63750). Refer to section VI.C of this preamble for further discussion of the EPA's evaluation and treatment of data assigned to the ''Inputs to Emission Equations'' data category.

Since the 2011 Final CBI Rule, we have followed the approach outlined above in all rulemakings for evaluating reporting requirements for confidentiality. However, in this document we are proposing to revise our approach to assessing data for confidentiality in response to *Food Marketing Institute* v. *Argus Leader Media,* 139 S. Ct. 2356 (2019) (hereafter referred to as *Argus Leader*).[168] In *Argus Leader,* the U.S. Supreme Court issued an opinion addressing the meaning of the word ''confidential'' in Exemption 4 of the Freedom of Information Act, 5 U.S.C. Section 552(b)(4)(2012 and Supp. V. 2017) stating that ''confidential'' must be given its ''ordinary'' meaning, which is information that is ''private'' or ''secret.'' As a result, starting with the date of the *Argus Leader* ruling, the EPA no longer assesses data elements using the rationale of whether disclosure will cause a likelihood of substantial competitive harm when making confidentiality determinations. Instead, the EPA assesses whether the information is customarily and actually treated as private by the reporter and whether the EPA has given an assurance at the time the information was submitted that the information will be kept confidential or not confidential.

We are proposing that the *Argus Leader* decision does not impact our approach to designating data elements as ''inputs to emission equations'' or our previous approach for designating new and revised reporting requirements as ''emission data.'' For a discussion of the EPA's rationale for why the *Argus Leader* decision does not impact our previous approach for handling ''inputs to emission equations,'' refer to section VI.C of this preamble. The *Argus Leader* decision does not apply to data elements designated as ''emission data,'' because section 114(c) of the CAA precludes ''emission data'' from being considered confidential and requires that such data be available to the public. Therefore, the *Argus Leader* decision does not impact our previous approach for designating new and revised reporting requirements as ''emission data.'' We propose to continue identifying new and revised reporting elements that qualify as ''emission data'' (*i.e.,* data necessary to determine the identity, amount, frequency, or concentration of the emission emitted by the reporting facilities) by evaluating the data for assignment to one of the four data categories designated by the 2011 Final CBI Rule to meet the CAA definition of ''emission data'' in 40 CFR 2.301(a)(2)(i) [169] (hereafter referred to as ''emission data categories''). As discussed in section II.B of the July 7, 2010 proposal (75 FR 39100), the four emission data categories include the following categories of data reported by direct emitters (*i.e.,* ''emission data'' does not apply to suppliers reporting under the GHGRP as discussed in section II.C.2 of the preamble for the 2011 Final CBI Rule (76 FR 30782, May 26, 2011)):

- Category 1: Facility and Unit Identifier Information;
- Category 2: Emissions;
- Category 3: Calculation Methodology and Methodological Tier; and
- Category 4: Data Elements Reported for Periods of Missing Data that are Not Inputs to Emission Equations.

Refer to section II.B of the July 7, 2010 proposal for descriptions of each of these data categories and the EPA's rationale for designating each data category as ''emission data.'' Note that the proposed ''emission data'' designations discussed in section VI.B.2 of this preamble involve assignment to only the first three emission data categories in the bulleted list above (*i.e.,* we are not proposing that any reported elements be assigned to the ''Data Elements Reported for Periods of Missing Data that are Not Inputs to Emission Equations'' data category).

For reporting elements that the EPA does not designate as ''emission data'' or ''inputs to emission equations,'' the EPA is proposing a revised approach for assessing data confidentiality. We propose to assess each individual reporting element according to the *Argus Leader* criteria (*i.e.,* whether the information is customarily and actually treated as private by the reporter); therefore, we are not proposing to assign the data elements to *any* data category established by the 2011 Final CBI Rule. Refer to section VI.B.2 of this preamble for further discussion of the EPA's evaluation of data elements according to the *Argus Leader* criteria and proposed confidentiality determinations.

2. Proposed Confidentiality Determinations and ''Emission Data'' Designations

In this section, we discuss the proposed confidentiality determinations

[167] See section I.C of the preamble for the July 7, 2010 CBI proposal (75 FR 39094, July 7, 2010) for further discussion of CAA section 114 requirements. The term ''emission data'' is defined at 40 CFR 2.301(a)(2)(i).

[168] Available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

[169] See section I.C of the July 7, 2010 proposal (75 FR 39100) for a discussion of the definition of ''emission data.'' As discussed therein, the relevant paragraphs (to the GHGRP) of the CAA definition of ''emission data'' include 40 CFR 2.301(a)(2)(i)(A) and (C), as follows: (A) ''Information necessary to determine the identity, amount, frequency, concentration, or other characteristics (to the extent related to air quality) of any emission which has been emitted by the source (or of any pollutant resulting from any emission by the source), or any combination of the foregoing;'' and (C) ''A general description of the location and/or nature of the source to the extent necessary to identify the source and to distinguish it from other sources (including, to the extent necessary for such purposes, a description of the device, installation, or operation constituting the source).''

and ''emission data'' designations for: (1) 283 new or substantially revised data elements, (2) 33 existing data elements (*i.e.,* not proposed to be substantially revised) for which we have not previously finalized a confidentiality determination or ''emission data'' designation, and (3) 33 existing data elements for which we are amending an existing confidentiality determination. We are also clarifying 12 previous confidentiality determinations, as discussed in section VI.B.2.d of this preamble.

Further, we are confirming that, except for the specific situations discussed in sections VI.B.2.c and VI.D of this preamble, the data elements previously determined to be entitled to confidential treatment in the following rulemakings will continue to be treated as such under the new confidentiality standard set forth in *Argus Leader:*

• 2011 Final CBI Rule;
• 77 FR 48072, August 13, 2012;
• 78 FR 68162; November 13, 2013;
• 78 FR 69337, November 29, 2013;
• 79 FR 63750, October 24, 2014;
• 79 FR 70352, November 25, 2014;
• 79 FR 73750, December 11, 2014;
• 80 FR 64262, October 22, 2015;
• 81 FR 86490, November 30, 2016; and
• 81 FR 89188, December 9, 2016.

a. Proposed Confidentiality Determinations and ''Emission Data'' Designations for New or Substantially Revised Data Reporting Elements

For the 283 new and substantially revised data elements, the EPA is proposing ''emission data'' designations for 90 data elements and confidentiality determinations for 193 data elements. The EPA is proposing to designate 90 new or substantially revised data elements as ''emission data'' by assigning the data elements to three emission data categories (established in the 2011 Final CBI Rule as discussed in section VI.B.1 of this preamble), as follows:

• 44 data elements that are proposed to be reported under subparts G, P, S, W, and VV are proposed to be assigned to the ''Emissions'' emission data category;

• 25 data elements that are proposed to be reported under subparts C, Q, and W are proposed to be assigned to the ''Facility and Unit Identifier Information'' emission data category; and

• 21 data elements that are proposed to be reported under subparts I, W, and SS are proposed to be assigned to the ''Calculation Methodology and Methodological Tier'' emission data category.

Refer to Table 1 in the memorandum, *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule,* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424), for a list of these 88 specific data elements proposed to be designated as ''emission data,'' the proposed emission data category assignments for each data element, and the EPA's rationales for the proposed emission data category assignments.

The remaining 193 new and substantially revised data elements not proposed to be designated as ''emission data,'' or ''inputs to emission equations,'' are proposed to be reported under subparts H, N, Q, S, W, X, Y, BB, DD, GG, HH, OO, PP, SS, and VV. This proposal assesses each individual reporting element according to the *Argus Leader* criteria as discussed in section VI.B.1 of this preamble. Refer to Table 2 in the memorandum, *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule,* to see a list of these 193 specific data elements with this status receiving a determination, the proposed confidentiality determination for each data element, and the EPA's rationales for the proposed confidentiality determinations.

b. Proposed Confidentiality Determinations and ''Emission Data'' Designations for Existing Part 98 Data Reporting Elements for Which No Determination Has Been Previously Established

We are also proposing confidentiality determinations and ''emission data'' designations for 33 data elements currently in subparts A, I, K, W, and HH for which no confidentiality determination or ''emission data'' designation has been previously finalized under part 98. We reviewed previous rulemakings and found the following instances where a confidentiality determination or ''emission data'' designation had not been made:

• For subparts A, K, and HH, three data elements were added in the 2009 Final Rule following public comment. The EPA did not make confidentiality determinations in that rulemaking and has not finalized determinations for these data elements in subsequent rulemakings.

• Also for subpart A, one data element was added in the August 13, 2012 rulemaking (77 FR 48072) following public comment. The EPA did not make a confidentiality determination in that rulemaking and has not finalized a determination for the data element in a subsequent rulemaking.

• For subpart I, one data element was added in the final rulemaking published on August 13, 2012 (77 FR 48072), and one data element was revised in the final rulemaking published on November 13, 2013 (78 FR 68162). For the data element added on August 13, 2012, the EPA had not proposed a confidentiality determination and, therefore, did not finalize a determination in the final rule. For the data element revised on November 13, 2013, the EPA retained a previous decision for the previous version of the data element not to assign a confidentiality determination to the data element (see the final rulemaking on August 13, 2012, 77 FR 48072). Since the EPA did not evaluate either data element for confidentiality in those two rulemakings or in subsequent rulemakings, the EPA has not previously finalized a confidentiality determination for the data element.

• Also for subpart A, one data element was added in the final rulemaking published on December 11, 2014 (79 FR 73750) following public comment. The EPA had not proposed a confidentiality determination or ''emission data'' designation for the data element and therefore did not finalize confidentiality determinations in the final rule.

• For Subpart W, 21 data elements were added or substantially revised in the final rulemaking published on November 25, 2014 (79 FR 70352) following public comment. Additionally, 5 data elements were added in the final rulemaking published on October 22, 2015 (80 FR 64242) following public comment. The EPA had not proposed a confidentiality determination or ''emission data'' designation for these new or revised data elements, and therefore did not finalize confidentiality determinations in the final rules.

Of these 33 data elements, we propose to designate 26 data elements as ''emission data'' and therefore they would not be entitled to confidential treatment by assigning the data elements to three emission data categories (established in the 2011 Final CBI Rule as discussed in section VI.B.1 of this preamble), as follows:

• 11 data elements in subparts A and W are proposed to be assigned to the ''Emissions'' emission data category;

• 14 data elements in subparts A and W are proposed to be assigned to the

''Facility and Unit Identifier Information'' emission data category; and

• 1 data element in subpart I is proposed to be assigned to the ''Calculation Methodology and Methodological Tier'' emission data category.

Refer to Table 3 in the memorandum, *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule,* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424), for a list of these 26 specific data elements proposed to be designated as ''emission data'', the proposed emission data category assignment for each data element, and the EPA's rationale for the proposed emission data category assignments.

For the remaining 7 existing reported data elements in subparts A, I, K, W, and HH for which no confidentiality determination or ''emission data'' designation has been previously finalized under part 98, we propose to assess each individual data element according to the *Argus Leader* criteria as discussed in section VI.B.1 of this preamble. Refer to Table 4 in the memorandum, *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule* (available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424), for a list of each of these seven specific data elements with this status receiving a determination, the proposed confidentiality determination for each data element, and the EPA's rationales for the proposed confidentiality determinations.

c. Proposed Confidentiality Determinations for Existing Part 98 Data Reporting Elements for Which a Previous Determination Is Proposed To Be Amended

We are proposing to amend the confidentiality determinations previously finalized under part 98 for five existing data elements in subpart A, 16 data elements in subpart RR, and 12 data elements in subpart UU. In amending the confidentiality determinations, we propose to evaluate each individual data element according to the *Argus Leader* criteria as discussed in section VI.B.1 of this preamble. Three of these data elements from subpart A (40 CFR 98.3(c)(5)(ii)(A) through (C)) were added to subpart A in the December 9, 2016 rulemaking (81 FR 89188). The EPA finalized confidentiality determinations for these three data elements in that rule. We are now proposing to amend those finalized confidentiality determinations from ''emissions data'' to ''not CBI'' for the data reported by suppliers under subpart OO. We are amending the previous determinations, because no data reported by suppliers meet the definition of ''emission data'' for the purposes of the GHGRP.[170] Two more data elements from subpart A (40 CFR 98.3(c)(5)(ii)) for both subparts LL and MM) were added to subpart A in the 2009 Final Rule. The EPA finalized confidentiality determinations for the data elements in the 2011 Final CBI Rule (76 FR 30782). We are proposing to amend the existing determinations because those determinations did not take into account situations where the data may already be publicly available.

With respect to subparts RR and UU, we are proposing to amend the confidentiality determinations for 16 data elements in subpart RR where previously no categorical CBI determinations were made and for 12 data elements in subpart UU where the EPA previously determined the data elements to be CBI. More specifically, we are proposing to change the confidentiality determinations for the 16 Subpart RR and 12 subpart UU data elements to ''Not CBI'' consistent with the *Argus Leader* criteria.

Subpart RR and UU reporters must report the quantities of CO_2 received at the custody transfer meter. Subpart RR reporters must also report the quantities of CO_2 produced at the separator flow meter if they are actively producing oil or natural gas or any other fluids. The EPA originally proposed that the quantities of CO_2 received and CO_2 produced including the mass and volumetric flow and CO_2 concentrations used to calculate these values would not be CBI (77 FR 1434, January 10, 2012). Following review of public comment, however, the EPA in its final rulemaking (77 FR 48072, August 13, 2012) determined that the quantities of CO_2 received and CO_2 produced could contain sensitive information for some facilities that report under subparts RR and UU, thus presenting the potential for competitive harm to the submitter if the information was released. At the time, the EPA was not aware that this information could be found publicly. The EPA, therefore, made categorical determinations of ''CBI'' for the 12 subpart UU data elements and did not make categorical determinations for the 16 subpart RR data elements.

We have revisited the original confidentiality determinations for these data elements under the *Argus Leader* standard and have determined that the EPA's original basis for the confidentiality determinations is not valid. The EPA has now determined that company and facility-level data for CO_2 received and CO_2 produced are often available to the public through company websites and annual reports, company filings with the Securities and Exchange Commission, presentations at conferences and other events, and third-party analyses. In addition, oil and gas production to the well level is reported to state oil and gas commissions and is widely available to the public through the commission websites and records as well as through third parties. General rules-of-thumb for the quantity of CO_2 required to produce a barrel of oil are often used in the oil and gas industry to estimate CO_2 quantities received and injected. Since the EPA has now found that this information is largely publicly available, we are determining in the proposed rule that the quantities of CO_2 received and CO_2 produced submitted under subparts RR and UU cannot be entitled to confidential treatment under the standard set forth by the *Argus Leader* decision.

Refer to Table 5 in the memorandum, *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule,* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424) for a list of each of the 33 data elements with this status receiving a determination, the proposed confidentiality determination for each data element, and the Agency's rationale for each proposed determination.

d. Clarification of Previous Confidentiality Determinations

We are clarifying the confidentiality determinations previously finalized under 40 CFR part 98 for 12 data elements currently in subparts A, LL (Suppliers of Coal-based Liquid Fuels), MM (Suppliers of Petroleum Productions), and NN. These 12 data elements were added in the 2009 Final Rule, and confidentiality determinations were finalized in the 2011 Final CBI Rule (76 FR 30782). For these 12 data elements, there were discrepancies regarding the finalized confidentiality determinations in the 2011 Final CBI Rule (76 FR 30782) between the confidentiality determination specified in the preamble to the final rule and the

[170] See section II.C.2 of the preamble for the 2011 Final CBI Rule (76 FR 30782, May 26, 2011) for further discussion of the EPA's determination that the supplier data elements do not meet the definition of emission data.

confidentiality determination specified in the April 29, 2011 memorandum to the rulemaking.[171] We are clarifying which explanation of the Agency's confidentiality determination for each of the 12 data elements was correct, and we are providing explanations for the discrepancies between the determination specified in the preamble to the final rule and the supporting memorandum. These clarifications do not change the EPA's treatment of these 12 data elements; the confidentiality determinations being clarified are consistent with how the EPA has treated these reported data since promulgation of the May 26, 2011 final rule. This clarification will be effective for all previous and future reporting years. However, due to the conflict in the previous rules, we are providing a new opportunity to comment on the Agency's treatment of these data. Refer to Table 6 in the memorandum, *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule,* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424), for a list of the 12 data elements with this status, the clarified confidentiality determinations for each data element, and an explanation of the discrepancy in the documentation of their confidentiality determinations.

C. Proposed Reporting Determinations for Inputs to Emission Equations

As discussed in section I.C of the preamble to the October 24, 2014 rule (79 FR 63750), the EPA organizes data assigned to the ''Inputs to Emission Equations'' data category into two subcategories. The first subcategory includes ''inputs to emission equations'' entered into e-GGRT's Inputs Verification Tool (IVT). These ''inputs to emission equations'' are entered into IVT to satisfy the EPA's verification requirements. These data must be maintained as records by the submitter, but the data are not included in the annual report that is submitted to the EPA. This is done in circumstances where the EPA has determined that the ''inputs to emission equations'' meet the criteria necessary for them to be entered into the IVT system. The second subcategory includes ''inputs to emission equations'' that must be included in the annual report submitted to the EPA. This is done in circumstances where the EPA has determined that the data elements assigned to the ''Inputs to Emission Equations'' category do not meet the criteria necessary for them to be entered into the IVT system. These ''inputs to emission equations,'' once received by the EPA, are not held as confidential.

As stated in section VI.B.1 of this preamble, the EPA is determining that the *Argus Leader* decision does not impact our approach for handling of data elements assigned to the ''Inputs to Emission Equations'' data category. Data assigned to this data category and subcategorized by the Agency as ''inputs to emission equations'' entered into IVT do not become federal records for the purposes of part 98 reporting, so no confidentiality determination needs to be made for data elements determined to fall within this subcategory of data. Since this subcategory of data is only entered into the IVT system and not in the annual report sent directly to the EPA, the *Argus Leader* decision does not affect the approach to these data or the criteria the Agency uses to determine whether these data should be considered to fall within this subcategory. Likewise, for the same reason, the *Argus Leader* decision does not impact actions in previous rulemakings designating certain data as ''inputs to emission equations'' to be entered into the IVT system.

In continuation of this past approach, we are proposing to assign 125 new or substantially revised data elements in subparts I, W, DD, and SS to the ''Inputs to Emission Equations'' data category. Based on our evaluation of each data element assigned to the ''Inputs to Emission Equations'' data category, we determined that none of these 125 evaluated data meet the criteria necessary for them to be entered into the IVT system; therefore, we propose that all 125 of these data elements be reported to the EPA and would be considered ''emission data.'' These ''inputs to emission equations'' once received by the EPA would not qualify to be held as confidential. Refer to Table 1 in the memorandum, *Proposed Reporting Determinations for Data Elements Assigned to the Inputs to Emission Equations Data Category in Proposed Revisions to the Greenhouse Gas Reporting Rule,* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424) for a list of the 125 data elements proposed to be reported that are being designated as ''inputs to emission equations,'' and the EPA's rationale for the proposed reporting determinations. The table also includes a discussion of the criteria that we established in 2011 for evaluating whether data assigned to the ''Inputs to Emission Equations'' data category should be entered into the IVT system. In our evaluation we found that even if the 2011 criteria were based on the standard for confidential treatment set forth in the Supreme Court's 2019 *Argus Leader* decision, it would not impact our determination that these 125 data elements should be directly reported to EPA instead of entered into IVT.

Note that this proposal also includes proposed revisions to calculation methodologies in direct emitter subparts G, P, S, and Y that would require reporters under these subparts to enter new or substantially revised ''inputs to emission equations'' in IVT. These new and substantially revised data elements are not proposed to be included in the reporting section of those subparts but would instead be retained as records. Since the EPA is not proposing to include these data in the annual report, the data elements are not included in the evaluation discussed in this section. Refer to section III of this preamble for discussion of all proposed revisions to the recordkeeping sections of subparts G, P, S, and Y.

D. Proposed Revision to Confidentiality Determinations for Existing 40 CFR Part 98 Data Elements Affected by the AIM Implementation Rule

On October 5, 2021, the EPA finalized the AIM Implementation Rule (86 FR 55116), which establishes a program to phase down hydrofluorocarbon production and consumption (hereafter referred to as the ''AIM Act'') at 40 CFR part 84 (hereafter referred to as ''Part 84''). There are cases where similar or identical data will be collected under both the AIM Act under Part 84 and the GHGRP under part 98. For some of these overlapping data, the EPA had previously determined under part 98 that the data would be treated as confidential when collected under the GHGRP. However, pursuant to the AIM Act, the EPA subsequently determined that the overlapping data elements collected under the AIM Act would not be provided confidential treatment. Refer to section X.C of the AIM Implementation Rule for the Agency's rationale for these determinations (86 FR 55191). Specifically, the AIM Implementation Rule determined that 12 data elements would not be eligible for confidential treatment when reported under the AIM Act where the data had previously been determined to be entitled to confidential treatment under the GHGRP.

To align the GHGRP with the AIM Act, we are proposing to amend the confidentiality determinations made

[171] See April 29, 2011 memorandum ''Final Data Category Assignments and Confidentiality Determinations for Part 98 Reporting Elements,'' available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

under the GHGRP for these 12 overlapping data elements. As these 12 data elements are not eligible for confidential treatment and will be publicly released under the AIM Act, there is no basis for treating the data as confidential under the GHGRP. Therefore, we are proposing that the data no longer be entitled to confidential treatment when reported under the GHGRP. We are proposing to amend the confidentiality determinations for these 12 overlapping data elements for only those reporting years that the data are collected under the AIM Act and only those GHGs covered by the AIM Act. First, regarding the reporting years, the EPA has been collecting many of these 12 data elements under the GHGRP since 2010, whereas the EPA will only begin collecting data under the AIM Act for activities beginning in 2022. Therefore, we are not proposing to amend the confidentiality determinations for any years prior to 2022 that the data were collected under the GHGRP. Instead, we propose to amend the part 98 confidentiality determinations prospectively, such that these 12 data elements would not be treated as confidential for the annual reports covering RY2022 and future years. Second, regarding GHGs, the AIM Act requires reporting of 18 GHGs, whereas the GHGRP covers a much broader set of GHGs. We are proposing to amend the part 98 confidentiality determinations for these 12 data elements only for reported data associated with the exact GHGs covered under the AIM Act as listed in appendix A of part 84.

The 12 overlapping data elements for which we are proposing to amend the confidentiality determination include data elements currently reported under subparts A and OO of part 98. A list of these 12 affected data elements and the proposed determinations are specifically listed in Table 1 in the memorandum titled *Proposed Determinations that would Align the Greenhouse Gas Reporting Program with the Determinations Made under the AIM Act Regulations* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

The AIM Implementation Rule also included one HFC data element to be used in the administration of the AIM Act that is only reported under part 98 but not under the AIM Act, specifically under 40 CFR 98.416(a). This data element is ''Annual quantities of fluorinated greenhouse gases [other than HFCs regulated under the AIM Act], identified by type, intentionally produced on a facility line that also produces HFC-23.'' [172] The Agency will invoke the modification provisions of 40 CFR 2.301(d)(4) to make an individual determination on this specific data element. Once that process is completed, the Agency may make a conforming change to the confidentiality determination for that data category in the final version of this rulemaking. Note that the determination affects only fluorinated greenhouse gases that are produced on a facility line that also produces HFC–23.

E. Request for Comments on Proposed Category Assignments, Confidentiality Determinations, or Reporting Determinations

By proposing confidentiality determinations prior to data reporting through this proposal and rulemaking process, we provide potential reporters an opportunity to submit comments, particularly comments identifying data elements proposed by the Agency to be ''not CBI'' that reporters consider to be customarily and actually treated as private. Likewise, we provide potential reporters an opportunity to submit comments on whether there are disclosure concerns for ''inputs to emission equations'' that we propose would be included in the annual reports and subsequently released by the EPA. This opportunity to submit comments is intended to provide reporters with the opportunity that is afforded to reporters when the EPA considers claims for confidential treatment of information in case-by-case confidentiality determinations under 40 CFR part 2. In addition, the comment period provides an opportunity to respond to the EPA's proposed determinations with more information for the Agency to consider prior to finalization. We will evaluate the comments on our proposed determinations, including claims of confidentiality and information substantiating such claims, before finalizing the confidentiality determinations. Please note that this will be reporters' only opportunity to substantiate a confidentiality claim for data elements included in this rulemaking where a confidentiality determination or reporting determination is being proposed. Upon finalizing the confidentiality determinations and reporting determinations of the data elements identified in this proposed rule, the EPA will release or withhold these data in accordance with 40 CFR 2.301(d), which contains special provisions governing the treatment of part 98 data for which confidentiality determinations have been made through rulemaking pursuant to CAA sections 114 and 307(d).

If members of the public have reason to believe any data elements in this proposed rule that are proposed to be treated as confidential are not customarily and actually treated as private by reporters, please provide comment explaining why the Agency should not provide an assurance of confidential treatment for data.

When submitting comments regarding the confidentiality determinations or reporting determinations we are proposing in this action, please identify each individual proposed new, revised, or existing data element you consider to be confidential or do not consider to be ''emission data'' in your comments. If the data element has been designated as ''emission data,'' please explain why you do not believe the information should be considered ''emission data'' as defined in 40 CFR 2.301(a)(2)(i). If the data has not been designated as ''emission data'' and is proposed to be not entitled to confidential treatment, please explain specifically how the data element is commercial or financial information that is both customarily and actually treated as private. Particularly describe the measures currently taken to keep the data confidential and how that information has been customarily treated by your company and/or business sector in the past. This explanation is based on the requirements for confidential treatment set forth in *Argus Leader.* If the data element has been designated as an ''input to an emission equation'' (*i.e.,* not entitled to confidential treatment), please explain specifically why there are disclosure concerns.

Please also discuss how this data element may be different from or similar to data that are already publicly available, including data already collected and published annually by the GHGRP, as applicable. Please submit information identifying any publicly available sources of information containing the specific data elements in question. Data that are already available through other sources would likely be found not to qualify for confidential treatment. In your comments, please identify the manner and location in which each specific data element you identify is publicly available, including a citation. If the data are physically published, such as in a book, industry trade publication, or federal agency publication, provide the title, volume number (if applicable), author(s),

[172] See pg. 12 of ''Memorandum—Classification of Data Reported Under the HFC Phasedown Rule'' available at Docket Id. No. EPA–HQ–OAR–2021–0044–0227 and in the docket to for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

publisher, publication date, and International Standard Book Number (ISBN) or other identifier. For data published on a website, provide the address of the website, the date you last visited the website and identify the website publisher and content author. Please avoid conclusory and unsubstantiated statements, or general assertions regarding the confidential nature of the information.

Finally, we are not proposing new confidentiality determinations and reporting determinations for data reporting elements proposed to be unchanged or minimally revised because the final confidentiality determinations and reporting determinations that the EPA made in previous rules for these unchanged or minimally revised data elements are unaffected by this proposed amendment and will continue to apply. The minimally revised data elements are those where we are proposing revisions that would not require additional or different data to be reported. For example, under subpart FF, we are proposing to revise a data element to clarify the term ''Mine Safety and Health Administration (MSHA) number'' to be ''Mine Safety and Health Administration (MSHA) identification number'' (see 40 CFR 98.246(t)). This proposed change would not impact the data collected, and therefore we are not proposing a new or revised confidentiality determination. However, we are soliciting comment on any cases where a minor revision would impact the previous confidentiality determination or reporting determination. In your comments, please identify the specific data element, including name and citation, and explain why the minor revision would impact the previous confidentiality determination or reporting determination.

VII. Impacts of the Proposed Amendments

The EPA is proposing amendments to part 98 in order to implement improvements to the GHGRP, including revisions to update existing emission factors and emissions estimation methodologies, revisions to require reporting of additional data to understand new source categories or new emission sources for specific sectors and address potential gaps in reporting, and revisions to collect data that would improve the EPA's understanding of the sector-specific processes or other factors that influence GHG emission rates, verification of collected data, or to complement or inform other EPA programs. The EPA is also proposing revisions that would improve implementation of the program, such as those that would update applicability estimation methodologies, provide flexibility for or simplifying calculation and monitoring methodologies, streamline recordkeeping and reporting, and other minor technical corrections or clarifications identified as a result of working with the affected sources during rule implementation and outreach. The EPA anticipates that the proposed revisions would result in an overall increase in burden for reporters. The proposed revisions would increase burden in cases where the proposed amendments add or revise reporting requirements or require additional emissions data to be reported. We anticipate a decrease in burden where the proposed revisions would adjust or improve the estimation methodologies for determining applicability, simplify calculation methodologies or monitoring requirements, or simplify the data that must be reported. In several cases, we are proposing changes where we anticipate increased clarity or more flexibility for reporters that could result in a potential decrease in burden, but we are unable to quantify this decrease.

As discussed in section V of this preamble, we are proposing to implement these changes for RY2023 reports. Costs have been estimated over the three years following the year of implementation. The incremental implementation costs for all subparts for each reporting year are summarized in Table 6 of this preamble. The estimated annual average labor burden is $1,417,494 per year. The incremental burden by subpart is shown in Table 6 of this preamble.

TABLE 6—TOTAL INCREMENTAL LABOR BURDEN FOR REPORTING YEARS 2023–2025

[$2017/year]

Cost summary	RY2023	RY2024	RY2025	Annual average
Burden by Year (all subparts)	$1,417,591	$1,416,802	$1,418,090	$1,417,494

There is an additional annual incremental burden of $7,281 for capital and operation and maintenance (O&M) costs, which reflects changes to applicability and monitoring for subparts I, P, W, UU, and VV. Including capital and O&M costs, the total annual average burden is $1,424,775 over the next 3 years.

The incremental burden by subpart is shown in Table 7 of this preamble. Note that subparts with proposed revisions that would not result in any changes to burden (*e.g.,* subparts FF and NN) are excluded from this table.

TABLE 7—TOTAL INCREMENTAL BURDEN BY SUBPART

[$2017/year] [a]

Subpart	Labor costs		Capital and O&M
	Initial year	Subsequent years	
C—General Stationary Fuel Combustion Sources			
Facilities Reporting only to Subpart C	$70,732	$70,732	
Facilities Reporting to Subpart C plus another subpart	94,999	94,999	
G—Ammonia Manufacturing	250	250	
H—Cement Production	3,655	3,655	
I—Electronics Manufacturing [b]	19,056	17,839	$50

TABLE 7—TOTAL INCREMENTAL BURDEN BY SUBPART—Continued

[$2017/year] [a]

Subpart	Labor costs		Capital and O&M
	Initial year	Subsequent years	
N—Glass Production	818	818	
P—Hydrogen Production	628	628	(1,536)
Q—Iron and Steel Production	1,454	1,454	
S—Lime Manufacturing	1,351	1,351	
W—Petroleum and Natural Gas Systems	1,211,076	1,211,076	8,667
X—Petrochemical Production	528	528	
Y—Petroleum Refineries	801	801	
BB—Silicon Carbide Production	20	20	
DD—Electrical Equipment Use	7,106	7,106	
GG—Zinc Production	20	20	
HH—Municipal Solid Waste Landfills	3,297	3,297	
OO—Suppliers of Industrial Greenhouse Gases	810	810	
PP—Suppliers of Carbon Dioxide	629	629	
SS—Electrical Equipment Manufacture or Refurbishment	338	338	
UU [c]	(1,831)	(1,831)	(100)
VV [d]	1,833	3,355	200
Total [e]	1,417,591	1,417,446	7,281

[a] Includes estimated increase or decrease in costs following implementation of revisions in RY2023.

[b] Average subsequent year labor costs for Subpart I. Subpart I subsequent year costs include $17,252 in Year 2 and $17,526 in Year 3.

[c] Annual burden includes labor costs and annual O&M savings for two reporters who will begin submitting reports under proposed subpart VV in each year.

[d] Subsequent year labor costs include $2,848 in Year 2 and $3,862 in Year 3. O&M costs are based on $100 in Year 1, $200 in Year 2, and $300 in Year 3.

[e] Subsequent year labor costs include $1,416,802 in Year 2 and $1,418,090 in Year 3.

A full discussion of the cost and emission impacts may be found in the memorandum, *Assessment of Burden Impacts for Proposed Revisions for the Greenhouse Gas Reporting Rule* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

VIII. Statutory and Executive Order Reviews

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

This action is a significant regulatory action that was submitted to the OMB for review. This action involves proposed amendments that raise novel legal or policy issues. Any changes made in response to OMB recommendations have been documented in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

B. Paperwork Reduction Act

The information collection activities in this proposed rule have been submitted for approval to the OMB under the PRA. The ICR document that the EPA prepared has been assigned EPA ICR number 2300.19. You can find a copy of the ICR in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424, and it is briefly summarized here.

The EPA does not anticipate that the proposed amendments would result in substantial burden, based on the changes to the reporting requirements, in any of the subparts for which amendments are being proposed. In many cases, the proposed amendments to the requirements would reduce the reporting burden by clarifying or improving the estimation methodologies for determining applicability, simplifying calculation methodologies or providing flexibility for monitoring requirements, or simplifying the data that must be reported. The estimated annual average burden is 16,366 hours and $1,424,775 over the 3 years covered by this information collection. The burden costs include $1,424,772 from revisions implemented in the first year, $1,424,082 from revisions implemented in the second year, and $1,425,471 from revisions implemented in the third year. Further information on the EPA's assessment on the impact on burden can be found in the memorandum, *Assessment of Burden Impacts for Proposed Revisions for the Greenhouse Gas Reporting Rule* in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

Respondents/affected entities: Owners and operators of facilities that must report their GHG emissions and other data to the EPA to comply with 40 CFR part 98.

Respondent's obligation to respond: The respondent's obligation to respond is mandatory under the authority provided in CAA section 114.

Estimated number of respondents: 10,041 (affected by proposed amendments).

Frequency of response: Annually.

Total estimated burden: 16,366 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $1,424,775, includes $7,281 annualized capital or operation & maintenance costs.

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

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. The EPA will respond to any ICR-related comments in the final rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs using the interface at *https://www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under Review—Open for Public Comments'' or by using the search function. OMB must receive comments no later than August 22, 2022.

C. Regulatory Flexibility Act (RFA)

I certify that this proposed action would not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this action are small businesses across all sectors encompassed by the rule, small governmental jurisdictions and small non-profits. In the development of 40 CFR part 98, the EPA determined that some small businesses are affected because their production processes emit GHGs that must be reported, because they have stationary combustion units on site that emit GHGs that must be reported, or because they have fuel supplier operations for which supply quantities and GHG data must be reported. Small governments and small non-profits are generally affected because they have regulated landfills or stationary combustion units on site, or because they own an LDC. In the promulgation of the rule, the EPA took several steps to reduce the impact on small entities. For example, the EPA determined appropriate thresholds that reduced the number of small businesses reporting. In addition, the EPA conducted several meetings with industry associations to discuss regulatory options and the corresponding burden on industry, such as recordkeeping and reporting. Except as discussed below, the proposed revisions would not revise these thresholds for existing subparts, therefore, we do not expect any additional small entities will be impacted under the proposed rule revisions. The proposed rule amendments predominantly apply to existing reporters and are amendments that would improve the existing emissions estimation methodologies; implement requirements to collect additional data to understand new source categories or emissions sources; improve the EPA's understanding of the sector-specific processes or other factors that influence GHG emission rates and improve verification of collected data; and provide additional data to complement or inform other EPA programs under the CAA and to more broadly inform climate programs and policies. We are also proposing revisions that clarify or update provisions that have been unclear, or that streamline or simplify requirements, for example, by increasing flexibility for reporters or removing redundant requirements. In general, these changes are improvements or clarifications of requirements that do not require new data monitoring and would not significantly increase reporter burden, or are changes that require data that is readily available and may be obtained from company records or estimated from existing inputs or data elements already collected under part 98.

In evaluating the impacts of the proposed revisions, we assessed the costs and impacts to small entities in three areas, including revisions to subpart applicability, changes to existing monitoring or calculation methodologies, and revisions to reporting and recordkeeping requirements for data provided to the program. First, we evaluated the costs to entities who may be affected by changes to applicability. In general, this is the area that would be most likely to have greater impacts, as facilities assume substantially higher cost when they become newly applicable to the full set of requirements under part 98 versus the costs associated with an incremental change in an existing requirement. Only the proposed revisions to applicability to subpart I (discussed in section III.E.2 of this preamble) are anticipated to potentially impact new reporters that have not previously reported to the GHGRP. The SBA size standard for facilities falling under the NAICS code 334413 (Semiconductor and Related Device Manufacturing) is 1,250 employees. In the subpart I initial promulgation package, we originally assessed the impact of complying with subpart I requirements on all small entities by calculating a cost-to-sales ratio for six enterprise size ranges using the average total annualized reporting costs to the average annual sales receipts for each establishment (85 FR 74813, December 1, 2010). Based on this analysis, the cost-to-sales ratio for all entity sizes except for the smallest sized enterprises (1 to 20 employee range) was less than one percent. The EPA further concluded that although the cost-to-sales ratio for the 1 to 20 employee range for semiconductor and related device manufacturing was greater than one percent (*i.e.,* 1.16 percent); facilities with emissions greater than 25,000 $mtCO_2e$ per year are unlikely to be included in the 1 to 20 employees size category. Under this proposed action, we estimate there is one (1) affected facility that does not currently report under the GHGRP that may be required to report. The affected facility is included in the 100 to 499 employee range. Although the affected facility meets the SBA size standard for a small business and would potentially incur costs from becoming newly subject the GHGRP ($18,736 in the first year and $17,032 in subsequent years), the costs-to-sales ratio for a facility in this size range would be anticipated to be less than 0.10%. Therefore, we have determined there would not be a significant economic impact on a substantial number of small entities from the proposed revisions to subpart I.

Next, we evaluated the costs and impacts to small entities associated with revisions to monitoring and calculation methodologies to each subpart. For those subparts where the EPA is proposing revisions to update or streamline monitoring and calculation methodologies (*i.e.,* subparts C, G, I, P, and S), we estimate no change or a decrease in burden; therefore, there would be no significant economic impacts on small entities from these proposed revisions. For a subset of subpart W reporters, the proposed monitoring revisions would result in a modest increase in labor costs of $430 per affected reporter, and $12 operation and maintenance costs per reporter. Detailed small business analyses were performed for subpart W in the initial promulgation package from 2011 (75 FR 74458, November 30, 2010) for the eight original industry segments and in the 2015 amendments to subpart W for three additional industry segments (80 FR 64262, October 22, 2015). Both analyses stated that the rule will not have a significant economic impact on a substantial number of small entities, because we concluded that small businesses are unlikely be impacted.[173] Furthermore, because the costs associated with the proposed monitoring revisions are minimal, no significant small entity impacts are anticipated for facilities subject to the proposed subpart W amendments. Because the EPA does not foresee an increase in the number of reporters or any changes in the affected industry

[173] The original analyses, in section III.D of the 2011 package (75 FR 74458, November 30, 2010), stated, ''smaller enterprises have very small operations (such as a single family owning a few production wells) that are unlikely to cross the 25,000 metric tons CO_2e reporting threshold.'' The second analysis, in section IV.B of the preamble to the 2015 proposed amendments (79 FR 76267; December 9, 2014), stated, ''The petroleum and natural gas industry has a large number of enterprises, the majority of them in the 1–20 employee range. However, a large fraction of production comes from large corporations and not those with less than 20 employee enterprises. The smaller enterprises in most cases deal with very small operations (such as a single family owning a few production wells) that are unlikely to cross the 25,000 metric tons CO_2e threshold.''

segments from the proposed revisions, we have determined that the previous small business analyses still apply and there will not be a significant economic impact on a substantial number of small entities from the proposed revisions to monitoring for subpart W.

Finally, we evaluated the costs associated with revisions to recordkeeping and reporting, specifically revisions to the data elements that are reported in e-GGRT or entered into IVT, for each subpart (C, G, H, I, N, P, Q, S, W, X, Y, BB, DD, GG, HH, OO, PP, and SS). Based on the detailed small business analyses performed for each subpart in the initial promulgation packages (74 FR 56370, October 10, 2009; 75 FR 39738, July 12, 2010; 75 FR 75075, December 1, 2010; and 75 FR 74813, December 1, 2010), the costs associated with the reporting program are estimated to be less than one percent of sales in all firm size categories, with the exception of a small number of entities in the 1 to 20 employee range, which we determined to be unlikely to meet the regulatory thresholds and unlikely to be covered by the rule. With the exception of subpart W, the impacts from the proposed revisions to reporting and recordkeeping in this action for each subpart are less than $100 per entity, with an average annual burden increase of $46 per entity. For subpart C reporters, the highest average burden increase is $44 per facility. Because these costs are minimal, we have determined that the proposed revisions are unlikely to result in costs exceeding more than one percent of sales in any firm size category. For subpart W, the total annual average costs from the proposed revisions to reporting and recordkeeping are $412 per facility. However, as noted above in this section, we do not anticipate any small entities are currently subject to or reporting under subpart W. Further, the proposed revisions to reporting and recordkeeping under subpart W are unlikely to result in costs exceeding more than one percent of sales in any firm size category. Therefore, we have determined there are no significant economic impacts for any potential small entities subject to the revisions to reporting or recordkeeping requirements.

We have therefore concluded that this proposed action will have no significant regulatory burden for any directly regulated small entities and thus that this proposed action would not have a significant economic impact on a substantial number of small entities. Details of this analysis are presented in the memorandum, *Assessment of Burden Impacts for Proposed Revisions for the Greenhouse Gas Reporting Rule* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424. The EPA continues to conduct significant outreach on the GHGRP and maintains an ''open door'' policy for stakeholders to help inform the EPA's understanding of key issues for the industries. We continue to be interested in the potential impacts of the proposed rule amendments on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action implements mandate(s) specifically and explicitly set forth in CAA section 114(a)(1) without the exercise of any policy discretion by the EPA.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

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. This regulation will apply directly to stationary combustion units, cement production facilities, landfills, and petroleum and natural gas facilities that may be owned by tribal governments that emit GHGs. However, it will only have tribal implications where the tribal entity owns a facility that directly emits GHGs above threshold levels; therefore, relatively few (approximately 8) tribal facilities would be affected. This regulation is not anticipated to impact facilities or suppliers of additional sectors owned by tribal governments. Further, the proposed rule amendments are amendments that would improve the existing emissions estimation methodologies; implement requirements to collect additional data to understand new source categories or new emission sources for specific sectors; improve the EPA's understanding of the sector-specific processes or other factors that influence GHG emission rates and improve verification of collected data; provide additional data to complement or inform other EPA programs; clarify or update provisions that have been unclear; or that streamline or simplify requirements. In general, these changes are improvements or clarifications of requirements that for the most part would not require new equipment, sampling, or monitoring, and instead, would only require reporters to provide data that is readily available and may be obtained from company records or estimated from existing inputs or data elements already collected under part 98. Therefore, these proposed changes do not significantly change the part 98 requirements that may apply to tribal facilities because they generally do not require new equipment, sampling, or monitoring, and would not substantially increase reporter burden, impose significant direct compliance costs for tribal facilities, or preempt tribal law.

Although few facilities subject to part 98 are likely to be owned by tribal governments, the EPA previously sought opportunities to provide information to tribal governments and representatives during the development of the proposed and final rules for part 98 subparts that were promulgated on October 30, 2009 (74 FR 52620), July 12, 2010 (75 FR 39736), November 30, 2010 (75 FR 74458), and December 1, 2010 (75 FR 74774 and 75 FR 75076). Consistent with the 2011 EPA Policy on Consultation and Coordination with Indian Tribes,[174] the EPA previously consulted with tribal officials early in the process of developing part 98 regulations to permit them to have meaningful and timely input into its development and to provide input on the key regulatory requirements established for these facilities. A summary of these consultations is provided in section VIII.F of the preamble to the final rule published on October 30, 2009 (74 FR 52620), section V.F of the preamble to the final rule published on July 12, 2010 (75 FR 39736), section IV.F of the preamble to the re-proposal of subpart W (Petroleum and Natural Gas Systems) published on April 12, 2010 (75 FR 18608), section IV.F of the preambles to the final rules published on December 1, 2010 (75 FR 74774 and 75 FR 75076). As described in this section, the proposed rule does not significantly revise the established regulatory requirements and would not

[174] EPA Policy on Consultation and Coordination with Indian Tribes, May 4, 2011. Available at: *https://www.epa.gov/sites/default/files/2013-08/documents/cons-and-coord-with-indian-tribes-policy.pdf.*

substantially change the equipment, monitoring, or reporting activities conducted by these facilities, or result in other substantial impacts for tribal facilities.

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

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

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

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. The proposed amendments would improve the existing emissions estimation methodologies; implement requirements to collect additional data to understand new source categories or new emission sources for specific sectors; improve the EPA's understanding of factors that influence GHG emission rates; improve verification of collected data; and provide additional data to complement or inform other EPA programs. We are also proposing revisions that clarify or update provisions that have been unclear, or that streamline or simplify requirements, alleviate burden through revision, simplification, or removal of certain calculation, monitoring, recordkeeping, or reporting requirements. In general, these changes would not substantially impact the supply, distribution, or use of energy. In addition, the EPA is proposing confidentiality determinations for new and revised data elements proposed in this rulemaking and for certain existing data elements for which a confidentiality determination has not previously been proposed, or where the EPA has determined that the current determination is no longer appropriate. These proposed amendments and confidentiality determinations do not make any changes to the existing monitoring, calculation, and reporting requirements under part 98 that would affect the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act and 1 CFR Part 51

This action involves technical standards. The EPA proposes to allow the use of an alternate method, ASTM E415–17, *Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry* (2017), for the purposes of subpart Q (Iron and Steel Production) monitoring and reporting. The EPA currently allows for the use of standard methods based on atomic emission spectrometry in other sections of part 98, including under 40 CFR 98.144(b) where it can be used to determine the composition of coal, coke, and solid residues from combustion processes by glass production facilities. Therefore, the EPA is allowing ASTM E415–17 to be used in subpart Q. ASTM E415–17 uses spark atomic emission vacuum spectrometry to determine 21 alloying and residual elements in carbon and low-alloy steels. The method is designed for chill-cast, rolled, and forged specimens. Anyone may access the standards on the ASTM website (*https://www.astm.org/*) for additional information. These standards are available to everyone at a cost determined by the ASTM ($50). The ASTM also offers memberships or subscriptions that allow unlimited access to their methods. The cost of obtaining these methods is not a significant financial burden, making the methods reasonably available for reporters. The EPA is also proposing to add new subpart VV for certain EOR operations that choose to use the ISO standard designated as CSA/ANSI ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO2–EOR)* (2019), as a means of quantifying geologic sequestration. The method quantifies CO_2 that is stored in association with EOR operations, focusing on the safe, long-term containment of CO_2 within the EOR complex. CSA/ANSI ISO 27916:2019 identifies and quantifies CO_2 losses (including fugitive emissions) and quantifies the amount of CO_2 stored in association with the CO2–EOR project. It also shows how allocation rations can be used to account for the anthropogenic portion of the stored CO_2. Anyone may access the standard on the ANSI/ISO website (*https://webstore.ansi.org/SDO/ISO/*) for additional information. The standard is available to everyone at a cost determined by ANSI/ISO ($225). ANSI/ISO also offers memberships or subscriptions for reduced costs. Because the proposed standard is optional, the cost of obtaining this standard is not a significant financial burden. The EPA will also make a copy of these documents available in hard copy at the appropriate EPA office (see the **FOR FURTHER INFORMATION CONTACT** section of this preamble for more information) for review purposes only.

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

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations as it does not affect the level of protection provided to human health or the environment because it is a rule addressing information collection and reporting procedures.

K. Determination Under CAA Section 307(d)

Pursuant to CAA section 307(d)(1)(V), the Administrator determines that this action is subject to the provisions of CAA section 307(d). Section 307(d)(1)(V) of the CAA provides that the provisions of CAA section 307(d) apply to ''such other actions as the Administrator may determine.''

List of Subjects

40 CFR Part 9

Environmental protection, Administrative practice and procedure, Reporting and recordkeeping requirements

40 CFR Part 98

Environmental protection, Administrative practice and procedure, Greenhouse gases, Incorporation by reference, Reporting and recordkeeping requirements, Suppliers.

Michael S. Regan,

Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency proposes to amend title 40, chapter I, of the Code of Federal Regulations 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. Amend § 9.1 by adding an undesignated center heading and an entry for ''98.1–98.489'' in numerical order to read as follows:

§ 9.1 OMB approvals under the Paperwork Reduction Act.

* * * * *

40 CFR citation	OMB control No.
* * * * *	
Mandatory Greenhouse Gas Reporting	
98.1–98.489	2060–0629
* * * * *	

PART 98—MANDATORY GREENHOUSE GAS REPORTING

■ 3. The authority citation for part 98 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart A—General Provision

■ 4. Amend § 98.1 by revising paragraph (c) to read as follows:

§ 98.1 Purpose and scope.

* * * * *

(c) For facilities required to report under onshore petroleum and natural gas production under subpart W of this part, the terms *Owner* and *Operator* used in this subpart have the same definition as *Onshore petroleum and natural gas production owner or operator,* as defined in § 98.238. For facilities required to report under onshore petroleum and natural gas gathering and boosting under subpart W of this part, the terms *Owner* and *Operator* used in this subpart have the same definition as *Gathering and boosting system owner or operator*, as defined in § 98.238. For facilities required to report under onshore natural gas transmission pipeline under subpart W of this part, the terms *Owner* and *Operator* used in this subpart have the same definition as *Onshore natural gas transmission pipeline owner or* operator, as defined in § 98.238.

■ 5. Amend § 98.2 by revising paragraphs (f)(1) and (i)(1) and (2) and adding paragraph (k) to read as follows:

§ 98.2 Who must report?

* * * * *

(f) * * *

(1) Calculate the mass in metric tons per year of CO_2, N_2O, each fluorinated GHG, and each fluorinated heat transfer fluid that is imported and the mass in metric tons per year of CO_2, N_2O, each fluorinated GHG, and each fluorinated heat transfer fluid that is exported during the year.

* * * * *

(i) * * *

(1) If reported CO_2e emissions, calculated in accordance with § 98.3(c)(4)(i), are less than 25,000 metric tons per year for five consecutive years, then the owner or operator may discontinue complying with this part provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the fifth consecutive year of emissions less than 25,000 tons CO_2e per year. The owner or operator must maintain the corresponding records required under § 98.3(g) for each of the five consecutive years prior to notification of discontinuation of reporting and retain such records for three years following the year that reporting was discontinued. The owner or operator must resume reporting if annual CO_2e emissions, calculated in accordance with paragraph (b)(4) of this section, in any future calendar year increase to 25,000 metric tons per year or more.

(2) If reported CO_2e emissions, calculated in accordance with § 98.3(c)(4)(i), were less than 15,000 metric tons per year for three consecutive years, then the owner or operator may discontinue complying with this part provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the third consecutive year of emissions less than 15,000 tons CO_2e per year. The owner or operator must maintain the corresponding records required under § 98.3(g) for each of the three consecutive years and retain such records for three years prior to notification of discontinuation of reporting following the year that reporting was discontinued. The owner or operator must resume reporting if annual CO_2e emissions, calculated in accordance with paragraph (b)(4) of this section, in any future calendar year increase to 25,000 metric tons CO_2e per year or more.

* * * * *

(k) To calculate GHG quantities for comparison to the 25,000 metric ton CO_2e per year threshold under paragraph (a)(4) of this section for facilities that destroy fluorinated GHGs or fluorinated heat transfer fluids, the owner or operator shall calculate the mass in metric tons per year of CO_2e destroyed as described in paragraphs (k)(1) through (k)(3) of this section.

(1) Calculate the mass in metric tons per year of each fluorinated GHG or fluorinated heat transfer fluid that is destroyed during the year.

(2) Convert the mass of each destroyed fluorinated GHG or fluorinated heat transfer fluid from paragraph (k)(1) of this section to metric tons of CO_2e using Equation A–1 of this section.

(3) Sum the total annual metric tons of CO_2e in paragraph (k)(2) of this section for all destroyed fluorinated GHGs and destroyed fluorinated heat transfer fluids.

■ 6. Amend § 98.3 by revising paragraphs (b)(2) and (h)(4) to read as follows:

§ 98.3 What are the general monitoring, reporting, recordkeeping and verification requirements of this part?

* * * * *

(b) * * *

(2) For a new facility or supplier that begins operation on or after January 1, 2010 and becomes subject to the rule in the year that it becomes operational, report emissions starting the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

* * * * *

(h) * * *

(4) Notwithstanding paragraphs (h)(1) and (2) of this section, upon request by the owner or operator, the Administrator may provide reasonable extensions of the 45-day period for submission of the revised report or information under paragraphs (h)(1) and (2). If the Administrator receives a request for extension of the 45-day period, by email to an address prescribed by the Administrator prior to the expiration of the 45-day period, the extension request is deemed to be automatically granted for 30 days. The Administrator may grant an additional extension beyond the automatic 30-day extension if the owner or operator submits a request for an additional extension and the request is received by

the Administrator prior to the expiration of the automatic 30-day extension, provided the request demonstrates that it is not practicable to submit a revised report or information under paragraphs (h)(1) and (2) within 75 days. The Administrator will approve the extension request if the request demonstrates to the Administrator's satisfaction that it is not practicable to collect and process the data needed to resolve potential reporting errors identified pursuant to paragraph (h)(1) or (2) within 75 days. The Administrator will only approve an extension request for a total of 180 days after the initial notification of a substantive error.

* * * * *

■ 7. Amend § 98.4 by revising paragraph (h) and adding paragraph (n) to read as follows:

§ 98.4 Authorization and responsibilities of the designated representative.

* * * * *

(h) *Changes in owners and operators.* Except as provided in paragraph (n) of this section, in the event an owner or operator of the facility or supplier is not included in the list of owners and operators in the certificate of representation under this section for the facility or supplier, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the facility or supplier, as if the owner or operator were included in such list. Within 90 days after any change in the owners and operators of the facility or supplier (including the addition of a new owner or operator), the designated representative or any alternate designated representative shall submit a certificate of representation that is complete under this section except that such list shall be amended to reflect the change. If the designated representative or alternate designated representative determines at any time that an owner or operator of the facility or supplier is not included in such list and such exclusion is not the result of a change in the owners and operators, the designated representative or any alternate designated representative shall submit, within 90 days of making such determination, a certificate of representation that is complete under this section except that such list shall be amended to include such owner or operator.

* * * * *

(n) *Alternative provisions for changes in owners and operators for industry segments with a unique definition of facility as defined in § 98.238.* When there is a change to the owner or operator of a facility required to report under the onshore petroleum and natural gas production, natural gas distribution, onshore petroleum and natural gas gathering and boosting, or onshore natural gas transmission pipeline industry segments of subpart W of this part, or a change to the owner or operator for some emission sources from the facility in one of these industry segments, the provisions specified in paragraphs (n)(1) through (4) of this section apply for the respective type of change in owner or operator and the provisions specified in paragraph (n)(5) of this section apply to all types of change in owner or operator for such facilities.

(1) If the entire facility is acquired by an owner or operator that does not already have a reporting facility in the same industry segment and basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution), a certificate of representation that is complete under this section shall be submitted to reflect the new owner or operator within 90 days after the change in the owner or operator and according to the procedure specified in paragraph (b) of this section. If the new owner or operator already had emission sources listed in the applicable paragraph of § 98.232 prior to the acquisition in the same basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution) as the acquired facility but had not previously met the applicability requirements in § 98.2(a) and § 98.231, then per the applicable definition of facility in § 98.238, the previously owned applicable emission sources must be included in the acquired facility. The new owner or operator and the new designated representative shall be responsible for submitting the annual report for the facility for the entire reporting year beginning with the reporting year in which the acquisition occurred.

(2) If the entire facility is acquired by an owner or operator that already has a reporting facility in the same industry segment and basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution), the new owner or operator shall merge the acquired facility with their existing facility for purposes of the annual GHG report. Within 90 days after the change in the owner or operator, a certificate of representation that is complete under this section shall be submitted for the acquired facility to reflect the new owner or operator. The owner or operator shall also follow the provisions of § 98.2(i)(6) to notify EPA that the acquired facility will discontinue reporting and shall provide the e-GGRT identification number of the merged, or reconstituted, facility. The owner or operator of the merged facility shall be responsible for submitting the annual report for the merged facility for the entire reporting year beginning with the reporting year in which the acquisition occurred.

(3) If only some emission sources from the facility are acquired by one or more new owners or operators, the existing owner or operator (*i.e.,* the owner or operator of the portion of the facility that is not sold) shall continue to report under subpart W of this part for the retained emission sources unless and until that facility meets one of the criteria in § 98.2(i). Each owner or operator that acquires emission sources from the facility must account for those acquired emission sources according to paragraph (n)(3)(i) or (ii) of this section, as applicable.

(i) If the purchasing owner or operator that acquires only some of the emission sources from the existing facility does not already have a reporting facility in the same industry segment and basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution), the purchasing owner or operator shall begin reporting as a new facility. The new facility must include the acquired emission sources listed in the applicable paragraph of § 98.232 and any emission sources the purchasing owner or operator already owned in the same industry segment and basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution). The designated representative for the new facility must be selected by the purchasing owner or operator according to the schedule and procedure specified in paragraphs (b) through (d) of this section. The purchasing owner or operator shall be responsible for submitting the annual report for the new facility for the entire reporting year beginning with the reporting year in which the acquisition occurred.

(ii) If the purchasing owner or operator that acquires only some of the emission sources from the existing facility already has a reporting facility in the same industry segment and basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution), then per the applicable definition of facility in § 98.238, the purchasing owner or operator must add the acquired emission sources listed in the applicable paragraph of § 98.232 to their existing facility for purposes of reporting under subpart W. The purchasing owner or operator shall be responsible for submitting the annual report for the entire facility, including the acquired emission sources, for the entire reporting year beginning with the reporting year in which the acquisition occurred.

(4) If all the emission sources from a facility are sold to multiple owners or operators, such that the current owner or operator of the existing facility does not retain any of the emission sources, then the current owner or operator of the existing facility shall notify EPA within 90 days of the transaction that all of the facility's emission sources were acquired by multiple purchasers. Each owner or operator that acquires emission sources from a facility shall account for those sources according to paragraph (n)(3)(i) or (ii) of this section, as applicable.

(5) Each owner or operator involved in a transaction that results in a change to the owner or operator of a facility shall, as part of the acquisition agreement or ownership transfer contract, agree upon the entity who will be responsible for revisions to annual GHG reports under § 98.3(h) for reporting years prior to the reporting year in which the transaction occurred. That responsible entity will select a representative who will submit revisions to annual GHG reports under § 98.3(h) for that facility. If the selected individual is not the designated representative for the facility, the individual must be designated as the alternate designated representative or an agent for the facility.

■ 8. Amend § 98.6 by:

■ a. Revising the definitions for ''Carbon dioxide stream'', ''Dehydrator'', and ''Dehydrator vent emissions;''

■ b. Removing the definition for ''Desiccant'';

■ c. Adding a definition for ''Direct air capture (DAC)'' in alphabetical order; and

■ d. Revising the definition for ''Vapor recovery system''.

The revisions and addition read follows:

§ 98.6 Definitions.

* * * * *

Carbon dioxide stream means carbon dioxide that has been captured from an emission source (*e.g.,* a power plant or other industrial facility, captured from ambient air (*e.g.,* direct air capture), or extracted from a carbon dioxide production well plus incidental associated substances either derived from the source materials and the capture process or extracted with the carbon dioxide.

* * * * *

Dehydrator means a device in which a liquid absorbent (*e.g.,* ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

Dehydrator vent emissions means natural gas and CO_2 released from a natural gas dehydrator system absorbent (typically glycol) regenerator and, if present, a flash tank separator, to the atmosphere, flare, regenerator fire-box/fire tubes, or vapor recovery system. Emissions include stripping natural gas and motive natural gas used in absorbent circulation pumps.

* * * * *

Direct air capture (DAC), with respect to a facility, technology, or system, means that the facility, technology, or system uses carbon capture equipment to capture carbon dioxide directly from the air. Direct air capture does not include any facility, technology, or system that captures carbon dioxide:

(1) That is deliberately released from a naturally occurring subsurface spring or

(2) Using natural photosynthesis.

* * * * *

Vapor recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel. For purposes of § 98.233, routing emissions from a dehydrator regenerator still vent or flash tank separator vent to a regenerator fire-box/fire tubes does not meet the definition of vapor recovery system.

* * * * *

■ 9. Amend § 98.7 as follows:

■ a. Revise the introductory text;

■ b. In paragraph (c)(1), remove the text '', incorporation by reference (IBR)'' and add, in its place, the text ''; IBR'';

■ c. Redesignate paragraph (e)(38) as paragraph (e)(39);

■ d. Add new paragraph (e)(38) and paragraph (g)(6); and

■ e. In addition to the previous amendments to this section, remove the text '', IBR'' and add, in its place, the text ''; IBR'' wherever it appears throughout this section.

The revision and additions read as follows:

§ 98.7 What standardized methods are incorporated by reference into this part?

Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, the EPA must publish a document in the **Federal Register** and the material must be available to the public. All approved incorporation by reference (IBR) material is available for inspection at the EPA and at the National Archives and Records Administration (NARA). Contact EPA at: EPA Docket Center, Public Reading Room, EPA WJC West, Room 3334, 1301 Constitution Ave. NW, Washington, DC; phone: 202–566–1744. For information on the availability of this material at NARA, email *fr.inspection@nara.gov,* or go to *www.archives.gov/federal-register/cfr/ibr-locations.html.* The material may be obtained from the following source(s):

* * * * *

(e) * * *

(38) ASTM E415–17, Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry; IBR approved for § 98.174(b).

* * * * *

(g) * * *

(6) CSA/ANSI ISO 27916:19, Carbon dioxide capture, transportation and geological storage—Carbon dioxide storage using enhanced oil recovery (CO_2-EOR). Edition 1. January 2019; IBR approved for §§ 98.480(a), 98.481(a) and (b), 98.482, 98.483, 98.484, 98.485, 98.486(g), 98.487, 98.488(a)(5), and 98.489.

* * * * *

■ 10. Amend table A–1 to subpart A of part 98 by:

■ a. Adding under the heading ''Other Fluorinated Compounds'' the entry ''Carbonyl fluoride'' after the entry ''2-Bromo-2-chloro-1,1,1-trifluoroethane (Halon-2311/Halothane);''

■ b. Removing the heading ''Fluorinated GHG Group [d]'' and adding in its place the heading ''Fluorinated GHG Group [e]''

■ c. Revising the entry ''Unsaturated perfluorocarbons (PFCs), unsaturated HFCs, unsaturated hydrochlorofluorocarbons (HCFCs), unsaturated halogenated ethers, unsaturated halogenated esters, fluorinated aldehydes, and fluorinated ketones'' under the revised heading ''Fluorinated GHG Group; [e]''

■ d. Redesignating footnote ''d'' as footnote ''e;'' and

■ e. Adding new footnote ''d'' and footnote ''f.''

The additions and revisions read as follows:

* * * * *

TABLE A–1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
* * * * * * *			
Other Fluorinated Compounds			
* * * * * * *			
Carbonyl fluoride	353–50–4	COF_2	[d] 0.14
Fluorinated GHG Group [e]			
* * * * * * *			
Unsaturated perfluorocarbons (PFCs), unsaturated HFCs, unsaturated hydrochlorofluorocarbons (HCFCs), unsaturated halogenated ethers, unsaturated halogenated esters, unsaturated bromofluorocarbons, unsaturated chlorofluorocarbons, unsaturated bromochlorofluorocarbons, unsaturated hydrobromofluorocarbons, unsaturated hydrobromochlorofluorocarbons, fluorinated aldehydes, and fluorinated ketones [f]			1
* * * * * * *			

* * * * *

[d] This compound was added to Table A–1 in the final rule published on [Date of publication of the final rule in the FEDERAL REGISTER] and effective on January 1, 2023.

[e] For electronics manufacturing (as defined in § 98.90), the term ''fluorinated GHGs'' in the definition of each fluorinated GHG group in § 98.6 shall include fluorinated heat transfer fluids (as defined in § 98.98), whether or not they are also fluorinated GHGs.

[f] This fluorinated GHG group was updated in the final rule published on [Date of publication of the final rule in the **Federal Register**] and effective on January 1, 2023.

■ 11. Amend table A–3 to subpart A of part 98 by:

■ a. Revising the entry ''Electrical transmission and distribution equipment use at facilities where the total nameplate capacity of SF6 and PFC containing equipment exceeds 17,820 pounds, as determined under § 98.301 (subpart DD).'';

■ b. Removing the entry for ''Electrical transmission and distribution equipment manufacture or refurbishment (subpart SS).''; and

■ c. Adding the entry ''Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916 (subpart VV).'' at the end of the table.

The revision and addition read as follows:

* * * * *

TABLE A–3 TO SUBPART A OF PART 98—SOURCE CATEGORY LIST FOR § 98.2(a)(1)

* * * * * * *

Additional Source Categories [a] Applicable in Reporting Year 2011 and Future Years

Electrical transmission and distribution equipment use at facilities where the total estimated emissions from fluorinated GHGs, as determined under § 98.301 (subpart DD), are equivalent to 25,000 metric tons CO_2e or more per year.

* * * * * * *

Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916 (subpart VV).

[a] Source categories are defined in each applicable subpart.

* * * * *

■ 12. Amend table A–4 to subpart A of part 98 by adding the entry ''Electrical transmission and distribution equipment manufacture or refurbishment, as determined under § 98.451 (subpart SS).'' after the entry ''Industrial wastewater treatment (subpart II).'' to read as follows:

TABLE A–4 TO SUBPART A OF PART 98—SOURCE CATEGORY LIST FOR § 98.2(a)(2)

* * * * * * *

Additional Source Categories [a] Applicable in Reporting Year 2011 and Future Years

* * * * * * *

Electrical transmission and distribution equipment manufacture or refurbishment, as determined under § 98.451 (subpart SS).

TABLE A–4 TO SUBPART A OF PART 98—SOURCE CATEGORY LIST FOR § 98.2(a)(2)—Continued

*	*	*	*	*	*	*

[a] Source categories are defined in each applicable subpart.

* * * * *

Subpart C—General Stationary Fuel Combustion Sources

■ 13. Amend § 98.33 by:
■ a. Revising parameters ''CC'' and ''MW'' of Equation C–5 in paragraph (a)(3)(iii) introductory text;
■ b. Adding paragraphs (a)(3)(iii)(A) and (B);
■ c. Revising paragraph (b)(1)(vii);
■ d. Revising parameter ''EF'' of Equations C–8 in paragraph (c)(1) introductory text, C–8a in paragraph (c)(1)(i), C–8b in paragraph (c)(1)(ii), C–9a in paragraph (c)(2), C–9b in paragraph (c)(3), and C–10 in paragraph (c)(4) introductory text;
■ e. Revising paragraphs (c)(6)(i), (c)(6)(ii) introductory text, and (c)(6)(ii)(A) and (C);
■ f. Removing and reserving paragraph (c)(6)(ii)(B);
■ g. Revising parameter ''R'' of Equation C–11 in paragraph (d)(1); and
■ h. Revising the introductory text of paragraphs (e), (e)(1), (e)(2)(v), and (e)(3) and paragraph (e)(3)(iv).

The additions and revisions read as follows:

§ 98.33 Calculating GHG emissions.

* * * * *

(a) * * *

(3) * * *

(iii) * * *

CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the procedures specified in paragraphs (a)(3)(iii)(A)(*1*) and (a)(3)(iii)(A)(*2*) of this section.

MW = Annual average molecular weight of the gaseous fuel (kg per kg-mole). The annual average molecular weight shall be determined using the procedures specified in paragraphs (a)(3)(iii)(A)(*3*) and (a)(3)(iii)(A)(*4*) of this section.

* * * * *

(A) The minimum required sampling frequency for determining the annual average carbon content (*e.g.,* monthly, quarterly, semi-annually, or by lot) is specified in § 98.34. The method for computing the annual average carbon content for Equation C–5 is a function of unit size and how frequently you perform or receive from the fuel supplier the results of fuel sampling for carbon content. The methods are specified in paragraphs (a)(3)(iii)(A)(*1*) and (*2*) of this section, as applicable.

(*1*) If the results of fuel sampling are received monthly or more frequently, then for each unit with a maximum rated heat input capacity greater than or equal to 100 mmBtu/hr (or for a group of units that includes at least one unit of that size), the annual average carbon content for Equation C–5 shall be calculated using Equation C–5a of this section. If multiple carbon content determinations are made in any month, average the values for the month arithmetically.

$$(CC)_{annual} = \frac{\sum_{i=1}^{n} (CC)_i * (Fuel)_i * (MW)_i \ / \ MVC}{\sum_{i=1}^{n} (Fuel)_i * (MW)_i \ / \ MVC} \qquad \text{(Eq. C-5a)}$$

Where:

$(CC)_{annual}$ = Weighted annual average carbon content of the fuel (kg C per kg of fuel).

$(CC)_I$ = Measured carbon content of the fuel, for sample period ''i'' (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (kg C per kg of fuel).

(Fuel)i = Volume of the fuel (scf) combusted during the sample period ''i'' (*e.g.,* monthly, quarterly, semi-annually, or by lot) from company records.

(MW)i = Measured molecular weight of the fuel, for sample period ''i'' (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (kg per kg-mole).

MVC = Molar volume conversion factor at standard conditions, as defined in § 98.6. Use 849.5 scf per kg-mole if you select 68 °F as standard temperature and 836.6 scf per kg-mole if you select 60 °F as standard temperature.

n = Number of sample periods in the year.

(*2*) If the results of fuel sampling are received less frequently than monthly, or, for a unit with a maximum rated heat input capacity less than 100 mmBtu/hr (or a group of such units) regardless of the carbon content sampling frequency, the annual average carbon content for Equation C–5 shall either be computed according to paragraph (a)(3)(iii)(A)(*1*) of this section or as the arithmetic average carbon content for all values for the year (including valid samples and substitute data values under § 98.35).

(B) The minimum required sampling frequency for determining the annual average molecular weight (*e.g.,* monthly, quarterly, semi-annually, or by lot) is specified in § 98.34. The method for computing the annual average molecular weight for Equation C–5 is a function of unit size and how frequently you perform or receive from the fuel supplier the results of fuel sampling for molecular weight. The methods are specified in paragraphs (a)(3)(iii)(B)(1) and (a)(3)(iii)(B)(2) of this section, as applicable.

(*1*) If the results of fuel sampling are received monthly or more frequently, then for each unit with a maximum rated heat input capacity greater than or equal to 100 mmBtu/hr (or for a group of units that includes at least one unit of that size), the annual average molecular weight for Equation C–5 shall be calculated using Equation C–5b of this section. If multiple molecular weight determinations are made in any month, average the values for the month arithmetically.

$$(MW)_{annual} = \frac{\sum_{i=1}^{n} (MW)_i * (Fuel)_i \ / \ MVC}{\sum_{i=1}^{n} (Fuel)_i \ / \ MVC} \ (Eq. C\text{-}5b)$$

Where:

$(MW)_{annual}$ = Weighted annual average molecular weight of the fuel (kg per kg-mole).

$(MW)_i$ = Measured molecular weight of the fuel, for sample period ''i'' (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (kg per kg-mole).

$(Fuel)_i$ = Volume of the fuel (scf) combusted during the sample period ''i'' (*e.g.,* monthly, quarterly, semi-annually, or by lot) from company records.

MVC = Molar volume conversion factor at standard conditions, as defined in § 98.6. Use 849.5 scf per kg-mole if you select 68 °F as standard temperature and 836.6 scf per kg-mole if you select 60 °F as standard temperature.

n = Number of sample periods in the year.

(*2*) If the results of fuel sampling are received less frequently than monthly, or, for a unit with a maximum rated heat input capacity less than 100 mmBtu/hr (or a group of such units) regardless of the molecular weight sampling frequency, the annual average molecular weight for Equation C–5 shall either be computed according to paragraph (a)(3)(iii)(A)(*3*) of this section or as the arithmetic average molecular weight for all values for the year (including valid samples and substitute data values under § 98.35).

* * * * *

(b) * * *

(1) * * *

(vii) May be used for the combustion of MSW and/or tires in a unit, provided that no more than 10 percent of the unit's annual heat input is derived from those fuels, combined.

* * * * *

(c) * * *

(1) * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas compressor drivers at facilities subject to subpart W of this part, which must use the applicable CH_4 emission factor from Table W–9 to subpart W of this part.

* * * * *

(i) * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas compressor drivers at facilities subject to subpart W of this part, which must use the applicable CH_4 emission factor from Table W–9 to subpart W of this part.

* * * * *

(ii) * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas compressor drivers at facilities subject to subpart W of this part, which must use the applicable CH_4 emission factor from Table W–9 to subpart W of this part.

* * * * *

(2) * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas compressor drivers at facilities subject to subpart W of this part, which must use the applicable CH_4 emission factor from Table W–9 to subpart W of this part.

* * * * *

(3) * * *

EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas compressor drivers at facilities subject to subpart W of this part, which must use the applicable CH_4 emission factor from Table W–9 to subpart W of this part.

* * * * *

(4) * * *

EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas compressor drivers at facilities subject to subpart W of this part, which must use the applicable CH_4 emission factor from Table W–9 to subpart W of this part.

* * * * *

(6) * * *

(i) If the mass, volume, or heat input of each component fuel in the blend is determined before the fuels are mixed and combusted, calculate and report CH_4 and N_2O emissions separately for each component fuel, using the applicable procedures in this paragraph (c).

(ii) If the mass, volume, or heat input of each component fuel in the blend is not determined before the fuels are mixed and combusted, a reasonable estimate of the percentage composition of the blend, based on best available information, is required. Perform the following calculations for each component fuel ''i'' that is listed in Table C–2:

(A) Multiply (% Fuel)i, the estimated mass, volume, or heat input percentage of component fuel ''i'' (expressed as a decimal fraction), by the total annual mass, volume, or heat input of the blended fuel combusted during the reporting year, to obtain an estimate of the annual value for component ''i'';

* * * * *

(C) Calculate the annual CH_4 and N_2O emissions from component ''i'', using Equation C–8 (fuel mass or volume), C–8a (fuel heat input), C–8b (fuel heat input), C–9a (fuel mass or volume), or C–10 (fuel heat input) of this section, as applicable;

* * * * *

(d) * * *

(1) * * *

R = The number of moles of CO_2 released per mole of sorbent used (R = 1.00 when the sorbent is $CaCO_3$ and the targeted acid gas species is SO_2).

* * * * *

(e) *Biogenic CO_2 emissions from combustion of biomass with other fuels.* Use the applicable procedures of this paragraph (e) to estimate biogenic CO_2 emissions from units that combust a combination of biomass and fossil fuels (*i.e.,* either co-fired or blended fuels). Separate reporting of biogenic CO_2 emissions from the combined combustion of biomass and fossil fuels is required for those biomass fuels listed in Table C–1 of this section, MSW, and tires. In addition, when a biomass fuel that is not listed in Table C–1 is combusted in a unit that has a maximum rated heat input greater than 250 mmBtu/hr, if the biomass fuel accounts for 10% or more of the annual heat input to the unit, and if the unit does not use CEMS to quantify its annual CO_2 mass emissions, then, pursuant to § 98.33(b)(3)(iii), Tier 3 must be used to determine the carbon content of the biomass fuel and to calculate the biogenic CO_2 emissions from combustion of the fuel. Notwithstanding these requirements, in accordance with § 98.3(c)(12), separate reporting of biogenic CO_2 emissions is optional for the 2010 reporting year for units subject to subpart D of this part and for units that use the CO_2 mass emissions calculation methodologies in part 75 of this chapter, pursuant to paragraph (a)(5) of this section. However, if the owner or operator opts to report biogenic CO_2 emissions separately for these units, the appropriate method(s) in this paragraph (e) shall be used.

(1) You may use Equation C–1 of this subpart to calculate the annual CO_2 mass emissions from the combustion of the biomass fuels listed in Table C–1 of this subpart, in a unit of any size, including units equipped with a CO_2 CEMS, except when the use of Tier 2 is required as specified in paragraph (b)(1)(iv) of this section. Determine the quantity of biomass combusted using one of the following procedures in this paragraph (e)(1), as appropriate, and document the selected procedures in the Monitoring Plan under § 98.3(g):

* * * * *

(2) * * *

(v) Calculate the biogenic percentage of the annual CO_2 emissions expressed as a decimal fraction, using Equation C–14 of this section:

* * * * *

(3) You must use the procedures in paragraphs (e)(3)(i) through (iii) of this section to determine the annual biogenic CO_2 emissions from the

combustion of MSW, except as otherwise provided in paragraph (e)(3)(iv) of this section. These procedures also may be used for any unit that co-fires biomass and fossil fuels, including units equipped with a CO_2 CEMS.

* * * * *

(iv) In lieu of following the procedures in paragraphs (e)(3)(i) through (iii) of this section, the procedures of this paragraph may be used for the combustion of tires regardless of the percent of the annual heat input provided by tires. The calculation procedure in this paragraph may be used for the combustion of MSW if the combustion of MSW provides no more than 10 percent of the annual heat input to the unit or if a small, batch incinerator combusts no more than 1,000 tons per year of MSW.

(A) Calculate the total annual CO_2 emissions from combustion of MSW and/or tires in the unit, using the applicable methodology in paragraphs (a)(1) through (3) of this section for units using Tier 1, Tier 2, or Tier 3; otherwise use the Tier 1 calculation methodology in paragraph (a)(1) of this section for units using either the Tier 4 or Alternative Part 75 calculation methodologies to calculate total CO_2 emissions.

(B) Multiply the result from paragraph (e)(3)(iv)(A) of this section by the appropriate default factor to determine the annual biogenic CO_2 emissions, in metric tons. For MSW, use a default factor of 0.60 and for tires, use a default factor of 0.24.

* * * * *

■ 14. Amend § 98.34 by revising paragraphs (c)(6) and (d) to read as follows:

§ 98.34 Monitoring and QA/QC requirements.

* * * * *

(c) * * *

(6) For applications where CO_2 concentrations in process and/or combustion flue gasses are lower or higher than the typical CO_2 span value for coal-based fuels (*e.g.,* 20 percent CO_2 for a coal fired boiler), cylinder gas audits of the CO_2 monitor under appendix F to part 60 of this chapter may be performed at 40–60 percent and 80–100 percent of CO_2 span, in lieu of the prescribed calibration levels of 5–8 percent and 10–14 percent CO_2 by volume.

* * * * *

(d) Except as otherwise provided in § 98.33(e)(3)(iv), when municipal solid waste (MSW) is either the primary fuel combusted in a unit or the only fuel with a biogenic component combusted in the unit, determine the biogenic portion of the CO_2 emissions using ASTM D6866–16 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis) and ASTM D7459–08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources (both incorporated by reference, see § 98.7). Perform the ASTM D7459–08 sampling and the ASTM D6866–16 analysis at least once in every calendar quarter in which MSW is combusted in the unit. Collect each gas sample during normal unit operating conditions for at least 24 total (not necessarily consecutive) hours, or longer if the facility deems it necessary to obtain a representative sample. Notwithstanding this requirement, if the types of fuels combusted and their relative proportions are consistent throughout the year, the minimum required sampling time may be reduced to 8 hours if at least two 8-hour samples and one 24-hour sample are collected under normal operating conditions, and arithmetic average of the biogenic fraction of the flue gas from the 8-hour samples (expressed as a decimal) is within ±5 percent of the biogenic fraction from the 24-hour test. There must be no overlapping of the 8-hour and 24-hour test periods. Document the results of the demonstration in the unit's monitoring plan. If the types of fuels and their relative proportions are not consistent throughout the year, an optional sampling approach that facilities may wish to consider to obtain a more representative sample is to collect an integrated sample by extracting a small amount of flue gas (*e.g.,* 1 to 5 cc) in each unit operating hour during the quarter. Separate the total annual CO_2 emissions into the biogenic and non-biogenic fractions using the average proportion of biogenic emissions of all samples analyzed during the reporting year. Express the results as a decimal fraction (*e.g.,* 0.30, if 30 percent of the CO_2 is biogenic). When MSW is the primary fuel for multiple units at the facility, and the units are fed from a common fuel source, testing at only one of the units is sufficient.

* * * * *

■ 15. Amend § 98.36 by:

■ a. Revising paragraphs (c)(1) introductory text, (c)(1)(ii) and (vi), (c)(3) introductory text, and (c)(3)(vi);

■ b. Adding paragraph (c)(3)(xi); and

■ c. Revising paragraphs (e)(2)(ii)(C) and (e)(2)(xi).

The revisions and addition read as follows:

§ 98.36 Data reporting requirements.

* * * * *

(c) * * *

(1) *Aggregation of units.* If a facility contains two or more units (*e.g.,* boilers or combustion turbines), each of which has a maximum rated heat input capacity of 250 mmBtu/hr or less, you may report the combined GHG emissions for the group of units in lieu of reporting GHG emissions from the individual units, provided that the use of Tier 4 is not required or elected for any of the units and the units use the same tier for any common fuels combusted. Compressor drivers that calculate emissions using an applicable CH_4 emission factor from Table W–9 to subpart W of this part, must be reported as their own aggregation of units configuration, according to design class (*i.e.,* two-stroke lean-burn, four-stroke lean-burn, and four-stroke rich-burn). You may not have a combination of one design class of compressor driver (using one Table W–9 CH_4 emission factor) and other combustion units (*e.g.,* using a Table C–2 CH_4 emission factor or another Table W–9 CH_4 emission factor) in the same aggregation of units configuration. If this option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

* * * * *

(ii) For each unit in the group greater than or equal to 10 mmBtu/hr, the unit type, maximum rated heat input capacity, and an estimate of the total annual heat input (expressed as a decimal fraction). To determine the total annual heat input decimal fraction for a unit, divide the actual heat input for that unit (all fuels) by the sum of the actual heat input for all units (all fuels), including units less than 10 mmBtu/hr. Estimates of the actual heat inputs may be based on company records. If all units in this configuration are less than 10 (mmBtu/hr), this requirement does not apply.

* * * * *

(vi) Annual CO_2 mass emissions and annual CH_4, and N_2O mass emissions, aggregated for each type of fuel combusted in the group of units during the report year, expressed in metric tons of each gas and in metric tons of CO_2e. If any of the units burn biomass, report also the annual CO_2 emissions from combustion of all biomass fuels combined, expressed in metric tons.

* * * * *

(3) *Common pipe configurations.* When two or more stationary combustion units at a facility combust the same type of liquid or gaseous fuel and the fuel is fed to the individual units through a common supply line or pipe, you may report the combined emissions from the units served by the common supply line, in lieu of separately reporting the GHG emissions from the individual units, provided that the total amount of fuel combusted by the units is accurately measured at the common pipe or supply line using a fuel flow meter, or, for natural gas, the amount of fuel combusted may be obtained from gas billing records. For Tier 3 applications, the flow meter shall be calibrated in accordance with § 98.34(b). If a portion of the fuel measured (or obtained from gas billing records) at the main supply line is diverted to either: A flare; or another stationary fuel combustion unit (or units), including units that use a CO_2 mass emissions calculation method in part 75 of this chapter; or a chemical or industrial process (where it is used as a raw material but not combusted), and the remainder of the fuel is distributed to a group of combustion units for which you elect to use the common pipe reporting option, you may use company records to subtract out the diverted portion of the fuel from the fuel measured (or obtained from gas billing records) at the main supply line prior to performing the GHG emissions calculations for the group of units using the common pipe option. If the diverted portion of the fuel is combusted, the GHG emissions from the diverted portion shall be accounted for in accordance with the applicable provisions of this part. When the common pipe option is selected, the applicable tier shall be used based on the maximum rated heat input capacity of the largest unit served by the common pipe configuration, except where the applicable tier is based on criteria other than unit size. For example, if the maximum rated heat input capacity of the largest unit is greater than 250 mmBtu/hr, Tier 3 will apply, unless the fuel transported through the common pipe is natural gas or distillate oil, in which case Tier 2 may be used, in accordance with § 98.33(b)(2)(ii). As a second example, in accordance with § 98.33(b)(1)(v), Tier 1 may be used regardless of unit size when natural gas is transported through the common pipe, if the annual fuel consumption is obtained from gas billing records in units of therms or mmBtu. Compressor drivers that calculate emissions using an applicable CH_4 emission factor from Table W–9 to subpart W of this part, must be reported as their own common pipe configuration, according to design class (*i.e.,* two-stroke lean-burn, four-stroke lean-burn, and four-stroke rich-burn). You may not have a combination of one design class of compressor driver (using one Table W–9 CH_4 emission factor) and other combustion units (*e.g.,* using a Table C–2 CH_4 emission factor or another Table W–9 CH_4 emission factor) in the same common pipe configuration. When the common pipe reporting option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

* * * * *

(vi) If any of the units burns biomass, the annual CO_2 emissions from combustion of all biomass fuels from the units served by the common pipe, expressed in metric tons.

* * * * *

(xi) For each unit in the group greater than or equal to 10 mmBtu/hr, the unit type, maximum rated heat input capacity, and an estimate of the total annual heat input (expressed as a decimal fraction). To determine the total annual heat input decimal fraction for a unit, divide the actual heat input for that unit (all fuels) by the sum of the actual heat input for all units (all fuels), including units less than 10 mmBtu/hr. Estimated heat input values may be based on company records. If all units in this configuration are less than 10 (mmBtu/hr), this requirement does not apply.

* * * * *

(e) * * *

(2) * * *

(ii) * * *

(C) The annual average, and, where applicable, monthly high heat values used in the CO_2 emissions calculations for each type of fuel combusted during the reporting year, in mmBtu per short ton for solid fuels, mmBtu per gallon for liquid fuels, and mmBtu per scf for gaseous fuels. Report an HHV value for each calendar month in which HHV determination is required. If multiple values are obtained in a given month, report the arithmetic average value for the month.

* * * * *

(xi) When ASTM methods D7459–08 and D6866–16 (both incorporated by reference, see § 98.7) are used in accordance with § 98.34(e) to determine the biogenic portion of the annual CO_2 emissions from a unit that co-fires biogenic fuels (or partly-biogenic fuels, including tires) and non-biogenic fuels, you shall report the results of each quarterly sample analysis, expressed as a decimal fraction (*e.g.,* if the biogenic fraction of the CO_2 emissions is 30 percent, report 0.30).

* * * * *

■ 16. Amend § 98.37 by revising paragraphs (b) introductory text, (b)(9) through (11), (14), (18), (20), (22), and (23) to read as follows:

§ 98.37 Records that must be retained.

* * * * *

(b) For each stationary fuel combustion source that elects to use the verification software specified in § 98.5(b) rather than report data specified in paragraphs (b)(9)(iii), (c)(2)(ix), (e)(2)(i), (e)(2)(ii)(A), (e)(2)(ii)(C), (e)(2)(ii)(D), (e)(2)(iv)(A), (e)(2)(iv)(C), (e)(2)(iv)(F), and (e)(2)(ix)(D) through (F) of this section, you must keep a record of the file generated by the verification software for the applicable data specified in paragraphs (b)(1) through (37) of this section. Retention of this file satisfies the recordkeeping requirement for the data in paragraphs (b)(1) through (37) of this section.

* * * * *

(9) Measured high heat value of each solid fuel, for month (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (mmBtu per ton) (Equation C–2b of § 98.33). Annual average HHV of each solid fuel (mmBtu per ton) (Equation C–2a of § 98.33).

(10) Measured high heat value of each liquid fuel, for month (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (mmBtu per gallons) (Equation C–2b). Annual average HHV of each liquid fuel (mmBtu per gallons) (Equation C–2a of § 98.33).

(11) Measured high heat value of each gaseous fuel, for month (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (mmBtu per scf) (Equation C–2b). Annual average HHV of each gaseous fuel (mmBtu per scf) (Equation C–2a of § 98.33).

* * * * *

(14) Volume of each gaseous fuel combusted during month (scf) (Equation C–2b, Equation C–5a, Equation C–5b).

* * * * *

(18) Annual average carbon content of each solid fuel (percent by weight, expressed as a decimal fraction) (Equation C–3). Where applicable, monthly carbon content of each solid fuel (which may be the arithmetic

average of multiple determinations), or, if applicable, an appropriate substitute data value (percent by weight, expressed as a decimal fraction) (Equation C–2b—see the definition of ''CC'' in Equation C–3).

* * * * *

(20) Annual average carbon content of each liquid fuel (kg C per gallon of fuel) (Equation C–4). Where applicable, monthly carbon content of each liquid fuel (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (kg C per gallon of fuel) (Equation C–2b—see the definition of ''CC'' in Equation C–3).

* * * * *

(22) Annual average carbon content of each gaseous fuel (kg C per kg of fuel) (Equation C–5). Where applicable, monthly carbon content of each gaseous fuel (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (kg C per kg of fuel) (Equation C–5a).

(23) Annual average molecular weight of each gaseous fuel (kg/kg-mole) (Equation C–5). Where applicable, monthly molecular weight of each gaseous (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (kg/kg-mole) (Equation C–5b).

* * * * *

■ 17. Amend table C–2 to subpart C of part 98 by revising the entry ''Natural Gas'' to read as follows:

TABLE C–2 TO SUBPART C OF PART 98—DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
* * *	* *	* *
Natural Gas [1]	1.0×10^{-03}	1.0×10^{-04}
* * *	* *	* *

* * * * *

Subpart G—Ammonia Manufacturing

■ 18. Amend § 98.72 by revising paragraph (a) to read as follows:

§ 98.72 GHGs to report.

* * * * *

(a) CO_2 process emissions from steam reforming of a hydrocarbon or the gasification of solid and liquid raw material, reported for each ammonia manufacturing unit following the requirements of this subpart.

* * * * *

■ 19. Amend § 98.73 by revising the introductory text and paragraph (b) to read as follows:

§ 98.73 Calculating GHG emissions

You must calculate and report the annual net CO_2 process emissions from each ammonia manufacturing unit using the procedures in either paragraph (a) or (b) of this section.

* * * * *

(b) Calculate and report under this subpart process CO_2 emissions using the procedures in paragraphs (b)(1) through (4) of this section, as applicable.

(1) *Gaseous feedstock.* You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from gaseous feedstock according to Equation G–1 of this section:

$$CO_{2,G} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_n * CC_n * \frac{MW}{MVC}\right) * 0.001 \qquad \text{(Eq.G-1)}$$

Where:

$CO_{2,G}$ = Annual CO_2 emissions arising from gaseous feedstock consumption (metric tons).

$Fdstk_n$ = Volume of the gaseous feedstock used in month n (scf of feedstock).

CC_n = Carbon content of the gaseous feedstock, for month n (kg C per kg of feedstock), determined according to 98.74(c).

MW = Molecular weight of the gaseous feedstock (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

n = Number of month.

(2) *Liquid feedstock.* You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from liquid feedstock according to Equation G–2 of this section:

$$CO_{2,L} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_n * CC_n\right) * 0.001 \qquad \text{(Eq.G-2)}$$

Where:

$CO_{2,L}$ = Annual CO_2 emissions arising from liquid feedstock consumption (metric tons).

$Fdstk_n$ = Volume of the liquid feedstock used in month n (gallons of feedstock).

[1] Reporters subject to subpart W of this part may only use the default CH_4 emission factor for natural gas-fired combustion units that are not compressor drivers. For natural gas-fired compressor drivers at facilities subject to subpart W of this part, reporters must use the applicable CH_4 emission factor from Table W–9 to subpart W of this part.

CC_n = Carbon content of the liquid feedstock, for month n (kg C per gallon of feedstock) determined according to 98.74(c).
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.
n = Number of month.

(3) *Solid feedstock.* You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from solid feedstock according to Equation G–3 of this section:

$$CO_{2,S} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_n * CC_n\right) * 0.001 \qquad \text{(Eq.G-3)}$$

Where:

$CO_{2,S}$ = Annual CO_2 emissions arising from solid feedstock consumption (metric tons).
$Fdstk_n$ = Mass of the solid feedstock used in month n (kg of feedstock).
CC_n = Carbon content of the solid feedstock, for month n (kg C per kg of feedstock), determined according to 98.74(c).
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.
n = Number of month.

(4) *Net CO_2 process emissions.* You must calculate the annual net CO_2 process emissions at each ammonia manufacturing unit according to Equation G–4 of this section:

$$CO_{2,net} = \sum_{p=1}^{3} CO_{2,p} - \sum_{n=1}^{12} CO_{2,urea,n} - \frac{44}{32} \sum_{n=1}^{12} MeOH_n \qquad \text{(Eq.G-4)}$$

Where:

$CO_{2,net}$ = Annual net CO_2 process emissions from each ammonia manufacturing unit (metric tons).
$CO_{2,p}$ = Annual CO_2 process emissions arising from feedstock consumption based on feedstock type ''p'' (metric tons/yr) as calculated in paragraphs (b)(1) through (3) of this section.
P = Index for feedstock type; 1 indicates gaseous feedstock; 2 indicates liquid feedstock; and 3 indicates solid feedstock.
$CO_{2,urea,n}$ = Amount of carbon dioxide collected from ammonia production and consumed on site for urea production, in month n (metric tons).
$MeOH_n$ = Mass of methanol intentionally produced as a desired product for month n (metric tons).
44/32 = Ratio of molecular weights, CO_2 to methanol.

* * * * *

■ 20. Amend § 98.76 by revising the introductory text and paragraphs (b)(1) and (13) to read as follows:

§ 98.76 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as applicable for each ammonia manufacturing unit.

* * * * *

(b) * * *

(1) Annual net CO_2 process emissions (metric tons) for each ammonia manufacturing unit.

* * * * *

(13) Annual amount of CO_2 collected from ammonia production (metric tons) and consumed on site for urea production and the method used to determine the CO_2 consumed in urea production.

* * * * *

■ 21. Amend § 98.77 by revising paragraph (c) introductory text and adding paragraphs (c)(8) and (9) to read as follows:

§ 98.77 Records that must be retained.

* * * * *

(c) You must keep a record of the file generated by the verification software specified in § 98.5(b) for the applicable data specified in paragraphs (c)(1) through (9) of this section. Retention of this file satisfies the recordkeeping requirement for the data in paragraphs (c)(1) through (9) of this section.

* * * * *

(8) Quantity of CO_2 collected from ammonia production and consumed on site for urea production in month (Equation G–4 of § 98.73).

(9) Quantity of methanol intentionally produced as a desired product in month (metric tons) (Equation G–4).

Subpart H—Cement Production

■ 22. Amend § 98.83 by:
■ a. Revising paragraph (d)(1);
■ b. Revising parameters ''CKD_{CaO},'' ''CKD_{CaO},'' ''CKD_{MgO},'' and ''CKD_{MgO}'' of Equation H–4 in paragraph (d)(2)(ii)(A); and
■ c. Revising paragraph (d)(3).

The revisions read as follows:

§ 98.83 Calculating GHG emissions.

* * * * *

(d) * * *

(1) Calculate CO_2 process emissions from all kilns at the facility using Equation H–1 of this section:

$$CO_{2\,CMF} = \sum_{m=1}^{k}\left[CO_{2\,Cli,m} + CO_{2\,rm,m}\right] \qquad \text{(Eq.H-1)}$$

Where:

$CO_{2\,CMF}$ = Annual process emissions of CO_2 from cement manufacturing, metric tons.
$CO_{2\,Cli,m}$ = Total annual emissions of CO_2 from clinker production from kiln m, metric tons.
$CO_{2\,rm,m}$ = Total annual emissions of CO_2 from raw materials from kiln m, metric tons.
K = Total number of kilns at a cement manufacturing facility.

(2) * * *
(ii) * * *
(A) * * *

CKD_{CaO} = Quarterly total CaO content of CKD not recycled to the kiln, wt-fraction.
CKD_{ncCaO} = Quarterly non-calcined CaO content of CKD not recycled to the kiln, wt-fraction.

* * * * *

CKD_{MgO} = Quarterly total MgO content of CKD not recycled to the kiln, wt-fraction.
CKD_{ncMgO} = Quarterly non-calcined MgO content of CKD not recycled to the kiln, wt-fraction.

* * * * *

(3) *CO_2 emissions from raw materials from each kiln.* Calculate CO_2 emissions from raw materials using Equation H–5 of this section:

$$CO_{2\,rm,m} = \sum_{i=1}^{M}\left[rm * TOC_{rm} * \frac{44}{12} * \frac{2000}{2205}\right] \quad \text{(Eq.H-5)}$$

Where:

rm = The amount of raw material i consumed annually from kiln m, tons/yr (dry basis) or the amount of raw kiln feed consumed annually from kiln m, tons/yr (dry basis).

$CO_{2,rm,m}$ = Annual CO2 emissions from raw materials from kiln m.

TOC_{rm} = Organic carbon content of raw material i from kiln m or organic carbon content of combined raw kiln feed (dry basis) from kiln m, as determined in § 98.84(c) or using a default factor of 0.2 percent of total raw material weight.

M = Number of raw materials or 1 if calculating emissions based on combined raw kiln feed.

44/12 = Ratio of molecular weights, CO2 to carbon.

2000/2205 = Conversion factor to convert tons to metric tons.

* * * * *

■ 23. Amend § 98.86 by adding paragraphs (a)(4) through (13) and (b)(19) through (28) to read as follows:

§ 98.86 Data reporting requirements.

* * * * *

(a) * * *

(4) Annual arithmetic average of total CaO content of clinker at the facility, wt-fraction.

(5) Annual arithmetic average of non-calcined CaO content of clinker at the facility, wt-fraction.

(6) Annual arithmetic average of total MgO content of clinker at the facility, wt-fraction.

(7) Annual arithmetic average of non-calcined MgO content of clinker at the facility, wt-fraction.

(8) Annual arithmetic average of total CaO content of CKD not recycled to the kiln(s) at the facility, wt-fraction.

(9) Annual arithmetic average of non-calcined CaO content of CKD not recycled to the kiln(s) at the facility, wt-fraction.

(10) Annual arithmetic average of total MgO content of CKD not recycled to the kiln(s) at the facility, wt-fraction.

(11) Annual arithmetic average of non-calcined MgO content not recycled to the kiln(s) at the facility, wt-fraction.

(12) Annual facility CKD not recycled to the kiln(s), tons.

(13) The amount of raw kiln feed consumed annually at the facility, tons (dry basis).

(b) * * *

(19) Annual arithmetic average of total CaO content of clinker at the facility, wt-fraction.

(20) Annual arithmetic average of non-calcined CaO content of clinker at the facility, wt-fraction.

(21) Annual arithmetic average of total MgO content of clinker at the facility, wt-fraction.

(22) Annual arithmetic average of non-calcined MgO content of clinker at the facility, wt-fraction.

(23) Annual arithmetic average of total CaO content of CKD not recycled to the kiln(s) at the facility, wt-fraction.

(24) Annual arithmetic average of non-calcined CaO content of CKD not recycled to the kiln(s) at the facility, wt-fraction.

(25) Annual arithmetic average of total MgO content of CKD not recycled to the kiln(s) at the facility, wt-fraction.

(26) Annual arithmetic average of non-calcined MgO content of CKD not recycled to the kiln(s) at the facility, wt-fraction.

(27) Annual facility CKD not recycled to the kiln(s), tons.

(28) The amount of raw kiln feed consumed annually at the facility, tons (dry basis).

Subpart I—Electronics Manufacturing

■ 24. Amend § 98.91 by revising paragraphs (a) introductory text and (a)(1) through (3), and parameters ‘‘E_i’’ and ‘‘i’’ of Equation I–4 in paragraph (a)(4) to read as follows:

§ 98.91 Reporting threshold.

(a) You must report GHG emissions under this subpart if electronics manufacturing production processes, as defined in § 98.90, are performed at your facility and your facility meets the requirements of either § 98.2(a)(1) or (a)(2). To calculate total annual GHG emissions for comparison to the 25,000 metric ton CO_2e per year emission threshold in § 98.2(a)(2), follow the requirements of § 98.2(b), with one exception. Rather than using the calculation methodologies in § 98.93 to calculate emissions from electronics manufacturing production processes, calculate emissions of each fluorinated GHG from electronics manufacturing production processes by using paragraph (a)(1), (2), or (3) of this section, as appropriate, and then sum the emissions of each fluorinated GHG and account for fluorinated heat transfer fluid emissions by using paragraph (a)(4) of this section.

(1) If you manufacture semiconductors or MEMS you must calculate annual production process emissions resulting from the use of each input gas for threshold applicability purposes using either the default emission factors shown in Table I–1 to this subpart and Equation I–1A of this subpart, or the consumption of each input gas, the default emission factors shown in Table I–2 to this subpart, and Equation I–1B of this subpart.

$$E_i = S * EF_i * GWP_i * 0.001 \quad \text{(Eq. I-1A)}$$

Where:

E_i = Annual production process emissions of gas i for threshold applicability purposes (metric tons CO_2e).

S = 100 percent of annual manufacturing capacity of a facility as calculated using Equation I–5 of this subpart (m^2).

EF_i = Emission factor for gas i (kg/m^2) shown in Table I–1 to this subpart.

GWP_i = Gas-appropriate GWP as provided in Table A–1 to subpart A of this part.

0.001 = Conversion factor from kg to metric tons.

i = Emitted gas.

$$E_i = C_i * (GWP_i * (1 - U_i) + GWP_{CF4} * BCF_4 + GWP_{C2F6} * BC_2F_6) * 0.001 \quad \text{(Eq. I-1B)}$$

E_i = Annual production process emissions resulting from the use of input gas i for threshold applicability purposes (metric tons CO_2e).

C_i = Annual GHG (input gas i) purchases or consumption (kg). Only gases that are used in semiconductor or MEMS manufacturing processes listed at § 98.90(a)(1) through (a)(4) must be considered for threshold applicability purposes.

$(1-U_i)$, BCF_4, and BC_2F_6 = Default emission factors for the gas consumption-based threshold applicability determination listed in Table I–2 to this subpart.

GWP_i = Gas-appropriate GWP as provided in Table A–1 to subpart A of this part.

0.001 = Conversion factor from kg to metric tons.

i = Input gas.

(2) If you manufacture LCDs, you must calculate annual production process emissions resulting from the use of each input gas for threshold applicability purposes using either the default emission factors shown in Table I–1 to this subpart and Equation I–2 of this subpart or the consumption of each input gas, the default emission factors shown in Table I–2 to this subpart, and Equation I–1B of this subpart.

$$E_i = S * EF_i * GWP_i * 0.000001 \quad \text{(Eq. I-2A)}$$

Where:

E_i = Annual production process emissions of gas i for threshold applicability purposes (metric tons CO_2e).

S = 100 percent of annual manufacturing capacity of a facility as calculated using Equation I–5 of this subpart (m^2).

EF_i = Emission factor for gas i (g/m^2).

GWP_i = Gas-appropriate GWP as provided in Table A–1 to subpart A of this part.

0.000001 = Conversion factor from g to metric tons.

i = Emitted gas.

$$E_i = C_i * (GWP_i * (1 - U_i) + GWP_{CF4} * BCF_4 + GWP_{C2F6} * BC_2F_6) * 0.001 \quad \text{(Eq. I-2B)}$$

Where:

E_i = Annual production process emissions resulting from the use of input gas i for threshold applicability purposes (metric tons CO_2e).

C_i = Annual GHG (input gas i) purchases or consumption (kg). Only gases that are used in LCD manufacturing processes listed at § 98.90(a)(1) through (a)(4) must be considered for threshold applicability purposes.

$(1-U_i)$, BCF_4, and BC_2F_6 = Default emission factors for the gas consumption-based threshold applicability determination listed in Table I–2 to this subpart.

GWP_i = Gas-appropriate GWP as provided in Table A–1 to subpart A of this part.

0.001 = Conversion factor from kg to metric tons.

i = Input gas.

(3) If you manufacture PVs, you must calculate annual production process emissions resulting from the use of each input gas i for threshold applicability purposes using gas-appropriate GWP values shown in Table A–1 to subpart A of this part, the default emission factors shown in Table I–2 to this subpart, and Equation I–3 of this subpart.

$$E_i = C_i * (GWP_i * (1 - U_i) + GWP_{CF4} * BCF_4 + GWP_{C2F6} * BC_2F_6) * 0.001 \quad \text{(Eq. I-3)}$$

Where:

E_i = Annual production process emissions resulting from the use of input gas i for threshold applicability purposes (metric tons CO_2e).

C_i = Annual fluorinated GHG (input gas i) purchases or consumption (kg). Only gases that are used in PV manufacturing processes listed at § 98.90(a)(1) through (a)(4) must be considered for threshold applicability purposes.

$(1-U_i)$, BCF_4, and BC_2F_6 = Default emission factors for the gas consumption-based threshold applicability determination listed in Table I–2 to this subpart.

GWP_i = Gas-appropriate GWP as provided in Table A–1 to subpart A of this part.

0.001 = Conversion factor from kg to metric tons.

i = Input gas.

(4) * * *

E_i = Annual production process emissions of gas i for threshold applicability purposes (metric tons CO_2e), as calculated in Equations I–1a, I–1b, I–2a, I–2b, or I–3 of this subpart.

i = Emitted gas.

* * * * *

■ 25. Amend § 98.92 by revising paragraph (a) to read as follows:

§ 98.92 GHGs to report.

(a) You must report emissions of fluorinated GHGs (as defined in § 98.6), N_2O, and fluorinated heat transfer fluids (as defined in § 98.98). The fluorinated GHGs and fluorinated heat transfer fluids that are emitted from electronics manufacturing production processes include, but are not limited to, those listed in Table I–21 to this subpart. You must individually report, as appropriate:

* * * * *

■ 26. Amend § 98.93 by:

■ a. Revising paragraph (a)(1) introductory text;

■ b. Revising parameters ‘‘E_{ij}’’ and ‘‘N’’ of Equation I–6 in paragraph (a)(1) introductory text;

■ c. Revising Equation I–7 in paragraph (a)(1) introductory text;

■ d. Revising parameters ‘‘BE_{ijk}’’ and ‘‘N’’ of Equation I–7 in paragraph (a)(1) introductory text;

■ e. Revising paragraphs (a)(1)(i) and (ii) and (a)(2) and (6);

■ f. Adding paragraph (a)(7);

■ g. Revising the introductory text of paragraphs (e) and (i);

■ h. Removing and reserving paragraphs (i)(1) and (2);

■ i. Revising paragraph (i)(3) introductory text and (i)(3)(i), (iii) through (vi), and (viii)).

■ j. Adding paragraph (i)(3)(ix);

■ k. Revising paragraph (i)(4); and

■ l. Removing paragraph (i)(5).

The revisions and additions read as follows:

§ 98.93 Calculating GHG emissions.

(a) * * *

(1) If you manufacture semiconductors, you must adhere to the procedures in paragraphs (a)(1)(i) through (iii) of this section. You must calculate annual emissions of each input gas and of each by-product gas using Equations I–6, I–7, and I–9 of this subpart. If your fab uses less than 50 kg of a fluorinated GHG in one reporting year, you may calculate emissions as equal to your fab's annual consumption for that specific gas as calculated in Equation I–11 of this subpart, plus any by-product emissions of that gas calculated under paragraph (a) of this section.

* * * * *

E_{ij} = Annual emissions of input gas i from process sub-type or process type j as calculated in Equation I–8A of this subpart (metric tons).

N = The total number of process sub-types j that depends on the electronics manufacturing fab and emission calculation methodology. If E_{ij} is calculated for a process type j in Equation I–8A of this subpart, N = 1.

* * * * *

$$ProcesstypeBE_k = \sum_{j=1}^{N} \sum_i BE_{kij} \quad \text{(Eq. I-7)}$$

* * * * *

BE_{kij} = Annual emissions of by-product gas k formed from input gas i used for process sub-type or process type j as calculated in Equation I–8B of this subpart (metric tons).

N = The total number of process sub-types j that depends on the electronics manufacturing fab and emission calculation methodology. If BE_{kij} is calculated for a process type j in Equation I–8B of this subpart, N = 1.

* * * * *

(i) You must calculate annual fab-level emissions of each fluorinated GHG used for the plasma etching/wafer cleaning process type using default utilization and by-product formation rates as shown in Table I–3 or I–4 of this subpart, and by using Equations I–8A and I–8B of this subpart.

$$E_{ij} = C_{ij}\left(1 - U_{ij}\right) * \left(1 - \left(a_{ij} * d_{ij} * UT_{ij}\right)\right) * 0.001 \quad \text{(Eq. I-8A)}$$

Where:

E_{ij} = Annual emissions of input gas i from process sub-type or process type j, on a fab basis (metric tons).

C_{ij} = Amount of input gas i consumed for process sub-type or process type j, as calculated in Equation I–13 of this subpart, on a fab basis (kg).

U_{ij} = Process utilization rate for input gas i for process sub-type or process type j (expressed as a decimal fraction).

A_{ij} = Fraction of input gas i used in process sub-type or process type j with abatement systems, on a fab basis (expressed as a decimal fraction).

D_{ij} = Fraction of input gas i destroyed or removed when fed into abatement systems by process tools where process sub-type, or process type j is used, on a fab basis, calculated by taking the tool weighted average of the claimed DREs for input gas on i on tools that use process type or process sub-type j (expressed as a decimal fraction). This is zero unless the facility adheres to the requirements in § 98.94(f).

UT_{ij} = The average uptime factor of all abatement systems connected to process tools in the fab using input gas i in process sub-type or process type j, as calculated in Equation I–15 of this subpart, on a fab basis (expressed as a decimal fraction).

0.001 = Conversion factor from kg to metric tons.

i = Input gas.

j = Process sub-type or process type.

$$BE_{kij} = B_{ijk} * C_{ij} * \left(1 - \left(a_{kij} * d_{kij} * UT_{kij}\right)\right) * 0.001 \quad \text{(Eq. I-8B)}$$

Where:

BE_{kij} = Annual emissions of by-product gas k formed from input gas I from process sub-type or process type j, on a fab basis (metric tons).

B_{ijk} = By-product formation rate of gas k created as a by-product per amount of input gas i (kg) consumed by process sub-type or process type j (kg). For non-carbon containing input gases used in chamber cleaning process sub-types, this is zero when the combination of input gas and chamber cleaning process sub-type is never used to clean chamber walls on equipment that process carbon-containing films during the year (*e.g.,* when NF_3 is used in remote plasma cleaning processes to only clean chambers that never process carbon-containing films during the year).

C_{ij} = Amount of input gas i consumed for process sub-type, or process type j, as calculated in Equation I–13 of this subpart, on a fab basis (kg).

a_{kij} = Fraction of input gas I used for process sub-type, or process type j with abatement systems, on a fab basis (expressed as a decimal fraction).

D_{kij} = Fraction of by-product gas k destroyed or removed in when fed into abatement systems by process tools where process sub-type or process type j is used, on a fab basis, calculated by taking the tool weighted average of the claimed DREs for by-product gas k on tools that use input gas i in process type or process sub-type j (expressed as a decimal fraction). This is zero unless the facility adheres to the requirements in § 98.94(f).

UT_{kij} = The average uptime factor of all abatement systems connected to process tools in the fab emitting by-product gas k, formed from input gas I in process sub-type or process type j, on a fab basis (expressed as a decimal fraction). For this equation, UT_{kij} is assumed to be equal to UT_{ij} as calculated in Equation I–15 of this subpart.

0.001 = Conversion factor from kg to metric tons.

i = Input gas.

j = Process sub-type or process type.

k = By-product gas.

(ii) You must calculate annual fab-level emissions of each fluorinated GHG used for each of the process sub-types associated with the chamber cleaning process type, including in-situ plasma chamber clean, remote plasma chamber clean, and in-situ thermal chamber clean, using default utilization and by-product formation rates as shown in Table I–3 or I–4 of this subpart, and by using Equations I–8A and I–8B of this subpart.

* * * * *

(2) If you manufacture MEMS or PVs and use semiconductor tools and processes, you may use § 98.3(a)(1) to calculate annual fab-level emissions for those processes. For all other tools and processes used to manufacture MEMs, LCD and PV, you must calculate annual fab-level emissions of each fluorinated GHG used for the plasma etching and chamber cleaning process types using default utilization and by-product formation rates as shown in Table I–5, I–6, or I–7 of this subpart, as appropriate, and by using Equations I–8A and I–8B of this subpart. If default values are not available for a particular input gas and process type or sub-type combination in Tables I–5, I–6, or I–7, you must follow the procedures in paragraph (a)(6) of this section. If your fab uses less than 50 kg of a fluorinated GHG in one reporting year, you may calculate emissions as equal to your fab's annual consumption for that specific gas as calculated in Equation I–11 of this subpart, plus any by-product emissions of that gas calculated under this paragraph (a).

* * * * *

(6) If you are required, or elect, to perform calculations using default emission factors for gas utilization and by-product formation rates according to the procedures in paragraph (a)(1) or (a)(2) of this section, and default values are not available for a particular input gas and process type or sub-type combination in Tables I–3, I–4, I–5, I–6, or I–7, you must use a utilization rate (U_{ij}) of 0.2 (*i.e.,* a 1–U_{ij} of 0.8) and by-product formation rates of 0.15 for CF_4 and 0.05 for C_2F_6 and use Equations I–8A and I–8B of this subpart.

(7) If your fab employs hydrocarbon-fuel-based emissions control systems (including, but not limited to, abatement systems as defined at § 98.98) to control emissions from tools that use either NF_3 in remote plasma cleaning processes or F_2 as an input gas in any process type or sub-type, you must calculate the amount CF_4 produced within and emitted from such systems using Equation I–9 using default utilization and by-product formation rates as shown in Table I–3 or I–4 of this subpart. A hydrocarbon-fuel-based emissions control system is assumed not to form CF_4 from F_2 if the electronics manufacturer can certify that the rate of conversion from F_2 to CF_4 is <0.1% for that hydrocarbon-fuel-based emissions control system.

$$EAB_{CF_4} = \sum_j C_{F_2,j} \bullet \left(1 - U_{F_2,j}\right) \bullet a_{F_2,j} \bullet UT_{F_2,j} \bullet AB_{CF_4,F_2} + C_{NF_3,RPC} \cdot B_{F_2,NF_3} \cdot a_{NF_3,RPC} \cdot UT_{NF_3,RPC,F2} \cdot AB_{CF_4,F_2} \quad \text{(Eq. I-9)}$$

Where:

EAB_{CF4} = Emissions of CF_4 from hydrocarbon-fuel-based emissions control systems when direct reaction between hydrocarbon fuel and F_2 is not certified not to occur by the emissions control system manufacturer or electronics manufacturer, kg.

$C_{F2,j}$ = Amount of F_2 consumed for process type or sub-type j, as calculated in Equation I–13 of this subpart, on a fab basis (kg).

$U_{F2,j}$ = Process utilization rate for F_2 for process type or sub-type j (expressed as a decimal fraction).

$A_{F2,j}$ = Within process sub-type or process type j, fraction of F_2 used in process tools with hydrocarbon-fuel-based abatement systems that are not certified not to form CF_4, on a fab basis, where the numerator is the number of tools that are equipped with hydrocarbon-fuel-based emissions control systems that are not certified not to form CF_4 that use F_2 in process type j and the denominator is the total number of tools in the fab that use F_2 in process type j (expressed as a decimal fraction).

$UT_{F2,j}$ = The average uptime factor of all abatement systems connected to process tools in the fab using F2 in process sub-type or process type j (expressed as a decimal fraction).

$AB_{CF4,F2}$ = Mass fraction of F_2 in process exhaust gas that is converted into CF_4 by direct reaction with hydrocarbon fuel in a combustion abatement system. The default value of $AB_{CF4,F2}$=0.116.

$C_{NF3,RPC}$ = Amount of NF_3 consumed in remote plasma cleaning processes, as calculated in Equation I–13 of this subpart, on a fab basis (kg).

$B_{F2,NF3}$ = By-product formation rate of F_2 created as a by-product per amount of NF_3 (kg) consumed in remote plasma cleaning processes (kg).

$a_{NF3,RPC}$ = Within remote plasma cleaning processes, fraction of NF_3 used in process tools with hydrocarbon-fuel-based abatement systems that are not certified not to form CF_4, where the numerator is the number of tools running remote plasma cleaning processes that are equipped with hydrocarbon-fuel-based emissions control systems that are not certified not to form CF_4 that use NF_3 and the denominator is the total number of tools that run remote plasma clean processes in the fab that use NF_3 (expressed as decimal fraction).

$UT_{NF3,RPC,F2}$ = The average uptime factor of all abatement systems connected to process tools in the fab emitting by-product gas F_2, formed from input gas NF_3 in remote plasma cleaning processes, on a fab basis (expressed as a decimal fraction). For this equation, $UT_{NF3,RPC,F2}$ is assumed to be equal to $UT_{NF3,RPC}$ as calculated in Equation I–15 of this subpart.

j = Process type or sub-type.

* * * * *

(e) You must calculate the amount of input gas i consumed, on a fab basis, for each process sub-type or process type j, using Equation I–13 of this subpart. Where a gas supply system serves more than one fab, Equation I–13 is applied to that gas which has been apportioned to each fab served by that system using the apportioning factors determined in accordance with § 98.94(c). If you elect to calculate emissions using the stack test method in paragraph (i) of this section and to use this paragraph to calculate the fraction each fluorinated input gas i exhausted from tools with abatement systems and the fraction of each by-product gas k exhausted from tools with abatement systems, you may substitute ''The set of tools with abatement systems'' for ''Process sub-type or process type'' in the definition of ''j'' in Equation I–13 of this subpart.

* * * * *

(i) *Stack Test Method.* As an alternative to the default emission factor method in paragraph (a) of this section, you may calculate fab-level fluorinated GHG emissions using fab-specific emission factors developed from stack testing. In this case, you must comply with the stack test method specified in paragraph (i)(3) of this section.

(1)–(2) [Reserved]

(3) *Stack system stack test method.* For each stack system in the fab, measure the emissions of each fluorinated GHG from the stack system by conducting an emission test. In addition, measure the fab-specific consumption of each fluorinated GHG by the tools that are vented to the stack systems tested. Measure emissions and consumption of each fluorinated GHG as specified in § 98.94(j). Develop fab-specific emission factors and calculate fab-level fluorinated GHG emissions using the procedures specified in paragraph (i)(3)(i) through (viii) of this section. All emissions test data and procedures used in developing emission factors must be documented and recorded according to § 98.97.

(i) You must measure the fab-specific fluorinated GHG consumption of the tools that are vented to the stack systems during the emission test as specified in § 98.94(j)(3). Calculate the consumption for each fluorinated GHG for the test period.

* * * * *

(iii) You must calculate a fab-specific emission factor for each fluorinated GHG input gas consumed (in kg of fluorinated GHG emitted per kg of input gas i consumed) in the tools that vent to stack systems, as applicable, using Equations I–19A and I–19B or I–19A and I–19c of this subpart. Use Equation I–19A to calculate the controlled emissions for each fluorinated GHG that would result during the sampling period if the utilization rate for the input gas were equal to 0.2 ($E_{imax,f}$). If $\mathbf{\Sigma}_s E_{i,s}$ (the total measured emissions of the fluorinated GHG across all stack systems, calculated based on the results of Equation I–17) is less than or equal to $E_{imax,f}$ calculated in I–19A, use Equation I–19B to calculate the emission factor for that fluorinated GHG. If $\mathbf{\Sigma}_s E_{i,s}$ is larger than the $E_{imax,f}$ calculated in I–19A, use Equation I–19C to calculate the emission factor and treat the difference between the total measured emissions $\mathbf{\Sigma}_s E_{i,s}$ and the maximum expected controlled emissions $E_{imax,f}$ as a by-product of the other input gases, using Equation I–20 of this subpart.

$$E_{imax,f} = 0.8 \bullet Activity_{if} \bullet \left(1 - UT_f \bullet a_{if} \bullet d_{if}\right) \qquad \text{(Eq. I-19A)}$$

Where:

$E_{imax,f}$ = Maximum expected controlled emissions of gas i from its use an input gas during the stack testing period, from fab f (max kg emitted).

$Activity_{if}$ = Consumption of fluorinated GHG input gas i, for fab f, in the tools vented to the stack systems being tested, during the sampling period, as determined following the procedures specified in § 98.94(j)(3) (kg consumed).

UT_f = The total uptime of all abatement systems for fab f, during the sampling period, as calculated in Equation I–23 of this subpart (expressed as decimal fraction). If the stack system does not have abatement systems on the tools vented to the stack system, the value of this parameter is zero.

a_{if} = Fraction of input gas i emitted from tools with abatement systems in fab f (expressed as a decimal fraction), as calculated in Equation I–24C.

d_{if} = Fraction of fluorinated GHG input gas i destroyed or removed when fed into abatement systems by process tools in fab f, as calculated in Equation I–24A of this subpart (expressed as decimal fraction).

f = Fab.

i = Fluorinated GHG input gas.

$$EF_{if} = \frac{\sum_s (E_{is})}{Activity_{if} * \left(UT_f + \left(\frac{1 - UT_f}{1 - \left(a_{if} \bullet d_{if}\right)} \right) \right)} \qquad \text{(Eq. I-19B)}$$

Where:

EF_{if} = Emission factor for fluorinated GHG input gas i, from fab f, representing 100 percent abatement system uptime (kg emitted/kg input gas consumed).

E_{is} = Mass emission of fluorinated GHG input gas i from stack system s during the sampling period (kg emitted).

$Activity_{if}$ = Consumption of fluorinated GHG input gas i, for fab f during the sampling period, as determined following the procedures specified in § 98.94(j)(3) (kg consumed).

UT_f = The total uptime of all abatement systems for fab f, during the sampling period, as calculated in Equation I–23 of this subpart (expressed as decimal fraction). If the stack system does not have abatement systems on the tools vented to the stack system, the value of this parameter is zero.

a_{if} = Fraction of fluorinated GHG input gas i exhausted from tools with abatement systems in fab f (expressed as a decimal fraction), as calculated in Equation I–24C.

d_{if} = Fraction of fluorinated GHG input gas i destroyed or removed when fed into abatement systems by process tools in fab f, as calculated in Equation I–24A of this subpart (expressed as decimal fraction). If the stack system does not have abatement systems on the tools vented to the stack system, the value of this parameter is zero.

f = Fab.

i = Fluorinated GHG input gas.

s = Stack system.

$$EF_{if} = 0.8 \bullet \left(1 - a_{if} \bullet d_{if}\right) \qquad \text{(Eq. I-19C)}$$

EF_{if} = Emission factor for input gas i, from fab f, representing a 20-percent utilization rate and a 100-percent abatement system uptime (kg emitted/kg input gas consumed).

a_{if} = Fraction of input gas i emitted from tools with abatement systems in fab f (expressed as a decimal fraction), as calculated in Equation I–24C.

d_{if} = Fraction of fluorinated GHG input gas i destroyed or removed when fed into abatement systems by process tools in fab f, as calculated in Equation I–24A of this subpart (expressed as decimal fraction).

f = Fab.

i = Fluorinated GHG input gas.

(iv) You must calculate a fab-specific emission factor for each fluorinated GHG formed as a by-product (in kg of fluorinated GHG per kg of total fluorinated GHG consumed) in the tools vented to stack systems, as applicable, using Equation I–20 of this subpart. When calculating the by-product emission factor for an input gas for which $\mathbf{\Sigma}_s E_{i,s}$ equals or exceeds $E_{imax,f}$, exclude the consumption of that input gas from the term "$\mathbf{\Sigma}(Activity_{if})$."

$$EF_{kf} = \frac{\sum_s (E_{ks})}{\sum_i Activity_{if} * \left(UT_f + \left(\frac{1 - UT_f}{1 - \left(a_{kif} * d_{kif}\right)} \right) \right)} \qquad \text{(Eq. I-20)}$$

Where:

EF_{kf} = Emission factor for fluorinated GHG by-product gas k, from fab f, representing 100 percent abatement system uptime (kg emitted/kg of all input gases consumed in tools vented to stack systems).

E_{ks} = Mass emission of fluorinated GHG by-product gas k, emitted from stack system s, during the sampling period (kg emitted).

$Activity_{if}$ = Consumption of fluorinated GHG input gas i for fab f in tools vented to stack systems during the sampling period as determined following the procedures specified in § 98.94(j)(3) (kg consumed).

UT_f = The total uptime of all abatement systems for fab f, during the sampling period, as calculated in Equation I–23 of this subpart (expressed as decimal fraction).

a_{kif} = Fraction of by-product k emitted from tools using input gas i with abatement systems in fab f (expressed as a decimal fraction), as calculated using Equation I–24D.

d_{kif} = Fraction of fluorinated GHG by-product gas k generated from input gas i destroyed or removed when fed into abatement systems by process tools in fab f, as calculated in Equation I–24B of this subpart (expressed as decimal fraction).

f = Fab.

i = Fluorinated GHG input gas.

k = Fluorinated GHG by-product gas.

s = Stack system.

(v) You must calculate annual fab-level emissions of each fluorinated GHG consumed using Equation I–21 of this section.

$$E_{if} = EF_{if} \bullet C_{if} \bullet UT_f + \frac{EF_{if}}{\left(1-(a_{if} \bullet d_{if})\right)} \bullet C_{if} \bullet \left(1 - UT_f\right) \qquad \text{(Eq. I-21)}$$

Where:

E_{if} = Annual emissions of fluorinated GHG input gas i (kg/year) from the stack systems for fab f.

EF_{if} = Emission factor for fluorinated GHG input gas i emitted from fab f, as calculated in Equation I–19 of this subpart (kg emitted/kg input gas consumed).

C_{if} = Total consumption of fluorinated GHG input gas i in tools that are vented to stack systems, for fab f, for the reporting year, as calculated using Equation I–13 of this subpart (kg/year).

UT_f = The total uptime of all abatement systems for fab f, during the reporting year, as calculated using Equation I–23 of this subpart (expressed as a decimal fraction).

a_{if} = Fraction of fluorinated GHG input gas i emitted from tools with abatement systems in fab f (expressed as a decimal fraction), as calculated using Equation I–24C or I–24D.

d_{if} = Fraction of fluorinated GHG input gas i destroyed or removed when fed into abatement systems by process tools in fab f that are included in the stack testing option, as calculated in Equation I–24A of this subpart (expressed as decimal fraction).

f = Fab.

i = Fluorinated GHG input gas.

(vi) You must calculate annual fab-level emissions of each fluorinated GHG by-product formed using Equation I–22 of this section.

$$E_{kf} = EF_{kf} \bullet \sum_i C_{if} \bullet UT_f + EF_{kf} \bullet \sum_i \frac{C_{if} \bullet \left(1 - UT_f\right)}{1 - a_{kif} \bullet d_{kif}} \qquad \text{(Eq. I-22)}$$

Where:

E_{kf} = Annual emissions of fluorinated GHG by-product gas k (kg/year) from the stack for fab f.

EF_{kf} = Emission factor for fluorinated GHG by-product gas k, emitted from fab f, as calculated in Equation I–20 of this subpart (kg emitted/kg of all fluorinated input gases consumed).

C_{if} = Total consumption of fluorinated GHG input gas i in tools that are vented to stack systems, for fab f, for the reporting year, as calculated using Equation I–13 of this subpart.

UT_f = The total uptime of all abatement systems for fab f, during the reporting year as calculated using Equation I–23 of this subpart (expressed as a decimal fraction).

a_{kif} = Estimate of fraction of fluorinated GHG by-product gas k emitted in fab f from tools using input gas i with abatement systems (expressed as a decimal fraction), as calculated using Equation I–24D.

d_{kif} = Fraction of fluorinated GHG by-product k generated from input gas i destroyed or removed when fed into abatement systems by process tools in fab f that are included in the stack testing option, as calculated in Equation I–24B of this subpart (expressed as decimal fraction).

f = Fab.

i = Fluorinated GHG input gas.

k = Fluorinated GHG by-product

* * * * *

(viii) When using the stack testing option described in paragraph (i) of this section and when using more than one DRE for the same input gas i or by-product gas k, you must calculate the weighted-average fraction of each fluorinated input gas i and each fluorinated by-product gas k that has more than one DRE and that is destroyed or removed in abatement systems for each fab f, as applicable, by using Equation I–24A (for input gases) and Equation I–24B (for by-product gases) of this subpart and Table I–18 of this subpart. If default values are not available in Table I–18 for a particular input gas, you must use a value of 10.

$$d_{if} = \frac{\sum_p (\gamma_{i,p} \cdot \sum_{DREy} n_{i,p,DREy} \cdot DRE_y) + \sum_{DREz} DRE_z \cdot m_{i,q,DREz}}{\sum_p \gamma_{i,p} \cdot n_{i,p,a} + m_{i,q,a}} \qquad \text{(Eq. I-24A)}$$

$$d_{kif} = \frac{\sum_p (\gamma_{k,i,p} \cdot \sum_{DREy} n_{k,i,p,DREy} \cdot DRE_y) + \sum_{DREz} DRE_z \cdot m_{k,i,q,DREz}}{\sum_p \gamma_{k,i,p} \cdot n_{k,i,p,a} + m_{k,i,q,a}} \qquad \text{(Eq. I-24B)}$$

Where:

d_{if} = The average weighted fraction of fluorinated GHG input gas i destroyed or removed when fed into abatement systems by process tools in fab f (expressed as a decimal fraction).

d_{kif} = The average weighted fraction of fluorinated GHG by-product gas k generated from input gas i that is destroyed or removed when fed into abatement systems by process tools in fab f (expressed as a decimal fraction).

$n_{i,p,DREy}$ = Number of tools that use gas i, that run chamber cleaning process p, and that are equipped with abatement systems for gas i that have the DRE DREy.

$m_{i,q,DREz}$ = Number of tools that use gas i, that run etch and/or wafer cleaning processes, and that are equipped with abatement systems for gas i that have the DRE DREz.

$n_{i,p,a}$ = Total number of tools that use gas i, run chamber cleaning process type p, and that are equipped with abatement systems for gas i.

$m_{i,q,a}$ = Total number of tools that use gas i, run etch and/or wafer cleaning processes, and that are equipped with abatement systems for gas i.

$n_{k,i,p,DREy}$ = Number of tools that use gas i, generate by-product k, that run chamber cleaning process p, and that are equipped with abatement systems for gas i that have the DRE DREy.

$m_{k,i,q,DREz}$ = Number of tools that use gas i, generate by-product k, that run etch and/or wafer cleaning processes, and that are equipped with abatement systems for gas i that have the DRE DREz.

$n_{k,i,p,a}$ = Total number of tools that use gas i, generate by-product k, run chamber cleaning process type p, and that are equipped with abatement systems for gas i.

$m_{k,i,q,a}$ = Total number of tools that use gas i, generate by-product k, run etch and/or wafer cleaning processes, and that are equipped with abatement systems for gas i.

$\gamma_{i,p}$ = Default factor reflecting the ratio of uncontrolled emissions per tool of input gas i from tools running process sub-type p processes to uncontrolled emissions per tool of input gas i from process tools running process type q processes.

$\gamma_{k,i,p}$ = Default factor reflecting the ratio of uncontrolled emissions per tool of input gas i from tools running process sub-type p processes to uncontrolled emissions per tool of input gas i from process tools running process type q processes.

DRE_y = Default or alternative certified DRE for gas i for abatement systems connected to CVD tool.

DRE_z = Default or alternative certified DRE for gas i for abatement systems connected to etching and/or wafer cleaning tool.

p = Chamber cleaning process sub-type.

q = Reference process type. There is one process type q that consists of the combination of etching and/or wafer cleaning processes.

f = Fab.

i = Fluorinated GHG input gas.

(ix) When using the stack testing method described in this paragraph (i), you must calculate the fraction each fluorinated input gas i exhausted in fab f from tools with abatement systems and the fraction of each by-product gas k exhausted from tools with abatement systems, as applicable, by following either the procedure set forth in paragraph (i)(3)(ix)(A) of this section or the procedure set forth in paragraph (i)(3)(ix)(B) of this section.

(A) Use Equation I–24C (for input gases) and Equation I–24D (for by-product gases) and Table I–18 of this subpart. If default values are not available in Table I–18 for a particular input gas, you must use a value of 10.

$$a_{i,f} = \frac{\sum_p \gamma_{i,p} \cdot n_{i,p,a} + m_i,q,a}{\sum_p \gamma_{i,p} \cdot n_{i,p} + m_{i,q}} \quad \text{Eq. I -24C}$$

Where:

a_{if} = Fraction of fluorinated input gas i exhausted from tools with abatement systems in fab f (expressed as a decimal fraction).

$n_{i,p,a}$ = Number of tools that use gas i, that run chamber cleaning process sub-type p, and that are equipped with abatement systems for gas i.

$m_{i,q,a}$ = Number of tools that use gas i, that run etch and/or wafer cleaning processes, and that are equipped with abatement systems for gas i.

$n_{i,p}$ = Total number of tools using gas i and running chamber cleaning process sub-type p.

$m_{i,q}$ = Total number of tools using gas i and running etch and/or wafer cleaning processes.

$\gamma_{i,p}$ = Default factor reflecting the ratio of uncontrolled emissions per tool of input gas i from tools running process type p processes to uncontrolled emissions per tool of input gas i from process tools running process type q processes.

p = Chamber cleaning process sub-type.

q = Reference process type. There is one process type q that consists of the combination of etching and/or wafer cleaning processes.

$$a_{k,i,f} = \frac{\sum_p \gamma_{k,i,p} \cdot n_{k,i,p,a} + m_{k,i,q,a}}{\sum_p \gamma_{k,i,p} \cdot n_{k,i,p} + m_{k,i,q}} \quad \text{Eq. I-24D}$$

Where:

$a_{k,i,f}$ = Fraction of by-product gas k exhausted from tools using input gas i with abatement systems in fab f (expressed as a decimal fraction).

$n_{k,i,p,a}$ = Number of tools that exhaust by-product gas k from input gas i, that run chamber cleaning process p, and that are equipped with abatement systems for gas k.

$m_{k,i,q,a}$ = Number of tools that exhaust by-product gas k from input gas i, that run etch and/or wafer cleaning processes, and that are equipped with abatement systems for gas k.

$n_{k,i,p}$ = Total number of tools emitting by-product k from input gas i and running chamber cleaning process p.

$m_{k,i,q}$ = Total number of tools emitting by-product k from input gas i and running etch and/or wafer cleaning processes.

$\gamma_{k,i,p}$ = Default factor reflecting the ratio of uncontrolled emissions per tool of by-product gas k from input gas i from tools running chamber cleaning process p to uncontrolled emissions per tool of by-product gas k from input gas i from process tools running etch and/or wafer cleaning processes.

p = Chamber cleaning process sub-type.

q = Reference process type. There is one process type q that consists of the combination of etching and/or wafer cleaning processes.

(B) Use paragraph (e) of this section to apportion consumption of gas i either to tools with abatement systems and tools without abatement systems or to each process type or sub-type, as applicable. If you apportion consumption of gas i to each process type or sub-type, calculate the fractions of input gas i and by-product gas k formed from gas i that are exhausted from tools with abatement systems based on the numbers of tools with and without abatement systems within each process type or sub-type.

(4) *Method to calculate emissions from fluorinated GHGs that are not tested.* Calculate emissions from consumption of each intermittent low-use fluorinated GHG as defined in § 98.98 of this subpart using the default utilization and by-product formation rates provided in Table I–11, I–12, I–13, I–14, or I–15 of this subpart, as applicable, and by using Equations I–8A, I–8B, I–9, and I–13 of this subpart. If a fluorinated GHG was not being used during the stack testing and does not meet the definition of intermittent low-use fluorinated GHG in § 98.98, then you must test the stack systems associated with the use of that fluorinated GHG at a time when that gas is in use at a magnitude that would allow you to determine an emission factor for that gas according to the procedures specified in paragraph (i)(3) of this section.

■ 27. Amend § 98.94 by revising paragraphs (c) introductory text, (e), (f)(3), (f)(4) introductory text, (f)(4)(iii), (j)(1) introductory text, (j)(1)(i), (j)(3) introductory text, (j)(5)(i), and (j)(5)(ii) introductory text and by removing and reserving paragraphs (j)(6) and (j)(8)(v).

The revisions read as follows:

§ 98.94 Monitoring and QA/QC requirements.

* * * * *

(c) You must develop apportioning factors for fluorinated GHG and N_2O consumption (including the fraction of gas consumed by process tools connected to abatement systems as in Equations I–8A, I–8B, I–9, and I–10 of this subpart), to use in the equations of this subpart for each input gas i, process sub-type, process type, stack system, and fab as appropriate, using a fab-specific engineering model that is documented in your site GHG Monitoring Plan as required under § 98.3(g)(5). This model must be based on a quantifiable metric, such as wafer passes or wafer starts, or direct measurement of input gas consumption as specified in paragraph (c)(3) of this section. To verify your model, you must demonstrate its precision and accuracy by adhering to the requirements in paragraphs (c)(1) and (2) of this section.

* * * * *

(e) If you use hydrocarbon-fuel-based emissions control systems to control emissions from tools that use either NF_3 as an input gas in remote plasma cleaning processes or F_2 as an input gas in any process, and if you use a value less than 1 for either $a_{F2,j}$ or $a_{NF3,RPC}$ in Equation I–9, you must certify and document that the model for each of the systems for which you are claiming that it does not form CF_4 from F_2 has been tested and verified to produce less than 0.1% CF_4 from F_2 and that each of the systems is installed, operated, and maintained in accordance with the directions of the emissions control system manufacturer. Hydrocarbon-fuel-based emissions control systems include but are not limited to abatement systems as defined in § 98.98 that are hydrocarbon-fuel-based. The rate of conversion from F_2 to CF_4 must be measured using a scientifically sound, industry-accepted method that accounts for dilution through the abatement device, such as EPA 430–R–10–003, adjusted to calculate the rate of conversion from F_2 to CF_4 rather than the DRE. Either the hydrocarbon-fuel-based emissions control system manufacturer or the electronics manufacturer may perform the measurement. The flow rate of F_2 into the tested emissions control system(s) may be metered using a calibrated mass flow controller.

(f) * * *

(3) If you use default destruction and removal efficiency values in your emissions calculations under § 98.93(a), (b), and/or (i), you must certify and document that the abatement systems at your facility for which you use default destruction or removal efficiency values are specifically designed for fluorinated GHG or N_2O abatement, as applicable, and that the abatement system has been tested by the abatement system manufacturer based on the methods specified in paragraph (f)(3)(i) of this section and verified to meet (or exceed) the default destruction or removal efficiency in Table I–16 for the fluorinated GHG or N_2O under worst-case flow conditions as defined in paragraph (f)(3)(ii) of this section. If you use a verified destruction and removal efficiency value that is lower than the default in Table I–16 in your emissions calculations under § 98.93(a), (b), and/or (i), you must certify and document that the abatement systems at your facility for which you use the verified destruction or removal efficiency values are specifically designed for fluorinated GHG or N_2O abatement, as applicable, and that the abatement system has been tested by the abatement system manufacturer based on the methods specified in paragraph (f)(3)(i) of this section and verified to meet or exceed the destruction or removal efficiency value used for that fluorinated GHG or N_2O under worst-case flow conditions as defined in paragraph (f)(3)(ii) of this section. If you elect to calculate fluorinated GHG emissions using the stack test method under § 98.93(i), you must also certify that you have included and accounted for all abatement systems designed for fluorinated GHG abatement and any respective downtime in your emissions calculations under § 98.93(i)(3).

(i) For purposes of paragraph (f)(3) of this section, destruction and removal efficiencies must be measured using a scientifically sound, industry-accepted measurement methodology that accounts for dilution through the abatement system, such as EPA 430–R–10–003 (incorporated by reference, see § 98.7).

(ii) Worst-case flow conditions are defined as the highest total fluorinated GHG or N_2O flows through each model of emissions control systems (gas by gas and process type by process type across the facility) and the highest total flow scenarios (with N_2 dilution accounted for) across the facility during which the abatement system is claimed to be operational.

(4) If you calculate and report controlled emissions using neither the default destruction or removal efficiency values in Table I–16 of this subpart nor a manufacturer verified lower destruction or removal efficiency values per paragraph (f)(3) of this section, you must use an average of properly measured destruction or removal efficiencies for each gas and process sub-type or process type combination, as applicable, determined in accordance with procedures in paragraphs (f)(4)(i) through (vi) of this section. This includes situations in which your fab employs abatement systems not specifically designed for fluorinated GHG or N_2O abatement and you elect to reflect emission reductions due to these systems. You must not use a default value from Table I–16 of this subpart for any abatement system not specifically designed for fluorinated GHG and N_2O abatement, for any abatement system not certified to meet the default value from Table I–16, or for any gas and process type combination for which you have measured the destruction or removal efficiency according to the requirements of paragraphs (f)(4)(i) through (vi) of this section.

* * * * *

(iii) If you elect to take credit for abatement system destruction or removal efficiency before completing testing on 20 percent of the abatement systems for that gas and process sub-type or process type combination, as applicable, you must use default destruction or removal efficiencies or a verified destruction or removal efficiency, if verified at a lower value, for a gas and process type combination. You must not use a default value from Table I–16 of this subpart for any abatement system not specifically designed for fluorinated GHG and N_2O abatement, and must not take credit for abatement system destruction or removal efficiency before completing testing on 20 percent of the abatement systems for that gas and process sub-type or process type combination, as applicable. Following testing on 20 percent of abatement systems for that gas and process sub-type or process type combination, you must calculate the average destruction or removal efficiency as the arithmetic mean of all test results for that gas and process sub-type or process type combination, until you have tested at least 30 percent of all abatement systems for each gas and process sub-type or process type combination. After testing at least 30 percent of all systems for a gas and process sub-type or process type combination, you must use the arithmetic mean of the most recent 30 percent of systems tested as the average destruction or removal efficiency. You may include results of testing conducted on or after January 1, 2011 for use in determining the site-specific destruction or removal efficiency for a given gas and process sub-type or process type combination if the testing was conducted in accordance with the requirements of paragraph (f)(4)(i) of this section.

* * * * *

(j) * * *

(1) *Stack system testing.* Conduct an emissions test for each stack system according to the procedures in paragraphs (j)(1)(i) through (iv) of this section.

(i) You must conduct an emission test during which the fab is operating at a representative operating level, as defined in § 98.98, and with the abatement systems connected to the stack system being tested operating with at least 90 percent uptime, averaged over all abatement systems, during the 8-hour (or longer) period for each stack system, or at no less than 90 percent of the abatement system uptime rate measured over the previous reporting year, averaged over all abatement systems. Hydrocarbon-fuel-based emissions control systems that are not certified not to form CF_4 must operate with at least 90 percent uptime during the test.

* * * * *

(3) *Fab-specific fluorinated GHG consumption measurements.* You must determine the amount of each fluorinated GHG consumed by each fab during the sampling period for all process tools connected to the stack systems under § 98.93(i)(3), according to the procedures in paragraphs (j)(3)(i) and (ii) of this section.

* * * * *

(5) * * *

(i) *Annual testing.* You must conduct an annual emissions test for each stack system unless you meet the criteria in paragraph (j)(5)(ii) of this section to skip annual testing. Each set of emissions testing for a stack system must be separated by a period of at least 2 months.

(ii) *Criteria to test less frequently.* After the first 3 years of annual testing, you may calculate the relative standard deviation of the emission factors for each fluorinated GHG included in the test and use that analysis to determine the frequency of any future testing. As an alternative, you may conduct all three tests in less than 3 calendar years for purposes of this paragraph (j)(5)(ii), but this does not relieve you of the obligation to conduct subsequent annual testing if you do not meet the criteria to test less frequently. If the criteria specified in paragraphs (j)(5)(ii)(A) and (B) of this section are met, you may use the arithmetic average of the three emission factors for each fluorinated GHG and fluorinated GHG byproduct for the current year and the next 4 years with no further testing unless your fab operations are changed in a way that triggers the re-test criteria in paragraph (j)(8) of this section. In the fifth year following the last stack test included in the previous average, you must test each of the stack systems and repeat the relative standard deviation analysis using the results of the most recent three tests (*i.e.,* the new test and the two previous tests conducted prior to the 4-year period). If the criteria specified in paragraphs (j)(5)(ii)(A) and (B) of this section are not met, you must use the emission factors developed from the most recent testing and continue annual testing. You may conduct more than one test in the same year, but each set of emissions testing for a stack system must be separated by a period of at least 2 months. You may repeat the relative standard deviation analysis using the most recent three tests, including those tests conducted prior to the 4-year period, to determine if you are exempt from testing for the next 4 years.

* * * * *

■ 28. Amend § 98.96 by:

■ a. Revising paragraphs (c)(1) and (2), (o), (p)(2), and (q)(2) and (3);

■ b. Revising Equation I–28 in paragraph (r)(2);

■ c. Revising parameters ''C_{if},'' ''EF_{kf},'' ''a_f,'' and ''d_{kf}'' of Equation I–28 in paragraph (r)(2); and

■ d. Revising paragraphs (w)(2), (y) introductory text, (y)(1), (y)(2)(i) and (iv), and (y)(4).

The revisions read as follows:

§ 98.96 Data reporting requirements.

* * * * *

(c) * * *

(1) When you use the procedures specified in § 98.93(a) of this subpart, each fluorinated GHG emitted from each process type for which your fab is required to calculate emissions as calculated in Equations I–6, I–7, and I–9 of this subpart.

(2) When you use the procedures specified in § 98.93(a), each fluorinated GHG emitted from each process type or process sub-type as calculated in Equations I–8A and I–8B of this subpart, as applicable.

* * * * *

(o) For all hydrocarbon-fuel-based emissions control systems that are used to control emissions from tools that use either NF_3 as an input gas in remote plasma clean processes or F_2 as an input gas in any process type or sub-type, certification that the rate of conversion from F_2 to CF_4 is <0.1% and that the systems are installed, operated, and maintained in accordance with the directions of the emissions control system manufacturer, unless the emissions control system is included in the count of systems not certified to not form CF_4 in Equation I–9. Hydrocarbon-fuel-based emissions control systems include but are not limited to abatement systems as defined in § 98.98 that are hydrocarbon-fuel-based. If you make the certification based on your own testing, you must certify that you tested the model of the system according to the requirements specified in § 98.94(e). If you make the certification based on testing by the emissions control system manufacturer, you must provide documentation from the emissions control system manufacturer that the rate of conversion from F_2 to CF_4 is <0.1% when tested according to the requirements specified in § 98.94(e).

(p) * * *

(2) The basis of the destruction or removal efficiency being used (default, manufacturer verified, or site-specific measurement according to § 98.94(f)(4)(i)) for each process sub-type or process type and for each gas.

(q) * * *

(2) If you use default destruction or removal efficiency values in your emissions calculations under § 98.93(a), (b), or (i), certification that the site maintenance plan for abatement systems for which emissions are being reported contains manufacturer's recommendations and specifications for installation, operation, and maintenance for each abatement system. To use the default or lower manufacturer-verified destruction or removal efficiency values, operation of the abatement system must be within manufacturer's specifications, including but not limited to specifications on vacuum pumps' purges, fuel and oxidizer settings, supply and exhaust flows and pressures, and utilities to the emissions control equipment including fuel gas flow and pressure, calorific value, and water quality, flow and pressure.

(3) If you use default destruction or removal efficiency values in your emissions calculations under § 98.93(a), (b), and/or (i), certification that the abatement systems for which emissions are being reported were specifically designed for fluorinated GHG or N_2O abatement, as applicable. You must support this certification by providing abatement system supplier documentation stating that the system was designed for fluorinated GHG or N_2O abatement, as applicable, and supply the destruction or removal efficiency value at which each abatement system is certified for the fluorinated GHG or N_2O abated, as applicable. You may only use the default destruction or removal efficiency value if the abatement system is verified to meet or exceed the destruction or removal efficiency default value in Table I–16. If the system is verified at a destruction or removal efficiency value lower than the default value, you may use the verified value.

* * * * *

(r) * * *

(2) * * *

$$SFGHG = \sum_i \left[\frac{EF_{if}}{\left(1-(a_{if} * d_{if})\right)} * C_{if} * GWP_i \right] + \sum_k \left[EF_{kf} * \sum_i \frac{C_{if}}{1-(a_{kif} \bullet d_{ik})} * GWP_k \right] \quad \text{Eq. I-28)}$$

* * * * *

C_{if} = Total consumption of fluorinated GHG input gas i, of tools vented to stack systems, for fab f, for the reporting year, expressed in metric ton CO_2e, which you used to calculate total emissions according to the procedures in § 98.93(i)(3) (expressed as a decimal fraction).

EF_{kf} = Emission factor for fluorinated GHG by-product gas k, emitted from fab f, as calculated in Equation I–20 of this subpart (kg emitted/kg of all input gases consumed in tools vented to stack systems).

a_{kif} = Fraction of fluorinated GHG by-product gas k emitted in fab f from tools using input gas i with abatement systems (expressed as a decimal fraction), as calculated using Equation I–24D.

d_{ik} = Fraction of fluorinated GHG byproduct k destroyed or removed in abatement systems connected to process tools in fab f, as calculated from Equation I–24B of this subpart, which you used to calculate total emissions according to the procedures in § 98.93(i)(3) (expressed as a decimal fraction).

* * * * *

(w) * * *

(2) An inventory of all stack systems from which process fluorinated GHG are emitted.

* * * * *

(y) If your semiconductor manufacturing facility manufactures wafers greater than 150 mm and emits more than 40,000 metric ton CO_2e of GHG emissions, based on your most recently submitted annual report as required in paragraph (c) of this section, from the electronics manufacturing processes subject to reporting under this subpart, you must prepare and submit a technology assessment report every five years to the Administrator (or an authorized representative) that meets the requirements specified in paragraphs (y)(1) through (6) of this section. Any other semiconductor manufacturing facility may voluntarily submit this report to the Administrator. If your semiconductor manufacturing facility manufactures only 150 mm or smaller wafers, you are not required to prepare and submit a technology assessment report, but you are required to prepare and submit a report if your facility begins manufacturing wafers 200 mm or larger during or before the calendar year preceding the year the technology assessment report is due. If your semiconductor manufacturing facility is no longer required to report to the GHGRP under subpart I due to the cessation of semiconductor manufacturing as described in § 98.2(i)(3), you are not required to submit a technology assessment report.

(1) The first technology assessment report due after January 1, 2023 is due on March 31, 2025, and subsequent reports must be delivered every 5 years no later than March 31 of the year in which it is due.

(2) * * *

(i) It must describe how the gases and technologies used in semiconductor manufacturing using 200 mm and 300 mm wafers in the United States have changed in the past 5 years and whether any of the identified changes are likely to have affected the emissions characteristics of semiconductor manufacturing processes in such a way that the default utilization and by-product formation rates or default destruction or removal efficiency factors of this subpart may need to be updated.

* * * * *

(iv) It must provide any utilization and byproduct formation rates and/or destruction or removal efficiency data that have been collected in the previous 5 years that support the changes in semiconductor manufacturing processes described in the report. Any utilization or byproduct formation rate data submitted must be reported using all of the methods specified in paragraphs (y)(2)(iv)(A) through (C) of this section if multiple fluorinated input gases are used. If only one fluorinated input gas is fed into the process, you must use Equations I–29a and I–29b. The report must include the input gases used and measured, the utilization rates measured, the byproduct formation rates measured, the process type, the process subtype for chamber clean processes, the wafer size, and the methods used for the measurements. The report must also specify the method used to calculate each reported utilization and by-product formation rate, and provide a unique record number for each data set. For any destruction or removal efficiency data submitted, the report must include the input gases used and measured, the destruction and removal efficiency measured, the process type, the methods used for the measurements, and whether the abatement system is specifically designed to abate the gas measured under the operating condition used for the measurement.

(A) *Dominant gas method.* Use Equation I–29a to calculate the input gas emission factor $(1 - U_{ij})$ for each input gas in a single test. If the result of Equation I–29a exceeds 0.8 for an F–GHG, you must instead use Equation I–29c to calculate the input gas emission factor for that F–GHG and Equation I–29d to calculate the by-product formation rate for that F–GHG from the other input F–GHGs. To calculate by-product emission factors for all other measured F–GHGs, use Equation I–29b and assign all measured by-products to the dominant gas. The dominant gas is the carbon-containing input F–GHG fed into the process in the largest quantity (mass). If there are no carbon containing input F–GHGs, the dominant gas is the input F–GHG with the largest input mass.

$$\left(1 - U_{ij}\right) = \frac{(E_i)}{(Mass_i)} \quad \text{(Eq. I-29a)}$$

Where:

U_{ij} = Process utilization rate for fluorinated GHG i, process type j.

E_i = The mass emissions of input gas i.

$Mass_i$ = The mass of input gas i fed into the Process.

i = Fluorinated GHG input gas i.

$$BEF_{ki} = \frac{(E_k)}{Mass_i} \quad \text{(Eq. I -29b)}$$

Where:

BEF_{ki} = By-product formation rate for gas k from input gas i, where gas k is not an input gas.

E_k = The mass emissions of by-product gas k.

$Mass_i$ = The mass of input gas i where i is the dominant gas, as defined in (A).

i = Fluorinated GHG input gas i.

k = By-product gas k.

$$(1 - U_{ij}) = 0.8 \quad \text{(Eq. I-29c)}$$

Where:

Uij = Process utilization rate for fluorinated GHG i, process type j.

$$BEF_{ijg} = \frac{(E_i - 0.8 * Mass_i)}{\sum_g Mass_g} \quad \text{(Eq. I-29d)}$$

Where:

BEF_{ijg} = By-product formation rate for gas i from input gas g for process type j.

E_i = The mass emissions of input gas i.

$Mass_i$ = The mass of input gas i where i is the dominant gas, as defined in (A).

$Mass_g$ = The mass of input gas g fed into the process, where g does not equal input gas i.

i = Fluorinated GHG.

g = Fluorinated GHG input gas, where gas g is not equal to gas i.

j = Process type.

(B) *All-input gas method.* Use Equation I–30a to calculate the input gas emission factor $(1-U_{ij})$ for each input gas in a single test. If the result of Equation I–30a exceeds 0.8 for an F–GHG, you must use Equation I–30c to calculate the input gas emission factor for that F–GHG and Equation I–30d to calculate the by-product formation rate for that F–GHG from the other input gases. Use Equation I–30b to calculate the by-product formation rates from each input gas for F–GHGs that are not input gases. If a test uses a cleaning or etching gas that does not contain carbon in combination with a cleaning or etching gas that does contain carbon and the process chamber is not used to etch or deposit carbon-containing films, you may elect to assign carbon containing by-products only to the carbon-containing input gases. If you choose to assign carbon containing by-products only to carbon-containing input gases, remove the input mass of the non-carbon containing gases from the sum of $Mass_i$ and the sum of $Mass_g$ in Equations I–30b and I–30d, respectively.

$$(1 - U_{ij}) = \frac{(E_i)}{(Mass_i)} \quad \text{(Eq. I-30a)}$$

Where:

U_{ij} = Process utilization rate for fluorinated GHG i, process type j.

E_i = The mass emissions of input gas i.

$Mass_i$ = The mass of input gas i fed into the Process.

i = Fluorinated GHG.

j = Process type.

$$BEF_{kji} = \frac{(E_k)}{\sum_i Mass_i} \quad \text{(Eq. I -30b)}$$

Where:

BEF_{kji} = By-product formation rate for gas k from input gas i, for process type j, where gas k is not an input gas.

E_k = The mass emissions of by-product gas k.

$Mass_i$ = The mass of input gas i fed into the Process.

i = Fluorinated GHG.

j = Process type.

k = Fluorinated GHG by-product.

$$(1 - U_{ij}) = 0.8 \quad \text{(Eq. I-30c)}$$

Where:

Uij = Process utilization rate for fluorinated GHG i, process type j.

$$BEF_{ijg} = \frac{(E_i - 0.8 * Mass_i)}{\sum_g Mass_g} \quad \text{(Eq. I -30d)}$$

Where:

BEF_{ijg} = By-product formation rate for gas i from input gas g for process type j.

E_i = The mass emissions of input gas i.

$Mass_i$ = The mass of input gas i fed into the process.

$Mass_g$ = The mass of input gas g fed into the process, where g does not equal input gas i.

i = Fluorinated GHG.

g = Fluorinated GHG input gas, where gas g is not equal to gas i.

j = Process type.

(C) *Reference emission factor method.* Calculate the input gas emission factors and by-product formation rates from a test using Equations I–31a and I–31b, and Table I–19 or I–20 of this subpart. In this case, use Equation I–31a to calculate the input gas emission factors and use Equation I–31b and I–30b to calculate the by-product formation rates.

$$(1-U_{ij}) = (1-U_{ijr}) * \left[\frac{E_i}{(Mass_i * (1-U_{ijr}) + \sum_g Mass_g BEF_{ijgr})} \right] \quad \text{(Eq. I-31a)}$$

Where:

U_{ij} = Process utilization rate for fluorinated GHG i, process type j.

U_{ijr} = Reference process utilization rate for fluorinated GHG i, process type j, for input gas i, using Table I–19 or I–20 of this subpart as appropriate.

E_i = The mass emissions of input gas i.

$Mass_i$ = The mass of gas i fed into the process.

$Mass_g$ = The mass of input gas g fed into the process, where g does not equal input gas i.

BEF_{ijgr} = Reference by-product formation rate for gas i from input gas g for process type j, using Table I–19.

i = Fluorinated GHG.

g = Fluorinated GHG input gas, where gas g is not equal to gas i.

r = Reference data.

$$BEF_{ijg} = BEF_{ijgr} * \left[\frac{E_i}{(Mass * (1-U_{ijr}) + \sum_g Mass_g BEF_{ijgr}} \right] \quad \text{(Eq. I -31b)}$$

Where:

BEF_{ijg} = By-product formation rate for gas i from input gas g for process type j, where gas i is also an input gas.

BEF_{ijgr} = By-product formation rate for gas i from input gas g for process type j from Table I–19 or I–20 of this subpart, as appropriate.

U_{ijr} = Process utilization rate for fluorinated GHG i, process type j, for input gas i, using Table I–19 or I–20 of this subpart, as appropriate.

E_i = The mass emissions of input gas i.

$Mass_i$ = The mass of gas i fed into the process.

$Mass_g$ = The mass of input gas g fed into the process, where g does not equal input gas i.

i = Fluorinated GHG.

j = Process type.

g = Fluorinated GHG input gas, where gas g is not equal to gas i.

r = Reference data.

* * * * *

(4) Multiple semiconductor manufacturing facilities may submit a single consolidated technology assessment report as long as the facility identifying information in § 98.3(c)(1) and the certification statement in § 98.3(c)(9) is provided for each facility for which the consolidated report is submitted.

* * * * *

■ 29. Amend § 98.97 by:

■ a. Revising paragraphs (b), (d)(1)(iii), (d)(3), (d)(5)(i), (d)(6) and (7), and (d)(9)(i) and (ii);

■ b. Removing and reserving paragraph (i)(1); and

■ c. Revising paragraphs (i)(5) and (9) and (k).

The revisions read as follows:

§ 98.97 Records that must be retained.

* * * * *

(b) If you use hydrocarbon-fuel-based emissions control systems to control emissions from tools that use either NF_3 as an input gas in remote plasma cleaning processes or F_2 as an input gas in any process, and if you use a value less than 1 for either $a_{F2,j}$ or $a_{NF3,RPC}$ in Equation I–9, certification and documentation that the model for each of the systems that you claim does not form CF_4 from F_2 has been tested and verified to produce less than 0.1% CF_4 from F_2, and certification that the site maintenance plan includes the emission control system manufacturer's recommendations and specifications for installation, operation, and maintenance of those systems. If you are relying on your own testing to make the certification that the model produces less than 0.1% CF_4 from F_2, the documentation must include the model tested, the method used to perform the testing (*e.g.,* EPA 430–R–10–003, modified to calculate the formation rate of CF_4 from F_2 rather than the DRE), complete documentation of the results of any initial and subsequent tests, and a final report similar to that specified in EPA 430–R–10–003, with appropriate adjustments to reflect the measurement of the formation rate of CF_4 from F_2 rather than the DRE. If you are relying on testing by the emissions control system manufacturer to make the to make the certification that the system produces less than 0.1% CF_4 from F_2, the documentation must include the model tested, the method used to perform the testing, and the results of the test.

* * * * *

(d) * * *

(1) * * *

(iii) If you use either default destruction or removal efficiency values or certified destruction or removal efficiency values that are lower than the default values in your emissions calculations under § 98.93(a), (b), and/or (i), certification that the abatement systems for which emissions are being reported were specifically designed for fluorinated GHG and N_2O abatement, as required under § 98.94(f)(3), certification that the site maintenance plan includes the abatement system manufacturer's recommendations and specifications for installation, operation, and maintenance, and the certified destruction and removal efficiency values for all applicable abatement systems. For abatement systems purchased after January 1, 2023, also include records of the method used to measure the destruction and removal efficiency values.

* * * * *

(3) Where either the default destruction or removal efficiency value or a certified destruction or removal efficiency value that is lower than the default is used, documentation from the abatement system supplier describing the equipment's designed purpose and

emission control capabilities for fluorinated GHG and N_2O.

* * * * *

(5) * * *

(i) The number of abatement systems of each manufacturer, and model numbers, and the manufacturer's certified fluorinated GHG and N_2O destruction or removal efficiency, if any.

* * * * *

(6) Records of all inputs and results of calculations made accounting for the uptime of abatement systems used during the reporting year, in accordance with Equations I–15 or I–23 of this subpart, as applicable. The inputs should include an indication of whether each value for destruction or removal efficiency is a default value, lower manufacturer verified value, or a measured site-specific value.

(7) Records of all inputs and results of calculations made to determine the average weighted fraction of each gas destroyed or removed in the abatement systems for each stack system using Equations I–24A and I–24B of this subpart, if applicable. The inputs should include an indication of whether each value for destruction or removal efficiency is a default value, lower manufacturer-verified value, or a measured site-specific value.

* * * * *

(9) * * *

(i) The site maintenance plan for abatement systems must be based on the abatement system manufacturer's recommendations and specifications for installation, operation, and maintenance if you use default or lower-manufacturer verified destruction and removal efficiency values in your emissions calculations under § 98.93(a), (b), and/or (i). If the manufacturer's recommendations and specifications for installation, operation, and maintenance are not available, you cannot use default destruction and removal efficiency values or lower manufacturer verified value in your emissions calculations under § 98.93(a), (b), and/or (i). If you use an average of properly measured destruction or removal efficiencies determined in accordance with the procedures in § 98.94(f)(4)(i) through (vi), the site maintenance plan for abatement systems must be based on the abatement system manufacturer's recommendations and specifications for installation, operation, and maintenance, where available. If you deviate from the manufacturer's recommendations and specifications, you must include documentation that demonstrates how the deviations do not negatively affect the performance or destruction or removal efficiency of the abatement systems.

(ii) The site maintenance plan for abatement systems must include a defined preventative maintenance process and checklist. Preventative maintenance must include, but is not limited to, calibration of pump purge flow indicators. Pump purge flow indicators must be calibrated each time a vacuum pump is serviced or exchanged.

* * * * *

(i) * * *

(5) The fab-specific emission factor and the calculations and data used to determine the fab-specific emission factor for each fluorinated GHG and by-product, as calculated using Equations I–19A, I–19B, I–19C and I–20 of § 98.93(i)(3).

* * * * *

(9) The number of tools vented to each stack system in the fab and all inputs and results for the calculations accounting for the fraction of gas exhausted through abatement systems using Equations I–24C and I–24D.

* * * * *

(k) Annual gas consumption for each fluorinated GHG and N_2O as calculated in Equation I–11 of this subpart, including where your fab used less than 50 kg of a particular fluorinated GHG or N_2O used at your facility for which you have not calculated emissions using Equations I–6, I–7, I–8A, I–8B, I–9, I–10, I–21, or I–22 of this subpart, the chemical name of the GHG used, the annual consumption of the gas, and a brief description of its use.

* * * * *

■ 30. Amend § 98.98 by adding in alphabetical order a definition for ''Hydrocarbon-fuel based emission control systems'' and revising the definition of ''Operational mode'' to read as follows:

§ 98.98 Definitions.

* * * * *

Hydrocarbon-fuel based emission control systems means a hydrocarbon fuel based combustion device or equipment that is designed to destroy or remove gas emissions in exhaust streams via combustion from one or more electronics manufacturing production processes, and includes both emission control systems that are and are not designed to destroy or remove fluorinated GHGs or N_2O.

* * * * *

Operational mode means the time in which an abatement system is properly installed, maintained, and operated according to the site maintenance plan for abatement systems as required in § 98.94(f)(1) and defined in § 98.97(d)(9). This includes being properly operated within the range of parameters as specified in the site maintenance plan for abatement systems and within the range of parameters as specified in the DRE certification documentation. An abatement system is considered to not be in operational mode when it is not operated and maintained according to the site maintenance plan for abatement systems and within the range of parameters as specified in the DRE certification documentation.

* * * * *

■ 31. Revise table I–1 to subpart I of part 98 to read as follows:

TABLE I–1 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS FOR MANUFACTURING CAPACITY-BASED THRESHOLD APPLICABILITY DETERMINATION

Product type	Emission factors EFi							
	CF_4	C_2F_6	CHF_3	$c\text{-}C_4F_8$	C_3F_8	NF_3	SF_6	N_2O
Semiconductors (kg/m^2)	0.9	1.0	0.04	NA	0.05	0.04	0.20	NA
LCD (g/m^2)	0.65	NA	0.0024	0.00	NA	1.29	4.14	17.06
MEMS (kg/m^2)	0.015	NA	NA	0.076	NA	NA	1.86	NA

Notes: NA denotes not applicable based on currently available information.

■ 32. Redesignate table I–2 to subpart I of part 98 as table I–21 to subpart I of part 98.

■ 33. Add new table I–2 to subpart I of part 98 in numerical order to read as follows:

TABLE I–2 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS FOR GAS CONSUMPTION-BASED THRESHOLD APPLICABILITY DETERMINATION

	Process gas i	
	Fluorinated GHGs	N_2O
$1–U_i$	0.8	1
BCF_4	0.15	0
BC_2F_6	0.05	0

■ 34. Revise table I–3 to subpart I of part 98 to read as follows:

TABLE I–3 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS ($1\text{-}U_{ij}$) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR 150 MM AND 200 MM WAFER SIZES

Process type/sub-type	Process gas i												
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_2HF_5	CH_3F	C_3F_8	C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
ETCHING/WAFER CLEANING													
$1–U_i$	0.73	0.72	0.51	0.13	0.064	0.70	NA	0.14	0.19	0.55	0.083	0.072	NA
BCF_4	NA	0.10	0.085	0.079	0.077	NA	NA	0.11	0.0040	0.13	0.095	NA	NA
BC_2F_6	0.041	NA	0.035	0.025	0.024	0.0034	NA	0.037	0.025	0.11	0.073	0.014	NA
BC_4F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
$BCHF_3$	0.091	0.047	NA	0.049	NA	NA	NA	0.040	NA	0.0012	0.066	0.0039	NA
CHAMBER CLEANING													
IN SITU PLASMA CLEANING													
$1–U_i$	0.92	0.55	NA	NA	NA	NA	0.40	0.10	0.18	NA	NA	NA	0.14
BCF_4	NA	0.19	NA	NA	NA	NA	0.20	0.11	0.14	NA	NA	NA	0.13
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.045
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
REMOTE PLASMA CLEANING													
$1–U_i$	NA	NA	NA	NA	NA	NA	NA	NA	0.028	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	0.015	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BF_2	NA	NA	NA	NA	NA	NA	NA	NA	0.5	NA	NA	NA	NA
IN SITU THERMAL CLEANING													
$1–U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA = Not applicable; *i.e.,* there are no applicable default emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

■ 35. Revise table I–4 to subpart I of part 98 to read as follows:

TABLE I–4 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS ($1\text{-}U_{ij}$) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR 300 MM AND 450 MM WAFER SIZE

Process type/sub-type	Process gas i											
	CF_4	C_2F_6	CHF_3	CH_2F_2	CH_3F	C_3F_8	C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
ETCHING/WAFER CLEANING												
$1–U_i$	0.65	0.80	0.37	0.20	0.30	0.30	0.18	0.16	0.30	0.15	0.10	NA
BCF_4	NA	0.21	0.076	0.060	0.0291	0.21	0.045	0.044	0.033	0.059	0.11	NA
BC_2F_6	0.058	NA	0.058	0.043	0.009	0.18	0.027	0.045	0.041	0.062	0.083	NA
BC_4F_8	0.0046	NA	0.0027	0.054	0.0070	NA	NA	NA	NA	0.0051	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00012	NA
$BCHF_3$	0.012	NA	NA	0.057	0.016	0.012	0.028	0.023	0.0039	0.017	0.0069	NA

TABLE I–4 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1-U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR 300 MM AND 450 MM WAFER SIZE—Continued

Process type/ sub-type	Process gas i											
	CF_4	C_2F_6	CHF_3	CH_2F_2	CH_3F	C_3F_8	C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
BCH_2F_2	0.005	NA	0.0024	NA	0.0033	NA	0.0021	0.00074	0.000020	0.000030	NA	NA
BCH_3F	0.0061	NA	0.027	0.0036	NA	0.00073	0.0063	0.0080	0.0082	0.00065	NA	NA
CHAMBER CLEANING												
IN SITU PLASMA CLEANING												
1–U_i	NA	NA	NA	NA	NA	NA	NA	0.20	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	0.037	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
REMOTE PLASMA CLEANING												
1–U_i	NA	NA	NA	NA	NA	0.063	NA	0.018	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	0.037	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
$BCHF_3$	NA	NA	NA	NA	NA	NA	NA	0.000059	NA	NA	NA	NA
BCH_2F_2	NA	NA	NA	NA	NA	NA	NA	0.00088	NA	NA	NA	NA
BCH_3F	NA	NA	NA	NA	NA	NA	NA	0.0028	NA	NA	NA	NA
BF_2	NA	NA	NA	NA	NA	NA	NA	0.5	NA	NA	NA	NA
IN SITU THERMAL CLEANING												
1–U_i	NA	NA	NA	NA	NA	NA	NA	0.28	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	0.010	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA = Not applicable; *i.e.,* there are no applicable default emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

■ 36. Revise table I–8 to subpart I of part 98 to read as follows:

TABLE I–8 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1–$UN_2O_{,j}$) FOR N_2O UTILIZATION ($UN_2O_{,j}$)

Manufacturing type/process type/wafer size	N_2O
Semiconductor Manufacturing:	
200 mm or Less:	
CVD 1–U_i	1.0
Other Manufacturing Process 1–U_i	1.0
300 mm or greater:.	
CVD 1–U_i	0.5
Other Manufacturing Process 1–U_i	1.0
LCD Manufacturing:	
CVD Thin Film Manufacturing 1–U_i	0.63
All other N_2O Processes	1.0

■ 37. Revise table I–11 to subpart I of part 98 to read as follows:

TABLE I–11 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1-U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR USE WITH THE STACK TEST METHOD

[150 mm and 200 mm Wafers]

All processes	Process gas i													
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_2HF_5	CH_3F	C_3F_8	C_4F_8	NF_3	NF_3 Re-mote	SF_6	C_4F_6	C_5F_8	C_4F_8O
1–U_i	0.79	0.55	0.51	0.13	0.064	0.70	0.40	0.12	0.18	0.028	0.58	0.083	0.072	0.14
BCF_4	NA	0.19	0.085	0.079	0.077	NA	0.20	0.11	0.11	0.015	0.13	0.095	NA	0.13
BC_2F_6	0.027	NA	0.035	0.025	0.024	0.0034	NA	0.019	0.0059	NA	0.10	0.073	0.014	0.045
BC_4F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_5F_8	0.00077	NA	0.0012	NA	NA	NA	NA	0.0043	NA	NA	NA	NA	NA	NA

TABLE I–11 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1-U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR USE WITH THE STACK TEST METHOD—Continued

[150 mm and 200 mm Wafers]

All processes	Process gas i													
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_2HF_5	CH_3F	C_3F_8	C_4F_8	NF_3	NF_3 Remote	SF_6	C_4F_6	C_5F_8	C_4F_8O
$BCHF_3$	0.060	0.0020	NA	0.049	NA	NA	NA	0.020	NA	NA	0.0011	0.066	0.0039	NA
BF_2	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.50	NA	NA	NA	NA

Notes: NA = Not applicable; *i.e.,* there are no applicable emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

■ 38. Revise table I–12 to subpart I of part 98 to read as follows:

TABLE I–12 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1-U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR USE WITH THE STACK TEST METHOD

[300 mm and 450 mm Wafers]

All processes	Process gas i													
	CF_4	C_2F_6	CHF_3	CH_2F_2	CH_3F	C_3F_8	C_3F_8 Remote	C_4F_8	NF_3	NF_3 Remote	SF_6	C_4F_6	C_5F_8	C_4F_8O
1–U_i	0.65	0.80	0.37	0.20	0.30	0.30	0.063	0.183	0.19	0.018	0.30	0.15	0.100	NA
BCF_4	NA	0.21	0.076	0.060	0.029	0.21	NA	0.045	0.040	0.037	0.033	0.059	0.109	NA
BC_2F_6	0.058	NA	0.058	0.043	0.0093	0.18	NA	0.027	0.0204	NA	0.041	0.062	0.083	NA
BC_4F_6	0.0083	NA	0.01219	NA	0.001	NA	NA	0.008	NA	NA	NA	NA	NA	NA
BC_4F_8	0.0046	NA	0.00272	0.054	0.007	NA	NA	NA	NA	NA	NA	0.0051	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00012	NA
BCH_2F_2	0.005	NA	0.0024	NA	0.0033	NA	NA	0.0021	0.00034	0.00088	0.000020	0.000030	NA	NA
BCH_3F	0.0061	NA	0.027	0.0036	NA	0.0007	NA	0.0063	0.0036	0.0028	0.0082	0.00065	NA	NA
$BCHF_3$	0.012	NA	NA	0.057	0.016	0.012	NA	0.028	0.0106	0.000059	0.0039	0.017	0.0069	NA
BF_2	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.50	NA	NA	NA	NA

■ 39. Revise table I–16 to subpart I of part 98 to read as follows:

TABLE I–16 TO SUBPART I OF PART 98—DEFAULT EMISSION DESTRUCTION OR REMOVAL EFFICIENCY (DRE) FACTORS FOR ELECTRONICS MANUFACTURING

Manufacturing type/process type/gas	Default DRE (percent)
MEMS, LCDs, and PV Manufacturing	60
Semiconductor Manufacturing	
CF_4	87
CH_3F	98
CHF_3	97
CH_2F_2	98
C_4F_8	93
C_4F_8O	93
C_5F_8	97
C_4F_6	95
C_3F_8	98
C_2HF_5	97
C_2F_6	98
SF_6	95
NF_3	88
All other carbon-based fluorinated GHGs used in Semiconductor Manufacturing	60
N_2O Processes	
CVD and all other N_2O-using processes	60

■ 40. Add table I–18 to subpart I of part 98 to read as follows:

TABLE I–18 TO SUBPART I OF PART 98 DEFAULT FACTORS FOR GAMMA ($\gamma_{i,p}$ AND $\gamma_{k,i,p}$) FOR SEMICONDUCTOR MANUFACTURING AND FOR MEMS AND PV MANUFACTURING UNDER CERTAIN CONDITIONS* FOR USE WITH THE STACK TESTING METHOD

Process type	In-situ thermal or in-situ plasma cleaning					Remote plasma cleaning		
Gas	CF_4	C_2F_6	c-C_4F_8	NF_3	SF_6	C_3F_8	CF_4	NF_3
If manufacturing wafer sizes ≤200 mm AND manufacturing 300 mm (or greater) wafer sizes								
γ_i	13	9.3	4.7	14	11	NA	NA	5.7
$\gamma_{CF4,i}$	NA	23	6.7	63	8.7	NA	NA	58
$\gamma_{C2F6,i}$	NA	NA	NA	NA	3.4	NA	NA	NA
$\gamma_{CHF3,i}$	NA	NA	NA	NA	NA	NA	NA	0.12
$\gamma_{CH2F2,i}$	NA	NA	NA	NA	NA	NA	NA	55
$\gamma_{CH3F,i}$	NA	NA	NA	NA	NA	NA	NA	16
If manufacturing ≤200 mm OR manufacturing 300 mm (or greater) wafer sizes								
γ_i (≤ 200 mm wafer size)	13	9.3	4.7	2.9	11	NA	NA	1.4
$\gamma_{CF4,i}$ (≤ 200 mm wafer size)	NA	23	6.7	110	8.7	NA	NA	36
$\gamma_{C2F6,i}$(≤ 200 mm wafer size)	NA	NA	NA	NA	3.4	NA	NA	NA
γ_i (300 mm wafer size)	NA	NA	NA	26	NA	NA	NA	10
$\gamma_{CF4,i}$(300 mm wafer size)	NA	NA	NA	17	NA	NA	NA	80
$\gamma_{C2F6,i}$ (300 mm wafer size)	NA	NA	NA	NA	NA	NA	NA	NA
$\gamma_{CHF3,i}$ (300 mm wafer size)	NA	NA	NA	NA	NA	NA	NA	0.24
$\gamma_{CH2F2,i}$ (300 mm wafer size)	NA	NA	NA	NA	NA	NA	NA	111
$\gamma_{CH3F,i}$ (300 mm wafer size)	NA	NA	NA	NA	NA	NA	NA	33

*If you manufacture MEMS or PVs and use semiconductor tools and processes, you may you use the corresponding γ in this table. For all other tools and processes, a default γ of 10 must be used.

■ 41. Add table I–19 to subpart I of part 98 to read as follows:

TABLE I–19 TO SUBPART I OF PART 98 REFERENCE EMISSION FACTORS ($1–U_{ij}$) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR 150 MM AND 200 MM WAFER SIZES

Process type/sub-type	Process gas i												
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_2HF_5	CH_3F	C_3F_8	C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
ETCHING/WAFER CLEANING													
1–Ui	0.73	0.46	0.31	0.37	0.064	0.66	NA	0.21	0.20	0.55	0.086	0.072	NA
BCF_4	NA	0.20	0.10	0.031	0.077	NA	NA	0.17	0.0040	0.023	0.089	NA	NA
BC_2F_6	0.029	NA	NA	NA	NA	NA	NA	0.065	NA	NA	0.045	0.014	NA
BC_4F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_4F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_5F_8	NA	NA	NA	NA	NA	NA	NA	0.016	NA	NA	NA	NA	NA
$BCHF_3$	0.13	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.0039	NA
CHAMBER CLEANING													
IN SITU PLASMA CLEANING													
1–Ui	0.92	0.55	NA	NA	NA	NA	0.40	0.10	0.18	NA	NA	NA	0.14
BCF_4	NA	0.19	NA	NA	NA	NA	0.20	0.11	0.14	NA	NA	NA	0.13
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.045
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
REMOTE PLASMA CLEANING													
1–Ui	NA	NA	NA	NA	NA	NA	NA	NA	0.028	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	0.015	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
IN SITU THERMAL CLEANING													
1–Ui	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

■ 42. Add table I–20 to subpart I of part 98 to read as follows:

TABLE I–20 TO SUBPART I OF PART 98 REFERENCE EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR 300 MM WAFER SIZES

Process type/ sub-type	Process gas i											
	CF_4	C_2F_6	CHF_3	CH_2F_2	CH_3F	C_3F_8	C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
ETCHING/WAFER CLEANING												
1–Ui	0.68	0.80	0.35	0.15	0.34	0.30	0.16	0.17	0.28	0.17	0.10	NA
BCF4	NA	0.21	0.073	0.020	0.038	0.21	0.045	0.035	0.0072	0.034	0.11	NA
BC2F6	0.041	NA	0.040	0.0065	0.0064	0.18	0.030	0.038	0.0017	0.025	0.083	NA
BC4F6	0.0015	NA	0.00010	NA	0.0010	NA	0.0083	NA	NA	NA	NA	NA
BC4F8	0.0051	NA	0.00061	NA	0.0070	NA	NA	NA	NA	NA	NA	NA
BC3F8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00012	NA
BC5F8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
$BCHF_3$	0.0056	NA	NA	0.033	0.0049	0.012	0.029	0.0065	0.0012	0.019	0.0069	NA
BCH2F2	0.014	NA	0.0026	NA	0.0023	NA	0.0014	0.00086	0.000020	0.000030	NA	NA
BCH3F	0.00057	NA	0.12	NA	NA	0.00073	NA	NA	0.0082	NA	NA	NA
CHAMBER CLEANING												
IN SITU PLASMA CLEANING												
1–Ui	NA	NA	NA	NA	NA	NA	NA	0.20	NA	NA	NA	NA
BCF4	NA	NA	NA	NA	NA	NA	NA	0.037	NA	NA	NA	NA
BC2F6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC3F8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
REMOTE PLASMA CLEANING												
1–Ui	NA	NA	NA	NA	NA	0.063	NA	0.018	NA	NA	NA	NA
BCF4	NA	NA	NA	NA	NA	NA	NA	0.038	NA	NA	NA	NA
BC2F6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC3F8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCHF3	NA	NA	NA	NA	NA	NA	NA	0.000059	NA	NA	NA	NA
BCH2F2	NA	NA	NA	NA	NA	NA	NA	0.0016	NA	NA	NA	NA
BCH3F	NA	NA	NA	NA	NA	NA	NA	0.0028	NA	NA	NA	NA
IN SITU THERMAL CLEANING												
1–Ui	NA	NA	NA	NA	NA	NA	NA	0.28	NA	NA	NA	NA
BCF4	NA	NA	NA	NA	NA	NA	NA	0.010	NA	NA	NA	NA
BC2F6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC3F8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Subpart N—Glass Production

■ 43. Amend § 98.146 by revising paragraphs (a)(2) and (b)(3) to read as follows:

§ 98.146 Data reporting requirements.

* * * * *

(a) * * *

(2) Annual quantity of glass produced (tons), by glass type, from each continuous glass melting furnace and from all furnaces combined.

(b) * * *

(3) Annual quantity of glass produced (tons), by glass type, from each continuous glass melting furnace and from all furnaces combined.

* * * * *

■ 44. Amend § 98.147 by revising paragraphs (a)(1) and (b)(1) to read as follows:

§ 98.147 Records that must be retained.

* * * * *

(a) * * *

(1) Monthly glass production rate for each continuous glass melting furnace, by glass type (tons).

* * * * *

(b) * * *

(1) Monthly glass production rate for each continuous glass melting furnace, by glass type (metric tons).

* * * * *

Subpart P—Hydrogen Production

■ 45. Amend § 98.163 by revising the introductory text and paragraph (b) introductory text and adding paragraph (d) to read as follows:

§ 98.163 Calculating GHG emissions.

You must calculate and report the annual CO2 emissions from each hydrogen production process unit using the procedures specified in paragraphs (a) through (d) of this section, as applicable.

* * * * *

(b) Fuel and feedstock material balance approach. Calculate and report CO2 emissions as the sum of the annual emissions associated with each fuel and feedstock used for hydrogen production by following paragraphs (b)(1) through (3) of this section. Adjust the emissions estimated using paragraphs (b)(1) through (b)(3) by correcting for non-CO_2 carbon produced, if applicable, according to paragraph (d) of this section. The carbon content and molecular weight shall be obtained from the analyses conducted in accordance with § 98.164(b)(2), (b)(3), or (b)(4), as applicable, or from the missing data procedures in § 98.165. If the analyses are performed annually, then the annual value shall be used as the monthly average. If the analyses are performed more frequently than monthly, use the arithmetic average of values obtained during the month as the monthly average.

* * * * *

(d) If carbon other than CO_2 is collected and transferred off site or if methanol is intentionally produced as a desired product, you must correct the

CO_2 emissions determined in paragraph (b) of this section to determine the net CO_2 emissions according to Equation P–4 of this section.

$$CO_{2,net} = \sum_{p=1}^{3} CO_{2,p} - \frac{44}{12}\sum_{n=1}^{k} C_{offsite,n} - \frac{44}{32}\sum_{n=1}^{k} MeOH_n \qquad \text{(Eq. P-4)}$$

$CO_{2,net}$ = Annual net CO_2 process emissions from hydrogen production unit (metric tons/yr).
$CO_{2,p}$ = Annual CO_2 process emissions arising from fuel and feedstock consumption based on fuel type ''p'' (metric tons/yr).
p = index for fuel or feedstock type; 1 indicates gaseous fuel or feedstocks; 2 indicates liquid fuel or feedstocks; and 3 indicates solid fuel or feedstocks
$C_{offsite,n}$ = Mass of carbon other than CO_2 or methanol collected from the hydrogen production unit and transferred off site, from company records for month n (metric tons carbon).
$MeOH_n$ = Mass of methanol intentionally produced as a desired product from the hydrogen production unit, from company records for month n (metric tons). If the methanol product has a 99.5 weight percent or higher purity, use the mass of methanol product produced; otherwise, you must correct that mass of product produced by the methanol purity (determined from company records) to determine the mass of methanol intentionally produced.
k = Months in the year.
44/12 = Ratio of molecular weights, CO_2 to carbon.
44/32 = Ratio of molecular weights, CO_2 to methanol.

■ 46. Amend § 98.164 by revising paragraphs (b)(2) through (4) and (b)(5) introductory text and adding paragraph (b)(5)(xix) to read as follows:

§ 98.164 Monitoring and QA/QC requirements.

* * * * *

(b) * * *

(2) Determine the carbon content and the molecular weight annually of standard gaseous hydrocarbon fuels and feedstocks having consistent composition (*e.g.,* natural gas) using the applicable methods in paragraph (b)(5) of this section. For non-hydrocarbon gaseous fuels and feedstocks that have a maximum product specification for carbon content less than or equal to 0.00002 kg carbon per kg of gaseous fuel or feedstock, you may determine the carbon content and the molecular weight annually using the product specification's maximum carbon content and molecular weight rather than using the methods specified in paragraph (b)(5) of this section. For other gaseous fuels and feedstocks (*e.g.,* biogas, refinery gas, or process gas), sample and analyze no less frequently than weekly to determine the carbon content and molecular weight of the fuel and feedstock using the applicable methods in paragraph (b)(5) of this section.

(3) Determine the carbon content of fuel oil, naphtha, and other liquid fuels and feedstocks at least monthly, except annually for standard liquid hydrocarbon fuels and feedstocks having consistent composition, or upon delivery for liquid fuels and feedstocks delivered by bulk transport (*e.g.,* by truck or rail) using the applicable methods in paragraph (b)(5) of this section. For non-hydrocarbon liquid fuels and feedstocks that have a maximum product specification for carbon content less than or equal to 0.00006 kg carbon per gallon of liquid fuel or feedstock, you may determine the carbon content annually using the product specification's maximum carbon content rather than using the methods specified in paragraph (b)(5) of this section.

(4) Determine the carbon content of coal, coke, and other solid fuels and feedstocks at least monthly, except annually for standard solid hydrocarbon fuels and feedstocks having consistent composition, or upon delivery for solid fuels and feedstocks delivered by bulk transport (*e.g.,* by truck or rail) using the applicable methods in paragraph (b)(5) of this section.

(5) Except as provided in paragraphs (b)(2) and (3) of this section for certain non-hydrocarbon feedstocks, you must use the following applicable methods to determine the carbon content for all fuels and feedstocks, and molecular weight of gaseous fuels and feedstocks. Alternatively, you may use the results of chromatographic analysis of the fuel and feedstock, provided that the chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the chromatograph are documented in the written monitoring plan for the unit under § 98.3(g)(5).

* * * * *

(xix) For non-hydrocarbon fuels and feedstocks, if the methods listed in paragraphs (b)(5)(i) through (xviii) of this section are not appropriate because the relevant compounds cannot be detected, the quality control requirements are not technically feasible, or use of the method would be unsafe, you may use modifications of the methods listed in paragraphs (b)(5)(i) through (xviii) or use other methods that are applicable to your fuel or feedstock.

■ 47. Amend § 98.166 by revising the introductory text and paragraphs (b)(1) and (d) to read as follows:

§ 98.166 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraph (a) or (b) of this section, as appropriate, and paragraphs (c) through (e) of this section:

* * * * *

(b) * * *

(1) Unit identification number and annual CO_2 emissions (determined in accordance with § 98.163(b) or (d), as applicable).

* * * * *

(d) Annual quantity of carbon other than CO_2 collected and transferred off site in either gas, liquid, or solid forms (metric tons carbon), excluding methanol, for each process unit.

* * * * *

■ 48. Amend § 98.167 by revising paragraph (b) and paragraph (e) introductory text and adding paragraphs (e)(13) and (14) to read as follows:

§ 98.167 Records that must be retained.

* * * * *

(b) If a CEMS is not used to measure CO_2 emissions, then you must retain records of all analyses and calculations conducted to determine the values reported in § 98.166(b) through (e).

* * * * *

(e) You must keep a record of the file generated by the verification software specified in § 98.5(b) for the applicable data specified in paragraphs (e)(1) through (14) of this section.

Retention of this file satisfies the recordkeeping requirement for the data in paragraphs (e)(1) through (14) of this section for each hydrogen production unit.

* * * * *

(13) Monthly mass of carbon other than CO_2 or methanol collected and transferred off site (metric tons carbon) (Equation P–4).

(14) Monthly mass of methanol intentionally produced as a desired product (metric tons) (Equation P–4).

Subpart Q—Iron and Steel Production

■ 49. Amend § 98.173 by revising Equation Q–5 in paragraph (b)(1)(v) to read as follows:

§ 98.173 Calculating GHG emissions.

* * * * *

(b) * * *

(1) * * *

(v) * * *

$$CO_2 = \frac{44}{12} * \left[(Iron) * (C_{iron}) + (Scrap) * (C_{scrap}) + (Flux) * (C_{Flux}) + (Electrode) * (C_{Electrode}) + (Carbon) * (C_{Carbon}) - (Steel) * (C_{Steel}) + (F_g) * (C_{gf}) * \frac{MW}{MVC} * 0.001 - (Slag) * (C_{Slag}) - (R) * (C_R) \right] \quad \text{(Eq. Q-5)}$$

* * * * *

■ 50. Amend § 98.174 by:

■ a. Revising paragraph (b)(2) introductory text;

■ b. Redesignating paragraph (b)(2)(vi) as paragraph (b)(2)(vii); and

■ c. Adding new paragraph (b)(2)(vi).

The revision and addition read as follows:

§ 98.174 Monitoring and QA/QC requirements.

* * * * *

(b) * * *

(2) Except as provided in paragraph (b)(4) of this section, determine the carbon content of each process input and output annually for use in the applicable equations in § 98.173(b)(1) based on analyses provided by the supplier, analyses provided by material recyclers who manage process outputs for sale or use by other industries, or by the average carbon content determined by collecting and analyzing at least three samples each year using the standard methods specified in paragraphs (b)(2)(i) through (b)(2)(vii) of this section as applicable.

* * * * *

(vi) ASTM E415–17, Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry (incorporated by reference, *see* § 98.7) as applicable for steel.

* * * * *

■ 51. Amend § 98.176 by revising paragraphs (e)(2) and (g) to read as follows:

§ 98.176 Data reporting requirements.

* * * * *

(e) * * *

(2) Whether the carbon content was determined from information from the supplier, material recycler, or by laboratory analysis, and if by laboratory analysis, the method used in § 98.174(b)(2).

* * * * *

(g) For each unit, the type of unit, the annual production capacity, and annual operating hours.

* * * * *

Subpart S—Lime Manufacturing

■ 52. Amend § 98.193 by revising paragraph (b)(2)(iv) to read as follows:

§ 98.193 Calculating GHG emissions.

* * * * *

(b) * * *

(2) * * *

(iv) You must calculate annual net CO_2 process emissions for all lime kilns using Equation S–4 of this section:

$$E_{CO2,net} = \sum_{i=1}^{t}\sum_{n=1}^{12}\left(EF_{LIME,i,n} * M_{LIME,i,n}\right) + \sum_{i=1}^{b}\sum_{n=1}^{12}\left(EF_{LKD,i,n} * M_{LKD,i,n}\right) + \sum_{i=1}^{z} E_{waste,i} - \sum_{n=1}^{12} E_{product,n} \quad \text{(Eq. S-4)}$$

Where:

$E_{CO2,\ net}$ = Annual net CO_2 process emissions from lime production from all lime kilns (metric tons/year).

$EF_{LIME,i,n}$ = Emission factor for lime type i produced, in calendar month n (metric tons CO_2/ton lime) from Equation S–1 of this section.

$M_{LIME,i,n}$ = Weight or mass of lime type i produced in calendar month n (tons).

$EF_{LKD,i,n}$ = Emission factor of calcined byproducts or wastes sold for lime type i in calendar month n, (metric tons CO_2/ ton byproduct or waste) from Equation S–2 of this section.

$M_{LKD,i,n}$ = Monthly weight or mass of calcined byproducts or waste sold (such as lime kiln dust, LKD) for lime type i in calendar month n (tons).

$E_{waste,i}$ = Annual CO_2 emissions for calcined lime byproduct or waste type i that is not sold (metric tons CO_2) from Equation S–3 of this section.

$E_{product,n}$ = Monthly amount of CO_2 from lime production that is captured for use in all on-site processes in calendar month n, as described in § 98.196(b)(17) (metric tons).

t = Number of lime types produced

b = Number of calcined byproducts or wastes that are sold.

z = Number of calcined byproducts or wastes that are not sold.

* * * * *

■ 53. Amend § 98.196 by:

■ a. Revising paragraph (a) introductory text;

■ b. Adding paragraphs (a)(9) through (14);

■ c. Revising paragraphs (b) introductory text, (b)(1), (b)(17) introductory text, and (b)(17)(i); and

■ d. Adding paragraphs (b)(22) and (23).

The revisions and additions read as follows:

§ 98.196 Data reporting requirements.

* * * * *

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required by § 98.36 and the information listed in paragraphs (a)(1) through (14) of this section.

* * * * *

(9) Annual arithmetic average of calcium oxide content for each type of

lime product produced (metric tons CaO/metric ton lime).

(10) Annual arithmetic average of magnesium oxide content for each type of lime product produced (metric tons MgO/metric ton lime).

(11) Annual arithmetic average of calcium oxide content for each type of calcined lime byproduct/waste sold (metric tons CaO/metric ton lime).

(12) Annual arithmetic average of magnesium oxide content for each type of calcined lime byproduct/waste sold (metric tons MgO/metric ton lime).

(13) Annual arithmetic average of calcium oxide content for each type of calcined lime byproduct/waste not sold (metric tons CaO/metric ton lime).

(14) Annual arithmetic average of magnesium oxide content for each type of calcined lime byproduct/waste not sold (metric tons MgO/metric ton lime).

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the information listed in paragraphs (b)(1) through (23) of this section.

(1) Annual net CO_2 process emissions from all lime kilns combined (metric tons).

* * * * *

(17) Indicate whether CO_2 was captured and used on-site (*e.g.,* for use in a purification process, the manufacture of another product). If CO_2 was captured and used on-site, provide the information in paragraphs (b)(17)(i) and (ii) of this section.

(i) The annual amount of CO_2 captured for use in all on-site processes.

* * * * *

(22) Annual average results of chemical composition analysis of all lime byproducts or wastes not sold.

(23) Annual quantity (tons) of all lime byproducts or wastes not sold.

■ 54. Amend § 98.197 by revising paragraph (c) introductory text and adding paragraph (c)(10) to read as follows:

§ 98.197 Records that must be retained.

* * * * *

(c) You must keep a record of the file generated by the verification software specified in § 98.5(b) for the applicable data specified in paragraphs (c)(1) through (10) of this section. Retention of this file satisfies the recordkeeping requirement for the data in paragraphs (c)(1) through (10) of this section.

* * * * *

(10) Monthly amount of CO_2 from lime production that is captured for use in all on-site processes, as described in § 98.196(b)(17) (metric tons) (Equation S–4).

Subpart W—Petroleum and Natural Gas Systems

■ 55. Amend § 98.230 by revising paragraph (a)(3) to read as follows:

§ 98.230 Definition of the source category.

(a) * * *

(3) *Onshore natural gas processing.* Natural gas processing means the forced extraction of natural gas liquids (NGLs) from field gas, fractionation of mixed NGLs to natural gas products, or both. Natural gas processing does not include a Joule-Thomson valve, a dew point depression valve, or an isolated or standalone Joule-Thomson skid. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant.

* * * * *

■ 56. Amend § 98.232 by:
■ a. Revising paragraphs (b) and (c)(21);
■ b. Adding paragraph (c)(23);
■ c. Revising paragraph (d)(7);
■ d. Adding paragraphs (d)(8) and (9);
■ e. Revising paragraph (e)(8);
■ f. Adding paragraph (e)(9);
■ g. Revising paragraphs (f)(6) and (8);
■ h. Adding paragraph (f)(9);
■ i. Revising paragraphs (g)(6) and (7);
■ j. Adding paragraph (g)(8);
■ k. Revising paragraphs (h)(7) and (8);
■ l. Adding paragraphs (h)(9) and (10) and (i)(8);
■ m. Revising paragraph (j)(10);
■ n. Adding paragraph (j)(13); and
■ o. Revising paragraph (m).

The revisions and additions read as follows:

§ 98.232 GHGs to report.

* * * * *

(b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEM in compliance with 30 CFR 550.302 through 304 and CO_2 and CH_4 emissions from other large release events. Offshore platforms do not need to report portable emissions.

(c) * * *

(21) Equipment leaks listed in paragraph (c)(21)(i) or (ii) of this section, as applicable:

(i) Equipment leaks from components including valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components listed in paragraph (c)(11) or (19) of this section, and it does not include thief hatches or other openings on a storage vessel).

(ii) Equipment leaks from major equipment including wellheads, separators, meters/piping, compressors, acid gas removal units, dehydrators, heater treaters, and storage vessels.

* * * * *

(23) Other large release events.

(d) * * *

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters, and equipment leaks from all other components in gas service that either are subject to equipment leak standards for processing plants in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(8) Natural gas pneumatic device venting.

(9) Other large release events.

(e) * * *

(8) Equipment leaks from all other components that are not listed in paragraph (e)(1), (2), or (7) of this section and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, or that you elect to survey using a leak detection method described in § 98.234(a). The other components subject to this paragraph (e)(8) also do not include thief hatches or other openings on a storage vessel.

(9) Other large release events.

(f) * * *

(6) Equipment leaks from all other components that are associated with storage stations, are not listed in paragraph (f)(1), (2), or (5) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

* * * * *

(8) Equipment leaks from all other components that are associated with storage wellheads, are not listed in paragraph (f)(1), (2), or (7) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a, of

this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(9) Other large release events.

(g) * * *

(6) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(7) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(8) Other large release events.

(h) * * *

(7) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(8) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in 40 CFR part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(9) Acid gas removal vents.

(10) Other large release events.

(i) * * *

(8) Other large release events.

(j) * * *

(10) Equipment leaks listed in paragraph (j)(10)(i) or (ii) of this section, as applicable:

(i) Equipment leaks from components including valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components in paragraph (j)(8) or (9) of this section, and it does not include thief hatches or other openings on a storage vessel).

(ii) Equipment leaks from major equipment including wellheads, separators, meters/piping, compressors, acid gas removal units, dehydrators, heater treaters, and storage vessels.

* * * * *

(13) Other large release events.

* * * * *

(m) For onshore natural gas transmission pipeline, report pipeline blowdown CO_2 and CH_4 emissions from blowdown vent stacks and CO_2 and CH_4 emissions from other large release events.

■ 57. Amend § 98.233 by:

■ a. Revising paragraphs (a), (c), (d) introductory text, and (d)(4)(vi);

■ b. Adding paragraph (d)(12);

■ c. Revising paragraphs (e) introductory text, (e)(1) introductory text; (e)(1)(x), and (e)(2) introductory text;

■ d. Revising parameter ''Count'' of Equation W–5 in paragraph (e)(2);

■ e. Removing and reserving paragraph (e)(3);

■ f. Removing paragraph (e)(4);

■ g. Redesignating paragraphs (e)(5) and (6) as (e)(4) and (5), respectively;

■ h. Revising newly redesignated paragraphs (e)(4) and (5) and paragraphs (g)(4), (h)(2), (i) introductory text, and (i)(2) introductory text;

■ i. Revising parameters ''T_a'' and ''P_a'' of Equation W–14A in paragraph (i)(2)(i);

■ j. Revising parameters ''$T_{a,p}$'', ''$P_{a,b,p}$'', and ''$P_{a,e,p}$'' of Equation W–14B in paragraph (i)(2)(i);

■ k. Adding paragraph (i)(2)(iv);

■ l. Revising paragraphs (j) introductory text, (j)(1) introductory text, (j)(1)(iii), (iv), and (vii), and (j)(2);

■ m. Revising parameter ''Count'' of Equation W–15 in paragraph (j)(3);

■ n. Revising paragraphs (j)(4) through (6), (k)(5), (l)(6), and (m)(3) introductory text;

■ o. Revising parameters ''$V_{p,q}$'' and ''$SG_{p,q}$'' of Equation W–18 in paragraph (m)(3);

■ p. Revising paragraphs (m)(5), (n) introductory text, (n)(1), (n)(2) introductory text, and (n)(5);

■ q. Removing and reserving paragraph (n)(9);

■ r. Revising paragraphs (o) introductory text, (o)(1)(i) introductory text, (o)(1)(i)(A) through (C), (o)(2) introductory text, (o)(2)(i) introductory text, and (o)(2)(ii);

■ s. Adding paragraph (o)(2)(iii);

■ t. Removing and reserving paragraph (o)(4)(ii)(D);

■ u. Revising paragraphs (o)(4)(ii)(E) and (o)(6)(i) introductory text;

■ v. Revising parameter ''m'' of Equation W–21 in paragraph (o)(6)(i);

■ w. Revising paragraph (o)(6)(ii) introductory text;

■ x. Revising parameter ''m'' of Equation W–22 in paragraph (o)(6)(ii);

■ y. Revising paragraph (o)(6)(iii) introductory text;

■ z. Revising parameter ''m'' of Equation W–23 in paragraph (o)(6)(iii);

■ aa. Revising parameter ''T_g'' of Equation W–24B in paragraph (o)(8);

■ bb. Revising paragraph (o)(10) introductory text;

■ cc. Revising parameter ''Count'' of Equation W–25 in paragraph (o)(10);

■ dd. Revising paragraphs (p) introductory text, (p)(1)(i), (p)(2) introductory text, (p)(2)(ii) introductory text, (p)(2)(ii)(C), (p)(2)(iii)(A), and (p)(4)(ii)(C);

■ ee. Removing and reserving paragraph (p)(4)(ii)(D);

■ ff. Revising paragraphs (p)(4)(ii)(E), (p)(6)(ii) introductory text, (p)(6)(iii) introductory text, and (p)(10) introductory text;

■ gg. Revising parameter ''Count'' of Equation W–29D in paragraph (p)(10);

■ hh. Revising paragraphs (q) introductory text, (q)(1), and (q)(2) introductory text;

■ ii. Revising parameter ''$EF_{s,p}$'' of Equation W–30 in paragraph (q)(2) introductory text;

■ jj. Revising paragraphs (q)(2)(i), (iii), (v), (x), and (xi);

■ kk. Adding paragraph (q)(3);

■ ll. Revising paragraph (r) introductory text;

■ mm. Revising parameters ''$E_{s,e,I}$,'' ''$E_{s,MR,I}$,'' ''$Count_e$,'' ''$Count_{MR}$,'' and ''$EF_{s,e}$'' of Equations W–32A and W–32B in paragraph (r) introductory text;

■ nn. Revising paragraphs (r)(2), (r)(6)(i) and (ii), and (s);

■ oo. Revising parameter "Z_a" of Equation W–34 in paragraph (t)(2);

■ pp. Removing the unnumbered text "You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions." after parameter "Z_a" of Equation W–34 in paragraph (t)(2); and

■ qq. Revising paragraphs (u)(2)(ii), (y), and (z).

The revisions and additions read as follows:

§ 98.233 Calculating GHG emissions.

* * * * *

(a) *Natural gas pneumatic device venting.* For all natural gas pneumatic devices at onshore natural gas processing facilities, onshore natural gas transmission compression facilities, and underground natural gas storage facilities, use methods specified in paragraphs (a)(1) through (5) of this section to calculate CH_4 and CO_2 emissions. For all continuous high bleed and continuous low bleed natural gas pneumatic devices at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility, use methods specified in paragraphs (a)(1) through (5) of this section to calculate CH_4 and CO_2 emissions. For intermittent bleed natural gas pneumatic devices at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility that are subject to monitoring requirements in part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, use the methods specified in paragraph (a)(6) of this section to calculate CH_4 and CO_2 emissions from those pneumatic devices. For intermittent bleed natural gas pneumatic devices at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility that are not subject to monitoring requirements in part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you may either elect to monitor your intermittent bleed natural gas pneumatic devices at least annually following the methods specified in part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, as applicable, and use the methods specified in paragraph (a)(6) of this section to calculate CH_4 and CO_2 emissions from your natural gas intermittent bleed pneumatic devices or use the methods specified in paragraphs (a)(1) through (5) of this section to calculate CH_4 and CO_2 emissions from your natural gas intermittent bleed pneumatic devices.

(1) Calculate CH_4 and CO_2 volumetric emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices using Equation W–1A of this section.

$$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t \qquad \text{(Eq. W-1A)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from natural gas pneumatic device vents, of types "t" (continuous high bleed, continuous low bleed, intermittent bleed), for GHG_i.

$Count_t$ = Total number of natural gas pneumatic devices of type "t" (continuous high bleed, continuous low bleed, intermittent bleed) as determined in paragraph (a)(1) or (a)(2) of this section.

EF_t = Population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type "t" listed in Tables W–1A, W–2B, W–3B, and W–4B to this subpart for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting, onshore natural gas processing, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively.

GHG_i = For onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas processing, onshore natural gas transmission compression facilities, and underground natural gas storage facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas or processed natural gas for each facility as specified in paragraphs (u)(2)(i) through (iv) of this section.

T_t = Average estimated number of hours in the operating year the devices, of each type "t", were in service (*i.e.,* supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours.

(2) For all industry segments, determine "$Count_t$" for Equation W–1A of this subpart for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) by counting the devices, except as specified in paragraph (a)(3) of this section. The reported number of devices must represent the total number of devices for the reporting year.

(3) For the onshore petroleum and natural gas production industry segment, you have the option in the first two consecutive calendar years to determine "$Count_t$" for Equation W–1A of this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) using engineering estimates based on best available data. For the onshore petroleum and natural gas gathering and boosting industry segment, you have the option in the first two consecutive calendar years to determine "$Count_t$" for Equation W–1A for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) using engineering estimates based on best available data.

(4) For all industry segments, determine the type of pneumatic device using engineering estimates based on best available information.

(5) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(6) Calculate CH_4 and CO_2 volumetric emissions using Equation W–1B of this section from natural gas intermittent bleed pneumatic devices that are monitored according to the requirements in this paragraph (a)(6).

$$E_i = GHG_i * \left[\left(24.1 * \sum_{z=1}^{x} T_z\right) + \left(0.3 * Count * T_{avg}\right)\right] \qquad \text{(Eq. W-1B)}$$

Where:

E_i = Annual total volumetric emissions of GHG_i from natural gas intermittent bleed pneumatic devices in standard cubic feet.

GHG_i = Concentration of GHG_i, CH_4, or CO_2, in natural gas supplied to the intermittent bleed device as defined in paragraph (u)(2) of this section.

x = Total number of intermittent bleed devices detected as malfunctioning in any pneumatic device monitoring survey during the year. A component found as malfunctioning in two or more surveys during the year is counted as one malfunctioning component.

24.1 = Whole gas emission factor for malfunctioning intermittent bleed natural gas pneumatic devices, in standard cubic feet per hour per device.

T_z = The total time the surveyed pneumatic device ''z'' was in service (*i.e.,* supplied with natural gas) and assumed to be leaking, in hours. If one pneumatic device monitoring survey is conducted in the calendar year, assume the device found malfunctioning was malfunctioning for the entire calendar year. If multiple pneumatic device monitoring surveys are conducted in the calendar year, assume a device found malfunctioning in the first survey was malfunctioning since the beginning of the year until the date of the survey; assume a device found malfunctioning in the last survey of the year was malfunctioning from the preceding survey through the end of the year; assume a device found malfunctioning in a survey between the first and last surveys of the year was malfunctioning since the preceding survey until the date of the survey; and sum times for all malfunctioning periods.

0.3 = Whole gas emission factor for properly operating intermittent bleed natural gas pneumatic devices, in standard cubic feet per hour.

Count = Total number of intermittent bleed devices that were never observed to be malfunctioning during any monitoring survey during the year.

T_{avg} = The average time the pneumatic devices that were never observed to be malfunctioning during any monitoring survey were in service (*i.e.,* supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours.

(i) You must conduct pneumatic device monitoring surveys using the methods in either paragraph (a)(6)(i) or (ii) of this paragraph.

(A) For intermittent bleed natural gas pneumatic devices that are subject to monitoring requirements in part 60, subpart OOOOb of this chapter or an approved state plan or Federal plan in part 62 of this chapter, as applicable, you must use the methods specified in the applicable standard.

(B) For intermittent bleed natural gas pneumatic devices that are not subject to monitoring requirements in part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter and that you elect to monitor, you must use the methods specified in part 60, subpart OOOOb of this chapter.

(ii) You must conduct at least one complete pneumatic device monitoring survey in a calendar year. If you conduct multiple complete pneumatic device monitoring surveys in a calendar year, you must use the results from each complete pneumatic device monitoring survey when calculating emissions using Equation W–1B.

(iii) Calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section.

* * * * *

(c) *Natural gas driven pneumatic pump venting.* Calculate emissions from natural gas driven pneumatic pumps venting directly to the atmosphere as specified in paragraphs (c)(1) and (2) of this section. Calculate emissions from natural gas driven pneumatic pumps routed to flares, combustion, or vapor recovery systems as specified in paragraph (c)(3) of this section. You do not have to calculate emissions from natural gas driven pneumatic pumps covered in paragraph (e) of this section under this paragraph (c).

(1) Calculate CH_4 and CO_2 volumetric emissions from natural gas driven pneumatic pump venting using Equation W–2 of this section.

$$E_{s,i} = Count * EF * GHG_i * T \qquad \text{(Eq. W-2)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from all natural gas driven pneumatic pump venting, for GHG_i.

Count = Total number of natural gas driven pneumatic pumps that vented directly to the atmosphere.

EF = Population emission factors for natural gas driven pneumatic pumps (in standard cubic feet per hour per pump) listed in Table W–1A of this subpart for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities.

GHG_i = Concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2)(i) of this section.

T = Average estimated number of hours in the operating year the pumps that vented directly to the atmosphere were in service (*i.e.,* supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours for pumps that only vented directly to the atmosphere.

(2) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(3) Calculate emissions from natural gas driven pneumatic pumps routed to flares, combustion, or vapor recovery systems as specified in paragraph (c)(3)(i) or (ii) of this section, as applicable. If a pump was vented directly to the atmosphere for part of the year and routed to a flare, combustion, or vapor recovery system during another part of the year, then calculate emissions from the time the pump vents directly to the atmosphere as specified in paragraphs (c)(1) and (2) of this section and calculate emissions from the time the pump was routed to a flare or combustion as specified in paragraphs (c)(3)(i) and (ii) of this section, as applicable. For emissions that are collected in a vapor recovery system that is not routed to combustion, paragraphs (c)(1) and (2) and (c)(3)(i) and (ii) do not apply and no emissions calculations are required.

(i) If any natural gas driven pneumatic pumps were routed to a flare, you must calculate CH_4, CO_2, and N_2O emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n), without subtracting emissions attributable to natural gas driven pneumatic pumps from the flare.

(ii) If emissions from any natural gas driven pneumatic pumps were routed to combustion, you must calculate emissions for the combustion equipment as specified in paragraph (z) of this section and report emissions from the combustion equipment as specified in § 98.236(z).

(d) *Acid gas removal (AGR) vents.* For AGR vents (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or emitted through an engine (*e.g.,* permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant, using any of the calculation methods described in paragraphs (d)(1) through (4) of this section, and also comply with paragraphs (d)(5) through (11), as applicable. For AGR emissions that are routed to a flare, calculate the flared emissions as specified in paragraph (d)(12) of this section.

* * * * *

(4) * * *

(vi) Solvent type, pressure, temperature, circulation rate, and composition.

* * * * *

(12) For AGR vents routed to a flare, calculate CO_2 emissions from the AGR as specified in paragraph (d)(12)(i) or (ii) of this section, as applicable.

(i) For emissions from an AGR unit that are routed to a dedicated flare, or if the emissions from the AGR unit are comingled with emissions from any other source types for routing to a flare and you do not continuously measure either flow or composition of the comingled gas stream, then calculate CO_2 emissions from the AGR using a method specified in paragraph (d)(1) through (4) of this section, as applicable. You must also incorporate your AGR data into the parameters V_s and X_{CO2} in Equation W–20 to account for the AGR portion of the total flared CO_2 emissions for all miscellaneous flared sources as described in paragraphs (n)(1) and (2) of this section.

(ii) For emissions from an AGR unit that are comingled with emissions from any other source types for routing to a flare and you continuously measure flow and/or composition of the comingled gas stream, then calculate total emissions from all miscellaneous flared sources (which includes AGRs) for the flare(s) to which the AGR emissions are routed using the procedures specified in paragraphs (n)(1) through (8) of this section. Use site-specific engineering estimates based on best available data to calculate the portion of the total flared CO_2 emissions from the miscellaneous flared sources that entered the flare from the AGR. Report the calculated portion of the total flared CO_2 emissions that entered the flare from the AGR as CO_2 emissions from the AGR as specified in § 98.236(d)(1)(v). Subtract this amount of CO_2 from the total flared CO_2 and report the remainder as CO_2 from miscellaneous flared sources as specified in § 98.236(n)(1)(xi).

(e) *Dehydrator vents.* For dehydrator vents, calculate annual CH_4 and CO_2 emissions using the applicable calculation methods described in paragraphs (e)(1) through (5) of this section. If emissions from dehydrator vents are routed to a vapor recovery system, you must adjust the emissions downward according to paragraph (e)(4) of this section. If emissions from dehydrator vents are routed to a flare or regenerator firebox/fire tubes, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (e)(5) of this section.

(1) *Calculation Method 1.* Calculate annual mass emissions from glycol dehydrators that have an annual average of daily natural gas throughput that is greater than or equal to 0.4 million standard cubic feet per day by using a software program, such as AspenTech HYSYS® or GRI–GLYCalc™, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas, and a gas injection pump or gas assist pump. Emissions must be modeled from both the still vent and, if applicable, the flash tank vent. The following parameters must be determined by engineering estimate based on best available data and must be used at a minimum to characterize emissions from dehydrators:

* * * * *

(x) Wet natural gas temperature and pressure at the absorber inlet.

* * * * *

(2) *Calculation Method 2.* Calculate annual volumetric emissions from glycol dehydrators that have an annual average of daily natural gas throughput that is less than 0.4 million standard cubic feet per day using Equation W–5 of this section, and then calculate the collective CH_4 and CO_2 mass emissions from the volumetric emissions using the procedures in paragraph (v) of this section:

* * * * *

Count = Total number of glycol dehydrators that have an annual average daily natural gas throughput that is greater than 0 million standard cubic feet per day and less than 0.4 million standard cubic feet per day.

* * * * *

(4) If the dehydrator unit has vapor recovery, calculate annual emissions as specified in paragraphs (e)(4)(i) and (ii) of this section.

(i) Adjust the emissions estimated in paragraphs (e)(1) and (2) of this section, as applicable, downward by the magnitude of emissions recovered using a vapor recovery system and by the amount of emissions routed to flares or regenerator firebox/fire tubes as determined by engineering estimate based on best available data. Report unrecovered emissions that are not routed to flares or regenerator fireboxes/fire tubes as emissions vented directly to the atmosphere.

(ii) If unrecovered emissions from the dehydrator are routed to flares or regenerator fireboxes/fire tubes, use the calculation method of flare stacks in paragraph (n) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent. Use the volume routed to the flares or regenerator fireboxes/fire tubes and the dehydrator vent gas composition as determined using either engineering estimates based on best available data or the procedures specified in paragraph (u)(2) of this section, as applicable. Report unrecovered emissions that are routed to flares or regenerator fireboxes/fire tubes as flared emissions from dehydrators.

(5) If any dehydrator vent streams are routed to a flare or regenerator firebox/ fire tubes, calculate emissions from these devices attributable to dehydrators as specified in paragraphs (e)(5)(i) through (v) of this section. If you operate a CEMS to monitor the emissions from the flare in accordance with paragraph (n)(8) of this section, calculate emissions as specified in paragraph (e)(5)(v) of this section instead of the provisions of paragraphs (e)(5)(i) through (iv) of this section.

(i) Determine the volume of gas from the dehydrator(s) to each flare using any of the methods specified in paragraph (e)(5)(i)(A) or (B) of this section. You are not required to use the same method for all dehydrator streams.

(A) Use the vented volume as determined in paragraphs (e)(1) through (4) of this section.

(B) Measure the flow from the dehydrator(s) to the flare or regenerator firebox/fire tubes using a continuous flow measurement device. If the measured volume is in a manifold that combines flow from multiple dehydrators or from dehydrators and other sources, use engineering calculations based on process knowledge and best available data to estimate the portion(s) of the total flow (in scf) from each large dehydrator or from all small dehydrators combined.

(ii) Except as specified in paragraph (e)(5)(iii) of this section, determine composition of the gas from the dehydrator(s) to each flare or regenerator firebox/fire tubes using any of the methods specified in paragraphs (e)(5)(ii)(A) through (C) of this section. You are not required to use the same method for all dehydrator streams.

(A) Use the gas composition as determined in paragraphs (e)(1) through (4) of this section.

(B) Measure the composition of the gas from the dehydrator(s) to the flare or regenerator firebox/fire tubes using a continuous composition analyzer. If the measured composition is in a manifold that combines streams only from multiple dehydrators, assume the measured composition applies to all dehydrators that route gas through the manifold.

(C) Measure the composition of the total gas to the flare or regenerator firebox/fire tubes using a continuous composition analyzer. If the measured composition is in a manifold that combines flow from dehydrators and other sources, use engineering calculations based on available sampling data for other sources, process knowledge, and best available data to estimate the composition of the flow from each large dehydrator or from all small dehydrators combined.

(iii) If you continuously measure flow in accordance with paragraph (e)(5)(i)(B) of this section and/or continuously measure gas composition in accordance with paragraph (e)(5)(ii)(B) or (C) of this section, then those measured data must be used, either directly or after disaggregating to individual sources, to calculate dehydrator emissions from flares or regenerator firebox/fire tubes.

(iv) Use the calculation method of flare stacks in paragraphs (n)(3) through (7) of this section to calculate annual dehydrator emissions from flares or regenerator firebox/fire tubes.

(v) If you monitor the flare with CEMS, use the calculation procedures in paragraph (n)(8) of this section. If the flare receives gas from multiple dehydrators or from both dehydrators and other sources, then use engineering calculations based on process knowledge and best available data to estimate the portions of the total CO_2 emissions measured by the CEMS that are from each large dehydrator and from all small dehydrators combined.

* * * * *

(g) * * *

(4) If any streams from well completions and workovers with hydraulic fracturing are flared, calculate annual emissions as specified in paragraphs (g)(4)(i) through (v) of this section. If you operate a CEMS to monitor the emissions from the flare in accordance with paragraph (n)(8) of this section, calculate emissions as specified in paragraph (g)(4)(v) of this section instead of the provisions of paragraphs (g)(4)(i) through (iv) of this section.

(i) Determine the volume of gas from well completions and workovers with hydraulic fracturing routed to each flare using any of the methods specified in paragraph (g)(4)(i)(A) or (B) of this section. You are not required to use the same method for all streams.

(A) Use the volume from gas venting to the atmosphere during well completions and workovers with hydraulic fracturing as determined in paragraph (g) of this section. Subtract the estimated amount vented to the atmosphere, if any, from this total volume.

(B) Measure the flow from well completions and workovers with hydraulic fracturing to the flare using a continuous flow measurement device. If the measured volume is in a manifold that combines flow from well completions and workovers with hydraulic fracturing and other sources, use engineering calculations based on process knowledge and best available data to estimate the portion(s) of the total flow (in scf) from well completions and workovers with hydraulic fracturing.

(ii) Except as specified in paragraph (g)(4)(iii) of this section, determine composition of the gas from well completions and workovers with hydraulic fracturing to each flare using any of the methods specified in paragraphs (g)(4)(ii)(A) through (C) of this section. You are not required to use the same method for all streams.

(A) Use the gas composition as determined in paragraph (g)(3) of this section.

(B) Measure the composition of the gas from well completions and workovers with hydraulic fracturing to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines streams only from well completions and workovers with hydraulic fracturing, assume the measured composition applies to all completions and workovers with hydraulic fracturing that route gas through the manifold.

(C) Measure the composition of the total gas to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines flow from well completions and workovers with hydraulic fracturing and other sources, use engineering calculations based on available sampling data for other sources, process knowledge, and best available data to estimate the composition of the flow from each well completions and workovers with hydraulic fracturing.

(iii) If you continuously measure flow in accordance with paragraph (g)(4)(i)(B) of this section and/or continuously measure gas composition in accordance with paragraph (g)(4)(ii)(B) or (C) of this section, then those measured data must be used, either directly or after disaggregating to individual sources, to calculate well completion and workover from hydraulic fracturing emissions from flares.

(iv) Use the calculation method of flare stacks in paragraphs (n)(3) through (7) of this section to calculate annual emissions for the portion of gas flared during well completions and workovers using hydraulic fracturing.

(v) If you monitor the flare with CEMS, use the calculation procedures in paragraph (n)(8) of this section. If the flare receives gas from multiple well completions and workovers with hydraulic fracturing or from both well completions and workovers with hydraulic fracturing and other sources, then use engineering calculations based on process knowledge and best available data to estimate the portions of the total CO_2 emissions measured by the CEMS that are from well completions and workovers with hydraulic fracturing.

(h) * * *

(2) If any streams from gas well completions and workovers without hydraulic fracturing are flared, calculate annual emissions of CH_4, CO_2, and N_2O as specified in paragraphs (h)(2)(i) through (v) of this section. If you operate a CEMS to monitor the emissions from the flare in accordance with paragraph (n)(8) of this section, calculate emissions as specified in paragraph (h)(2)(v) of this section instead of the provisions of paragraphs (h)(2)(i) through (iv) of this section.

(i) Determine the volume of gas from well completions and workovers without hydraulic fracturing routed to each flare using any of the methods specified in paragraph (h)(2)(i)(A) or (B) of this section. You are not required to use the same method for all streams.

(A) Use the gas well venting volume during well completions and workovers without hydraulic fracturing that are flared as determined using the methods specified in paragraphs (h) and (h)(1) of this section.

(B) Measure the flow from well completions and workovers without hydraulic fracturing to the flare using a continuous flow measurement device. If the measured volume is in a manifold that combines flow from well completions and workovers without hydraulic fracturing and other sources, use engineering calculations based on process knowledge and best available data to estimate the portion(s) of the total flow (in scf) from well completions and workovers without hydraulic fracturing.

(ii) Determine composition of the gas from well completions and workovers without hydraulic fracturing to each flare using any of the methods specified in paragraphs (h)(2)(ii)(A) through (C) of this section. You are not required to use the same method for all streams.

(A) Use the gas composition as determined in paragraphs (h) introductory text and (h)(1) of this section.

(B) Measure the composition of the gas from well completions and workovers without hydraulic fracturing to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines streams only from well completions and workovers without hydraulic fracturing, assume the measured composition applies to all completions and workovers without hydraulic fracturing that route gas through the manifold.

(C) Measure the composition of the total gas to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines flow from well completions and workovers without hydraulic fracturing and other sources, use engineering calculations based on available sampling data for other sources, process knowledge, and best available data to estimate the composition of the flow from each well completions and workovers without hydraulic fracturing.

(iii) If you continuously measure flow in accordance with paragraph (h)(2)(i)(B) of this section and/or continuously measure gas composition in accordance with paragraph (h)(2)(ii)(B) or (C) of this section, then those measured data must be used, either directly or after disaggregating to individual sources, to calculate well completion and workover from hydraulic fracturing emissions from flares.

(iv) Use the calculation method of flare stacks in paragraphs (n)(3) through (7) of this section to calculate annual emissions from the flare for gas well venting to a flare during completions and workovers without hydraulic fracturing.

(v) If you monitor the flare with CEMS, use the calculation procedures in paragraph (n)(8) of this section. If the flare receives gas from multiple well completions and workovers without hydraulic fracturing or from both well completions and workovers without hydraulic fracturing and other sources, then use engineering calculations based on process knowledge and best available data to estimate the portions of the total CO_2 emissions measured by the CEMS that are from well completions and workovers without hydraulic fracturing.

(i) *Blowdown vent stacks.* Calculate CO_2 and CH_4 blowdown vent stack emissions from the depressurization of equipment to reduce system pressure for planned or emergency shutdowns resulting from human intervention or to take equipment out of service for maintenance as specified in either paragraph (i)(2) or (3) of this section. You may use the method in paragraph (i)(2) of this section for some blowdown vent stacks at your facility and the method in paragraph (i)(3) of this section for other blowdown vent stacks at your facility. Equipment with a unique physical volume of less than 50 cubic feet as determined in paragraph (i)(1) of this section are not subject to the requirements in paragraphs (i)(2) through (4) of this section. The requirements in this paragraph (i) do not apply to blowdown vent stack emissions from depressurizing to a flare, over-pressure relief, operating pressure control venting, and blowdown of non-GHG gases.

* * * * *

(2) *Method for determining emissions from blowdown vent stacks according to equipment or event type.* If you elect to determine emissions according to each equipment or event type, using unique physical volumes as calculated in paragraph (i)(1) of this section, you must calculate emissions as specified in paragraph (i)(2)(i) of this section and either paragraph (i)(2)(ii) of this section or, if applicable, paragraph (i)(2)(iii) of this section for each equipment or event type. Categorize equipment and event types for each industry segment as specified in paragraph (i)(2)(iv) of this section.

(i) * * *

T_a = Temperature at actual conditions in the unique physical volume (°F). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates based on best available information may be used to determine the temperature.

* * * * *

P_a = Absolute pressure at actual conditions in the unique physical volume (psia). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates based on best available information may be used to determine the pressure.

* * * * *

$T_{a,p}$ = Temperature at actual conditions in the unique physical volume (°F) for each blowdown ''p''. For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates based on best available information may be used to determine the temperature.

* * * * *

$P_{a,b,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown ''p''. For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates based on best available information may be used to determine the pressure at the beginning of the blowdown.

$P_{a,e,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown ''p''; 0 if blowdown volume is purged using non-GHG gases. For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates based on best available information may be used to determine the pressure at the end of the blowdown.

* * * * *

(iv) Categorize blowdown vent stack emission events as specified in paragraphs (i)(2)(iv)(A) and (B) of this section, as applicable.

(A) For the onshore natural gas processing, transmission compression, LNG import and export equipment, and onshore petroleum and natural gas gathering and boosting industry segments, equipment or event types must be grouped into the following seven categories: Facility piping (*i.e.,* physical volumes associated with piping for which the entire physical volume is located within the facility boundary), pipeline venting (*i.e.,* physical volumes associated with pipelines for which a portion of the physical volume is located outside the facility boundary and the remainder, including the blowdown vent stack, is located 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. If a blowdown event resulted in emissions from multiple equipment types and the emissions cannot be apportioned to the different equipment types, then categorize the blowdown event as the equipment type that represented the largest portion of the emissions for the blowdown event.

(B) For the onshore natural gas transmission pipeline segment, pipeline segments or event types must be grouped into the following eight categories: Pipeline integrity work (*e.g.,* the preparation work of modifying facilities, ongoing assessments, maintenance or mitigation), traditional operations or pipeline maintenance, equipment replacement or repair (*e.g.,* valves), pipe abandonment, new construction or modification of pipelines including commissioning and change of service, operational precaution during activities (*e.g.* excavation near pipelines), emergency shutdowns including pipeline incidents as defined in 49 CFR 191.3, and all other pipeline segments with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple categories and the emissions cannot be apportioned to the different categories, then categorize the blowdown event in the category that represented the largest portion of the emissions for the blowdown event.

* * * * *

(j) *Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.* Calculate CH_4, CO_2, and N_2O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities (including stationary liquid storage not owned or operated by the reporter), as specified in this paragraph (j). For gas-liquid separators or onshore petroleum and natural gas gathering and boosting non-separator equipment (*e.g.,* stabilizers, slug catchers) with annual average daily throughput of hydrocarbon liquids greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 using Calculation Method 1 or 2 as specified in paragraphs (j)(1) and (2) of this section. For wells flowing directly to atmospheric storage tanks without passing through a separator with throughput greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 emissions using Calculation Method 2 as specified in paragraph (j)(2) of this section. For hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks with throughput less than 10 barrels per day, use Calculation Method 3 as specified in paragraph (j)(3) of this section. If you use Calculation Method 1 or Calculation Method 2 for separators, you must also calculate emissions that may have occurred due to dump valves not closing properly using the method specified in paragraph (j)(6) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a vapor recovery system, you must adjust the emissions downward according to paragraph (j)(4) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (j)(5) of this section.

(1) *Calculation Method 1.* Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks and onshore petroleum and natural gas gathering and boosting storage tanks using operating conditions in the last gas-liquid separator or non-separator equipment before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the hydrocarbon liquids from the separator or non-separator equipment enter an atmospheric pressure storage tank. The following parameters must be determined for typical operating conditions over the year by engineering estimate and process knowledge based on best available data, and must be used at a minimum to characterize emissions from liquid transferred to tanks:

* * * * *

(iii) Sales oil or stabilized hydrocarbon liquids API gravity.

(iv) Sales oil or stabilized hydrocarbon liquids production rate.

* * * * *

(vii) Separator or non-separator equipment hydrocarbon liquids composition and Reid vapor pressure. If this data is not available, determine these parameters by using one of the methods described in paragraphs (j)(1)(vii)(A) through (C) of this section.

(A) If separator or non-separator equipment hydrocarbon liquid composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator or non-separator equipment pressure first, and API gravity secondarily.

(B) If separator or non-separator equipment hydrocarbon liquids composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category for onshore petroleum and natural gas production or from the county for onshore petroleum and natural gas gathering and boosting.

(C) Analyze a representative sample of separator or non-separator equipment hydrocarbon liquids in each sub-basin category for onshore petroleum and natural gas production or each county for onshore petroleum and natural gas gathering and boosting for hydrocarbon liquids composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Method 2.* Calculate annual CH_4 and $COCO_2$ emissions using the methods in paragraph (j)(2)(i) of this section for gas-liquid separators with annual average daily throughput of hydrocarbon liquids greater than or equal to 10 barrels per day. Calculate annual CH_4 and $COCO_2$ emissions using the methods in paragraph (j)(2)(ii) of this section for wells with annual average daily hydrocarbon liquids production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting (if applicable). Calculate annual CH_4 and $COCO_2$ emissions using the methods in paragraph (j)(2)(iii) of this section for non-separator equipment with annual average daily hydrocarbon liquids throughput greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas gathering and boosting.

(i) *Flow to storage tank after passing through a separator.* Assume that all of the CH_4 and $COCO_2$ in solution at separator temperature and pressure is emitted from hydrocarbon liquids sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in § 98.234(b) to sample and analyze separator hydrocarbon liquids composition at separator pressure and temperature.

(ii) *Flow to storage tank direct from wells.* Calculate CH_4 and $COCO_2$ emissions using either of the methods in paragraph (j)(2)(ii)(A) or (B) of this section.

(A) If well production hydrocarbon liquids and gas compositions are available through a previous analysis, select the latest available analysis that is representative of produced hydrocarbon liquids and gas from the sub-basin category and assume all of the CH4 and CO2 in both hydrocarbon liquids and gas are emitted from the tank.

(B) If well production hydrocarbon liquids and gas compositions are not available, use default hydrocarbon liquids and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match the well production gas/oil ratio and API gravity and assume all of the CH4 and CO2 in both hydrocarbon liquids and gas are emitted from the tank.

(iii) Flow to storage tank direct from non-separator equipment. Calculate CH4 and CO2 emissions using either of the methods in paragraph (j)(2)(iii)(A) or (B) of this section.

(A) If other non-separator equipment hydrocarbon liquids and gas compositions are available through a previous analysis, select the latest available analysis that is representative of hydrocarbon liquids and gas from non-separator equipment in the same county and assume all of the CH4 and CO2 in both hydrocarbon liquids and gas are emitted from the tank.

(B) If non-separator equipment hydrocarbon liquids and gas compositions are not available, use default hydrocarbon liquids and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match the non-separator equipment gas/liquid ratio and API gravity and assume all of the CH4 and CO2 in both hydrocarbon liquids and gas are emitted from the tank.

(3) * * *

Count = Total number of separators, wells, or non-separator equipment with annual average daily throughput less than 10 barrels per day. Count only separators, wells, or non-separator equipment that feed hydrocarbon liquids directly to the storage tank.

* * * * *

(4) If the storage tank receiving your hydrocarbon liquids has a vapor recovery system, calculate annual emissions from storage tanks as specified in paragraphs (j)(4)(i) and (ii) of this section.

(i) Using engineering estimates based on best available data, determine the portion of the total emissions estimated in paragraphs (j)(1) through (3) of this section that is recovered using a vapor recovery system. You must take into account periods with reduced capture efficiency of the vapor recovery system (*e.g.,* when a thief hatch is open or not properly seated) when calculating emissions recovered.

(ii) Determine total emissions not recovered by a vapor recovery system as specified in paragraphs (j)(4)(ii)(A) and (B) of this section.

(A) Adjust the emissions estimated in paragraphs (j)(1) through (3) of this section downward by the magnitude of emissions recovered using a vapor recovery system and by the amount of emissions routed to flares. Unrecovered emissions may include, but are not limited to, emissions during periods when the vapor recovery system is not operating, losses from the tank when the vapor recovery system is not operating and the tank is connected to a flare, and losses from the tank during periods when the vapor recovery system is operating. These losses may include, but are not limited to, emissions due to open or unseated thief hatches. Report unrecovered emissions that are not routed to flares as emissions vented directly to the atmosphere.

(B) If unrecovered emissions from atmospheric tanks are routed to flares, determine the volume of gas routed to flares, calculate annual emissions from flares as specified in paragraphs (j)(5)(i) through (iii) of this section, and report as flared emissions from atmospheric tanks.

(5) If the storage tank receiving your hydrocarbon liquids has a flare(s), calculate annual flared emissions from storage tanks as specified in paragraphs (j)(5)(i) through (v) of this section and calculate emissions vented directly to the atmosphere as specified in paragraph (j)(5)(vi) of this section. For atmospheric tanks with emissions calculated using Calculation Method 3 in paragraph (j)(3) of this section, this paragraph (j)(5) only applies when at least half of the hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks are directed to atmospheric tanks that used flares to control emissions. If you operate a CEMS to monitor the emissions from the flare in accordance with paragraph (n)(8) of this section, calculate emissions as specified in paragraph (j)(5)(v) of this section instead of the provisions of paragraphs (j)(5)(i) through (iv) of this section.

(i) Estimate the volume routed to the flare using any of the methods specified in paragraph (j)(5)(i)(A) or (B) of this section. You are not required to use the same method for all storage tanks.

(A) If unrecovered emissions from the storage tank are calculated in accordance with paragraph (j)(4) of this section, then determine the volume of the unrecovered emissions routed to flares based on best available data. If no emissions from the storage tank are routed to vapor recovery, then use the storage tank emissions volume as determined in paragraphs (j)(1) through (3) of this section, except that you must also adjust this total volume of emissions downward by the estimated portion of the total volume that is not routed to the flare (*e.g.,* when the flare is bypassed or when a thief hatch is open or not properly seated). Estimate the volume of the emissions not routed to flares based on best available data.

(B) Measure the flow from the storage tank(s) to the flare using a continuous flow measurement device. If the measured volume is in a manifold that combines flow from storage tanks and other sources, use engineering calculations based on process knowledge and best available data to estimate the portion(s) of the total flow (in scf) from each storage tank.

(ii) Except as specified in paragraph (j)(5)(iii) of this section, determine the composition of the gas from the storage tanks routed to the flare using any of the methods specified in paragraphs (j)(5)(ii)(A) through (C) of this section. You are not required to use the same method for all storage tanks.

(A) If you use Calculation Method 1 or Calculation Method 2, use your gas composition as determined in paragraphs (j)(1) and (2) of this section. If you use Calculation Method 3 in paragraph (j)(3) of this section, determine the gas composition using either engineering estimates based on best available data or the procedures specified in paragraph (u)(2)(i) of this section.

(B) Measure the composition of the gas from the storage tanks to the flare using a continuous gas composition analyzer. If the measured composition is in a manifold that combines streams only from multiple storage tanks, assume the measured composition applies to all storage tanks that route gas through the manifold.

(C) Measure the composition of the total gas to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines flow from storage tanks and other sources, use engineering calculations based on available sampling data for other sources, process knowledge, and best available data to estimate the composition of the flow from storage tanks.

(iii) If you continuously measure flow in accordance with paragraph (j)(5)(i)(B) of this section and/or continuously measure gas composition in accordance with paragraph (j)(5)(ii)(B) or (C) of this section, then those measured data must be used, either directly or after disaggregating to individual sources, to calculate storage tank emissions from flares.

(iv) Use the calculation method of flare stacks in paragraphs (n)(3) through (7) of this section with the volume and composition determined according to paragraphs (j)(5)(i) and (ii) of this section to determine storage tank emissions from the flare.

(v) If you monitor the flare with CEMS, use the calculation procedures in paragraph (n)(8) of this section. If the flare receives gas from both storage tanks and other sources, then use engineering calculations based on process knowledge and best available data to estimate the portions of the total CO_2 emissions measured by the CEMS that are from storage tanks.

(vi) For storage tanks with no vapor recovery system, if the volume routed to the flare as determined in paragraph (j)(5)(i)(A) or (B) of this section is less than the total volume of emissions from the tank as estimated in paragraphs (j)(1) through (3) of this section, then use the volume not sent to the flare to calculate emissions of flash gas vented directly to the atmosphere from the storage tank.

(6) If you use Calculation Method 1 or Calculation Method 2 in paragraph (j)(1) or (2) of this section, calculate emissions from occurrences of gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W–16 of this section.

$$E_{s,i,dv} = CF_{dv} \times \frac{E_{s,i}}{8{,}760} \times T_{dv} \qquad \text{(Eq. W-16)}$$

Where:

$E_{s,i,dv}$ = Annual volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet from storage tanks that resulted from the dump valve on the gas-liquid separator not closing properly.

$E_{s,i}$ = Annual volumetric GHG emissions (either CO_2 or CH_4) as determined in paragraphs (j)(1) and (2) and, if applicable, (j)(4) and (5) of this section, in standard cubic feet per year, from storage tanks with dump valves on an associated gas-liquid separator that did not close properly.

T_{dv} = Total time a dump valve is not closing properly in the calendar year in hours. Estimate T_{dv} based on maintenance, operations, or routine separator inspections that indicate the period of time when the valve was malfunctioning in open or partially open position.

CF_{dv} = Correction factor for tank emissions for time period T_{dv} is 2.87 for crude oil production. Correction factor for tank emissions for time period T_{dv} is 4.37 for gas condensate production.

8,760 = Conversion to hourly emissions.

* * * * *

(k) * * *

(5) If any transmission storage tanks are routed to flares, calculate emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n), without subtracting emissions attributable to transmission tanks from the flare. If the volume to the flare is not continuously measured for the duration of time that flaring occurred, then conduct an annual leak measurement as specified in paragraph (k)(1)(ii) or (iv) of this section. If a leak is detected, quantify the leak in accordance with paragraph (k)(2)(i) or (ii) of this section and determine the time leaking as specified in paragraph (k)(3) of this section. Use these data when estimating total flow to the flare in accordance with paragraph (n)(1) of this section.

(l) * * *

(6) If any emissions from well testing are routed to a flare, calculate flared emissions from well testing as specified in paragraphs (l)(6)(i) through (v) of this section. If you operate a CEMS to monitor the emissions from the flare in accordance with paragraph (n)(8) of this section, calculate emissions as specified in paragraph (l)(6)(v) of this section instead of the provisions of paragraphs (l)(6)(i) through (iv) of this section.

(i) Determine the volume of gas from well testing to each flare using any of the methods specified in paragraph (l)(6)(i)(A) or (B) of this section. You are not required to use the same method for all well testing.

(A) Use the well testing emissions volume as determined in paragraphs (l)(1) through (4) of this section.

(B) Measure the flow from well testing to the flare using a continuous flow measurement device. If the measured volume is in a manifold that combines flow from well testing and other sources, use engineering calculations based on process knowledge and best available data to estimate the portion(s) of the total flow (in scf) from well testing.

(ii) Except as specified in paragraph (l)(6)(iii) of this section, determine composition of the gas from well testing to each flare using any of the methods specified in paragraphs (l)(6)(ii)(A) through (C) of this section. You are not required to use the same method for all well testing.

(A) Use the gas composition as determined in paragraphs (l)(1) through (4) of this section.

(B) Measure the composition of gas from well testing to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines streams only from testing of multiple wells, assume the measured composition applies to all well testing gas routed through the manifold.

(C) Measure the composition of the total gas to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines flow from well testing and other sources, use engineering calculations based on available sampling data for other sources, process knowledge, and best available data to estimate the composition of the flow from well testing.

(iii) If you continuously measure flow in accordance with paragraph (l)(6)(i)(B) of this section and/or continuously measure gas composition in accordance with paragraph (l)(6)(ii)(B) or (C) of this section, then those measured data must be used, either directly or after disaggregating to individual sources, to calculate well testing emissions from flares.

(iv) Use the calculation method of flare stacks in paragraphs (n)(3) through (7) of this section to determine annual well testing emissions from the flare.

(v) If you monitor the flare with CEMS, use the calculation procedures in paragraph (n)(8) of this section. If the flare receives gas from both well testing and other sources, then use engineering calculations based on process knowledge and best available data to estimate the portions of the total CO_2 emissions measured by the CEMS that are from well testing.

(m) * * *

(3) Estimate venting emissions using Equation W–18 of this section. Alternatively, if you measure the flow to a vent using a continuous flow measurement device, you must use the measured flow volumes to calculate vented associated gas emissions.

* * * * *

$V_{p,q}$ = Volume of oil produced, for well p in sub-basin q, in barrels in the calendar year only during time periods in which associated gas was vented or flared.

$SG_{p,q}$ = Volume of associated gas sent to sales, for well p in sub-basin q, in standard cubic feet of gas in the calendar year only during time periods in which associated gas was vented or flared.

* * * * *

(5) Calculate flared associated natural gas emissions as specified in paragraphs (m)(5)(i) through (v) of this section. If you operate a CEMS to monitor the emissions from the flare in accordance

with paragraph (n)(8) of this section, calculate emissions as specified in paragraph (m)(5)(v) of this section instead of the provisions of paragraphs (m)(5)(i) through (iv) of this section.

(i) Determine the volume of associated gas to each flare using any of the methods specified in paragraph (m)(5)(i)(A) or (B) of this section. You are not required to use the same method for all associated gas streams.

(A) Use the associated natural gas volume as determined in paragraphs (m)(1) through (4) of this section.

(B) Measure the flow of associated gas to the flare using a continuous flow measurement device. If the measured volume is in a manifold that combines flow from multiple associated gas streams or from associated gas streams and other sources, use engineering calculations based on process knowledge and best available data to estimate the portions of the total flow (in scf) that is associated gas.

(ii) Except as specified in paragraph (m)(5)(iii) of this section, determine composition of the associated gas to each flare using any of the methods specified in paragraphs (m)(5)(ii)(A) through (C) of this section. You are not required to use the same method for all associated gas streams.

(A) Use the associated gas composition as determined in paragraphs (m)(1) through (4) of this section.

(B) Measure the composition of the associated gas to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines only associated gas streams, assume the measured composition applies to all associated gas that is routed through the manifold.

(C) Measure the composition of the total gas to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines both associated gas and gas from other sources, use engineering calculations based on available sampling data for other sources, process knowledge, and best available data to estimate the composition of the associated gas in the combined stream.

(iii) If you continuously measure flow in accordance with paragraph (m)(5)(i)(B) of this section and/or continuously measure gas composition in accordance with paragraph (m)(5)(ii)(B) or (C) of this section, then those measured data must be used, either directly or after disaggregating to individual sources, to calculate associated gas emissions from flares.

(iv) Use the calculation method of flare stacks in paragraphs (n)(3) through (7) of this section to calculate annual associated gas emissions from flares.

(v) If you monitor the flare with CEMS, use the calculation procedures in paragraph (n)(8) of this section. If the flare receives both associated gas and gas from other sources, then use engineering calculations based on process knowledge and best available data to estimate the portions of the total CO_2 emissions measured by the CEMS that are from associated gas.

(n) *Flare stack emissions.* As applicable for the industry segment, use the procedures in paragraphs (n)(3) through (9) of this section to calculate CO_2, CH_4, and N_2O emissions per flare stack separately from dehydrators as specified in paragraph (e)(5) of this section, completions and workovers with hydraulic fracturing as specified in paragraph (g)(4) of this section, completions and workovers without hydraulic fracturing as specified in paragraph (h)(2) of this section, atmospheric tanks as specified in paragraph (j)(5) of this section, well testing as specified in paragraph (l)(6) of this section, and associated gas as specified in paragraph (m)(5) of this section. Also use the procedures specified in paragraphs (n)(1) through (9) of this section to calculate the collective emissions per flare stack from all miscellaneous flared sources (*i.e.,* sources that are not subject to source-specific flared emissions reporting for your industry segment).

(1) If you have a continuous flow measurement device on gas to the flare, you must use the measured flow volumes to calculate the flare gas emissions from miscellaneous flared sources. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data. If you do not have a continuous flow measurement device on gas to the flare, or if a continuous flow measurement device measures a stream that combines flow from sources that are subject to source-specific flared emissions reporting as well as flow from miscellaneous flared sources, you can use engineering calculations based on process knowledge and best available data to estimate the flow from the miscellaneous flared sources. Best available data also includes the procedures specified in paragraphs (e)(5), (g)(4), (h)(2), (j)(5), (k)(5), (l)(6), and (m)(5) of this section. If a continuous flow measurement device is not installed on an AGR that is routed to a flare, the volumetric CO_2 emissions calculated using AGR Calculation Method 3 or 4 and paragraph (d)(9) of this section must be incorporated into the parameter V_s in Equation W–20 to account for the AGR portion of the total flared CO_2 emissions.

(2) If you have a continuous gas composition analyzer on gas to the flare, you must use these compositions in calculating emissions from miscellaneous flared sources, except when the measured stream to the flare includes emissions from an AGR unit that are comingled with emissions from other sources. If you do not have a continuous gas composition analyzer on gas to the flare, or if the stream to the flare consists of AGR emissions that are comingled with emissions from other sources, you must use the appropriate gas compositions for each stream of hydrocarbons going to the flare from an emission source other than an AGR vent as specified in paragraphs (n)(2)(i) through (iii) of this section. For emissions from AGR vents that do not have a continuous gas composition analyzer, you may use either site-specific engineering estimates based on best available data or a default CO_2 mole fraction of 1.

* * * * *

(5) Calculate GHG volumetric emissions from flaring at standard conditions using Equations W–19 and W–20 of this section. Emissions may be calculated per stream routed to the flare and then summed over all streams per emissions source type. Alternatively, you may sum the total volume of all streams from a particular emission source type, determine the flow-weighted average CO_2 and hydrocarbon concentrations over all streams per source type, and then perform a single calculation using Equation W–19 and a single calculation using Equation W–20 to calculate the total CH_4 and CO_2 emissions per source type.

$$E_{s,CH_4} = V_s * X_{CH_4} * \left[(1-\eta) * Z_L + Z_U\right] \quad \text{(Eq. W-19)}$$

$$E_{s,CO_2} = V_s * X_{CO_2} + \sum_{j=1}^{5}\left(\eta * V_s * Y_j * R_j * Z_L\right) \quad \text{(Eq. W-20)}$$

Where:

$E_{s,CH4}$ = Annual CH_4 emissions per emission source type from flare stack in cubic feet, at standard conditions.

$E_{s,CO2}$ = Annual CO_2 emissions per emission source type from flare stack in cubic feet, at standard conditions.

V_s = Volume of gas sent to flare per emission source type in standard cubic feet, during the year as determined in paragraph (e)(5)(i), (g)(4)(i), (h)(2)(i), (j)(5)(i), (l)(6)(i), (m)(5)(i), or (n)(1) of this section.

η = Flare combustion efficiency, expressed as fraction of gas combusted by a burning flare (default is 0.98).

X_{CH4} = Mole fraction of CH_4 in the feed gas to the flare per emission source type as determined in paragraph (e)(5)(ii), (g)(4)(ii), (h)(2)(ii), (j)(5)(ii), (l)(6)(ii), (m)(5)(ii), or (n)(2) of this section. Use a flow-weighted mole fraction if multiple streams from the same source type are combined for the emissions calculation.

X_{CO2} = Mole fraction of CO_2 in the feed gas to the flare per emission source type as determined in paragraph (e)(5)(ii), (g)(4)(ii), (h)(2)(ii), (j)(5)(ii), (l)(6)(ii), (m)(5)(ii), or (n)(2) of this section. Use a flow-weighted mole fraction if multiple streams from the same source type are combined for the emissions calculation.

Z_U = Fraction of the feed gas sent to an un-lit flare per emission source type determined by engineering estimate and process knowledge based on best available data and operating records.

Z_L = Fraction of the feed gas sent to a burning flare per emission source type (equal to $1 - Z_U$).

Y_j = Mole fraction of hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus) in the feed gas to the flare per emissions source type as determined in paragraph (e)(5)(ii), (g)(4)(ii), (h)(2)(ii), (j)(5)(ii), (l)(6)(ii), (m)(5)(ii), or (n)(2) of this section.

R_j = Number of carbon atoms in the hydrocarbon constituent j in the feed gas to the flare per emission source type: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus).

* * * * *

(o) *Centrifugal compressor venting.* If you are required to report emissions from centrifugal compressor venting as specified in § 98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2), you must conduct volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section; perform calculations specified in paragraphs (o)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11) of this section. If you are required to report emissions from centrifugal compressor venting at an onshore petroleum and natural gas production facility as specified in § 98.232(c)(19) or an onshore petroleum and natural gas gathering and boosting facility as specified in § 98.232(j)(8), you must calculate volumetric emissions as specified in paragraph (o)(10); and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11). If emissions from a compressor source are routed to a flare, paragraphs (o)(1) through (11) do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (o)(12) of this section. If emissions from a compressor source are routed to combustion, paragraphs (o)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part or paragraph (z) of this section, as applicable. If emissions from a compressor source are routed to vapor recovery, paragraphs (o)(1) through (12) do not apply.

(1) * * *

(i) *Centrifugal compressor source as found measurements.* Measure venting from each compressor according to either paragraph (o)(1)(i)(A), (B), or (C) of this section at least once annually, based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement, except as specified in paragraph (o)(1)(i)(D) of this section. If additional measurements beyond the required annual testing are performed (including duplicate measurements or measurement of additional operating modes), then all measurements satisfying the applicable monitoring and QA/QC that is required by this paragraph (o) must be used in the calculations specified in this section.

(A) For a compressor measured in operating-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in paragraph (o)(2)(i) of this section, measure volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section if the compressor has wet seal oil degassing vents, and measure volumetric emissions from dry seal vents as specified in paragraph (o)(2)(iii) of this section if the compressor has dry seals.

(B) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in paragraph (o)(2)(i) of this section. If a compressor is not operated and has blind flanges in place throughout the reporting period, measurement is not required in this compressor mode.

(C) For a compressor measured in standby-pressurized-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in paragraph (o)(2)(i) of this section, measure volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section if the compressor has wet seal oil degassing vents, and measure volumetric emissions from dry seal vents as specified in paragraph (o)(2)(iii) of this section if the compressor has dry seals.

* * * * *

(2) *Methods for performing as found measurements from individual centrifugal compressor sources.* If conducting measurements for each compressor source, you must determine the volumetric emissions from blowdown valves and isolation valves as specified in paragraph (o)(2)(i) of this section, the volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section, and the volumetric emissions from dry seal vents as specified in paragraph (o)(2)(iii) of this section.

(i) For blowdown valves on compressors in operating-mode or in standby-pressurized-mode and for isolation valves on compressors in not-operating-depressurized-mode, determine the volumetric emissions using one of the methods specified in paragraphs (o)(2)(i)(A) through (D) of this section.

* * * * *

(ii) For wet seal oil degassing vents in operating-mode or in standby-pressurized-mode, determine volumetric flow at standard conditions, using one of the methods specified in paragraphs (o)(2)(ii)(A) through (C) of this section. You must quantitatively measure the volumetric flow for wet seal oil degassing vent; you may not use screening methods set forth in § 98.234(a) to screen for emissions for the wet seal oil degassing vent.

(A) Use a temporary meter such as a vane anemometer or permanent flow meter according to methods set forth in § 98.234(b).

(B) Use calibrated bags according to methods set forth in § 98.234(c).

(C) Use a high volume sampler according to methods set forth in § 98.234(d).

(iii) For dry seal vents in operating-mode or in standby-pressurized-mode, determine volumetric flow at standard conditions from each dry seal vent using one of the methods specified in paragraphs (o)(2)(ii)(A) through (D) of this section. If a compressor has more than one dry seal vent, determine the aggregate dry seal vent volumetric flow for the compressor as the sum of the volumetric flows determined for each dry seal vent on the compressor.

(A) Use a temporary meter such as a vane anemometer or permanent flow meter according to methods set forth in § 98.234(b).

(B) Use calibrated bags according to methods set forth in § 98.234(c).

(C) Use a high volume sampler according to methods set forth in § 98.234(d).

(D) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using one of these specified methods, then you must use one of the methods specified in paragraph (o)(2)(iii)(A) through (C) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the methods. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening dry seal vents.

* * * * *

(4) * * *

(ii) * * *

(E) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using one of these methods, then you must use one of the methods specified in paragraph (o)(4)(ii)(A) through (D) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the method. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening a manifolded group of compressor sources.

* * * * *

(6) * * *

(i) Using Equation W–21 of this section, calculate the annual volumetric GHG emissions for each centrifugal compressor mode-source combination specified in paragraphs (o)(1)(i)(A) through (C) of this section that was measured during the reporting year.

* * * * *

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A), (B), or (C) of this section that was measured for the reporting year.

(ii) Using Equation W–22 of this section, calculate the annual volumetric GHG emissions from each centrifugal compressor mode-source combination specified in paragraphs (o)(1)(i)(A) through (C) of this section that was not measured during the reporting year.

* * * * *

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A), (B), or (C) of this section that was not measured in the reporting year.

(iii) Using Equation W–23 of this section, develop an emission factor for each compressor mode-source combination specified in paragraphs (o)(1)(i)(A) through (C) of this section. These emission factors must be calculated annually and used in Equation W–22 of this section to determine volumetric emissions from a centrifugal compressor in the mode-source combinations that were not measured in the reporting year.

* * * * *

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A), (B), or (C) of this section.

* * * * *

(8) * * *

Tg = Total time the manifolded group of compressor sources g had potential for emissions in the reporting year, in hours. Include all time during which at least one compressor source in the manifolded group of compressor sources g was in a mode-source combination specified in either paragraph (o)(1)(i)(A), (o)(1)(i)(B), (o)(1)(i)(C), (p)(1)(i)(A), (p)(1)(i)(B), or (p)(1)(i)(C) of this section. Default of 8760 hours may be used.

* * * * *

(10) *Method for calculating volumetric GHG emissions from wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate emissions from atmospheric centrifugal compressor wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W–25 of this section. Emissions from centrifugal compressor wet seal oil degassing vents that are routed to a flare, combustion, or vapor recovery are not required to be determined under this paragraph (o).

* * * * *

Count = Total number of centrifugal compressors that have wet seal oil degassing vents that are vented to the atmosphere.

* * * * *

(p) *Reciprocating compressor venting.* If you are required to report emissions from reciprocating compressor venting as specified in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1), you must conduct volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section; perform calculations specified in paragraphs (p)(6) through (9) of this section; and calculate CH4 and CO2 mass emissions as specified in paragraph (p)(11) of this section. If you are required to report emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility as specified in § 98.232(c)(11) or an onshore petroleum and natural gas gathering and boosting facility as specified in § 98.232(j)(5), you must calculate volumetric emissions as specified in paragraph (p)(10); and calculate CH4 and CO2 mass emissions as specified in paragraph (p)(11). If emissions from a compressor source are routed to a flare, paragraphs (p)(1) through (11) do not apply and instead you must calculate CH4, CO2, and N2O emissions as specified in paragraph (p)(12) of this section. If emissions from a compressor source are routed to combustion, paragraphs (p)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part or paragraph (z) of this section, as applicable. If emissions from a compressor source are routed to vapor recovery, paragraphs (p)(1) through (12) do not apply.

(1) * * *

(i) *Reciprocating compressor source as found measurements.* Measure venting from each compressor according to either paragraph (p)(1)(i)(A), (B), or (C) of this section at least once annually, based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement, except as specified in paragraph (p)(1)(i)(D) of this section. If additional measurements beyond the required annual testing are performed (including duplicate measurements or measurement of additional operating modes), then all measurements satisfying the applicable monitoring and QA/QC that is required by this paragraph (p) must be used in the calculations specified in this section.

(A) For a compressor measured in operating-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in paragraph (p)(2)(i) of this section, and measure volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) or (iii) of this section, as applicable.

(B) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in paragraph (p)(2)(i) of this section. If a compressor is not operated and has blind flanges in place throughout the reporting period, measurement is not required in this compressor mode.

(C) For a compressor measured in standby-pressurized-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in paragraph (p)(2)(i) of this section and measure volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) or (iii) of this section, as applicable.

(D) An annual as found measurement is not required in the first year of operation for any new compressor that begins operation after as found measurements have been conducted for all existing compressors. For only the first year of operation of new compressors, calculate emissions according to paragraph (p)(6)(ii) of this section.

* * * * *

(2) *Methods for performing as found measurements from individual reciprocating compressor sources.* If conducting measurements for each compressor source, you must determine the volumetric emissions from blowdown valves and isolation valves as specified in paragraph (p)(2)(i) of this section. You must determine the volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) or (iii) of this section, as applicable.

* * * * *

(ii) For reciprocating rod packing equipped with an open-ended vent line on compressors in operating-mode or standby-pressurized-mode, determine the volumetric emissions using one of the methods specified in paragraphs (p)(2)(ii)(A) through (C) of this section.

* * * * *

(C) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using one of these specified methods, then you must use one of the methods specified in paragraph (p)(2)(ii)(A) and (B) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph (p)(2)(ii)(C), when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the method. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening or measuring rod packing emissions.

(iii) * * *

(A) You must use the methods described in § 98.234(a)(1) through (3) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or for compressors with a closed distance piece, conduct annual detection of gas emissions from the rod packing vent, distance piece vent, compressor crank case breather cap, or other vent emitting gas from the rod packing. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening rod packing emissions.

* * * * *

(4) * * *

(ii) * * *

(C) A high volume sampler according to methods set forth in § 98.234(d).

* * * * *

(E) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using one of these specified methods, then you must use one of the methods specified in paragraph (p)(4)(ii)(A) through (D) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the method. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening a manifolded group of compressor sources.

* * * * *

(6) * * *

(ii) Using Equation W–27 of this section, calculate the annual volumetric GHG emissions from each reciprocating compressor mode-source combination specified in paragraphs (p)(1)(i)(A) through (C) of this section that was not measured during the reporting year.

* * * * *

(iii) Using Equation W–28 of this section, develop an emission factor for each compressor mode-source combination specified in paragraphs (p)(1)(i)(A) through (C) of this section. These emission factors must be calculated annually and used in Equation W–27 of this section to determine volumetric emissions from a reciprocating compressor in the mode-source combinations that were not measured in the reporting year.

* * * * *

(10) *Method for calculating volumetric GHG emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate emissions from reciprocating compressor atmospheric venting of rod packing emissions at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W–29D of this section. Reciprocating compressor rod packing emissions that are routed to a flare, combustion, or vapor recovery are not required to be determined under this paragraph (p).

* * * * *

Count = Total number of reciprocating compressors with rod packing emissions vented to the atmosphere.

* * * * *

(q) *Equipment leak surveys.* For the components identified in paragraphs (q)(1)(i) through (iii) of this section, you must conduct equipment leak surveys using the leak detection methods specified in paragraphs (q)(1)(i) through (iii) and (v) of this section. For the components identified in paragraph (q)(1)(iv) of this section, you may elect to conduct equipment leak surveys, and if you elect to conduct surveys, you must use a leak detection method specified in paragraph (q)(1)(iv) of this section. This paragraph (q) applies to components in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Components in streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (q) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported.

(1) *Survey requirements.* (i) For the components listed in § 98.232(e)(7), (f)(5), (g)(4), and (h)(5), that are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive

emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must conduct surveys using any of the leak detection methods listed in § 98.234(a) and calculate equipment leak emissions using the procedures specified in either paragraph (q)(2) or (3) of this section.

(ii) For the components listed in § 98.232(i)(1), you must conduct surveys using any of the leak detection methods listed in § 98.234(a) except § 98.234(a)(2)(ii) and calculate equipment leak emissions using the procedures specified in either paragraph (q)(2) or (3) of this section.

(iii) For the components listed in § 98.232(c)(21)(i), (e)(7) and (8), (f)(5) through (8), (g)(4), (g)(6) and (7), (h)(5), (h)(7) and (8), and (j)(10)(i) that are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must conduct surveys using any of the leak detection methods in § 98.234(a)(1)(ii) or (iii) or (a)(2)(ii), as applicable, and calculate equipment leak emissions using the procedures specified in either paragraph (q)(2) or (3) of this section.

(iv) For the components listed in § 98.232(c)(21)(i), (e)(8), (f)(6) through (8), (g)(6) or (7), (h)(7) or (8), or (j)(10)(i), that are not subject to fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you may elect to conduct surveys according to this paragraph (q), and, if you elect to do so, then you must use one of the leak detection methods in § 98.234(a).

(A) If you elect to use a leak detection method in § 98.234(a) for the surveyed component types in § 98.232(c)(21)(i), (f)(7), (g)(6), (h)(7), or (j)(10)(i) in lieu of the population count methodology specified in paragraph (r) of this section, then you must calculate emissions for the surveyed component types in § 98.232(c)(21)(i), (f)(7), (g)(6), (h)(7), or (j)(10)(i) using the procedures in either paragraph (q)(2) or (3) of this section.

(B) If you elect to use a leak detection method in § 98.234(a) for the surveyed component types in § 98.232(e)(8), (f)(6) and (8), (g)(7), and (h)(8), then you must use the procedures in either paragraph (q)(2) or (3) of this section to calculate those emissions.

(C) If you elect to use a leak detection method in § 98.234(a)(1)(ii) or (iii), or (a)(2)(ii), as applicable, for any elective survey under this subparagraph (q)(1)(iv), then you must survey the component types in § 98.232(c)(21)(i), (e)(8), (f)(6) through (8), (g)(6) and (7), (h)(7) and (8), and (j)(10)(i) that are not subject to fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in 40 CFR part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, and you must calculate emissions from the surveyed component types in § 98.232(c)(21)(i), (e)(8), (f)(6) through (8), (g)(6) and (7), (h)(7) and (8), and (j)(10)(i) using the emission calculation requirements in either paragraph (q)(2) or (3) of this section.

(v) For the components listed in § 98.232(d)(7), you must conduct surveys as specified in paragraphs (q)(1)(v)(A) and (B) of this section and you must calculate equipment leak emissions using the procedures specified in either paragraph (q)(2) or (3) of this section.

(A) For the components listed in § 98.232(d)(7) that are not subject to the equipment leak standards in the equipment leak standards for processing plants in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you may use any of the leak detection methods listed in § 98.234(a).

(B) For the components listed in § 98.232(d)(7) that are subject to the equipment leak standards in the equipment leak standards for processing plants in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must use either of the leak detection methods in § 98.234(a)(1)(iii) or (a)(2)(ii).

(vi) Except as provided in paragraph (q)(1)(vii) of this section, you must conduct at least one complete leak detection survey in a calendar year. If you conduct multiple complete leak detection surveys in a calendar year, you must use the results from each complete leak detection survey when calculating emissions using the procedures specified in either paragraph (q)(2) or (3) of this section. Except as provided in paragraphs (q)(1)(v)(A) through (G) of this section, a complete leak detection survey is a survey in which all equipment components required to be surveyed as specified in paragraphs (q)(1)(i) through (v) of this section are surveyed.

(A) For components subject to the well site and compressor station fugitive emissions standards in § 60.5397a of this chapter, each survey conducted in accordance with § 60.5397a of this chapter will be considered a complete leak detection survey for purposes of this section.

(B) For components subject to the well site and compressor station fugitive emissions standards in the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, each survey conducted in accordance with the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter will be considered a complete leak detection survey for purposes of this section.

(C) For components subject to the well site and compressor station fugitive emissions standards in an applicable approved state plan or applicable Federal plan in part 62 of this chapter, each survey conducted in accordance with the applicable approved state plan or applicable Federal plan in part 62 of this chapter will be considered a complete leak detection survey for purposes of this section.

(D) For an onshore petroleum and natural gas production facility electing to conduct leak detection surveys according to paragraph (q)(1)(iv) of this section, a survey of all required components at a single well-pad will be considered a complete leak detection survey for purposes of this section.

(E) For an onshore petroleum and natural gas gathering and boosting facility electing to conduct leak detection surveys according to paragraph (q)(1)(iv) of this section, a survey of all required components at a gathering compressor station or centralized oil production site, as defined in § 98.238, will be considered a complete leak detection survey for purposes of this section.

(F) For an onshore natural gas processing facility subject to the equipment leak standards for onshore natural gas processing plants in the equipment leak standards for onshore natural gas processing plants in part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, each survey conducted in accordance with the equipment leak standards for onshore natural gas processing plants in part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter will be considered a complete leak detection survey for the purposes of calculating emissions using the procedures specified in either paragraph (q)(2) or (3) of this section. However, this provision does not absolve you of the responsibility to conduct a complete leak detection survey of all components listed in § 98.232(d)(7) and subject to this paragraph (q) at least once during the calendar year.

(G) For natural gas distribution facilities that choose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years as provided in paragraph (q)(1)(vii) of this section, a survey of all required components at the above grade transmission-distribution transfer stations monitored during the calendar year will be considered a complete leak detection survey for purposes of this section.

(vii) Natural gas distribution facilities are required to perform equipment leak surveys only at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do not meet the definition of transmission-distribution transfer stations are not required to perform equipment leak surveys under this section. Natural gas distribution facilities may choose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years ''n,'' not exceeding a five-year period to cover all above grade transmission-distribution transfer stations. If the facility chooses to use the multiple year option, then the number of transmission-distribution transfer stations that are monitored in each year should be approximately equal across all years in the cycle.

(2) *Calculation Method 1: Leaker emission factor* calculation methodology. If you elect to use this method, you must use this method for all components included in a complete leak survey. For industry segments listed in § 98.230(a)(2) through (9), if equipment leaks are detected during surveys required or elected for components listed in paragraphs (q)(1)(i) through (iv) of this section, then you must calculate equipment leak emissions per component type per reporting facility using Equation W–30 of this section and the requirements specified in paragraphs (q)(2)(i) through (ix) of this section. For the industry segment listed in § 98.230(a)(8), the results from Equation W–30 are used to calculate population emission factors on a meter/regulator run basis using Equation W–31 of this section. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(1)(vii) of this section, then you must calculate the emissions from all above grade transmission-distribution transfer stations as specified in paragraph (q)(2)(xi) of this section.

* * * * *

$EF_{s,p}$ = Leaker emission factor for specific component types by leak detection method listed in Tables W–1E, W–2A, W–3A, W–4A, W–5A, W–6A, and W–7A to this subpart.

* * * * *

(i) The leak detection surveys selected for use in Equation W–30 must be conducted during the calendar year as indicated in paragraph (q)(1)(vi) and (vii) of this section, as applicable.

* * * * *

(iii) Onshore petroleum and natural gas production facilities must use the appropriate default whole gas leaker emission factors consistent with the well type, where components associated with gas wells are considered to be in gas service and components associated with oil wells are considered to be in oil service as listed in Table W–1E to this subpart.

* * * * *

(v) Onshore natural gas processing facilities must use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in Table W–2A to this subpart.

* * * * *

(x) Natural gas distribution facilities must use Equation W–30 of this section and the default methane leaker emission factors for transmission-distribution transfer station components in gas service listed in Table W–7 to this subpart to calculate component emissions from annual equipment leak surveys conducted at above grade transmission-distribution transfer stations.

(A) Use Equation W–31 of this section to determine the meter/regulator run population emission factors for each GHGi. As additional survey data become available, you must recalculate the meter/regulator run population emission factors for each GHGi annually according to paragraph (q)(2)(x)(B) of this section.

$$EF_{s,MR,i} = \frac{\sum_{y=1}^{n}\sum_{p=1}^{7} E_{s,p,i,y}}{\sum_{y=1}^{n}\sum_{w=1}^{Count_{MR,y}} T_{w,y}} \qquad \text{(Eq. W-31)}$$

Where:

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over ''n'' years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs.

$E_{s,p,i,y}$ = Annual total volumetric emissions at standard conditions of GHG_i from component type ''p'' during year ''y'' in standard (''s'') cubic feet, as calculated using Equation W–30 of this section.

p = Seven component types listed in Table W–7 to this subpart for transmission-distribution transfer stations.

$T_{w,y}$ = The total time the surveyed meter/regulator run ''w'' was operational, in hours during survey year ''y'' using an engineering estimate based on best available data.

$Count_{MR,y}$ = Count of meter/regulator runs surveyed at above grade transmission-distribution transfer stations in year ''y''.

y = Year of data included in emission factor ''$EF_{s,MR,i}$'' according to paragraph (q)(2)(x)(B) of this section.

n = Number of years of data, according to paragraph (q)(1)(vii) of this section, whose results are used to calculate emission factor ''$EF_{s,MR,i}$'' according to paragraph (q)(2)(x)(B) of this section.

(B) The emission factor ''$EF_{s,MR,i}$'' based on annual equipment leak surveys at above grade transmission-distribution transfer stations, must be calculated annually. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(1)(vii) of this section and you have submitted a smaller number of annual reports than the duration of the selected cycle period of 5 years or less, then all available data from the current year and previous years must be used in the calculation of the emission factor ''$EF_{s,MR,i}$'' from Equation W–31 of this section. After the first survey cycle of ''n'' years is completed and beginning in calendar year (n+1), the survey will continue on a rolling basis by including the survey results from the current calendar year ''y'' and survey results from all previous $(n-1)$ calendar years, such that each annual calculation of the emission factor ''$EF_{s,MR,i}$'' from Equation W–31 is based on survey results from ''n'' years. Upon completion of a cycle, you may elect to change the number of years in the next cycle period (to be 5 years or less). If the number of years in the new cycle is greater than the number of years in the previous cycle, calculate ''$EF_{s,MR,i}$'' from Equation W–31 in each year of the new cycle using the survey results from the current calendar year and the survey results from the preceding number years that is equal to the number of years in the previous cycle period. If the number of years, ''n_{new},'' in the new cycle is smaller than the number of years in the previous cycle, ''n,'' calculate ''$EF_{s,MR,i}$'' from Equation W–31 in each year of the new cycle using the survey results from the current calendar year and survey results from all previous $(n_{new}-1)$ calendar years.

(xi) If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(1)(vii) of this section, you must use the meter/regulator run population emission factors calculated using Equation W–31 of this section and the total count of all meter/regulator runs at above grade transmission-distribution transfer stations to calculate emissions from all above grade transmission-distribution transfer stations using Equation W–32B in paragraph (r) of this section.

(3) *Calculation Method 2: Leaker measurement methodology.* If you elect to use this method, you must use this method for all components included in a complete leak survey. For industry segments listed in § 98.230(a)(2) through (9), if equipment leaks are detected during surveys required or elected for components listed in paragraphs (q)(1)(i) through (v) of this section, you must determine the volumetric flow rate of each natural gas leak identified during the leak survey and aggregate the emissions by component type as specified in paragraphs (q)(3)(i) through (vii) of this section.

(i) Determine the volumetric flow rate of each natural gas leak identified during the leak survey following the methods § 98.234(b) through (d), as appropriate for each leak identified. You do not need to use the same measurement method for each leak measured.

(ii) For each leak, calculate the volume of natural gas emitted as the product of the natural gas flow rate measured in paragraph (q)(3)(i) of this section and the duration of the leak. If one leak detection survey is conducted in the calendar year, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted in the calendar year, assume a component found leaking in the first survey was leaking since the beginning of the year until the date of the survey; assume a component found leaking in the last survey of the year was leaking from the preceding survey through the end of the year; assume a component found leaking in a survey between the first and last surveys of the year was leaking since the preceding survey until the date of the survey. For each leaking component, account for time the component was not operational (*i.e.,* not operating under pressure) using an engineering estimate based on best available data.

(iii) For each leak, convert the volumetric emissions of natural gas determined in paragraph (q)(3)(ii) of this section to standard conditions using the method specified in paragraph (t)(1) of this section.

(iv) For each leak, convert the volumetric emissions of natural gas at standard conditions determined in paragraph (q)(3)(iii) of this section to CO_2 and CH_4 volumetric emissions at standard conditions using the methods specified in paragraph (u) of this section.

(v) For each leak, convert the GHG volumetric emissions at standard conditions determined in paragraph (q)(3)(iv) of this section to GHG mass emissions using the methods specified in paragraph (v) of this section.

(vi) Sum the CO_2 and CH_4 mass emissions determined in paragraph (q)(3)(v) of this section separately for each type of component required to be surveyed for which a leak was detected.

(vii) For natural gas distribution facilities:

(A) Use Equation W–31 of this section to determine the meter/regulator run population emission factors for each GHG_i using the methods as specified in paragraphs (q)(2)(x)(A) and (B) of this section, except use the GHG mass emissions calculated in paragraph (q)(3)(vi) rather than the emissions calculated using Equation W–30.

(B) If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(1)(vii) of this section, you must use the meter/regulator run population emission factors calculated according to paragraph (q)(3)(vii)(A) of this section and the total count of all meter/regulator runs at above grade transmission-distribution transfer stations to calculate emissions from all above grade transmission-distribution transfer stations using Equation W–32B in paragraph (r) of this section.

(r) *Equipment leaks by population count.* This paragraph (r) applies to emissions sources listed in § 98.232(c)(21)(ii), (f)(7), (g)(5), (h)(6), and (j)(10)(ii) if you are not required to comply with paragraph (q) of this section and if you do not elect to comply with paragraph (q) of this section for these components in lieu of this paragraph (r). This paragraph (r) also applies to emission sources listed in § 98.232(i)(2) through (6) and (j)(11). To be subject to the requirements of this paragraph (r), the listed emissions sources also must contact streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources that contact streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (r) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. You must calculate emissions from all emission sources listed in this paragraph (r) using Equation W–32A of this section, except for natural gas distribution facility emission sources listed in § 98.232(i)(3). Natural gas distribution facility emission sources listed in § 98.232(i)(3) must calculate emissions using Equation W–32B of this section and according to paragraph (r)(6)(ii) of this section.

* * * * *

$E_{s,e,i}$ = Annual volumetric emissions of GHG_i from the emission source type in standard cubic feet. The emission source type may be a major equipment (*e.g.,* wellhead, separator), component (*e.g.,* connector, open-ended line), below grade metering-regulating station, below grade transmission-distribution transfer station, distribution main, distribution service, or gathering pipeline.

$E_{s,MR,i}$ = Annual volumetric emissions of GHG_i from all meter/regulator runs at above grade metering regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(2)(xi) or (q)(3)(vii)(B) of this section, the annual volumetric emissions of GHG_i from all meter/regulator runs at above grade transmission-distribution transfer stations.

$Count_e$ = Total number of the emission source type at the facility. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must count each major equipment piece listed in Table W–1A to this subpart. Onshore petroleum and natural gas gathering and boosting facilities must also count the miles of gathering pipelines by material type (protected steel, unprotected steel, plastic, or cast iron). Underground natural gas storage facilities must count each component listed in Table W–4B to this subpart. LNG storage facilities must count the number of vapor recovery compressors. LNG import and export facilities must count the number of vapor recovery compressors. Natural gas distribution facilities must count the: (1) Number of distribution services by material type; (2) miles of distribution mains by material type; (3) number of below grade transmission-distribution transfer stations; and (4) number of below grade metering-regulating stations; as listed in Table W–8 to this subpart.

$Count_{MR}$ = Total number of meter/regulator runs at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(2)(xi) or (q)(3)(vii)(B) of this section, the total number of meter/regulator runs at above grade transmission-distribution transfer stations.

$EF_{s,e}$ = Population emission factor for the specific emission source type, as listed in Tables W–1A, W–4B, W–5B, W–6B, and W–8 to this subpart.

* * * * *

(2) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must use the appropriate default whole gas population emission factors listed in Table W–1A of this subpart. Major equipment associated with gas wells are considered gas service equipment in Table W–1A of this subpart. Onshore petroleum and natural gas gathering and boosting facilities shall use the gas service equipment emission factors in Table W–1A of this subpart. Major equipment associated with crude oil wells are considered crude service equipment in Table W–1A of this subpart. Where facilities conduct EOR operations the emission factor listed in Table W–1A of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. For meters/piping, use one meters/piping per well-pad for onshore petroleum and natural gas production operations and the number of meters in the facility for onshore petroleum and natural gas gathering and boosting operations.

* * * * *

(6) * * *

(i) Below grade transmission-distribution transfer stations, below grade metering-regulating stations, distribution mains, and distribution services must use the appropriate default methane population emission factors listed in Table W–8 of this subpart to estimate emissions from components listed in § 98.232(i)(2), (4), (5), and (6), respectively.

(ii) Above grade metering-regulating stations that are not above grade transmission-distribution transfer stations must use the meter/regulator run population emission factor calculated in Equation W–31 for the components listed in § 98.232(i)(3). Natural gas distribution facilities that do not have above grade transmission-distribution transfer stations are not required to calculate emissions for above grade metering-regulating stations and are not required to report GHG emissions in § 98.236(r)(2)(v).

(s) *Offshore petroleum and natural gas production facilities.* Report CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEM in compliance with 30 CFR 550.302 through 304.

(1) Offshore production facilities under BOEM jurisdiction shall report the same annual emissions as calculated and reported by BOEM in data collection and emissions estimation study published by BOEM referenced in 30 CFR 550.302 through 304.

(i) For any calendar year that does not overlap with the most recent BOEM emissions study publication year, report the most recent BOEM reported emissions data published by BOEM referenced in 30 CFR 550.302 through 304. Adjust emissions based on the operating time for the facility relative to the operating time in the most recent BOEM published study.

(ii) [Reserved]

(2) Offshore production facilities that are not under BOEM jurisdiction must use the most recent monitoring methods and calculation methods published by BOEM referenced in 30 CFR 550.302 through 304 to calculate and report annual emissions.

(i) For any calendar year that does not overlap with the most recent BOEM emissions study publication, you may report the most recently reported emissions data submitted to demonstrate compliance with this subpart of part 98, with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

(ii) [Reserved]

(3) If BOEM discontinues or delays their data collection effort by more than 4 years, then offshore reporters shall once in every 4 years use the most recent BOEM data collection and emissions estimation methods to estimate emissions. These emission estimates would be used to report emissions from the facility sources as required in paragraph (s)(1)(i) of this section.

(4) For either first or subsequent year reporting, offshore facilities either within or outside of BOEM jurisdiction that were not covered in the previous BOEM data collection cycle must use the most recent BOEM data collection and emissions estimation methods published by BOEM referenced in 30 CFR 550.302 through 304 to calculate and report emissions.

(t) * * *

(2) * * *

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Z_a = Compressibility factor at actual conditions for GHG_i. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

* * * * *

(u) * * *

(2) * * *

(ii) *GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities.* For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in § 98.234(b).

* * * * *

(y) *Other large release events.* Calculate CO_2 and CH_4 emissions from other release events for each release that emits GHG in excess of 250 metric tons of CO_2e as specified in paragraphs (y)(1) through (4) of this section.

(1) Estimate the total volume of gas released during the event in standard

cubic feet using any combination of measurement data, engineering estimates, and best available data. Typically, total volume of gas released would be estimated as the product of the estimated flow or release rate and the estimated event duration.

(2) Determine the composition of the gas released to the atmosphere using measurement data, if available, or process knowledge, engineering estimates and best available data. In the event of an explosion or fire, where a portion of the natural gas may be combusted, estimate the composition of the gas released to the atmosphere considering the fraction of natural gas that was converted to CO_2 during the release event.

(3) Calculate the GHG volumetric emissions using Equation W–35 in paragraph (u)(1) of this section.

(4) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(z) *Onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution combustion emissions.* Except as specified in paragraphs (z)(5) and (6) of this section, calculate CO_2, CH_4, and N_2O combustion-related emissions from stationary or portable equipment using the applicable method in paragraphs (z)(1) through (3) of this section according to the fuel combusted as specified in those paragraphs:

(1) If a fuel combusted in the stationary or portable equipment meets the specifications of paragraph (z)(1)(i) of this section, then calculate emissions according to paragraph (z)(1)(ii) of this section.

(i) The fuel combusted in the stationary or portable equipment is listed in Table C–1 of subpart C of this part or is a blend in which all fuels are listed in Table C–1. If the fuel is natural gas or the blend contains natural gas, the natural gas must also meet the criteria of paragraphs (z)(1)(i)(A) and (B) of this section.

(A) The natural gas must be of pipeline quality specification.

(B) The natural gas must have a minimum higher heating value of 950 Btu per standard cubic foot.

(ii) For fuels listed in paragraph (z)(1)(i) of this section, calculate CO_2, CH_4, and N_2O emissions according to any Tier listed in subpart C of this part, except that natural gas-fired compressor-drivers must use the appropriate emission factor in Table W–9 for quantifying CH_4 emissions instead of the CH_4 emission factor in Table C–2 of subpart C of this part. You must follow all applicable calculation requirements for that tier listed in § 98.33, any monitoring or QA/QC requirements listed for that tier in § 98.34, any missing data procedures specified in § 98.35, and any recordkeeping requirements specified in § 98.37. You must report emissions according to paragraph (z)(4) of this section.

(2) If a fuel combusted in the stationary or portable equipment meets the specifications of paragraph (z)(2)(i) of this section, then calculate emissions according to paragraph (z)(2)(ii) of this section.

(i) The fuel combusted in the stationary or portable equipment is natural gas that is not pipeline quality or it is a blend containing natural gas that is not pipeline quality and other gaseous fuels listed in Table C–1. The natural gas also must meet the criteria of paragraphs (z)(2)(i)(A) through (C) of this section.

(A) The natural gas must have a minimum higher heating value of 950 Btu per standard cubic foot.

(B) The natural gas must have a maximum CO_2 content of 1 percent by volume.

(C) The natural gas must have a minimum CH_4 content of 85 percent by volume.

(ii) For fuels listed in paragraph (z)(2)(i) of this section, calculate CO_2, CH_4, and N_2O emissions according to Tier 2, Tier 3, or Tier 4 listed in subpart C of this part, except that natural gas-fired compressor-drivers must use the appropriate emissions factor in Table W–9 for quantifying CH_4 emissions instead of the CH_4 emission factor in Table C–2 of subpart C of this part. You must follow all applicable calculation requirements for that tier listed in § 98.33, any monitoring or QA/QC requirements listed for that tier in § 98.34, any missing data procedures specified in § 98.35, and any recordkeeping requirements specified in § 98.37. You must report emissions according to paragraph (z)(4) of this section.

(3) If a fuel combusted in the stationary or portable equipment meets the specifications of paragraph (z)(3)(i) of this section, then calculate emissions according to paragraph (z)(3)(ii) of this section.

(i) The fuel is not listed in Table C–1 of subpart C of this part, the fuel is a blend containing one or more fuels not listed in Table C–1, or the fuel is natural gas or contains natural gas that does not meet the criteria of either paragraph (z)(1)(i) or (z)(2)(i) of this section. This includes natural gas that has a higher heating value of less than 950 Btu per standard cubic feet and natural gas that is not pipeline quality and does not meet the composition criteria of either paragraph (z)(2)(i)(B) or (C) of this section. This also includes field gas that does not meet the definition of natural gas in § 98.238, and blends containing field gas that does not meet the definition of natural gas in § 98.238.

(ii) For fuels listed in paragraph (z)(3)(i) of this section, calculate combustion emissions for each unit or group of units combusting the same fuel as follows:

(A) You may use company records to determine the volume of fuel combusted in the unit or group of units during the reporting year.

(B) If you have a continuous gas composition analyzer on fuel to the combustion unit(s), you must use these compositions for determining the concentration of each hydrocarbon constituent in the flow of gas to the unit or group of units. If you do not have a continuous gas composition analyzer on gas to the combustion unit(s), you may use engineering estimates based on best available data to determine the concentration of each hydrocarbon constituent in the flow of gas to the unit or group of units. Otherwise, you must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit(s) as specified in the applicable paragraph in (u)(2) of this section.

(C) Calculate GHG volumetric emissions at actual conditions using Equations W–39A and W–39B of this section:

$$E_{a,CO_2} = (V_a * Y_{CO_2}) \quad + \quad \eta * \sum_{j=1}^{5} V_a * Y_j * R_j \qquad \text{(Eq. W-39A)}$$

$$E_{a,CH_4} = V_a * (1 - \eta) * Y_{CH_4} \quad \text{(Eq. W-39B)}$$

Where:

$E_{a,CO2}$ = Contribution of annual CO_2 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

V_a = Volume of gas sent to the combustion unit or group of units in actual cubic feet, during the year.

Y_{CO2} = Mole fraction of CO_2 in gas sent to the combustion unit or group of units.

$E_{a,CH4}$ = Contribution of annual CH_4 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

η = Fraction of gas combusted for portable and stationary equipment determined using engineering estimation. For internal combustion devices that are not compressor-drivers, a default of 0.995 can be used. For two-stroke lean-burn compressor-drivers, a default of 0.953 must be used; for four- stroke lean-burn compressor-drivers, a default of 0.962 must be used; and for four-stroke rich-burn compressor-drivers, a default of 0.997 must be used.

Y_j = Mole fraction of hydrocarbon constituent j (such as methane, ethane, propane, butane, and pentanes plus) in gas sent to the combustion unit or group of units.

R_j = Number of carbon atoms in the hydrocarbon constituent j in gas sent to the combustion unit or group of units; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus.

Y_{CH4} = Mole fraction of methane in gas sent to the combustion unit or group of units.

(D) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(E) Calculate both combustion-related CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(F) Calculate N_2O mass emissions using Equation W–40 of this section.

$$Mass_{N_2O} = (1 \times 10^{-3}) \times Fuel \times HHV \times EF \quad \text{(Eq. W-40)}$$

Where:

$Mass_{N2O}$ = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Annual mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = Higher heating value of fuel, mmBtu/unit of fuel (in units consistent with the fuel quantity combusted). For field gas or process vent gas, you may use either a default higher heating value of 1.235×10^{-3} mmBtu/scf or a site-specific higher heating value. For natural gas that is not of pipeline quality or that has a higher heating value less than 950 Btu per standard cubic foot, use a site-specific higher heating value.

EF = Use 1.0×10^{-4} kg N_2O/mmBtu.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(4) Emissions from fuel combusted in stationary or portable equipment at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities that are calculated according to the procedures in either paragraph (z)(1)(ii) or (z)(2)(ii) of this section must be reported according to the requirements specified in § 98.236(z) rather than the reporting requirements specified in subpart C of this part.

(5) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions or include these emissions for threshold determination in § 98.231(a). You must report the type and number of each external fuel combustion unit.

(6) Internal fuel combustion sources, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr (or the equivalent of 130 horsepower), do not need to report combustion emissions or include these emissions for threshold determination in § 98.231(a). You must report the type and number of each internal fuel combustion unit.

■ 58. Amend § 98.234 by revising the introductory text, paragraph (a), and paragraph (d)(3) and adding paragraphs (d)(5) and (i) to read as follows:

§ 98.234 Monitoring and QA/QC requirements.

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable as specified in this section. Offshore petroleum and natural gas production facilities shall adhere to the monitoring and QA/QC requirements as set forth in 30 CFR 550.

(a) You must use any of the applicable methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) or screening survey(s) as specified in § 98.233(k), (o), and (p) that occur during a calendar year. You must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(i) or (ii) or (q)(1)(v)(A) that occur during a calendar year. You must use one of the methods described in paragraph (a)(1)(ii) or (iii) or (a)(2)(ii) of this section, as applicable, to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(iii) or (q)(1)(v)(B). If electing to comply with § 98.233(q) as specified in § 98.233(q)(1)(iv), you must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of equipment leaks from component types as specified in § 98.233(q)(1)(iv) that occur during a calendar year. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. If the primary leak detection method employed cannot be used to monitor inaccessible components without elevating the monitoring personnel more than 2 meters above a support surface, you must use alternative leak detection devices as described in paragraph (a)(1) or (3) of this section to monitor inaccessible equipment leaks or vented emissions at least once per calendar year.

(1) *Optical gas imaging instrument.* Use an optical gas imaging instrument for equipment leak detection as specified in either paragraph (a)(1)(i), (ii), or (iii) of this section. You may use any of the methods as specified in paragraphs (a)(1)(i) through (iii) of this section unless you are required to use a specific method to comply with the fugitive emission component requirements in part 60, subpart OOOOa of this chapter or with the fugitive emission component or equipment leak requirements in part 60, OOOOb of this chapter or with the fugitive emission component or equipment leak requirements in an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(i) *Optical gas imaging instrument as specified in § 60.18 of this chapter.* Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, § 60.18 of the Alternative work practice for monitoring equipment leaks, § 60.18(i)(1)(i); § 60.18(i)(2)(i) except that the minimum monitoring frequency shall be annual using the detection sensitivity level of 60 grams per hour as stated in 40 CFR part 60, subpart A, Table 1: Detection Sensitivity Levels; § 60.18(i)(2)(ii) and (iii) except the gas chosen shall be methane, and § 60.18(i)(2)(iv) and (v); § 60.18(i)(3); § 60.18(i)(4)(i) and (v); including the requirements for daily instrument checks and distances, and excluding requirements for video records. Any emissions detected by the optical gas imaging instrument from an applicable component is a leak. In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(ii) *Optical gas imaging instrument as specified in § 60.5397a of this chapter.* Use an optical gas imaging instrument for equipment leak detection in accordance with § 60.5397a(b), (c)(3) and (7), and (e) of this chapter and paragraphs (a)(1)(ii)(A) through (C) of this section.

(A) For the purposes of this subpart, any visible emissions observed by the optical gas imaging instrument from a component required or elected to be monitored as specified in § 98.233(q)(1) is a leak.

(B) For the purposes of this subpart, the term ''fugitive emissions component'' in § 60.5397a of this chapter means ''component.''

(C) For the purpose of complying with § 98.233(q)(1)(iv), the phrase ''the collection of fugitive emissions components at well sites and compressor stations'' in § 60.5397a(b) of this chapter means ''the collection of components for which you elect to comply with § 98.233(q)(1)(iv).''

(iii) *Optical gas imaging instrument as specified in appendix K to part 60 of this chapter.* Use an optical gas imaging instrument for equipment leak detection in accordance with appendix K to part 60, *Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging.* Any emissions detected by the optical gas imaging instrument from an applicable component is a leak.

(2) *Method 21.* Use the equipment leak detection methods in Method 21 in appendix A–7 to part 60 of this chapter as specified in paragraph (a)(2)(i) or (ii) of this section. You may use either of the methods as specified in paragraphs (a)(2)(i) and (ii) of this section unless you are required to use a specific method to comply with the fugitive emission component requirements in part 60, subpart OOOOa of this chapter or with the fugitive emission component or equipment leak requirements in part 60, subpart OOOOb of this chapter or with the fugitive emission component or equipment leak requirements in an applicable approved state plan or applicable Federal plan in part 62 of this chapter. You must survey all applicable source types at the facility needed to conduct a complete equipment leak survey as defined in § 98.233(q)(1). For the purposes of this subpart, the term ''fugitive emissions component'' in § 60.5397a of this chapter means ''component.''

(i) *Method 21 with a leak definition of 10,000 ppm.* Use the equipment leak detection methods in Method 21 in appendix A–7 to part 60 of this chapter using methane as the reference compound. If an instrument reading of 10,000 ppm or greater is measured for any applicable component, a leak is detected.

(ii) *Method 21 with a leak definition of 500 ppm.* Use the equipment leak detection methods in Method 21 in appendix A–7 to part 60 of this chapter using methane as the reference compound. If an instrument reading of 500 ppm or greater is measured for any applicable component, a leak is detected.

(3) *Infrared laser beam illuminated instrument.* Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak. In addition, you must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(4) [Reserved]

(5) *Acoustic leak detection device.* Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, you must use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, you must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters. Acoustic stethoscope type devices designed to detect through valve leakage when put in contact with the valve body and that provide an audible leak signal but do not calculate a leak rate can be used to identify through-valve leakage. For these acoustic stethoscope type devices, a leak is detected if an audible leak signal is observed or registered by the device. If the acoustic stethoscope type device is used as a screening to a measurement method and a leak is detected, the leak must be measured using any one of the methods specified in paragraphs (b) through (d) of this section.

* * * * *

(d) * * *

(3) For high volume samplers that output methane mass emissions, you must use the calculations in § 98.233(u) and (v) in reverse to determine the natural gas volumetric emissions at standard conditions. For high volume samplers that output methane volumetric flow in actual conditions, divide the volumetric methane flow rate by the mole fraction of methane in the natural gas according to the provisions in § 98.233(u) and estimate natural gas volumetric emissions at standard conditions using calculations in § 98.233(t). Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(u) and (v).

* * * * *

(5) If the measured methane flow exceeds the manufacturer's reported quantitation limit or if the measured natural gas flow determined as specified in paragraph (d)(3) of this section exceeds 70 percent of the manufacturer's reported maximum sampling flow rate, then the flow exceeds the capacity of the instrument and you must either use a temporary or permanent flow meter according to paragraph (b) of this section or use calibrated bags according to paragraph (c) of this section to determine the leak or flow rate.

* * * * *

(i) *Special reporting provisions for best available monitoring methods in reporting year 2023*—(1) *Use of best available monitoring methods.* From January 1, 2023, to December 31, 2023, you must use the calculation methodologies and equations in § 98.233 but you may use the best available monitoring method as described in paragraph (i)(2) of this section for any parameter specified in paragraphs (i)(3) through (7) of this section for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2023. Starting no later than January 1, 2024, you must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part.

(2) *Best available monitoring methods.* Best available monitoring

methods means any of the following methods:

(i) Monitoring methods currently used by the facility that do not meet the specifications of this subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other facility records.

(3) *Best available monitoring methods for measurement data for natural gas pneumatic devices.* You may use best available monitoring methods for any measurement data, including activity data such as gas compositions and hours of operation, that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for natural gas pneumatic devices as specified in § 98.233(a) at onshore natural gas processing plants and for natural gas intermittent bleed pneumatic devices that are monitored as specified in § 98.233(a)(6).

(4) *Best available monitoring methods for measurement data for LNG import/export facilities.* You may use best available monitoring methods for any measurement data, including activity data such as flow rates, gas compositions, and hours of operation, that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for acid gas removal vents as specified in § 98.233(d) at LNG import/export facilities.

(5) *Best available monitoring methods for measurement data for other large release events.* You may use best available monitoring methods for any measurement data, including activity data such as flow rates, gas compositions, and hours of operation, that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for other large release events as specified in § 98.233(y).

(6) *Best available monitoring methods for measurement data for miscellaneous flared sources.* You may use best available monitoring methods for any measurement data, including activity data such as flow rates and gas compositions, that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for miscellaneous flared sources as specified in § 98.233(n)(1) and (2).

(7) *Best available monitoring methods for measurement data for specific emission sources routed to vapor recovery.* You may use best available monitoring methods for any measurement data, including activity data such as flow rates, gas compositions, and hours of operation, that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for dehydrator vents and storage tank vents routed to vapor recovery as specified in § 98.233(e)(4) and (j)(4), respectively.

(8) *Best available monitoring methods for measurement data for compressors.* You may use best available monitoring methods for any measurement data that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for dry seal vents on centrifugal compressors and all compressor sources for centrifugal compressors found in standby-pressurized-mode as specified in § 98.233(o). You may use best available monitoring methods for any measurement data that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for rod packing on reciprocating compressors in standby-pressurized-mode as specified in § 98.233(p).

(9) *Best available monitoring methods for measurement data for a facility that was part of a facility with respect to onshore petroleum and natural gas gathering and boosting prior to January 1, 2023, and meets the definition of onshore natural gas processing in § 98.230(a)(3) effective as of January 1, 2023.* You may use best available monitoring methods for measurement data, including activity data, as listed in paragraphs (i)(9)(i) through (iv) of this section that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart.

(i) Temperature and pressure for emergency blowdowns in § 98.233(i).

(ii) Equipment leak surveys in § 98.233(q).

(iii) Centrifugal compressors in § 98.233(o).

(iv) Reciprocating compressors in § 98.233(p).

(10) *Best available monitoring methods for measurement data for a facility that was an onshore natural gas processing facility prior to January 1, 2023, and became part of a facility with respect to onshore petroleum and natural gas gathering and boosting as defined in § 98.238 as of January 1, 2023, due to the change in definition of onshore natural gas processing in § 98.230(a)(3) effective as of January 1, 2023.* You may use best available monitoring methods for measurement data, including activity data, as listed in paragraphs (i)(10)(i) through (iii) of this section that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart.

(i) Natural gas driven pneumatic pumps in § 98.233(c).

(ii) Storage tanks in § 98.233(j).

(iii) Equipment leak surveys in § 98.233(q) and/or equipment leaks by population count in § 98.233(r), as applicable, for equipment components not required for the onshore natural gas processing industry segment (*i.e.,* pumps, flanges, other components, and gathering pipelines).

■ 59. Amend § 98.236 by:

■ a. Revising the introductory text and paragraphs (a)(1) introductory text and (a)(1)(xviii);

■ b. Adding paragraph (a)(1)(xix);

■ c. Revising paragraphs (a)(2) and (a)(3) introductory text;

■ d. Redesignating paragraphs (a)(3)(i) through (vii) as paragraphs (a)(3)(ii) through (viii), respectively;

■ e. Adding new paragraph (a)(3)(i) and paragraph (a)(3)(ix);

■ f. Revising paragraph (a)(4) introductory text;

■ g. Adding paragraph (a)(4)(viii);

■ h. Revising paragraph (a)(5) introductory text;

■ i. Adding paragraph (a)(5)(vii);

■ j. Revising paragraph (a)(6) introductory text;

■ k. Adding paragraph (a)(6)(vi);

■ l. Revising paragraph (a)(7) introductory text;

■ m. Redesignating paragraphs (a)(7)(i) through (vi) as paragraphs (a)(7)(ii) through (vii), respectively;

■ n. Adding new paragraph (a)(7)(i) and paragraph (a)(7)(viii);

■ o. Revising paragraph (a)(8) introductory text;

■ p. Adding paragraph (a)(8)(iv);

■ q. Revising paragraphs (a)(9) introductory text and (a)(9)(xii);

■ r. Adding paragraph (a)(9)(xiii);

■ s. Revising paragraphs (a)(10), (b), (c), (d)(1)(iii), and (d)(2)(iii)(L);

■ t. Adding paragraph (d)(2)(iv);

■ u. Revising paragraphs (e) introductory text, (e)(1) introductory text, and (e)(1)(viii), (xi), (xii), and (xv) through (xviii);

■ v. Adding paragraph (e)(1)(xix);

■ w. Revising paragraph (e)(2);

■ x. Removing and reserving paragraph (e)(3);

■ y. Revising paragraphs (f)(1) introductory text and (f)(1)(iii);

■ z. Adding paragraphs (f)(1)(xi)(F) and (f)(1)(xii)(F);

■ aa. Revising paragraphs (f)(2) introductory text and (f)(2)(iii), (ix) and (x);

■ bb. Adding paragraphs (f)(2)(xi) and (xii);

■ cc. Revising paragraphs (g)(10), (h)(2) introductory text, and (h)(2)(v) through (vii);

■ dd. Adding paragraphs (h)(2)(viii) through (xvi);

■ ee. Revising paragraphs (h)(4) introductory text and (h)(4)(iii) through (v);

■ ff. Adding paragraphs (h)(4)(vi) through (xiv);
■ gg. Revising paragraphs (i)(1) introductory text, (j) introductory text, (j)(1) and (2), (j)(3)(ii), (k)(1)(ii) through (iv), (k)(2) introductory text, (k)(3), (l)(1) introductory text, (l)(2) introductory text, and (l)(2)(vi) through (viii);
■ hh. Adding paragraphs (l)(2)(ix) through (xvii);
■ ii. Revising paragraphs (l)(3) introductory text, (l)(4) introductory text, and (l)(4)(v) through (vii);
■ jj. Adding paragraphs (l)(4)(viii) through (xvi);
■ kk. Revising paragraphs (m)(4) through (8), (n), (o)(1), (o)(2)(i)(B), (o)(2)(ii)(A), (o)(5)(i) through (iii), (p)(1), (p)(2)(ii)(A), (p)(3)(ii) introductory text, (p)(5)(i) through (iii), (q)(1) introductory text, and (q)(1)(iii);
■ ll. Adding paragraphs (q)(1)(vi) and (vii);
■ mm. Revising paragraphs (q)(2), (r)(1) introductory text, and (r)(1)(i);
■ nn. Removing and reserving paragraph (r)(3);
■ oo. Revising paragraphs (s) introductory text, (y), (z) introductory text, (z)(2)(i) and (iv) through (vi), (aa)(3) introductory text, and (aa)(3)(i);
■ pp. Adding paragraph (aa)(3)(viii);
■ qq. Removing and reserving paragraph (aa)(9);
■ rr. Revising paragraph (aa)(10) introductory text;
■ ss. Adding paragraphs (aa)(10)(v) and (vi); and
■ tt. Revising paragraphs (aa)(11)(ii) and (iii), (bb) introductory text, and (cc).

The revisions and additions read as follows:

§ 98.236 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain reported emissions and related information as specified in this section. Reporters that use a flow or volume measurement system that corrects to standard conditions as provided in the introductory text in § 98.233 for data elements that are otherwise required to be determined at actual conditions, report gas volumes at standard conditions rather than the gas volumes at actual conditions and report the standard temperature and pressure used by the measurement system rather than the actual temperature and pressure.

(a) * * *

(1) *Onshore petroleum and natural gas production.* For the equipment/activities specified in paragraphs (a)(1)(i) through (xix) of this section, report the information specified in the applicable paragraphs of this section.

* * * * *

(xviii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(xix) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(2) *Offshore petroleum and natural gas production.* Report the information specified in paragraphs (s) and (y) of this section.

(3) *Onshore natural gas processing.* For the equipment/activities specified in paragraphs (a)(3)(i) through (ix) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

* * * * *

(ix) *Other large release events.* Report the information specified in paragraph (y) of this section.

(4) *Onshore natural gas transmission compression.* For the equipment/activities specified in paragraphs (a)(4)(i) through (viii) of this section, report the information specified in the applicable paragraphs of this section.

* * * * *

(viii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(5) *Underground natural gas storage.* For the equipment/activities specified in paragraphs (a)(5)(i) through (vii) of this section, report the information specified in the applicable paragraphs of this section.

* * * * *

(vii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(6) *LNG storage.* For the equipment/activities specified in paragraphs (a)(6)(i) through (vi) of this section, report the information specified in the applicable paragraphs of this section.

* * * * *

(vi) *Other large release events.* Report the information specified in paragraph (y) of this section.

(7) *LNG import and export equipment.* For the equipment/activities specified in paragraphs (a)(7)(i) through (viii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Acid gas removal units.* Report the information specified in paragraph (d) of this section.

* * * * *

(viii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(8) *Natural gas distribution.* For the equipment/activities specified in paragraphs (a)(8)(i) through (iv) of this section, report the information specified in the applicable paragraphs of this section.

* * * * *

(iv) *Other large release events.* Report the information specified in paragraph (y) of this section.

(9) *Onshore petroleum and natural gas gathering and boosting.* For the equipment/activities specified in paragraphs (a)(9)(i) through (xiii) of this section, report the information specified in the applicable paragraphs of this section.

* * * * *

(xii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(xiii) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(10) *Onshore natural gas transmission pipeline.* For blowdown vent stacks, report the information specified in paragraphs (i) and (y) of this section.

(b) *Natural gas pneumatic devices.* You must indicate whether the facility contains the following types of equipment: Continuous high bleed natural gas pneumatic devices, continuous low bleed natural gas pneumatic devices, and intermittent bleed natural gas pneumatic devices. If the facility contains any continuous high bleed natural gas pneumatic devices, continuous low bleed natural gas pneumatic devices, or intermittent bleed natural gas pneumatic devices, then you must report the information specified in paragraphs (b)(1) through (4) of this section.

(1) The number of natural gas pneumatic devices as specified in paragraphs (b)(1)(i) through (iii) of this section.

(i) For onshore natural gas processing, onshore natural gas transmission compression, and underground natural gas storage facilities, the total number of devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed), determined according to § 98.233(a)(2).

(ii) For onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities, the number of devices by each type as specified in paragraphs (b)(1)(ii)(A) through (E) of this section.

(A) Continuous low bleed devices.

(B) Continuous high bleed devices.

(C) Intermittent bleed devices subject to part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter (*i.e.,* the number required to use Equation W–1B).

(D) Intermittent bleed devices not subject to part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter but routinely monitored (*i.e.,* the number electing to use Equation W–1B).

(E) Intermittent bleed devices not subject to part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter and not routinely monitored (*i.e.,* the number using Equation W–1A).

(iii) If the reported values in paragraphs (b)(1)(ii)(A), (B), and (E) of this section are estimated values determined according to § 98.233(a)(3), then you must report the information specified in paragraphs (b)(1)(iii)(A) through (C) of this section.

(A) The number of devices of each type reported in paragraphs (b)(1)(ii)(A), (B), and (E) of this section that are counted.

(B) The number of devices of each type reported in paragraphs (b)(1)(ii)(A), (B), and (E) of this section that are estimated (not counted).

(C) Whether the calendar year is the first calendar year of reporting or the second calendar year of reporting.

(2) For each type of pneumatic device for which Equation W–1A of this subpart is used, report the information in paragraphs (b)(2)(i) through (iii) of this section.

(i) The estimated average number of hours in the calendar year that the natural gas pneumatic devices reported in paragraph (b)(1)(i) or paragraphs (b)(1)(ii)(A), (B), and (E) of this section, as applicable, were in service (*i.e.,* supplied with natural gas) in the calendar year (''T_t'' in Equation W–1A of this subpart).

(ii) Annual CO_2 emissions, in metric tons CO_2, for the natural gas pneumatic devices combined, calculated using Equation W–1A of this subpart and § 98.233(a)(5), and reported in paragraph (b)(1)(i) or paragraphs (b)(1)(ii)(A), (B), and (E) of this section, as applicable.

(iii) Annual CH_4 emissions, in metric tons CH_4, for the natural gas pneumatic devices combined, calculated using Equation W–1A of this subpart and § 98.233(a)(5), and reported in paragraph (b)(1)(i) or paragraphs (b)(1)(ii)(A), (B), and (E) of this section, as applicable.

(3) For intermittent bleed pneumatic devices for which Equation W–1B of this subpart is used, report the information in paragraphs (b)(3)(i) through (iii) of this section.

(i) The total number of intermittent devices detected as malfunctioning in any pneumatic device monitoring survey during the calendar year (''x'' in Equation W–1B of this subpart).

(ii) Average time the intermittent devices were in service (*i.e.,* supplied with natural gas) and assumed to be malfunctioning in the calendar year (average value of ''T_z'' in Equation W–1B of this subpart).

(iii) The total number of intermittent devices that were monitored but were not detected as malfunctioning in any pneumatic device monitoring survey during the calendar year (''Count'' in Equation W–1B of this subpart).

(iv) Average time the intermittent devices that were monitored but were not detected as malfunctioning in any pneumatic device monitoring survey during the calendar year were in service (*i.e.,* supplied with natural gas) during the calendar year (''T_{avg}'' in Equation W–1B of this subpart).

(v) Annual CO_2 emissions, in metric tons CO_2, for the natural gas intermittent bleed pneumatic devices combined for which emissions were calculated using Equation W–1B of this subpart and § 98.233(a)(6).

(vi) Annual CH_4 emissions, in metric tons CH_4, for the natural gas pneumatic devices combined for which emissions were calculated using Equation W–1B of this subpart and § 98.233(a)(6).

(c) *Natural gas driven pneumatic pumps.* You must indicate whether the facility has any natural gas driven pneumatic pumps. If the facility contains any natural gas driven pneumatic pumps, then you must report the information specified in paragraphs (c)(1) through (6) of this section. If a pump was vented directly to the atmosphere for part of the year and routed to a flare, combustion, or vapor recovery system during another part of the year, then include the pump in each of the counts specified in paragraphs (c)(1) through (3) of this section.

(1) Count of natural gas driven pneumatic pumps vented directly to the atmosphere at any point during the year.

(2) Count of natural gas driven pneumatic pumps routed to a flare, combustion, or vapor recovery system at any point during the year.

(3) Total count of natural gas driven pneumatic pumps at the facility.

(4) Average estimated number of hours in the calendar year that natural gas driven pneumatic pumps that vented directly to atmosphere were in service (*i.e.,* supplied with natural gas) (''T'' in Equation W–2 of this subpart).

(5) Annual CO_2 emissions, in metric tons CO_2, for all natural gas driven pneumatic pumps vented directly to the atmosphere combined, calculated according to § 98.233(c)(1) and (2).

(6) Annual CH_4 emissions, in metric tons CH_4, for all natural gas driven pneumatic pumps vented directly to the atmosphere combined, calculated according to § 98.233(c)(1) and (2).

(d) * * *

(1) * * *

(iii) The calculation method used to calculate CO_2 emissions from the acid gas removal unit, as specified in § 98.233(d). If the AGR vent was routed to a flare and comingled with emissions from other sources and you continuously monitor the flow rate and/or composition, select ''Routed to a flare [§ 98.233(d)(12)(ii)]'' as the calculation method.

* * * * *

(2) * * *

(iii) * * *

(L) Solvent type, from one of the following options: Selexol™, Rectisol®, Purisol™, Fluor Solvent℠, Benfield™, 20 wt% MEA, 30 wt% MEA, 40 wt% MDEA, 50 wt% MDEA, and other.

(iv) If the AGR vent was routed to a flare, then you must report the unique name or ID for the flare stack to which the AGR vent is routed.

(e) *Dehydrators.* You must indicate whether your facility contains any of the following equipment: Glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 million standard cubic feet per day and glycol dehydrators with an annual average daily natural gas throughput less than 0.4 million standard cubic feet per day. If your facility contains any of the equipment listed in this paragraph (e), then you must report the applicable information in paragraphs (e)(1) through (3) of this section.

(1) For each glycol dehydrator that has an annual average daily natural gas throughput greater than or equal to 0.4 million standard cubic feet per day (as specified in § 98.233(e)(1)), you must report the information specified in paragraphs (e)(1)(i) through (xix) of this section for the dehydrator.

* * * * *

(viii) Whether stripping gas is used in dehydrator.

(A) If stripping gas is used in the dehydrator, type of stripping gas used (dry natural gas, flash gas, nitrogen/inert gas, other).

(B) If stripping gas is used in the dehydrator, average flow rate of stripping gas in standard cubic feet per minute.

* * * * *

(xi) Temperature of the wet natural gas at the absorber inlet, in degrees Fahrenheit.

(xii) Pressure of the wet natural gas at the absorber inlet, in pounds per square inch gauge.

* * * * *

(xv) Sub-basin ID that best represents the wells supplying gas to the dehydrator (for the onshore petroleum and natural gas production industry segment only) or name of the county that best represents the equipment supplying gas to the dehydrator (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(xvi) If a flash tank separator is used in the dehydrator, then you must report the information specified in paragraphs (e)(1)(xvi)(A) through (I) of this section for the emissions from the flash tank vent.

(A) Flash tank vent gas flow rate in standard cubic feet per hour.

(B) Flow-weighted average mole fraction of CO_2 in flash tank vent gas (''X_{CO2}'' in Equation W–20 of this subpart if the flash tank vent gas is routed to a flare).

(C) Flow-weighted average mole fraction of CH_4 in flash tank vent gas (''X_{CH4}'' in Equation W–19 of this subpart if the flash tank vent gas is routed to a flare).

(D) Whether any flash gas emissions are vented directly to the atmosphere, routed to a flare, routed to the regenerator firebox/fire tubes, routed to a vapor recovery system, used as stripping gas, or any combination.

(E) Annual CO_2 emissions, in metric tons CO_2, from the flash tank when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(iv), and, if applicable, (e)(1)(vi)(A).

(F) Annual CH_4 emissions, in metric tons CH_4, from the flash tank when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(iv) and, if applicable, (e)(1)(vi)(A).

(G) Annual CO_2 emissions, in metric tons CO_2, that resulted from routing flash gas to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(v) and, if applicable, (e)(1)(vi)(B).

(H) Annual CH_4 emissions, in metric tons CH_4, that resulted from routing flash gas to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(v) and, if applicable, (e)(1)(vi)(B).

(I) Annual N_2O emissions, in metric tons N_2O, that resulted from routing flash gas to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(v) and, if applicable, (e)(1)(vi)(B).

(xvii) If flash tank emissions were routed to a flare, then you must report the information specified in paragraphs (e)(1)(xvii)(A) through (G) of this section for the flared emissions from the flash tank vent.

(A) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (e)(1)(xvi)(H) and (I) and (e)(1)(xvii)(B) through (G) of this section do not apply.

(B) Indicate whether all gas from the flash tank was measured using a continuous flow monitor.

(C) Indicate whether all gas from the flash tank was measured with a continuous gas composition analyzer.

(D) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(E) Total volume of gas from the flash tank to a flare, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(F) Fraction of total flared gas from the flash tank routed to an un-lit flare (''Z_u'' in Equation W–19 of this subpart).

(G) Average flare combustion efficiency, expressed as a fraction of gas from the flash tank combusted by a burning flare.

(xviii) Report the information specified in paragraphs (e)(1)(xviii)(A) through (I) of this section for the emissions from the dehydrator still vent.

(A) Still vent gas flow rate in standard cubic feet per hour.

(B) Flow-weighted average mole fraction of CO_2 in still vent gas (''X_{CO2}'' in Equation W–20 of this subpart if the flash tank vent gas is routed to a flare).

(C) Flow-weighted average mole fraction of CH_4 in still vent gas (''X_{CH4}'' in Equation W–19 of this subpart if the flash tank vent gas is routed to a flare).

(D) Whether any still vent emissions are vented directly to the atmosphere, routed to a flare, routed to the regenerator firebox/fire tubes, or routed to a vapor recovery system.

(E) Annual CO_2 emissions, in metric tons CO_2, from the still vent when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(iv), and, if applicable, (e)(1)(vi)(A).

(F) Annual CH_4 emissions, in metric tons CH_4, from the still vent when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(iv) and, if applicable, (e)(1)(vi)(A).

(G) Annual CO_2 emissions, in metric tons CO_2, that resulted from routing still vent gas to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(v) and, if applicable, (e)(1)(vi)(B).

(H) Annual CH_4 emissions, in metric tons CH_4, that resulted from routing still vent gas to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(v) and, if applicable, (e)(1)(vi)(B).

(I) Annual N_2O emissions, in metric tons N_2O, that resulted from routing still vent gas to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(v) and, if applicable, (e)(1)(vi)(B).

(xix) If emissions from the still vent were routed to a flare, then you must report the information specified in paragraphs (e)(1)(xix)(A) through (G) of this section for the flared emissions from the still vent.

(A) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (e)(1)(xviii)(H) and (I) and (e)(1)(xix)(B) through (G) of this section do not apply.

(B) Indicate whether all gas from the still vent was measured using a continuous flow monitor.

(C) Indicate whether all gas from the still vent was measured with a continuous gas composition analyzer.

(D) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(E) Total volume of gas from the still vent to a flare, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(F) Fraction of total flared gas from the still vent routed to an un-lit flare (''Z_u'' in Equation W–19 of this subpart).

(G) Average flare combustion efficiency, expressed as a fraction of gas from the still vent combusted by a burning flare.

(2) You must report the information specified in paragraphs (e)(2)(i) through (v) of this section for all glycol dehydrators with an annual average daily natural gas throughput greater than 0 million standard cubic feet per day and less than 0.4 million standard cubic feet per day (as specified in § 98.233(e)(2)) at the facility.

(i) The total number of dehydrators at the facility.

(ii) Whether any dehydrator emissions were routed to a vapor recovery system. If any dehydrator emissions were routed to a vapor recovery system, then you must report the total number of dehydrators at the facility that routed to a vapor recovery system.

(iii) Whether any dehydrator emissions were routed to a control device other than a vapor recovery system or a flare or regenerator firebox/fire tubes. If any dehydrator emissions were routed to a control device(s) other than a vapor recovery system or a flare or regenerator firebox/fire tubes, then you must specify the type of control device(s) and the total number of dehydrators at the facility that were routed to each type of control device.

(iv) Whether any dehydrator emissions were routed to a flare or regenerator firebox/fire tubes. If any dehydrator emissions were routed to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(2)(iv)(A) through (L) of this section.

(A) The total number of dehydrators routed to a flare or regenerator firebox/fire tubes.

(B) Indicate whether all gas from the dehydrators routed to flares was measured using a continuous flow monitor.

(C) Indicate whether all gas from the dehydrators routed to flares was measured with a continuous gas composition analyzer.

(D) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(E) Total volume of gas from dehydrators to a flare, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(F) Fraction of total flared gas from the dehydrators routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(G) Average flare combustion efficiency, expressed as a fraction of gas from the dehydrators combusted by a burning flare.

(H) Flow-weighted average mole fraction of CH_4 in gas from the dehydrators routed to a flare (''X_{CH4}'' in Equation W–19 of this subpart).

(I) Flow-weighted average mole fraction of CO_2 in gas from the dehydrators routed to a flare (''X_{CO2}'' in Equation W–20 of this subpart).

(J) Annual CO_2 emissions, in metric tons CO_2, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to § 98.233(e)(5) and, if applicable, (e)(4)(ii).

(K) Annual CH_4 emissions, in metric tons CH_4, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to § 98.233(e)(5) and, if applicable, (e)(4)(ii).

(L) Annual N_2O emissions, in metric tons N_2O, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to § 98.233(e)(5) and, if applicable, (e)(4)(ii).

(v) For dehydrator emissions that were not routed to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(2)(v)(A) and (B) of this section.

(A) Annual CO_2 emissions, in metric tons CO_2, for emissions from all dehydrators reported in paragraph (e)(2)(i) of this section that were not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(2) and, if applicable, (e)(4)(i), where emissions are added together for all such dehydrators.

(B) Annual CH_4 emissions, in metric tons CH_4, for emissions from all dehydrators reported in paragraph (e)(2)(i) of this section that were not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(2) and, if applicable, (e)(4)(i), where emissions are added together for all such dehydrators.

* * * * *

(f) * * *

(1) For each sub-basin and well tubing diameter and pressure group for which you used Calculation Method 1 to calculate natural gas emissions from well venting for liquids unloading, report the information specified in paragraphs (f)(1)(i) through (xii) of this section. Report information separately for wells by unloading type combination.

* * * * *

(iii) Unloading type combination (with or without plunger lifts, automated or manual unloading).

* * * * *

(xi) * * *

(F) Unloading type (automated or manual).

(xii) * * *

(F) Unloading type (automated or manual).

(2) For each sub-basin for which you used Calculation Method 2 or 3 (as specified in § 93.233(f)) to calculate natural gas emissions from well venting for liquids unloading, you must report the information in paragraphs (f)(2)(i) through (xii) of this section. Report information separately for each calculation method and unloading type combination.

* * * * *

(iii) Unloading type combination (with or without plunger lifts, automated or manual unloadings).

* * * * *

(ix) Average flow-line rate of gas (average of ''SFR_p'' from Equation W–8 or W–9 of this subpart, as applicable), at standard conditions in cubic feet per hour.

(x) Cumulative amount of time that wells were left open to the atmosphere during unloading events (sum of ''$HR_{p,q}$'' from Equation W–8 or W–9 of this subpart, as applicable), in hours.

(xi) For wells without plunger lifts, the information in paragraphs (f)(2)(xi)(A) through (C) of this section.

(A) Average internal casing diameter (average of ''CD_p'' from Equation W–8 of this subpart), in inches.

(B) Average well depth (average of ''WD_p'' from Equation W–8 of this subpart), in feet.

(C) Average shut-in pressure, surface pressure, or casing pressure (average of ''SP_p'' from Equation W–8 of this subpart), in pounds per square inch absolute.

(xii) For wells with plunger lifts, the information in paragraphs (f)(2)(xii)(A) through (C) of this section.

(A) Average internal tubing diameter (average of ''TD_p'' from Equation W–9 of this subpart), in inches.

(B) Average tubing depth (average of ''WD_p'' from Equation W–9 of this subpart), in feet.

(C) Average flow line pressure (average of ''SP_p'' from Equation W–9 of this subpart), in pounds per square inch absolute.

(g) * * *

(10) If the well emissions were routed to a flare, then you must report the information specified in paragraphs (g)(10)(i) through (xi) of this section.

(i) Indicate whether the total emissions reported under paragraphs (g)(8) and (9) of this section include vented emissions during the initial flowback period.

(ii) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraph (g)(9) and paragraphs (g)(10)(iii) through (xi) of this section do not apply.

(iii) Indicate whether all of the gas from completions and workovers was measured using continuous flow monitors.

(iv) Indicate whether all of the gas streams from completions and workovers were measured with continuous gas composition analyzers.

(v) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(vi) Total volume of gas from completions and workovers to all flares, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(vii) Fraction of total flared gas from completions and workovers routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(viii) Average flare combustion efficiency, expressed as a fraction of gas from completions and workovers combusted by a burning flare.

(ix) Flow-weighted average mole fraction of CH_4 in gas from completions and workovers routed to flares (''X_{CH4}'' in Equation W–19 of this subpart).

(x) Flow-weighted average mole fraction of CO_2 in gas from completions and workovers routed to flares (''X_{CO2}'' in Equation W–20 of this subpart).

(xi) Total N_2O emissions, in metric tons N_2O.

(h) * * *

(2) For each sub-basin with gas well completions without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(2)(i) through (xvi) of this section.

* * * * *

(v) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (h)(2)(vi) through (xii), (xiv), and (xv) of this section do not apply.

(vi) Indicate whether all of the gas from completions was measured using continuous flow monitors.

(vii) Indicate whether all of the gas streams from completions were measured with continuous gas composition analyzers.

(viii) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(ix) Total volume of gas from completions to all flares, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(x) Fraction of total flared gas from completions routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(xi) Average flare combustion efficiency, expressed as a fraction of gas from completions combusted by a burning flare.

(xii) Flow-weighted average mole fraction of CH_4 in gas from completions routed to flares (''X_{CH4}'' in Equation W–19 of this subpart).

(xiii) Flow-weighted average mole fraction of CO_2 in gas from completions routed to flares (''X_{CO2}'' in Equation W–20 of this subpart).

(xiv) Annual CO_2 emissions, in metric tons CO_2, that resulted from completions that flared gas calculated according to § 98.233(h)(2).

(xv) Annual CH_4 emissions, in metric tons CH_4, that resulted from completions that flared gas calculated according to § 98.233(h)(2).

(xvi) Annual N_2O emissions, in metric tons N_2O, that resulted from completions that flared gas calculated according to § 98.233(h)(2).

* * * * *

(4) For each sub-basin with gas well workovers without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(4)(i) through (xiv) of this section.

* * * * *

(iii) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (h)(4)(iv) through (x), (xii), and (xiii) of this section do not apply.

(iv) Indicate whether all of the gas from workovers was measured using continuous flow monitors.

(v) Indicate whether all of the gas streams from workovers were measured with continuous gas composition analyzers.

(vi) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(vii) Total volume of gas from workovers to all flares, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(viii) Fraction of total flared gas from workovers routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(ix) Average flare combustion efficiency, expressed as a fraction of gas from workovers combusted by a burning flare.

(x) Flow-weighted average mole fraction of CH_4 in gas from workovers routed to flares (''X_{CH4}'' in Equation W–19 of this subpart).

(xi) Flow-weighted average mole fraction of CO_2 in gas from workovers routed to flares (''X_{CO2}'' in Equation W–20 of this subpart).

(xii) Annual CO_2 emissions, in metric tons CO_2 per year, that resulted from workovers that flared gas calculated as specified in § 98.233(h)(2).

(xiii) Annual CH_4 emissions, in metric tons CH_4 per year, that resulted from workovers that flared gas, calculated as specified in § 98.233(h)(2).

(xiv) Annual N_2O emissions, in metric tons N_2O per year, that resulted from workovers that flared gas calculated as specified in § 98.233(h)(2).

(i) * * *

(1) *Report by equipment or event type*. If you calculated emissions from blowdown vent stacks by the seven categories listed in § 98.233(i)(2)(iv) for onshore natural gas processing, onshore natural gas transmission compression, LNG import and export equipment, or onshore petroleum and natural gas gathering and boosting industry segments, then you must report the equipment or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each equipment or event type. If a blowdown event resulted in emissions from multiple equipment types, and the emissions cannot be apportioned to the different equipment types, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the equipment type that represented the largest portion of the emissions for the blowdown event. If you calculated emissions from blowdown vent stacks by the eight categories listed in § 98.233(i)(2)(iv) for the onshore natural gas transmission pipeline segment, then you must report the pipeline segments or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each ''equipment or event type'' (*i.e.,* category). If a blowdown event resulted in emissions from multiple categories, and the emissions cannot be apportioned to the different categories, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the ''equipment or event type'' (*i.e.,* category) that represented the largest portion of the emissions for the blowdown event.

* * * * *

(j) *Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.* You must indicate whether your facility sends hydrocarbon produced liquids to atmospheric tanks. If your facility sends hydrocarbon produced liquids to atmospheric tanks, then you must indicate which Calculation Method(s) you used to calculate GHG emissions, and you must report the information specified in paragraphs (j)(1) and (2) of this section as applicable. If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j), and any atmospheric tanks were observed to have malfunctioning dump valves during the calendar year, then you must indicate that dump valves were malfunctioning and must report the information specified in paragraph (j)(3) of this section.

(1) If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j) to calculate GHG emissions, then you must report the information specified in paragraphs (j)(1)(i) through (xvi) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and

boosting) and by calculation method. Onshore petroleum and natural gas gathering and boosting facilities do not report the information specified in paragraph (j)(1)(ix) of this section.

(i) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(ii) Calculation method used, and name of the software package used if using Calculation Method 1.

(iii) The total annual hydrocarbon liquids volume from gas-liquid separators and direct from wells or non-separator equipment that is sent to applicable onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with hydrocarbon liquids production greater than or equal to 10 barrels per day and flowing to gas-liquid separators or direct to storage tanks. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the total volume of hydrocarbon liquids from all wells and the well ID number(s) for the well(s) included in this volume.

(iv) The average gas-liquid separator or non-separator equipment temperature, in degrees Fahrenheit.

(v) The average gas-liquid separator or non-separator equipment pressure, in pounds per square inch gauge.

(vi) The average sales oil or stabilized hydrocarbon liquids API gravity, in degrees.

(vii) The flow-weighted average concentration (mole fraction) of CO_2 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks (calculated as the sum of all products of the concentration of CO_2 in the flash gas for each storage tank times the throughput for that storage tank, divided by the sum of all throughputs from storage tanks) (''X_{CO2}'' in Equation W–20 of this subpart if the flash gas is routed to a flare).

(viii) The flow-weighted average concentration (mole fraction) of CH4 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks (calculated as the sum of all products of the concentration of CH_4 in the flash gas for each storage tank times the throughput for that storage tank, divided by the sum of all throughputs from storage tanks) (''X_{CH4}'' in Equation W–19 of this subpart and ''Y_1'' in Equation W–20 of this subpart if the flash gas is routed to a flare).

(ix) The number of wells sending hydrocarbon liquids to gas-liquid separators or directly to atmospheric tanks.

(x) Count of atmospheric tanks specified in paragraphs (j)(1)(x)(A) through (D) of this section.

(A) The number of atmospheric tanks.

(B) The number of atmospheric tanks that vented gas directly to the atmosphere and did not control emissions using a vapor recovery system or one or more flares at any point during the reporting year.

(C) The number of atmospheric tanks that routed emissions to vapor recovery and/or one or more flares at any point during the reporting year.

(D) The number of atmospheric tanks in paragraph (j)(1)(x)(C) of this section that had an open or unseated thief hatch at some point during the year while the tank was also routing emissions to a vapor recovery system and/or a flare.

(xi) For the atmospheric tanks at your facility identified in paragraph (j)(1)(x)(B) of this section, you must report the information specified in paragraphs (j)(1)(xi)(A) and (B) of this section.

(A) Annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(j)(1) and (2).

(B) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(j)(1) and (2).

(xii) For the atmospheric tanks at your facility identified in paragraph (j)(1)(x)(C) of this section, you must report the information specified in paragraphs (j)(1)(xii)(A) through (N) of this section.

(A) Annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(j)(1), (2), and (4).

(B) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(j)(1), (2), and (4).

(C) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (j)(1)(xii)(D) through (K), (M), and (N) of this section do not apply.

(D) Indicate whether all of the gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(1)(xii) was measured using a continuous flow monitor.

(E) Indicate whether all of the gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(1)(xii) was measured with a continuous gas composition analyzer.

(F) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(G) Total volume of gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(1)(xii) that was routed to a flare, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(H) Fraction of total flared gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(1)(xii) that was routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(I) Average flare combustion efficiency, expressed as a fraction of gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(1)(xii) combusted by a burning flare.

(J) Annual CO_2 emissions, in metric tons CO_2, from flares used to control emissions, calculated according to § 98.233(j)(5).

(K) Annual CH_4 emissions, in metric tons CH_4, from flares used to control emissions, calculated according to § 98.233(j)(5).

(L) Annual N_2O emissions, in metric tons N_2O, from flares used to control emissions, calculated according to § 98.233(j)(5).

(M) Total CO_2 mass, in metric tons CO_2, that was recovered during the calendar year using a vapor recovery system.

(N) Total CH_4 mass, in metric tons CH_4, that was recovered during the calendar year using a vapor recovery system.

(xiii) For the atmospheric tanks at your facility identified in paragraph (j)(1)(x)(D) of this section, the total volume of gas vented through open or unseated thief hatches, in scf, during periods while the tanks were also routing emissions to vapor recovery systems and/or flares.

(2) If you used Calculation Method 3 to calculate GHG emissions, then you must report the information specified in paragraphs (j)(2)(i) through (iii) of this section.

(i) Report the information specified in paragraphs (j)(2)(i)(A) through (E) of this section, at the basin level, for atmospheric tanks where emissions were calculated using Calculation Method 3 of § 98.233(j).

(A) The total annual hydrocarbon liquids throughput that is sent to all atmospheric tanks in the basin, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with hydrocarbon liquids production less than 10 barrels per day and that send hydrocarbon liquids to atmospheric tanks. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total annual hydrocarbon liquids throughput from all wells and the well ID number(s) for the well(s) included in this volume.

(B) An estimate of the fraction of hydrocarbon liquids throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with flares.

(C) An estimate of the fraction of hydrocarbon liquids throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with vapor recovery systems.

(D) The number of atmospheric tanks in the basin.

(E) The total number of separators, wells, or non-separator equipment (''Count'' from Equation W–15 of this subpart) in the basin.

(ii) Report the information specified in paragraphs (j)(2)(ii)(A) through (D) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of § 98.233(j) and that either did not control emissions with flares or that used flares to control emissions from less than half the annual hydrocarbon liquids received.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares and for which emissions were calculated using Calculation Method 3.

(C) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W–15 of § 98.233(j) and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(D) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W–15 of § 98.233(j) and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(iii) Report the information specified in paragraphs (j)(2)(iii)(A) through (N) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of § 98.233(j) and that used flares to control emissions from at least half the annual hydrocarbon liquids received.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that controlled emissions with flares and for which emissions were calculated using Calculation Method 3.

(C) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (j)(2)(iii)(D) through (K), (M), and (N) of this section do not apply.

(D) Indicate whether all of the gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(2)(iii) was measured using a continuous flow monitor.

(E) Indicate whether all of the gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(2)(iii) was measured with a continuous gas composition analyzer.

(F) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(G) Total volume of gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(2)(iii) that was routed to a flare, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(H) Fraction of total flared gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(2)(iii) that was routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(I) Average flare combustion efficiency, expressed as a fraction of gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(2)(iii) combusted by a burning flare.

(J) Flow-weighted average mole fraction of CH_4 in gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(2)(iii) and routed to a flare (''X_{CH4}'' in Equation W–19 of this subpart).

(K) Flow-weighted average mole fraction of CO_2 in gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(2)(iii) and routed to a flare (''X_{CO2}'' in Equation W–20 of this subpart).

(L) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks that controlled emissions with flares, calculated according to § 98.233(j)(5) and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(M) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks that controlled emissions with flares, calculated according to § 98.233(j)(5) and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(N) Annual N_2O emissions, in metric tons N_2O, from atmospheric tanks that controlled emissions with flares, calculated according to § 98.233(j)(5).

(3) * * *

(ii) The total time the dump valves on gas-liquid separators did not close properly in the calendar year, in hours (sum of the ''T_{dv}'' values used in Equation W–16 of this subpart).

* * * * *

(k) * * *

(1) * * *

(ii) Indicate if there is a flare attached to the transmission storage tank vent stack.

(iii) Method used to determine if dump valve leakage occurred.

(iv) Indicate whether scrubber dump valve leakage occurred for the transmission storage tank vent according to § 98.233(k)(2) or § 98.233(k)(5).

(2) If scrubber dump valve leakage occurred for a transmission storage tank vent stack, as reported in paragraph (k)(1)(iv) of this section, and the vent stack vented directly to the atmosphere during the calendar year, then you must report the information specified in paragraphs (k)(2)(i) through (v) of this section for each transmission storage vent stack where scrubber dump valve leakage occurred.

* * * * *

(3) If scrubber dump valve leakage occurred for a transmission storage tank vent stack, as reported in paragraph (k)(1)(iv) of this section, and the vent stack routed to a flare during the calendar year, then you must report the information specified in paragraphs (k)(3)(i) through (iii) of this section.

(i) Indicate whether leak rate was determined using a continuous flow measurement device for the duration of the time that flaring occurred or if an annual measurement was conducted in accordance with paragraph (k)(1)(ii) of this section.

(ii) Measured leakage rate (average leak rate from a continuous flow measurement device) in standard cubic feet per hour.

(iii) Duration of time that flaring occurred in hours, as defined in § 98.233(k)(3) (may use best available data if a continuous flow measurement device was used).

(l) * * *

(1) If you used Equation W–17A of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are not routed to a flare, then you must report the information specified in paragraphs (l)(1)(i) through (vii) of this section.

* * * * *

(2) If you used Equation W–17A of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are routed to a flare, then you must report the information specified in paragraphs (l)(2)(i) through (xvii) of this section. All reported data elements should be specific to the wells for which Equation W–17A of § 98.233 was used and for which well testing emissions were routed to flares.

* * * * *

(vi) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (l)(2)(vii) through (xiv), (xvi), and (xvii) of this section do not apply.

(vii) Indicate whether all of the gas from well testing routed to flares was measured using continuous flow monitors.

(viii) Indicate whether all of the gas streams from well testing routed to flares were measured with continuous gas composition analyzers.

(ix) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(x) Total volume of gas from well testing routed to all flares, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(xi) Fraction of total flared gas from well testing routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(xii) Average flare combustion efficiency, expressed as a fraction of gas from well testing combusted by a burning flare.

(xiii) Flow-weighted average mole fraction of CH_4 in gas from well testing routed to flares (''X_{CH4}'' in Equation W–19 of this subpart).

(xiv) Flow-weighted average mole fraction of CO_2 in gas from well testing routed to flares (''X_{CO2}'' in Equation W–20 of this subpart).

(xv) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(l).

(xvi) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(l).

(xvii) Annual N_2O emissions, in metric tons N2O, calculated according to § 98.233(l).

(3) If you used Equation W–17B of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were not routed to a flare, then you must report the information specified in paragraphs (l)(3)(i) through (vi) of this section.

* * * * *

(4) If you used Equation W–17B of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were routed to a flare, then you must report the information specified in paragraphs (l)(4)(i) through (xvi) of this section. All reported data elements should be specific to the wells for which Equation W–17B of § 98.233 was used and for which well testing emissions were routed to flares.

* * * * *

(v) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (l)(4)(vi) through (xiii), (xv), and (xvi) of this section do not apply.

(vi) Indicate whether all of the gas from well testing routed to flares was measured using continuous flow monitors.

(vii) Indicate whether all of the gas streams from well testing routed to flares were measured with continuous gas composition analyzers.

(viii) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(ix) Total volume of gas from well testing routed to all flares, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(x) Fraction of total flared gas from well testing routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(xi) Average flare combustion efficiency, expressed as a fraction of gas from well testing combusted by a burning flare.

(xii) Flow-weighted average mole fraction of CH_4 in gas from well testing routed to flares (''X_{CH4}'' in Equation W–19 of this subpart).

(xiii) Flow-weighted average mole fraction of CO_2 in gas from well testing routed to flares (''X_{CO2}'' in Equation W–20 of this subpart).

(xiv) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(l).

(xv) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(l).

(xvi) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(l).

(m) * * *

(4) Average gas to oil ratio, in standard cubic feet of gas per barrel of oil (average of the ''GOR'' values used in Equation W–18 of this subpart). Do not report the GOR if you vented or flared associated gas and used a continuous flow monitor to determine the total volume of associated gas vented or routed to the flare in the sub-basin (*i.e.,* if you did not use Equation W–18 for any wells with associated gas venting or flaring emissions in the sub-basin).

(5) Volume of oil produced, in barrels, in the calendar year only during the time periods in which associated gas was vented or flared (the sum of ''$V_{p,q}$'' used in Equation W–18 of § 98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the volume of oil produced for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement. Do not report the volume of oil produced if you vented or flared associated gas and used a continuous flow monitor to determine the total volume of associated gas vented or routed to the flare in the sub-basin (*i.e.,* if you did not use Equation W–18 for any wells with associated gas venting or flaring emissions in the sub-basin).

(6) Total volume of associated gas sent to sales, in standard cubic feet, in the calendar year only during time periods in which associated gas was vented or flared (the sum of ''SG'' values used in Equation W–18 of § 98.233(m)). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured total volume of associated gas sent to sales for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement. Do not report the volume of gas sent to sales if you vented or flared associated gas and used a continuous flow monitor to determine the total volume of associated gas vented or routed to the flare in the sub-basin (*i.e.,* if you did not use Equation W–18 for any wells with associated gas venting or flaring emissions in the sub-basin).

(7) If you had associated gas emissions vented directly to the atmosphere without flaring, then you must report the information specified in paragraphs (m)(7)(i) through (viii) of this section for each sub-basin.

(i) Total number of wells for which associated gas was vented directly to the atmosphere without flaring and a list of their well ID numbers.

(ii) Indicate whether all of the associated gas volume vented in the sub-basin was measured using continuous flow monitors.

(iii) Indicate whether all associated gas streams vented in the sub-basin were measured with continuous gas composition analyzers.

(iv) Total volume of associated gas vented in the sub-basin, in standard cubic feet.

(v) Flow-weighted average mole fraction of CH_4 in associated gas vented in the sub-basin.

(vi) Flow-weighted average mole fraction of CO_2 in associated gas vented in the sub-basin.

(vii) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(m)(3) and (4).

(viii) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(m)(3) and (4).

(8) If you had associated gas emissions that were flared, then you must report the information specified in paragraphs (m)(8)(i) through (xiii) of this section for each sub-basin.

(i) Total number of wells for which associated gas was flared and a list of their well ID numbers.

(ii) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (m)(8)(iii) through (x), (xii), and (xiii) of this section do not apply.

(iii) Indicate whether all of the associated gas volume routed to flares in the sub-basin was measured using continuous flow monitors.

(iv) Indicate whether all associated gas streams routed to flares in the sub-basin were measured with continuous gas composition analyzers.

(v) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(vi) Total volume of associated gas routed to all flares in the sub-basin, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(vii) Fraction of total flared associated gas in the sub-basin routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(viii) Average flare combustion efficiency, expressed as a fraction of associated gas combusted by a burning flare.

(ix) Flow-weighted average mole fraction of CH_4 in associated gas routed to flares in the sub-basin (''X_{CH4}'' in Equation W–19 of this subpart).

(x) Flow-weighted average mole fraction of CO_2 in associated gas routed to flares in the sub-basin (''X_{CO2}'' in Equation W–20 of this subpart).

(xi) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(m)(5).

(xii) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(m)(5).

(xiii) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(m)(5).

(n) *Flare stacks.* You must indicate if your facility has any flare stacks to which emissions are routed from miscellaneous flared sources (*i.e.,* sources other than those subject to § 98.233(e), (g), (h), (j), (l), or (m), as applicable for the industry segment). If you have any miscellaneous flared sources, you must report the information specified in paragraph (n)(1) of this section for each flare used to control emissions from such sources. Additionally, for each flare at your facility, regardless of the source(s) controlled, you must report the information specified in paragraph (n)(2) of this section.

(1) For each flare stack used to control miscellaneous flared sources, you must report the information specified in paragraph (n)(1)(i) through (xiv) of this section.

(i) Unique name or ID for the flare stack. For the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single flare stack for each location where it operates at in a given calendar year.

(ii) Indicate whether the flare stack has a continuous flow measurement device.

(iii) Indicate whether the flare stack has a continuous gas composition analyzer on feed gas to the flare.

(iv) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(v) Estimated fraction of total volume flared that was received from another facility solely for flaring (*e.g.,* gas separated from liquid at a production facility that is routed to a flare that is assigned to an onshore petroleum and natural gas gathering and boosting facility).

(vi) Volume of gas from miscellaneous flared sources sent to the flare, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(vii) Fraction of the feed gas sent to an un-lit flare (''Z_u'' in Equation W–19 of this subpart).

(viii) Flare combustion efficiency, expressed as the fraction of gas combusted by a burning flare.

(ix) Flow-weighted average mole fraction of CH_4 in the feed gas from miscellaneous flared sources to the flare (''X_{CH4}'' in Equation W–19 of this subpart).

(x) Flow-weighted average mole fraction of CO_2 in the feed gas from miscellaneous flared sources to the flare (''X_{CO2}'' in Equation W–20 of this subpart).

(xi) Annual CO_2 emissions, in metric tons CO_2 (refer to Equation W–20 of this subpart). If gas from an acid gas removal unit is routed to the flare, then the CO_2 emissions to report should exclude the CO_2 emissions reported under paragraph (d)(1)(v) of this section to prevent double counting of emissions.

(xii) Annual CH_4 emissions, in metric tons CH_4 (refer to Equation W–19 of this subpart).

(xiii) Annual N_2O emissions, in metric tons N_2O (refer to Equation W–40 of this subpart).

(xiv) Indicate whether a CEMS was used to measure emissions from the flare. If a CEMS was used to measure emissions from the flare, then the information specified in paragraphs (n)(1)(ii) through (x), (xii), and (xiii) of this section do not apply for that flare; report only the CO_2 emissions as specified in paragraph (n)(1)(xi) of this section.

(2) For each flare stack at your facility, you must report the information specified in paragraphs (n)(2)(i) through (ix) of this section.

(i) Unique name or ID for the flare stack.

(ii) Indicate each emission source type that routed emissions to the flare stack during the reporting year (*i.e.,* dehydrator vents, well venting during completions and workovers with hydraulic fracturing, gas well venting during completions and workovers without hydraulic fracturing, onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, well testing venting and flaring, associated gas venting and flaring, miscellaneous flared sources).

(iii) Total volume of gas routed to the flare.

(iv) Indicate the type of flare (*i.e.,* open ground-level flare, enclosed ground-level flare, open elevated flare, or enclosed elevated flare).

(v) Indicate the type of flare assist (*i.e.,* unassisted, air-assisted with single speed fan/blower, air-assisted with dual speed fan/blower, air-assisted with variable speed fan/blower, steam-assisted, or pressure-assisted).

(vi) Indicate whether the flare has a continuous pilot or autoigniter.

(vii) If the flare has a continuous pilot, indicate whether the presence of flame is continuously monitored.

(viii) If the flare has a continuous pilot and the presence of a flame is not continuously monitored, indicate how periods when the pilot is not lit are identified (*i.e.,* assumed pilot is always lit, assumed pilot was unlit for a fixed number of hours or fraction of operating hours, visual observations of flare flame, other (specify)).

(ix) Estimated fraction of the total volume routed to the flare when it was not lit.

(o) * * *

(1) *Compressor activity data.* Report the information specified in paragraphs (o)(1)(i) through (x) of this section, as applicable, for each centrifugal compressor located at your facility.

(i) Unique name or ID for the centrifugal compressor.

(ii) Hours in operating-mode.

(iii) Hours in standby-pressurized-mode.

(iv) Hours in not-operating-depressurized-mode.

(v) If you conducted volumetric emission measurements as specified in § 98.233(o)(1):

(A) Indicate whether the compressor was measured in operating-mode.

(B) Indicate whether the compressor was measured in standby-pressurized-mode.

(C) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(vi) Indicate whether the compressor has blind flanges installed and associated dates.

(vii) Indicate whether the compressor has wet or dry seals.

(viii) If the compressor has wet seals, the number of wet seals.

(ix) If the compressor has dry seals, the number of dry seals.

(x) Power output of the compressor driver (hp).

(2) * * *

(i) * * *

(B) Centrifugal compressor source (wet seal, dry seal, isolation valve, or blowdown valve).

* * * * *

(ii) * * *

(A) Indicate whether the leak or vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the leak or vent are released to the atmosphere, routed to a flare, combustion, or vapor recovery.

* * * * *

(5) * * *

(i) Report the following activity data.

(A) Total number of centrifugal compressors at the facility.

(B) Number of centrifugal compressors that have wet seals.

(C) Number of centrifugal compressors that have atmospheric wet seal oil degassing vents (*i.e.,* wet seal oil degassing vents where the emissions are released to the atmosphere rather than being routed to flares, combustion, or vapor recovery).

(ii) Annual CO_2 emissions, in metric tons CO_2, from centrifugal compressors with atmospheric wet seal oil degassing vents.

(iii) Annual CH_4 emissions, in metric tons CH_4, from centrifugal compressors with atmospheric wet seal oil degassing vents.

(p) * * *

(1) *Compressor activity data.* Report the information specified in paragraphs (p)(1)(i) through (vii) of this section, as applicable, for each reciprocating compressor located at your facility.

(i) Unique name or ID for the reciprocating compressor.

(ii) Hours in operating-mode.

(iii) Hours in standby-pressurized-mode.

(iv) Hours in not-operating-depressurized-mode.

(v) If you conducted volumetric emission measurements as specified in § 98.233(p)(1):

(A) Indicate whether the compressor was measured in operating-mode.

(B) Indicate whether the compressor was measured in standby-pressurized-mode.

(C) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(vi) Indicate whether the compressor has blind flanges installed and associated dates.

(vii) Power output of the compressor driver (hp).

(2) * * *

(ii) * * *

(A) Indicate whether the leak or vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the leak or vent are released to the atmosphere, routed to a flare, combustion, or vapor recovery.

* * * * *

(3) * * *

(ii) For each compressor mode-source combination where a reporter emission factor as calculated in Equation W–28 was used to calculate emissions in Equation W–27, report the information specified in paragraphs (p)(3)(ii)(A) through (D) of this section.

* * * * *

(5) * * *

(i) Report the following activity data.

(A) Total number of reciprocating compressors at the facility.

(B) Number of reciprocating compressors that have rod packing emissions vented to the atmosphere (*i.e.,* rod packing vents where the emissions are released to the atmosphere rather than being routed to flares, combustion, or vapor recovery).

(ii) Annual CO_2 emissions, in metric tons CO_2, from reciprocating compressors with rod packing emissions vented to the atmosphere.

(iii) Annual CH_4 emissions, in metric tons CH_4, from reciprocating compressors with rod packing emissions vented to the atmosphere.

(q) * * *

(1) You must report the information specified in paragraphs (q)(1)(i) through (vii) of this section.

* * * * *

(iii) Except for natural gas distribution facilities, indicate whether any of the leak detection surveys used in calculating emissions per § 98.233(q)(2) were conducted for compliance with any of the standards in paragraphs (q)(1)(iii)(A) through (E) of this section. Report the indication per facility, not per component type, and indicate all that apply for the facility.

(A) The well site or compressor station fugitive emissions standards in § 60.5397a of this chapter.

(B) The well site or compressor station fugitive emissions standards in part 60, subpart OOOOb of this chapter.

(C) The well site or compressor station fugitive emissions standards in an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(D) The standards for equipment leaks at onshore natural gas plants in part 60, subpart OOOOb of this chapter.

(E) The standards for equipment leaks at onshore natural gas plants in an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

* * * * *

(vi) Report whether emissions were calculated using Calculation Method 1 (leaker factor emission calculation methodology) and/or using Calculation Method 2 (leaker measurement methodology).

(vii) For facilities in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting, report the number of major equipment (as listed in Table W–1A) by service type for which leak detection surveys were conducted and emissions calculated according to § 98.233(q).

(2) You must indicate whether your facility contains any of the component types subject to or complying with § 98.233(q) that are listed in § 98.232(c)(21), (d)(7), (e)(7) or (8), (f)(5), through (8), (g)(4), (g)(6) or (7), (h)(5), (h)(7) or (8), (i)(1), or (j)(10) for your facility's industry segment. For each component type that is located at your facility, you must report the information specified in paragraphs (q)(2)(i) through (v) of this section. If a component type is located at your facility and no leaks were identified from that component, then you must report the information in paragraphs (q)(2)(i) through (v) of this section but report a zero (''0'') for the information required according to paragraphs (q)(2)(ii) through (v) of this section. If you used Calculation Method 1 (leaker factor emission calculation methodology) for some complete leak surveys and used Calculation Method 2 (leaker measurement methodology) for some complete leak surveys, you must report the information specified in paragraphs (q)(2)(i) through (v) of this section separately for component surveys using Calculation Method 1 and Calculation Method 2.

(i) Component type.

(ii) Total number of the surveyed component type that were identified as leaking in the calendar year (''x_p'' in Equation W–30 of this subpart for the component type or the number of leaks measured for the specified component type according to the provisions in § 98.233(q)(3)(i)).

(iii) Average time the surveyed components are assumed to be leaking and operational, in hours (average of ''$T_{p,z}$'' from Equation W–30 of this subpart for the component type or average duration of leaks for the specified component type determined according to the provisions in § 98.233(q)(3)(ii)).

(iv) Annual CO_2 emissions, in metric tons CO_2, for the component type as calculated using Equation W–30 or § 98.233(q)(3)(vi) (for surveyed components only).

(v) Annual CH_4 emissions, in metric tons CH_4, for the component type as calculated using Equation W–30 or § 98.233(q)(3)(vi) (for surveyed components only).

* * * * *

(r) * * *

(1) You must indicate whether your facility contains any of the emission source types required to use Equation W–32A of § 98.233. You must report the information specified in paragraphs (r)(1)(i) through (v) of this section separately for each emission source type required to use Equation W–32A that is located at your facility. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(1)(i) through (v) separately by equipment type and service type.

(i) Emission source type. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the equipment type and service type.

* * * * *

(s) *Offshore petroleum and natural gas production.* You must report the information specified in paragraphs (s)(1) through (3) of this section for each emission source type listed in the most recent BOEM study.

* * * * *

(y) *Other large release events.* You must indicate whether there were any other large release events from your facility during the reporting year. If there were any other large release events, you must report the total number of other large release events from your facility that occurred during the reporting year and, for each other large release event, report the information specified in paragraphs (y)(1) through (8) of this section.

(1) Unique release event identification number (*e.g.,* Event 1, Event 2).

(2) The approximate start date, start time, and duration (in hours) of the release event.

(3) A general description of the event. Include:

(i) Identification of the equipment involved in the release.

(ii) A description of how the release occurred, from one of the following categories: fire/explosion, gas well blowout, oil well blowout, gas well release, oil well release, pressure relief, large leak, and other (specify).

(iii) A description of the technology or method used to identify the release.

(iv) An indication of whether the release was identified under the provisions of part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(v) An indication of whether a portion of the natural gas released was combusted during the release, and if so, the fraction of the natural gas released that was estimated to be combusted.

(4) The total volume of gas released during the event in standard cubic feet.

(5) The volume fraction of CO_2 in the gas released during the event.

(6) The volume fraction of CH_4 in the gas released during the event.

(7) Annual CO_2 emissions, in metric tons CO_2, from the release event.

(8) Annual CH_4 emissions, in metric tons CH_4, from the release event.

(z) *Combustion equipment at onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, and natural gas distribution facilities.* If your facility is required by § 98.232(c)(22), (i)(7), or (j)(12) to report emissions from combustion equipment, then you must indicate whether your facility has any combustion units subject to reporting according to paragraph (a)(1)(xix), (a)(8)(i), or (a)(9)(xiii) of this section. If your facility contains any combustion units subject to reporting according to paragraph (a)(1)(xix), (a)(8)(i), or (a)(9)(xiii) of this section, then you must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable.

* * * * *

(2) * * *

(i) The type of combustion unit. For internal fuel combustion units of any heat capacity that are compressor-drivers, you must also specify the design class as: 2-stroke lean-burn, 4-

stroke lean-burn, 4-stroke rich-burn, or other.

* * * * *

(iv) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(z)(1) through (3).

(v) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(z)(1) through (3).

(vi) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(z)(1) through (3).

(aa) * * *

(3) For natural gas processing, if your facility fractionates NGLs and also reports as a supplier to subpart NN of this part, you must report the information specified in paragraphs (aa)(3)(ii) and (aa)(3)(v) through (viii) of this section. Otherwise, report the information specified in paragraphs (aa)(3)(i) through (viii) of this section.

(i) The quantity of natural gas received at the gas processing plant for processing in the calendar year, in thousand standard cubic feet.

* * * * *

(viii) Indicate whether the facility reports as a supplier to subpart NN of this part.

* * * * *

(10) For onshore petroleum and natural gas gathering and boosting facilities, report the quantities specified in paragraphs (aa)(10)(i) through (vi) of this section.

* * * * *

(v) The number of compressor stations in the facility.

(vi) The number of centralized oil production sites in the facility.

(11) * * *

(ii) The quantity of natural gas withdrawn from underground natural gas storage and LNG storage (regasification) facilities owned and operated by the onshore natural gas transmission pipeline owner or operator that are not subject to this subpart in the calendar year, in thousand standard cubic feet.

(iii) The quantity of natural gas added to underground natural gas storage and LNG storage (liquefied) facilities owned and operated by the onshore natural gas transmission pipeline owner or operator that are not subject to this subpart in the calendar year, in thousand standard cubic feet.

* * * * *

(bb) For any missing data procedures used, report the information in § 98.3(c)(8) and the procedures used to substitute an unavailable value of a parameter, except as provided in paragraphs (bb)(1) and (2) of this section.

* * * * *

(cc) If you elect to delay reporting the information in paragraph (g)(5)(i) or (ii), (g)(5)(iii)(A) or (B), (h)(1)(iv), (h)(2)(iv), (j)(1)(iii), (j)(2)(i)(A), (l)(1)(v), (l)(2)(v), (l)(3)(iv), (l)(4)(iv), or (m)(5) or (6) of this section, you must report the information required in that paragraph no later than the date 2 years following the date specified in § 98.3(b) introductory text.

■ 60. Amend § 98.238 by:

■ a. Adding a definition for ''Centralized oil production site'' in alphabetical order;

■ b. Revising the definitions for ''Compressor mode'' and ''Compressor source'';

■ c. Adding a definition for ''Compressor station'' in alphabetical order;

■ d. Removing the second definition for ''Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements'';

■ e. Revising the definitions for ''Flare stack emissions'' and ''Forced extraction of natural gas liquids''; and

■ f. Adding definitions for ''Other large release event,'' ''Routed to combustion'', ''Well blowout'', and ''Well release'' in alphabetical order.

The additions and revisions read as follows:

§ 98.238 Definitions.

* * * * *

Centralized oil production site means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads.

* * * * *

Compressor mode means the operational and pressurized status of a compressor. For both centrifugal compressors and reciprocating compressors, ''mode'' refers to either: Operating-mode, standby-pressurized-mode, or not-operating-depressurized-mode.

Compressor source means the source of certain venting or leaking emissions from a centrifugal or reciprocating compressor. For centrifugal compressors, ''source'' refers to blowdown valve leakage through the blowdown vent, unit isolation valve leakage through an open blowdown vent without blind flanges, wet seal oil degassing vents, and dry seal vents. For reciprocating compressors, ''source'' refers to blowdown valve leakage through the blowdown vent, unit isolation valve leakage through an open blowdown vent without blind flanges, and rod packing emissions.

Compressor station means any permanent combination of one or more compressors located on one or more contiguous or adjacent properties that are part of the onshore petroleum and natural gas gathering and boosting facility that move natural gas at increased pressure through gathering pipelines or into or out of storage.

* * * * *

Flare stack emissions means CO_2 in gas routed to a flare, CO_2 from partial combustion of hydrocarbons in gas routed to a flare, CH_4 emissions resulting from the incomplete combustion of hydrocarbons in gas routed to a flare, and N_2O resulting from operation of a flare.

Forced extraction of natural gas liquids means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include but are not limited to refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes. Forced extraction does not include natural gas dehydration, the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, a Joule-Thomson valve, a dew point depression valve, or an isolated or standalone Joule-Thomson skid.

* * * * *

Other large release event means an unplanned, unexpected, and uncontrolled release to the atmosphere of gas, liquids, or mixture thereof, from wells and/or other equipment that result in emissions for which there are no methodologies in § 98.233 to appropriately estimate these emissions. Other large release events include, but are not limited to, well blowouts, well releases, pressure relief valve releases from process equipment other than onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, and releases that occur as a result of an accident, equipment rupture, fire, or explosion. Other large release events also include failure of equipment or equipment components such that a single equipment leak or release has emissions that exceed the emissions calculated for that source using applicable methods in § 98.233 by the threshold in § 98.233(y).

* * * * *

Routed to combustion means, for onshore petroleum and natural gas production facilities, natural gas distribution facilities, and onshore petroleum and natural gas gathering and boosting facilities, that emissions are routed to stationary or portable fuel combustion equipment specified in § 98.232(c)(22), (i)(7), or (j)(12), as applicable. For all other industry segments in this subpart, routed to combustion means that emissions are routed to a stationary fuel combustion unit subject to subpart C of this part (General Stationary Fuel Combustion Sources).

* * * * *

Well blowout means a complete loss of well control for a long duration of time resulting in an emissions release.

* * * * *

Well release means a short duration of uncontrolled emissions release from a well followed by a period of controlled emissions release in which control techniques were successfully implemented.

* * * * *

■ 61. Revise table W–1A to subpart W of part 98 to read as follows:

TABLE W–1A TO SUBPART W OF PART 98—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION FACILITIES AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING FACILITIES

Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/component)
Population Emission Factors—Pneumatic Device Vents and Pneumatic Pumps, Gas Service [1]	
Continuous Low Bleed Pneumatic Device Vents [2]	6.8
Continuous High Bleed Pneumatic Device Vents [2]	21.2
Intermittent Bleed Pneumatic Device Vents [2]	8.8
Pneumatic Pumps [3]	13.3
Population Emission Factors—Major Equipment, Gas Service	
Wellhead	0.59
Separator	0.84
Meters/Piping	2.8
Compressor	10
Acid Gas Removal Unit	2.4
Dehydrator	3.1
Heater Treater	0.12
Storage Vessel	0.85
Population Emission Factors—Major Equipment, Crude Service	
Wellhead	0.14
Separator	0.43
Meters/Piping	2.5
Compressor	10
Acid Gas Removal Unit	2.4
Dehydrator	3.1
Heater Treater	0.35
Storage Vessel	0.56
Population Emission Factors—Gathering Pipelines by Material Type [4]	
Protected Steel	0.91
Unprotected Steel	8.0
Plastic/Composite	0.27
Cast Iron	8.2

[1] For multi-phase flow that includes gas, use the gas service emission factors.
[2] Emission factor is in units of "scf/hour/device."
[3] Emission factor is in units of "scf/hour/pump."
[4] Emission factors are in units of "scf/hour/mile of pipeline."

Table W–1B to Subpart W of Part 98—Default Average Component Counts for Major Onshore Natural Gas Production Equipment and Onshore Petroleum and Natural Gas Gathering and Boosting Equipment for Reporting Year 2022 and Prior Reporting Years

■ 62. Revise the table heading for table W–1B to subpart W of part 98 to read as set forth above.

Table W–1C to Subpart W of Part 98—Default Average Component Counts for Major Crude Oil Production Equipment for Reporting Year 2022 and Prior Reporting Years

■ 63. Revise the table heading for table W–1C to subpart W of part 98 to read as set forth above.

Table W–1D to Subpart W of Part 98—Designation of Eastern and Western U.S. for Reporting Year 2022 and Prior Reporting Years

■ 64. Revise the table heading for table W–1D to subpart W of part 98 to read as set forth above.

■ 65. Revise table W–1E to subpart W of part 98 to read as follows:

TABLE W–1E TO SUBPART W OF PART 98—DEFAULT WHOLE GAS LEAKER EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING

Equipment components	Emission factor (scf/hour/component)		
	If you survey using method 21 as specified in § 98.234(a)(2)(i)	If you survey using method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—All Components, Gas Service [1]			
Valve	4.9	3.5	16
Flange	4.1	2.2	11
Connector (other)	1.3	0.8	7.9
Open-Ended Line [2]	2.8	1.9	10
Pressure Relief Valve	4.5	2.8	13
Pump Seal	3.7	1.4	23
Other [3]	4.5	2.8	15
Leaker Emission Factors—All Components, Oil Service			
Valve	3.2	2.2	9.2
Flange	2.7	1.4	11
Connector (other)	1.0	0.6	9.1
Open-Ended Line	1.6	1.1	6.6
Pump [4]	3.7	2.6	15
Other [3]	3.1	2.0	2.9

[1] For multi-phase flow that includes gas, use the gas service emission factors.
[2] The open-ended lines component type includes blowdown valve and isolation valve leaks emitted through the blowdown vent stack for centrifugal and reciprocating compressors.
[3] "Others" category includes any equipment leak emission point not specifically listed in this table, as specified in § 98.232(c)(21) and (j)(10).
[4] The pumps component type in oil service includes agitator seals.

■ 66. Remove table W–2 to subpart W of part 98 and add table W–2A and table W–2B to subpart W of part 98 in numerical order to read as follows:

TABLE W–2A TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS FOR ONSHORE NATURAL GAS PROCESSING

Onshore natural gas processing plants	Emission factor (scf/hour/component)		
	If you survey using method 21 as specified in § 98.234(a)(2)(i)	If you survey using method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—Compressor Components, Gas Service			
Valve [1]	14.84	9.51	61
Connector	5.59	3.58	23
Open-Ended Line	17.27	11.07	71
Pressure Relief Valve	39.66	25.42	163
Meter	19.33	12.39	79
Other [2]	4.1	2.63	17
Leaker Emission Factors—Non-Compressor Components, Gas Service			
Valve [1]	6.42	4.12	26
Connector	5.71	3.66	23
Open-Ended Line	11.27	7.22	46
Pressure Relief Valve	2.01	1.29	8.2
Meter	2.93	1.88	12
Other [2]	4.1	2.63	17

[1] Valves include control valves, block valves and regulator valves.
[2] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table.

TABLE W–2B TO SUBPART W OF PART 98—DEFAULT WHOLE GAS POPULATION EMISSION FACTORS FOR ONSHORE NATURAL GAS PROCESSING

Population emission factors—gas service onshore natural gas processing	Emission factor (scf whole gas/hour/device)
Continuous Low Bleed Pneumatic Device Vents	6.8
Continuous High Bleed Pneumatic Device Vents	32.4
Intermittent Bleed Pneumatic Device Vents	2.3

■ 67. Revise table W–3A to subpart W of part 98 to read as follows:

TABLE W–3A TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION

Onshore natural gas transmission compression	Emission factor (scf/hour/component)		
	If you survey using method 21 as specified in § 98.234(a)(2)(i)	If you survey using method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—Compressor Components, Gas Service			
Valve [1]	14.84	9.51	61
Connector	5.59	3.58	23
Open-Ended Line	17.27	11.07	71
Pressure Relief Valve	39.66	25.42	163
Meter or Instrument	19.33	12.39	79
Other [2]	4.1	2.63	17
Leaker Emission Factors—Non-Compressor Components, Gas Service			
Valve [1]	6.42	4.12	26
Connector	5.71	3.66	23
Open-Ended Line	11.27	7.22	46
Pressure Relief Valve	2.01	1.29	8.2
Meter or Instrument	2.93	1.88	12
Other [2]	4.1	2.63	17

[1] Valves include control valves, block valves and regulator valves.
[2] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in § 98.232(e)(8).

■ 68. Revise the table heading and table W–3B to subpart W of part 98 to read as follows:

TABLE W–3B TO SUBPART W OF PART 98—DEFAULT WHOLE GAS POPULATION EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION

Population emission factors—gas service onshore natural gas transmission compression	Emission factor (scf whole gas/hour/device)
Continuous Low Bleed Pneumatic Device Vents	6.8
Continuous High Bleed Pneumatic Device Vents	32.4
Intermittent Bleed Pneumatic Device Vents	2.3

■ 69. Revise table W–4A to subpart W of part 98 to read as follows:

TABLE W–4A TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS FOR UNDERGROUND NATURAL GAS STORAGE

Underground natural gas storage	Emission factor (scf/hour/component)		
	If you survey using method 21 as specified in § 98.234(a)(2)(i)	If you survey using method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—Storage Station, Gas Service			
Valve [1]	14.84	9.51	61
Connector (other)	5.59	3.58	23
Open-Ended Line	17.27	11.07	71
Pressure Relief Valve	39.66	25.42	163
Meter and Instrument	19.33	12.39	79
Other [2]	4.1	2.63	17
Leaker Emission Factors—Storage Wellheads, Gas Service			
Valve [1]	4.5	3.2	18
Connector (other than flanges)	1.2	0.7	4.9
Flange	3.8	2.0	16
Open-Ended Line	2.5	1.7	10
Pressure Relief Valve	4.1	2.5	17
Other [2]	4.1	2.5	17

[1] Valves include control valves, block valves and regulator valves.
[2] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in § 98.232(f)(6) and (8).

■ 70. Revise the table heading and table W–4B to subpart W of part 98 to read as follows:

TABLE W–4B TO SUBPART W OF PART 98—DEFAULT POPULATION EMISSION FACTORS FOR UNDERGROUND NATURAL GAS STORAGE

Underground natural gas storage	Emission factor (scf/hour/component)
Total Hydrocarbon Population Emission Factors—Storage Wellheads, Gas Service	
Connector	0.01
Valve	0.1
Pressure Relief Valve	0.17
Open-Ended Line	0.03
Whole Gas Population Emission Factors—Other Components, Gas Service	
Continuous Low Bleed Pneumatic Device Vents [1]	6.8
Continuous High Bleed Pneumatic Device Vents [1]	32.4
Intermittent Bleed Pneumatic Device Vents [1]	2.3

[1] Emission Factor is in units of "scf whole gas/hour/device."

■ 71. Revise table W–5A to subpart W of part 98 to read as follows:

TABLE W–5A TO SUBPART W OF PART 98—DEFAULT METHANE LEAKER EMISSION FACTORS FOR LIQUEFIED NATURAL GAS (LNG) STORAGE

LNG storage	Emission factor (scf/hour/component)		
	If you survey using method 21 as specified in § 98.234(a)(2)(i)	If you survey using method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—LNG Storage Components, LNG Service			
Valve	1.19	0.23	4.9
Pump Seal	4.00	0.73	16
Connector	0.34	0.11	1.4
Other [1]	1.77	0.99	7.3
Leaker Emission Factors—LNG Storage Components, Gas Service			
Valve [2]	14.84	9.51	61
Connector	5.59	3.58	23
Open-Ended Line	17.27	11.07	71
Pressure Relief Valve	39.66	25.42	163
Meter and Instrument	19.33	12.39	79
Other [3]	4.1	2.63	17

[1] "Other" equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.
[2] Valves include control valves, block valves and regulator valves.
[3] "Other" equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in § 98.232(g)(6) and (7).

■ 72. Revise table W–6A to subpart W of part 98 to read as follows:

TABLE W–6A TO SUBPART W OF PART 98—DEFAULT METHANE LEAKER EMISSION FACTORS FOR LNG IMPORT AND EXPORT EQUIPMENT

LNG import and export equipment	Emission factor (scf/hour/component)		
	If you survey using method 21 as specified in § 98.234(a)(2)(i)	If you survey using method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—LNG Terminals Components, LNG Service			
Valve	1.19	0.23	4.9
Pump Seal	4.00	0.73	16.
Connector	0.34	0.11	1.4
Other [1]	1.77	0.99	7.3
Leaker Emission Factors—LNG Terminals Components, Gas Service			
Valve [2]	14.84	9.51	61
Connector	5.59	3.58	23
Open-Ended Line	17.27	11.07	71
Pressure Relief Valve	39.66	25.42	163
Meter and Instrument	19.33	12.39	79
Other [3]	4.1	2.63	17

[1] "Other" equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.
[2] Valves include control valves, block valves and regulator valves.
[3] "Other" equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in § 98.232(h)(7) and (8).

■ 73. Revise table W–7 to subpart W of part 98 to read as follows:

TABLE W–7 TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS FOR ONSHORE NATURAL GAS PROCESSING

Natural gas distribution	Emission factor (scf/hour/component)	
	If you survey using method 21 as specified in § 98.234(a)(2)(i)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—Transmission-Distribution Transfer Station1 Components, Gas Service		
Connector	1.69	6.7
Block Valve	0.557	2.3
Control Valve	9.34	38
Pressure Relief Valve	0.27	1.1
Orifice Meter	0.212	0.87
Regulator	0.772	3.2
Open-ended Line	26.131	107

[1] Excluding customer meters.

■ 74. Add table W–8 to subpart W of part 98 to read as follows:

TABLE W–8 TO SUBPART W OF PART 98—DEFAULT METHANE POPULATION EMISSION FACTORS FOR NATURAL GAS DISTRIBUTION

Natural gas distribution	Emission factor (scf/hour/component)
Population Emission Factors—Below Grade Transmission-Distribution Transfer Station Components and Below Grade Metering-Regulating Station1 Components, Gas Service [2]	
Below Grade T–D Transfer Station	0.30
Below Grade M&R Station	0.30
Population Emission Factors—Distribution Mains, Gas Service [3]	
Unprotected Steel	1.2
Protected Steel	2.3
Plastic	0.45
Cast Iron	2.8
Population Emission Factors—Distribution Services, Gas Service [4]	
Unprotected Steel	0.086
Protected Steel	0.0077
Plastic	0.0016
Copper	0.03

[1] Excluding customer meters.
[2] Emission Factor is in units of "scf/hour/station."
[3] Emission Factor is in units of "scf/hour/mile."
[4] Emission Factor is in units of "scf/hour/number of services."

■ 75. Add table W–9 to subpart W of part 98 in numerical order to read as follows:

TABLE W–9 TO SUBPART W OF PART 98—DEFAULT METHANE EMISSION FACTORS FOR NATURAL GAS-FIRED COMPRESSOR-DRIVERS

Compressor-driver engine design class	Emission factor (kg CH_4/mmBtu)
2-stroke lean-burn	0.658
4-stroke lean-burn	0.522
4-stroke rich-burn	0.045

Subpart X—Petrochemical Production

■ 76. Amend § 98.243 by revising paragraphs (b)(3) and (d)(5) to read as follows:

§ 98.243 Calculating GHG emissions.

* * * * *

(b) * * *

(3) For each flare, calculate CO_2, CH_4, and N_2O emissions using the methodology specified in § 98.253(b).

* * * * *

(d) * * *

(5) For each flare, calculate CO_2, CH_4, and N_2O emissions using the methodology specified in § 98.253(b).

■ 77. Amend § 98.244 by revising paragraph (b)(4)(iii) to read as follows:

§ 98.244 vMonitoring and QA/QC requirements.

* * * * *

(b) * * *

(4) * * *

(iii) ASTM D2505–88 (Reapproved 2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography (incorporated by reference, *see* § 98.7).

* * * * *

■ 78. Amend § 98.246 by revising paragraphs (a) introductory text, (a)(2) and (5), (a)(13) and (15), (b)(7) and (8), (c) introductory text, and (c)(3) and (4) and adding paragraph (c)(6) to read as follows:

§ 98.246 Data reporting requirements.

* * * * *

(a) If you use the mass balance methodology in § 98.243(c), you must report the information specified in paragraphs (a)(1) through (15) of this section for each type of petrochemical produced, reported by process unit.

* * * * *

(2) The type of petrochemical produced.

* * * * *

(5) Annual quantity of each type of petrochemical produced from each process unit (metric tons). If you are electing to consider the petrochemical process unit to be the entire integrated ethylene dichloride/vinyl chloride monomer process, the portion of the total amount of EDC produced that is used in VCM production may be a measured quantity or an estimate that is based on process knowledge and best available data. The portion of the total amount of EDC produced that is not utilized in VCM production must be measured in accordance with § 98.244(b)(2) or (3). Sum the amount of EDC used in the production of VCM plus the amount of separate EDC product to report as the total quantity of EDC petrochemical from an integrated EDC/VCM petrochemical process unit.

* * * * *

(13) Name and annual quantity (in metric tons) of each product included in Equations X–1, X–2, and X–3 of § 98.243. If you are electing to consider the petrochemical process unit to be the entire integrated ethylene dichloride/vinyl chloride monomer process, the reported quantity of EDC product should include only that which was not used in the VCM process.

* * * * *

(15) For each gaseous feedstock or product for which the volume was used in Equation X–1, report the annual average molecular weight of the measurements or determinations, conducted according to § 98.243(c)(3) or (4). Report the annual average molecular weight in units of kg per kg mole.

(b) * * *

(7) Information listed in § 98.256(e) of subpart Y of this part for each flare that burns process off-gas. Additionally, provide estimates based on engineering judgment of the fractions of the total CO_2, CH_4 and N_2O emissions that are attributable to combustion of off-gas from the petrochemical process unit(s) served by the flare.

(8) Annual quantity of each type of petrochemical produced from each process unit (metric tons).

* * * * *

(c) If you comply with the combustion methodology specified in § 98.243(d), you must report under this subpart the information listed in paragraphs (c)(1) through (c)(6) of this section.

* * * * *

(3) Information listed in § 98.256(e) of subpart Y of this part for each flare that burns ethylene process off-gas. Additionally, provide estimates based on engineering judgment of the fractions of the total CO_2, CH_4 and N_2O emissions that are attributable to combustion of off-gas from the ethylene process unit(s) served by the flare.

(4) Name and annual quantity of each carbon-containing feedstock (metric tons).

* * * * *

(6) Name and annual quantity (in metric tons) of each product produced in each process unit.

Subpart Y—Petroleum Refineries

■ 79. Amend § 98.253 by:

■ a. Revising paragraph (b) introductory text, paragraph (c) introductory text, and paragraph (e) introductory text;

■ b. Revising Equation Y–18b in paragraph (i)(2);

■ c. Revising parameters ''Mwater'' and ''Hwater'' of Equation Y–18b in paragraph (i)(2);

■ d. Adding parameter ''fcoke'' to Equation Y–18b in paragraph (i)(2); and

■ e. Revising parameter ''Msteam'' of Equation Y–18f in paragraph (i)(5).

The revisions and addition read as follows:

§ 98.253 Calculating GHG emissions.

* * * * *

(b) For flares, calculate GHG emissions according to the requirements in paragraphs (b)(1) through (3) of this section. All gas discharged through the flare stack must be included in the flare GHG emissions calculations with the exception of the following, which may be excluded as applicable: (1) gas used for the flare pilots, and (2) if using the calculation method in paragraph (b)(1)(iii) of this section, the gas released during start-up, shutdown, or malfunction events of 500,000 scf/day or less.

* * * * *

(c) For catalytic cracking units and traditional fluid coking units, calculate the GHG emissions from coke burn-off using the applicable methods described in paragraphs (c)(1) through (c)(5) of this section.

* * * * *

(e) For catalytic reforming units, calculate the CO_2 emissions from coke burn-off using the applicable methods described in paragraphs (e)(1) through (e)(3) of this section and calculate the CH_4 and N_2O emissions using the methods described in paragraphs (c)(4) and (c)(5) of this section, respectively.

* * * * *

(i) * * *

(2) * * *

$$M_{water} = \rho_{water} \times \left((H_{water}) \times \frac{\pi \times D^2}{4} - \frac{f_{coke} \times M_{coke}}{\rho_{particle}} \right) \qquad \text{(Eq. Y-18b)}$$

* * * * *

M_{water} = Mass of water in the delayed coking unit vessel at the end of the cooling cycle just prior to atmospheric venting or draining (metric tons/cycle).

* * * * *

H_{water} = Typical distance from the bottom of the coking unit vessel to the top of the water level at the end of the cooling cycle just prior to atmospheric venting or draining (feet) from company records or engineering estimates.

f_{coke} = Fraction of the coke-filled bed that is covered by water at the end of the cooling cycle just prior to atmospheric venting or draining. Use 1 if the water fully covers coke-filled portion of the coke drum.

* * * * *

(5) * * *

* * * * *

M_{steam} = Mass of steam generated and released per decoking cycle (metric tons/cycle) as determined in paragraph (i)(4) of this section.

* * * * *

■ 80. Amend § 98.254 by revising paragraph (d) introductory text and paragraph (e) introductory text to read as follows:

§ 98.254 Monitoring and QA/QC requirements.

* * * * *

(d) Except as provided in paragraph (g) of this section, determine gas composition and, if required, average molecular weight of the gas using any of the following methods. Alternatively, the results of chromatographic or direct mass spectrometer analysis of the gas may be used, provided that the gas chromatograph or mass spectrometer is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the gas chromatograph or mass spectrometer are documented in the written Monitoring Plan for the unit under § 98.3(g)(5).

* * * * *

(e) Determine flare gas higher heating value using any of the following methods. Alternatively, the results of chromatographic analysis of the gas may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the gas chromatograph are documented in the written Monitoring Plan for the unit under § 98.3(g)(5).

* * * * *

■ 81. Amend § 98.256 by revising paragraph (k)(6) to read as follows:

§ 98.256 Data reporting requirements.

* * * * *

(k) * * *

(6) The basis for the typical dry mass of coke in the delayed coking unit vessel at the end of the coking cycle (mass measurements from company records or calculated using Equation Y–18a of this subpart). If you use mass measurements from company records to determine the typical dry mass of coke in the delayed coking unit vessel at the end of the coking cycle, you must also report:

(i) Internal height of delayed coking unit vessel (feet) for each delayed coking unit.

(ii) Typical distance from the top of the delayed coking unit vessel to the top of the coke bed (*i.e.,* coke drum outage) at the end of the coking cycle (feet) from company records or engineering estimates for each delayed coking unit.

* * * * *

■ 82. Amend § 98.257 by:

■ a. Revising paragraphs (b)(45), (46), and (53); and

■ b. Removing and reserving paragraphs (b)(54), (55), and (56).

The revisions read as follows:

§ 98.257 Records that must be retained.

* * * * *

(b) * * *

(45) Mass of water in the delayed coking unit vessel at the end of the cooling cycle prior to atmospheric venting or draining (metric ton/cycle) (Equations Y–18b and Y–18e in § 98.253) for each delayed coking unit.

(46) Typical distance from the bottom of the coking unit vessel to the top of the water level at the end of the cooling cycle just prior to atmospheric venting or draining (feet) from company records or engineering estimates (Equation Y–18b in § 98.253) for each delayed coking unit.

* * * * *

(53) Fraction of the coke-filled bed that is covered by water at the end of the cooling cycle just prior to atmospheric venting or draining (Equation Y–18b in § 98.253) for each delayed coking unit.

* * * * *

Subpart BB—Silicon Carbide Production

■ 83. Amend § 98.286 by revising the introductory text and adding paragraph (c) to read as follows:

§ 98.286 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraph (a) or (b) of this section, and paragraph (c) of this section, as applicable for each silicon carbide production facility.

* * * * *

(c) If methane abatement technology is used at the silicon carbide production facility, you must report the information in paragraphs (c)(1) through (3) of this section. Upon reporting this information once in an annual report, you are not required to report this information again unless the information changes during a reporting year, in which case, the reporter must include any updates in the annual report for the reporting year in which the change occurred.

(1) Type of methane abatement technology used on each silicon carbide process unit or production furnace, and date of installation for each.

(2) Methane destruction efficiency for each methane abatement technology (percent destruction). You must either use the manufacturer's specified destruction efficiency or the destruction efficiency determined via a performance test. If you report the destruction efficiency determined via a performance test, you must also report the test method that was used during the performance test.

(3) Percentage of annual operating hours that methane abatement technology was in use for all silicon carbide process units or production furnaces combined.

■ 84. Amend § 98.287 by revising the introductory text and adding paragraph (d) to read as follows:

§ 98.287 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (d) of this section for each silicon carbide production facility.

* * * * *

(d) Records of all information reported as required under § 98.286(c).

Subpart DD—Electrical Transmission and Distribution Equipment Use

■ 85. Amend § 98.300 by revising paragraphs (a) introductory text and (a)(3) and (7) to read as follows:

§ 98.300 Definition of the source category.

(a) The electrical transmission and distribution equipment use source category consists of all electric transmission and distribution equipment and servicing inventory insulated with or containing fluorinated GHGs, including but not limited to sulfur hexafluoride (SF_6) and perfluorocarbons (PFCs), used within an electric power system. Electric transmission and distribution equipment and servicing inventory includes, but is not limited to:

* * * * *

(3) Switchgear, including closed-pressure and hermetically sealed-pressure switchgear and gas-insulated lines containing fluorinated GHGs, including but not limited to SF6 and PFCs.

* * * * *

(7) Other containers of fluorinated GHG, including but not limited to SF6 and PFCs.

* * * * *

■ 86. Revise § 98.301 to read as follows:

§ 98.301 Reporting threshold.

(a) You must report GHG emissions under this subpart if you are an electric power system as defined in § 98.308 and your facility meets the requirements of § 98.2(a)(1). To calculate total annual GHG emissions for comparison to the 25,000 metric ton CO2e per year emission threshold in Table A–3, you must calculate emissions of each fluorinated GHG, including but not limited to SF_6 and PFCs, and then sum the emissions of each fluorinated GHG resulting from the use of electrical transmission and distribution equipment for threshold applicability purposes using Equation DD–1 of this subpart.

$$E = \sum_j \sum_i NC_{EPS,j} * GHG_{i,w} * GWP_i * EF * 0.000453592 \qquad \text{(Eq. DD-1)}$$

Where:

E = Annual emissions for threshold applicability purposes (metric tons CO2e).

$NC_{EPS,j}$ = the total nameplate capacity of insulating gas j-containing equipment (excluding hermetically sealed-pressure equipment) located within the facility plus the total nameplate capacity of insulting gas j-containing equipment (excluding hermetically sealed-pressure equipment) that is not located within the facility but is under common ownership or control

$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in insulating gas j in the gas insulated equipment included in the total nameplate capacity $NC_{EPS,j}$, expressed as a decimal fraction. If fluorinated GHG i is not part of a gas mixture, use a value of 1.0.

GWP_i = Gas-appropriate GWP as provided in Table A–1 to subpart A of this part.

EF = Emission factor for electrical transmission and distribution equipment (lbs emitted/lbs nameplate capacity). For all gases, use an emission factor or 0.1.

i = Fluorinated GHG contained in the electrical transmission and distribution equipment.

0.000453592 = Conversion factor from lbs to metric tons.

(b) A facility other than an electric power system that is subject to this part because of emissions from any other source category listed in Table A–3 or A–4 in subpart A of this part is not required to report emissions under subpart DD of this part unless the total estimated emissions from fluorinated gas, including but not limited to SF6 and PFCs, containing equipment located at the facility, as calculated in Equation DD–2 for comparison to the 25,000 metric ton CO2e per year emission threshold in Table A–3 meets or exceeds 25,000 tons CO2e.

$$E = \sum_j \sum_i NC_{other,j} * GHG_{i,w} * GWP_i * EF * 0.000453592 \qquad \text{(Eq. DD-2)}$$

Where:

E = Annual emissions for threshold applicability purposes (metric tons CO2e).

$NC_{other,j}$ = For a facility other than an electric power system, the total nameplate capacity of insulating gas j containing equipment (excluding hermetically sealed-pressure equipment) located within the facility

$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in insulating gas j in the gas insulated equipment included in the total nameplate capacity $NC_{other,j}$, expressed as a decimal fraction. If fluorinated GHG i is not part of a gas mixture, use a value of 1.0.

GWP_i = Gas-appropriate GWP as provided in Table A–1 to subpart A of this part.

EF = Emission factor for electrical transmission and distribution equipment (lbs emitted/lbs nameplate capacity). For all gases, use an emission factor or 0.1.

i = Fluorinated GHG contained in the electrical transmission and distribution equipment.

0.000453592 = Conversion factor from lbs to metric tons.

■ 87. Revise § 98.302 to read as follows:

§ 98.302 GHGs to report.

You must report emissions of each fluorinated GHG, including but not limited to SF_6 and PFC, from your facility (including emissions from fugitive equipment leaks, installation, servicing, equipment decommissioning and disposal, and from storage cylinders) resulting from the transmission and distribution servicing inventory and equipment listed in § 98.300(a). For acquisitions of equipment containing or insulated with fluorinated GHG, you must report emissions from the equipment after the title to the equipment is transferred to the electric power transmission or distribution entity.

■ 88. Revise § 98.303 to read as follows:

§ 98.303 Calculating GHG emissions.

(a) *Mass-balance approach.* Calculate the annual emissions of each fluorinated GHG (including but not limited to SF_6 and PFC) using the mass-balance approach in Equation DD–3 of this section:

$$\text{User Emissions}_i = GHG_{i,w} * [(\text{Decrease in Insulating gas j Inventory}) + (\text{Acquisitions of Insulating gas j}) - (\text{Disbursements of Insulating gas j}) - (\text{Net Increase in Total Nameplate Capacity of Equipment Operated Containing Insulating gas j})] \qquad \text{(Eq. DD-3)}$$

Where:

User Emissions_i = Emissions of fluorinated GHG i from the facility (pounds).

$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in insulating gas j if insulating gas j is a gas mixture, expressed as a decimal fraction. If fluorinated GHG i is not part of a gas mixture, use a value of 1.0.

Decrease in Insulating gas j Inventory = (pounds of insulating gas j stored in containers, but not in energized equipment, at the beginning of the year) − (pounds of insulating gas j stored in containers, but not in energized equipment, at the end of the year).

Acquisitions of Insulating gas j = (pounds of each insulating gas j purchased from chemical producers or distributors in bulk) + (pounds of each insulating gas j purchased from equipment manufacturers or distributors with or inside equipment, including hermetically sealed-pressure switchgear) + (pounds of each insulating gas j returned to facility after off-site recycling).

Disbursements of Insulating gas j = (pounds of each insulating gas j in bulk and contained in equipment that is sold to other entities) + (pounds of each insulating gas j returned to suppliers) + (pounds of each insulating gas j sent off site for recycling) + (pounds of each insulating gas j sent off-site for destruction).

Net Increase in Total Nameplate Capacity of Equipment Operated containing insulating gas j = (The Nameplate Capacity of new equipment containing insulating gas j in pounds, including hermetically sealed-pressure switchgear) − (Nameplate Capacity of retiring equipment containing insulating gas j in pounds, including hermetically sealed-pressure switchgear). (Note that

Nameplate Capacity refers to the full and proper charge of equipment rather than to the actual charge, which may reflect leakage).

(b) *Nameplate Capacity Adjustments.* Users of closed-pressure electrical equipment with a voltage capacity greater than 38 kV may measure and adjust the nameplate capacity value specified by the equipment manufacturer on the nameplate attached to that equipment, or within the equipment manufacturer's official product specifications, by following the requirements in paragraphs (b)(1) through (b)(10) of this section. Users of other electrical equipment are not permitted to adjust the nameplate capacity value of the other equipment.

(1) If you elect to measure the nameplate capacity value(s) of one or more pieces of electrical equipment with a voltage capacity greater than 38 kV, you must measure the nameplate capacity values of all the electrical equipment in your facility that has a voltage capacity greater than 38 kV and that is installed or retired in that reporting year and in subsequent reporting years.

(2) You must adopt the measured nameplate capacity value for any piece of equipment for which the absolute value of the difference between the measured nameplate capacity value and the nameplate capacity value most recently specified by the manufacturer equals or exceeds two percent of the nameplate capacity value most recently specified by the manufacturer.

(3) You may adopt the measured nameplate capacity value for equipment for which the absolute value of the difference between the measured nameplate capacity value and the nameplate capacity value most recently specified by the manufacturer is less than two percent of the nameplate capacity value most recently specified by the manufacturer, but if you elect to adopt the measured nameplate capacity for that equipment, then you must adopt the measured nameplate capacity value for all of the equipment for which the difference between the measured nameplate capacity value and the nameplate capacity value most recently specified by the manufacturer is less than two percent of the nameplate capacity value most recently specified by the manufacturer. This applies in the reporting year in which you first adopt the measured nameplate capacity for the equipment and in subsequent reporting years.

(4) Users of electrical equipment measuring the nameplate capacity of any new electrical equipment must:

(i) Record the amount of insulating gas in the equipment at the time the equipment was acquired (pounds), either per information provided by the manufacturer, or by transferring insulating gas from the equipment to a gas container and measuring the amount of insulating gas transferred. The equipment user is responsible for ensuring the gas is accounted for consistent with the methodologies specified in paragraphs (b)(4)(ii) through (b)(5) of this section. If no insulating gas was in the device when it was acquired, record this value as zero.

(ii) If insulating gas is added to the equipment subsequent to the acquisition of the equipment to energize it the first time, transfer the insulating gas to the equipment to reach the temperature-compensated design operating pressure per manufacturer specifications and measure and calculate the total amount of covered insulating gas added to the device using one of the methods specified in paragraphs (b)(4)(ii)(A) and (B) of this section.

(A) To determine the amount of covered insulating gas transferred to the electrical equipment, weigh the gas container being used to fill the device prior to, and after, the addition of the covered insulating gas to the electrical equipment, and subtract the second value (after-transfer gas container weight) from the first value (prior-to-transfer gas container weight). Account for any gas contained in hoses before and after the transfer.

(B) Connect a mass flow meter between the electrical equipment and a gas cart. Transfer gas to the equipment to reach the temperature-compensated design operating pressure per manufacturer specifications. Close the connection to the GIE from the mass flow meter hose and ensure that the gas trapped in the filling hose returns through the mass flow meter. Calculate the amount of gas transferred from the mass reading on the mass flow meter.

(iii) Sum the results of paragraphs (b)(4)(i) and (ii) to obtain the measured nameplate capacity for the new equipment.

(5) Electrical equipment users measuring the nameplate capacity of any retiring electrical equipment must:

(i) Record the initial system pressure and vessel temperature prior to removing any insulating gas.

(ii) Convert the initial system pressure to a temperature-compensated initial system pressure by using the temperature/pressure curve for that insulating gas.

(iii) If the temperature-compensated initial system pressure of the electrical equipment does not match the temperature-compensated design operating pressure specified by the equipment manufacturer, you may either:

(A) Add or remove insulating gas to/from the electrical equipment until the manufacturer-specified value is reached, or

(B) If the temperature-compensated initial system pressure of the electrical equipment is no less than 90 percent of the temperature-compensated design operating pressure specified by the manufacturer (in absolute terms), use Equation DD–4 to calculate the nameplate capacity based on the mass recorded under paragraph (b)(5)(vi) of this section.

(iv) Follow one of the following processes, depending on the methodology being used to measure the amount of gas recovered:

(A) Connect a mass flow meter between the electrical equipment and a gas cart; or

(B) Weigh the gas container being used to receive the gas and record this value.

(v) Recover insulating gas from the electrical equipment until five minutes after the pressure in the electrical equipment reaches the blank-off pressure unless the integrity of the electrical equipment has been compromised in such a way that air will be drawn into the electrical equipment and gas cart if the electrical equipment is drawn into a vacuum. If the integrity of the electrical equipment has been so compromised, recover the insulating gas until the pressure in the electrical equipment is no higher than zero pounds per square inch gauge (0 psig).

(vi) Record the amount of insulating gas recovered (pounds), either based on the reading from the mass flow meter, or by weighing the gas container that received the gas and subtracting the weight recorded pursuant to paragraph (b)(5)(iv)(B) of this section from this value. Account for any gas contained in hoses before and after the transfer. The amount of gas recovered shall be the measured nameplate capacity for the electrical equipment unless the final temperature-compensated pressure of the electrical equipment exceeds 0.068 psia (3.5 Torr) or the electrical equipment user is calculating the nameplate capacity pursuant to paragraph (b)(5)(iii)(B) of this section, in which cases the measured nameplate capacity shall be the result of Equation DD–4.

(vii) If you are calculating the nameplate capacity pursuant to paragraph (b)(5)(iii)(B), use Equation DD–4 to do so.

$$NC_C = \frac{P_{NC}}{(P_i - P_f)} \times M_R \qquad \text{DD-4}$$

Where:

NC_C = Nameplate capacity of the equipment measured and calculated by the equipment user (pounds).

P_i = Initial temperature-compensated pressure of the equipment, based on the temperature-pressure curve for the insulating gas (psia).

P_f = Final temperature-compensated pressure of the equipment, based on the temperature-pressure curve for the insulating gas (psia). This may be equated to zero if the final temperature-compensated pressure of the equipment is equal to or lower than 0.068 psia (3.5 Torr).

P_{NC} = Temperature-compensated pressure of the equipment at the manufacturer-specified filling density of the equipment (*i.e.,* at the full and proper charge, psia).

M_R = Mass of insulating gas recovered from the equipment, measured in paragraph (b)(5)(vi) of this section (pounds).

(viii) Record the final system pressure and vessel temperature.

(6) Instead of measuring the nameplate capacity of electrical equipment when it is retired, users may measure the nameplate capacity of electrical equipment during maintenance activities that require opening the gas compartment, but they must follow the procedures set forth in paragraph (b)(5) of this section.

(7) If the electrical equipment will remain energized, and the electrical equipment user is adopting the user-measured nameplate capacity, the electrical equipment user must affix a revised nameplate capacity label, showing the revised nameplate value and the year the nameplate capacity adjustment process was performed, to the device by the end of the calendar year in which the process was completed. The manufacturer's previous nameplate capacity label must remain visible after the revised nameplate capacity label is affixed to the device.

(8) For each piece of electrical equipment whose nameplate capacity was adjusted during the reporting year, the revised nameplate capacity value must be used in all provisions wherein the nameplate capacity is required to be recorded, reported, or used in a calculation in this subpart unless otherwise specified herein.

(9) The nameplate capacity of a piece of electrical equipment may only be adjusted more than once if the physical capacity of the device has changed (*e.g.,* replacement of bushings) after the initial adjustment was performed, in which case the equipment user must adjust the nameplate capacity pursuant to the provisions of this paragraph (b).

(10) Measuring devices used to measure the nameplate capacity of electrical equipment under this paragraph (b) must meet the following accuracy and precision requirements:

(i) Flow meters must be certified by the manufacturer to be accurate and precise to within one percent of the largest value that the flow meter can, according to the manufacturer's specifications, accurately record.

(ii) Pressure gauges must be certified by the manufacturer to be accurate and precise to within 0.5% of the largest value that the gauge can, according to the manufacturer's specifications, accurately record.

(iii) Temperature gauges must be certified by the manufacturer to be accurate and precise to within +/−1.0 °F.

(iv) Scales must be certified by the manufacturer to be accurate and precise to within one percent of the true weight.

■ 89. Amend § 98.304 by removing and reserving paragraph (a) and revising paragraphs (b)(1), (2), and (4).

The revisions read as follows:

§ 98.304 Monitoring and QA/QC requirements.

* * * * *

(b) * * *

(1) Review inputs to Equation DD–3 of this section to ensure inputs and outputs to the company's system are included.

(2) Do not enter negative inputs and confirm that negative emissions are not calculated. However, the Decrease in fluorinated GHG Inventory and the Net Increase in Total Nameplate Capacity may be calculated as negative numbers.

* * * * *

(4) Ensure that in addition to fluorinated GHG purchased from bulk gas distributors, fluorinated GHG purchased from Original Equipment Manufacturers (OEM) and fluorinated GHG returned to the facility from off-site recycling are also accounted for among the total additions.

* * * * *

■ 90. Revise § 98.305 to read as follows:

§ 98.305 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Replace missing data, if needed, based on data from equipment with a similar nameplate capacity for fluorinated GHGs, and from similar equipment repair, replacement, and maintenance operations.

■ 91. Amend § 98.306 by revising paragraphs (a) introductory text, (d) through (l), and (n) introductory text and adding paragraphs (o) through (r) to read as follows:

§ 98.306 Data reporting requirements.

* * * * *

(a) Nameplate capacity of equipment (pounds) containing each insulating gas:

* * * * *

(d) Pounds of each insulating gas stored in containers, but not in energized equipment, at the beginning of the year.

(e) Pounds of each insulating gas stored in containers, but not in energized equipment, at the end of the year.

(f) Pounds of each insulating gas purchased in bulk from chemical producers or distributors.

(g) Pounds of each insulating gas purchased from equipment manufacturers or distributors with or inside equipment, including hermetically sealed-pressure switchgear.

(h) Pounds of each insulating gas returned to facility after off-site recycling.

(i) Pounds of each insulating gas in bulk and contained in equipment sold to other entities.

(j) Pounds of each insulating gas returned to suppliers.

(k) Pounds of each insulating gas sent off-site for recycling.

(l) Pounds of each insulating gas sent off-site for destruction.

* * * * *

(n) The number of insulating gas containing pieces of equipment in each of the following equipment categories:

* * * * *

(o) The total of the nameplate capacity values most recently assigned by the electrical equipment manufacturer(s) to each of the following groups of equipment:

(1) All new equipment whose nameplate capacity values were measured by the user under this subpart and for which the user adopted the user-measured nameplate capacity value during the year.

(2) All retiring equipment whose nameplate capacity values were measured by the user under this subpart and for which the user adopted the user-measured nameplate capacity value during the year.

(p) The total of the nameplate capacity values measured by the electrical equipment user for each of the following groups of equipment:

(1) All new equipment whose nameplate capacity values were measured by the user under this subpart and for which the user adopted the user-measured nameplate capacity value during the year.

(2) All retiring equipment whose nameplate capacity values were measured by the user under this subpart and for which the user adopted the user-measured nameplate capacity value during the year.

(q) For each unique insulating gas reported in paragraphs (a), (d) through (l), and (n) of this section, an ID number or other appropriate descriptor.

(r) For each ID number or descriptor reported in paragraph (q) of this section for each unique insulating gas, the name (as required in § 98.3(c)(4)(iii)(G)(*1*)) and weight percent of each fluorinated gas in the insulating gas.

■ 92. Revise § 98.307 to read as follows:

§ 98.307 Records that must be retained.

(a) In addition to the information required by § 98.3(g), you must retain records of the information reported and listed in § 98.306.

(b) For each piece of electrical equipment whose nameplate capacity is measured by the equipment user, retain records of the following:

(1) Equipment manufacturer name.

(2) Year equipment was manufactured. If the date year the equipment was manufactured cannot be determined, report a best estimate of the year of manufacture and record how the estimated year was determined.

(3) Manufacturer serial number. For any piece of equipment whose serial number is unknown (*e.g.,* the serial number does not exist or is not visible), another unique identifier must be recorded as the manufacturer serial number. The electrical equipment user must retain documentation that allows for each electrical equipment to be readily identifiable.

(4) Equipment type (*i.e.,* closed-pressure vs. hermetically sealed-pressure).

(5) Equipment voltage capacity (in kilovolts).

(6) The name and GWP of each insulating gas used.

(7) Nameplate capacity value (pounds), as specified by the equipment manufacturer. The value must reflect the latest value specified by the manufacturer during the reporting year.

(8) Nameplate capacity value (pounds) measured by the equipment user.

(9) The date the nameplate capacity measurement process was completed.

(10) The measurements and calculations used to calculate the value in paragraph (b)(8) of this section.

(11) The temperature-pressure curve and/or other information used to derive the initial and final temperature-adjusted pressures of the equipment.

(12) Whether or not the nameplate capacity value in paragraph (b)(8) of this section has been adopted for the piece of electrical equipment.

■ 93. Amend § 98.308 by revising the definition of ''Facility'' and adding in alphabetical order definitions for ''Energized'', ''Insulating gas'', ''New equipment'', and ''Retired equipment'' to read as follows:

§ 98.308 Definitions.

* * * * *

Facility, with respect to an electric power system, means the electric power system as defined in this paragraph. An electric power system is comprised of all electric transmission and distribution equipment insulated with or containing fluorinated GHGs that is linked through electric power transmission or distribution lines and functions as an integrated unit, that is owned, serviced, or maintained by a single electric power transmission or distribution entity (or multiple entities with a common owner), and that is located between {1}The point(s) at which electric energy is obtained from an electricity generating unit or a different electric power transmission or distribution entity that does not have a common owner, and {2} the point(s) at which any customer or another electric power transmission or distribution entity that does not have a common owner receives the electric energy. The facility also includes servicing inventory for such equipment that contains fluorinated GHGs.

* * * * *

Energized, for the purposes of this subpart, means connected through busbars or cables to an electrical power system or fully-charged, ready for service, and being prepared for connection to the electrical power system. Energized equipment does not include spare gas insulated equipment (including hermetically-sealed pressure switchgear) in storage that has been acquired by the facility, and is intended for use by the facility, but that is not being used or prepared for connection to the electrical power system.

Insulating gas, for the purposes of this subpart, means any fluorinated GHG or fluorinated GHG mixture, including but not limited to SF6 and PFCs, that is used as an insulating and/or arc-quenching gas in electrical equipment.

New equipment, for the purposes of this subpart, means any gas insulated equipment, including hermetically-sealed pressure switchgear, that is not energized at the beginning of the reporting year, but is energized at the end of the reporting year. This includes equipment that has been transferred while in use, meaning it has been added to the facility's inventory without being taken out of active service (*e.g.,* when the equipment is sold to or acquired by the facility while remaining in place and continuing operation).

* * * * *

Retired equipment, for the purposes of this subpart, means any gas insulated equipment, including hermetically-sealed pressure switchgear, that is energized at the beginning of the reporting year, but is not energized at the end of the reporting year. This includes equipment that has been transferred while in use, meaning it has been removed from the facility's inventory without being taken out of active service (*e.g.,* when the equipment is acquired by a new facility while remaining in place and continuing operation).

Subpart FF—Underground Coal Mines

■ 94. Amend § 98.323 by revising parameter ''MCFi'' of Equation FF–3 in paragraph (b) introductory text to read as follows:

§ 98.323 Calculating GHG emissions.

* * * * *

(b) * * *

MCFi = Moisture correction factor for the measurement period, volumetric basis.

= 1 when Vi and Ci are measured on a dry basis or if both are measured on a wet basis.

= 1-(fH2O)i when Vi is measured on a wet basis and Ci is measured on a dry basis.

= 1/[1-(fH2O)i] when Vi is measured on a dry basis and Ci is measured on a wet basis.

* * * * *

■ 95. Amend § 98.326 by revising paragraph (t) to read as follows:

§ 98.326 Data reporting requirements.

* * * * *

(t) Mine Safety and Health Administration (MSHA) identification number for this coal mine.

Subpart GG—Zinc Production

■ 96. Amend § 98.333 by revising paragraph (b)(1) introductory text to read as follows:

§ 98.333 Calculating GHG emissions.

* * * * *

(b) * * *

(1) For each Waelz kiln or electrothermic furnace at your facility used for zinc production, you must determine the mass of carbon in each carbon-containing material, other than fuel, that is fed, charged, or otherwise introduced into each Waelz kiln and electrothermic furnace at your facility for each year and calculate annual CO_2 process emissions from each affected unit at your facility using Equation GG–1 of this section. For electrothermic furnaces, carbon containing input materials include carbon electrodes and carbonaceous reducing agents. For Waelz kilns, carbon containing input materials include carbonaceous reducing agents. If you document that a specific material contributes less than 1 percent of the total carbon into the process, you do not have to include the material in your calculation using Equation R–1 of § 98.183.

* * * * *

■ 97. Amend § 98.336 by adding paragraph (a)(6) and revising paragraph (b)(6) to read as follows:

§ 98.336 Data reporting requirements.

* * * * *

(a) * * *

(6) Total amount of electric arc furnace dust annually consumed by all Waelz kilns at the facility (tons).

(b) * * *

(6) Total amount of electric arc furnace dust annually consumed by all Waelz kilns at the facility (tons).

* * * * *

Subpart HH—Municipal Solid Waste Landfills

■ 98. Amend § 98.343 by revising paragraph (a)(2) to read as follows:

§ 98.343 Calculating GHG emissions.

(a) * * *

(2) For years when material-specific waste quantity data are available, apply Equation HH–1 of this section for each waste quantity type and sum the CH_4 generation rates for all waste types to calculate the total modeled CH_4 generation rate for the landfill. Use the appropriate parameter values for k, DOC, MCF, DOC_F, and F shown in Table HH–1 of this subpart. The annual quantity of each type of waste disposed must be calculated as the sum of the daily quantities of waste (of that type) disposed. You may use the uncharacterized MSW parameters for a portion of your waste materials when using the material-specific modeling approach for mixed waste streams that cannot be designated to a specific material type. For years when waste composition data are not available, use the bulk waste parameter values for k and DOC in Table HH–1 to this subpart for the total quantity of waste disposed in those years.

* * * * *

■ 99. Amend § 98.346 by adding paragraphs (i)(6)(i) and (ii) to read as follows:

§ 98.346 Data reporting requirements.

* * * * *

(i) * * *

(6) * * *

(i) The percentage of total recovered CH_4 that is sent to each measurement location (decimal, must total to 1 across all measurement locations at the facility).

(ii) For each measurement location, the percentage of total recovered CH_4 that is sent to a flare, a landfill gas to energy project, or an unknown option if gas is sent off-site for destruction and the type of destruction technology is unknown (decimal, must total to 1 for each measurement location).

* * * * *

■ 100. Revise table HH–1 to subpart HH of part 98 to read as follows:

TABLE HH–1 TO SUBPART HH OF PART 98—EMISSIONS FACTORS, OXIDATION FACTORS AND METHODS

Factor	Default value	Units
DOC and k values—Bulk waste option		
DOC (bulk waste)	0.17	Weight fraction, wet basis.
k (precipitation plus recirculated leachate [a] <20 inches/year)	0.055	yr^{-1}
k (precipitation plus recirculated leachate [a] 20–40 inches/year)	0.111	yr^{-1}
k (precipitation plus recirculated leachate [a] >40 inches/year)	0.142	yr^{-1}
DOC and k values—Modified bulk MSW option		
DOC (bulk MSW, excluding inerts and C&D waste)	0.27	Weight fraction, wet basis.
DOC (inerts, *e.g.,* glass, plastics, metal, concrete)	0.00	Weight fraction, wet basis.
DOC (C&D waste)	0.08	Weight fraction, wet basis.
k (bulk MSW, excluding inerts and C&D waste)	0.02 to 0.057 [b]	yr^{-1}
k (inerts, *e.g.,* glass, plastics, metal, concrete)	0.00	yr^{-1}
k (C&D waste)	0.02 to 0.04 [b]	yr^{-1}
DOC and k values—Waste composition option		
DOC (food waste)	0.15	Weight fraction, wet basis.
DOC (garden)	0.2	Weight fraction, wet basis.
DOC (paper)	0.4	Weight fraction, wet basis.
DOC (wood and straw)	0.43	Weight fraction, wet basis.
DOC (textiles)	0.24	Weight fraction, wet basis.
DOC (diapers)	0.24	Weight fraction, wet basis.
DOC (sewage sludge)	0.05	Weight fraction, wet basis.
DOC (inerts, *e.g.,* glass, plastics, metal, cement)	0.00	Weight fraction, wet basis.
DOC (Uncharacterized MSW)	0.32	Weight fraction, wet basis.
k (food waste)	0.06 to 0.185 [c]	yr^{-1}
k (garden)	0.05 to 0.10 [c]	yr^{-1}
k (paper)	0.04 to 0.06 [c]	yr^{-1}
k (wood and straw)	0.02 to 0.03 [c]	yr^{-1}

TABLE HH–1 TO SUBPART HH OF PART 98—EMISSIONS FACTORS, OXIDATION FACTORS AND METHODS—Continued

Factor	Default value	Units
DOC and k values—Waste composition option		
k (textiles)	0.04 to 0.06 [c]	yr^{-1}
k (diapers)	0.05 to 0.10 [c]	yr^{-1}
k (sewage sludge)	0.06 to 0.185 [c]	yr^{-1}
k (inerts, *e.g.,* glass, plastics, metal, concrete)	0.00	yr^{-1}
k (uncharacterized MSW)	0.055 to 0.142	yr^{-1}
Other parameters—All MSW landfills		
MCF	1..	
DOC_F	0.5.	
F	0.5.	
OX	See Table HH–4 of this subpart.	
DE	0.99.	

[a] Recirculated leachate (in inches/year) is the total volume of leachate recirculated from company records or engineering estimates divided by the area of the portion of the landfill containing waste with appropriate unit conversions. Alternatively, landfills that use leachate recirculation can elect to use the k value of 0.142 rather than calculating the recirculated leachate rate.

[b] Use the lesser value when precipitation plus recirculated leachate is less than 20 inches/year. Use the greater value when precipitation plus recirculated leachate is greater than 40 inches/year. Use the average of the range of values when precipitation plus recirculated leachate is 20 to 40 inches/year (inclusive). Alternatively, landfills that use leachate recirculation can elect to use the greater value rather than calculating the recirculated leachate rate.

[c] Use the lesser value when the potential evapotranspiration rate exceeds the mean annual precipitation rate plus recirculated leachate. Use the greater value when the potential evapotranspiration rate does not exceed the mean annual precipitation rate plus recirculated leachate. Alternatively, landfills that use leachate recirculation can elect to use the greater value rather than assessing the potential evapotranspiration rate or recirculated leachate rate.

Subpart OO—Suppliers of Industrial Greenhouse Gases

■ 101. Amend § 98.416 by revising paragraphs (c)(6) and (7) and (d)(4) and adding paragraph (k) to read as follows:

§ 98.416 Data reporting requirements.

* * * * *

(c) * * *

(6) Harmonized tariff system (HTS) code of the fluorinated GHGs, fluorinated HTFs, or nitrous oxide shipped.

(7) Customs entry summary number and importer number for each shipment.

* * * * *

(d) * * *

(4) Harmonized tariff system (HTS) code of the fluorinated GHGs, fluorinated HTFs, or nitrous oxide shipped.

* * * * *

(k) For nitrous oxide, saturated perfluorocarbons, and sulfur hexafluoride, report the end use(s) for which each GHG is transferred and the aggregated annual quantity of that GHG in metric tons that is transferred to that end use application, if known.

Subpart PP— Suppliers of Carbon Dioxide

■ 102. Amend § 98.420 by adding paragraph (a)(4) to read as follows:

§ 98.420 Definition of the source category.

(a) * * *

(4) Facilities with process units, including but not limited to direct air capture (DAC), that capture a CO_2 stream from ambient air for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground.

* * * * *

■ 103. Amend § 98.422 by adding paragraph (e) to read as follows:

§ 98.422 GHGs to report.

* * * * *

(e) Mass of CO_2 captured from DAC process units.

(1) Mass of CO_2 captured from ambient air.

(2) Mass of CO_2 captured from any on-site heat and/or electricity generation, where applicable.

■ 104. Amend § 98.423 by revising paragraphs (a)(3)(i) introductory text and (a)(3)(ii) introductory text to read as follows:

§ 98.423 Calculating CO_2 supply.

(a) * * *

(3) * * *

(i) For facilities with production process units, DAC process units, or production wells that capture or extract a CO_2 stream and either measure it after segregation or do not segregate the flow, calculate the total CO_2 supplied in accordance with Equation PP–3a in paragraph (a)(3).

* * * * *

(ii) For facilities with production process units or DAC process units that capture a CO_2 stream and measure it ahead of segregation, calculate the total CO_2 supplied in accordance with Equation PP–3b.

* * * * *

■ 105. Amend § 98.426 by adding paragraph (i) to read as follows:

§ 98.426 Data reporting requirements.

* * * * *

(i) If you capture a CO_2 stream at a facility with a DAC process unit, report the annual quantity of on-site and off-site electricity and heat generated for each DAC process unit as specified in paragraphs (i)(1) through (3) of this section. The quantities specified in paragraphs (i)(1) through (3) must be provided per energy source if known and must represent the electricity and heat used for the DAC process unit starting with air intake and ending with the compressed CO_2 stream (*i.e.,* the CO_2 stream ready for supply for commercial applications or, if maintaining custody of the stream, sequestration or injection of the stream underground).

(1) *Electricity excluding combined heat and power (CHP).* If electricity is provided to a dedicated meter for the DAC process unit, report the annual quantity of electricity consumed, in megawatt hours (MWh), and the information in paragraph (i)(1)(i) or (ii) of this section.

(i) If the electricity is sourced from a grid connection, report the following information:

(A) State where the facility with the DAC process unit is located.

(B) County where the facility with the DAC process unit is located.

(C) Name of the electric utility company that supplied the electricity as shown on the last monthly bill issued by the utility company during the reporting period.

(D) Name of the electric utility company that delivered the electricity. In states with regulated electric utility markets, this will generally be the same utility reported under paragraph (i)(1)(i)(C) of this section, but in states with deregulated electric utility markets, this may be a different utility company.

(E) Annual quantity of electricity consumed in MWh, calculated as the sum of the total energy usage values specified in all billing statements received during the reporting year. Most customers will receive 12 monthly billing statements during the reporting year. Many utilities bill their customers per kilowatt-hour (kWh); usage values on bills that are based on kWh should be divided by 1,000 to report the usage in MWh as required under this paragraph.

(ii) If electricity is sourced from on-site or through a contractual mechanism for dedicated off-site generation, for each applicable energy source specified in paragraphs (i)(1)(ii)(A) through (G) of this section, report the annual quantity of electricity consumed, in MWh. If the on-site electricity source is natural gas, oil, or coal, also indicate whether flue gas is also captured by the DAC process unit.

(A) Non-hydropower renewable sources including solar, wind, geothermal and tidal.

(B) Hydropower.

(C) Natural gas.

(D) Oil.

(E) Coal.

(F) Nuclear.

(G) Other.

(2) *Heat excluding CHP.* For each applicable energy source specified in paragraphs (i)(2)(i) through (vii) of this section, report the annual quantity of heat, steam, or other forms of thermal energy sourced from on-site or through a contractual mechanism for dedicated off-site generation, in megajoules (MJ). If the on-site heat source is natural gas, oil, or coal, also indicate whether flue gas is also captured by the DAC process unit.

(i) Solar.

(ii) Geothermal.

(iii) Natural gas.

(iv) Oil.

(v) Coal.

(vi) Nuclear.

(vii) Other.

(3) *CHP*—(i) *Electricity from CHP.* If electricity from CHP is sourced from on-site or through a contractual mechanism for dedicated off-site generation, for each applicable energy source specified in paragraphs (i)(3)(i)(A) through (G) of this section, report the annual quantity consumed, in MWh. If the on-site electricity source for CHP is natural gas, oil, or coal, also indicate whether flue gas is also captured by the DAC process unit.

(A) Non-hydropower renewable sources including solar, wind, geothermal and tidal.

(B) Hydropower.

(C) Natural gas.

(D) Oil.

(E) Coal.

(F) Nuclear.

(G) Other.

(ii) *Heat from CHP.* For each applicable energy source specified in paragraphs (i)(3)(ii)(A) through (G) of this section, report the quantity of heat, steam, or other forms of thermal energy from CHP sourced from on-site or through a contractual mechanism for dedicated off-site generation, in MJ. If the on-site heat source is natural gas, oil, or coal, also indicate whether flue gas is also captured by the DAC process unit.

(A) Solar.

(B) Geothermal.

(C) Natural gas.

(D) Oil.

(E) Coal.

(F) Nuclear.

(G) Other.

■ 106. Amend § 98.427 by revising paragraph (a) to read as follows:

§ 98.427 Records that must be retained.

* * * * *

(a) The owner or operator of a facility containing production process units or DAC process units must retain quarterly records of captured or transferred CO_2 streams and composition.

* * * * *

Subpart SS—Electrical Equipment Manufacture or Refurbishment

■ 107. Revise § 98.450 to read as follows:

§ 98.450 Definition of the source category.

The electrical equipment manufacturing or refurbishment category consists of processes that manufacture or refurbish gas-insulated substations, circuit breakers, other switchgear, gas-insulated lines, or power transformers (including gas-containing components of such equipment) containing fluorinated GHGs, including but not limited to sulfur-hexafluoride (SF6) and perfluorocarbons (PFCs). The processes include equipment testing, installation, manufacturing, decommissioning and disposal, refurbishing, and storage in gas cylinders and other containers.

■ 108. Revise § 98.451 to read as follows:

§ 98.451 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an electrical equipment manufacturing or refurbishing process and the facility meets the requirements of § 98.2(a)(2). To calculate total annual GHG emissions for comparison to the 25,000 metric ton CO2e per year emission threshold in § 98.2(a)(2), follow the requirements of § 98.2(b), with one exception. Instead of following the requirement of § 98.453 to calculate emissions from electrical equipment manufacture or refurbishment, you must calculate emissions of each fluorinated GHG, including but not limited to SF6 and PFCs, and then sum the emissions of each fluorinated GHG resulting from manufacturing and refurbishing electrical equipment using Equation SS–1 of this subpart.

$$E = \sum_j \sum_i P_j * \mathrm{GHG}_{i,w} * GWP_i * EF * 0.000453592 \qquad \text{(Eq. SS-1)}$$

Where:

E = Annual production process emissions for threshold applicability purposes (metric tons CO2e).

P_j = Total annual purchases of insulating gas j (lbs).

$\mathrm{GHG}_{i,w}$ = The weight fraction of fluorinated GHG i in insulating gas j if insulating gas j is a gas mixture. If not a mixture, use 1.

GWP_i = Gas-appropriate GWP as provided in Table A–1 to subpart A of this part.

EF = Emission factor for electrical transmission and distribution equipment (lbs emitted/lbs purchased). For all gases, use an emission factor of 0.1.

i = fluorinated GHG contained in the electrical transmission and distribution equipment.

0.000453592 = conversion factor from lbs to metric tons.

■ 109. Amend § 98.452 by revising paragraph (a) to read as follows:

§ 98.452 GHGs to report.

(a) You must report emissions of each fluorinated GHG, including but not limited to SF6 and PFCs, at the facility level. Annual emissions from the facility must include fluorinated GHG emissions from equipment that is installed at an off-site electric power transmission or distribution location whenever emissions from installation activities (*e.g.,* filling) occur before the title to the equipment is transferred to the electric power transmission or distribution entity.

* * * * *

■ 110. Amend § 98.453 by:

■ a. Revising paragraph (a);

■ b. Removing and reserving paragraph (b); and

■ c. Revising paragraphs (c) through (g), (h) introductory text, and (i).

The revisions read as follows:

§ 98.453 Calculating GHG emissions.

(a) For each electrical equipment manufacturer or refurbisher, estimate the annual emissions of each fluorinated GHG using the mass-balance approach in Equation SS–2 of this section:

$$\text{User emissions}_i = GHG_{i,w} * [(\text{Decrease in insulating gas j Inventory}) + (\text{Acquisitions of insulating gas j}) - (\text{Disbursements of insulating gas j})] \quad \text{(Eq. SS-2)}$$

Where:

User emissions_i = Annual emissions of each fluorinated GHG i (pounds).

$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in insulating gas j if insulating gas j is a gas mixture, expressed as a decimal fraction. If fluorinated GHG i is not part of a gas mixture, use a value of 1.0.

Decrease in insulating gas j Inventory = (Pounds of insulating gas j stored in containers at the beginning of the year) − (Pounds of insulating gas j stored in containers at the end of the year).

Acquisitions of insulating gas j = (Pounds of each insulating gas j purchased from chemical producers or suppliers in bulk) + (Pounds of each insulating gas j returned by equipment users) + (Pounds of each insulating gas j returned to site after off-site recycling).

Disbursements of insulating gas j = (Pounds of each insulating gas j contained in new equipment delivered to customers) + (Pounds of each insulating gas j delivered to equipment users in containers) + (Pounds of each insulating gas j returned to suppliers) + (Pounds of each insulating gas j sent off site for recycling) + (Pounds of each insulating gas j sent off-site for destruction).

* * * * *

(c) Estimate the disbursements of each insulating gas j (including, but not limited to SF_6 and PFCs) sent to customers in new equipment or cylinders or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers using Equation SS–3 of this section:

$$D_{GHG} = \sum_{p=1}^{n} Q_p \quad \text{(Eq.SS-3)}$$

Where:

D_{GHG} = The annual disbursement of each insulating gas j sent to customers in new equipment or cylinders or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers.

Q_p = The mass of each insulating gas j charged into equipment or containers over the period p sent to customers or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers.

n = The number of periods in the year.

(d) Estimate the mass of each insulating gas j (including, but not limited to SF_6 and PFCs) disbursed to customers in new equipment or cylinders over the period p by monitoring the mass flow of each insulating gas j into the new equipment or cylinders using a flowmeter, or by weighing containers before and after gas from containers is used to fill equipment or cylinders, or by using the nameplate capacity of the equipment.

(e) If the mass of insulating gas j disbursed to customers in new equipment or cylinders over the period p is estimated by weighing containers before and after gas from containers is used to fill equipment or cylinders, estimate this quantity using Equation SS–4 of this section:

$$Q_p = M_B - M_E - E_L \quad \text{(Eq.SS-4)}$$

Where:

Q_p = The mass of each insulating gas j charged into equipment or containers over the period p sent to customers or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers.

M_B = The mass of the contents of the containers used to fill equipment or cylinders at the beginning of period p.

M_E = The mass of the contents of the containers used to fill equipment or cylinders at the end of period p.

E_L = The mass of each insulating gas j emitted during the period p downstream of the containers used to fill equipment or cylinders and in cases where a flowmeter is used, downstream of the flowmeter during the period p (*e.g.,* emissions from hoses or other flow lines that connect the container to the equipment or cylinder that is being filled).

(f) If the mass of each insulating gas j (including, but not limited to SF_6 and PFCs) disbursed to customers in new equipment or cylinders over the period p is determined using a flowmeter, estimate this quantity using Equation SS–5 of this section:

$$Q_p = M_{mr} - E_L \quad \text{(Eq. SS-5)}$$

Where:

Q_p = The mass of each insulating gas j (including, but not limited to SF_6 and PFCs) charged into equipment or containers over the period p sent to customers or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers.

M_{mr} = The mass of each insulating gas j that has flowed through the flowmeter during the period p.

E_L = The mass of each insulating gas j emitted during the period p downstream of the containers used to fill equipment or cylinders and in cases where a flowmeter is used, downstream of the flowmeter during the period p (*e.g.,* emissions from hoses or other flow lines that connect the container to the equipment that is being filled).

(g) Estimate the mass of each insulating gas j emitted during the period p downstream of the containers used to fill equipment or cylinders (*e.g.,* emissions from hoses or other flow lines that connect the container to the equipment or cylinder that is being filled) using Equation SS–6 of this section:

$$E_L = \sum_{j=0}^{n} F_{Ci} * EF_{Ci} \qquad \text{(Eq. SS-6)}$$

Where:

E_L = The mass of each fluorinated GHG (including, but not limited to SF_6 and PFCs) or fluorinated GHG mixture emitted during the period p downstream of the containers used to fill equipment or cylinders and in cases where a flowmeter is used, downstream of the flowmeter during the period p (*e.g.,* emissions from hoses or other flow lines that connect the container to the equipment or cylinder that is being filled).

F_{Ci} = The total number of fill operations over the period p for the valve-hose combination Ci.

EF_{Ci} = The emission factor for the valve-hose combination Ci.

n = The number of different valve-hose combinations C used during the period p.

(h) If the mass of each insulating gas j disbursed to customers in new equipment or cylinders over the period p is determined by using the nameplate capacity, or by using the nameplate capacity of the equipment and calculating the partial shipping charge, use the methods in either paragraph (h)(1) or (h)(2) of this section.

* * * * *

(i) Estimate the annual emissions of each insulating gas j from the equipment that is installed at an off-site electric power transmission or distribution location before the title to the equipment is transferred by using Equation SS–7 of this section:

$$EI = GHG_{i,w} * (M_F + M_C - N_I) \qquad \text{Eq. SS-7}$$

Where:

EI = Total annual emissions of each insulating gas j from equipment installation at electric transmission or distribution facilities.

$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in insulating gas j if insulating gas j is a gas mixture, expressed as a decimal fraction. If the GHG i is not part of a gas mixture, use a value of 1.0.

M_F = The total annual mass of each insulating gas j, in pounds, used to fill equipment during equipment installation at electric transmission or distribution facilities.

M_C = The total annual mass of each insulating gas j, in pounds, used to charge the equipment prior to leaving the electrical equipment manufacturer facility.

N_I = The total annual nameplate capacity of the equipment, in pounds, installed at electric transmission or distribution facilities.

■ 111. Amend § 98.454 by removing and reserving paragraph (a) and revising paragraphs (b), (d) through (f), and (h)(1) through (4).

The revisions read as follows:

§ 98.454 Monitoring and QA/QC requirements.

* * * * *

(b) Ensure that all the quantities required by the equations of this subpart have been measured using either flowmeters with an accuracy and precision of ±1 percent of full scale or better or scales with an accuracy and precision of ±1 percent of the filled weight (gas plus tare) of the containers of each insulating gas that are typically weighed on the scale. For scales that are generally used to weigh cylinders containing 115 pounds of gas when full, this equates to ±1 percent of the sum of 115 pounds and approximately 120 pounds tare, or slightly more than ±2 pounds. Account for the tare weights of the containers. You may accept gas masses or weights provided by the gas supplier (*e.g.,* for the contents of cylinders containing new gas or for the heels remaining in cylinders returned to the gas supplier) if the supplier provides documentation verifying that accuracy standards are met; however, you remain responsible for the accuracy of these masses and weights under this subpart.

* * * * *

(d) For purposes of Equations SS–6 of this subpart, the emission factor for the valve-hose combination (EF_C) must be estimated using measurements and/or engineering assessments or calculations based on chemical engineering principles or physical or chemical laws or properties. Such assessments or calculations may be based on, as applicable, the internal volume of hose or line that is open to the atmosphere during coupling and decoupling activities, the internal pressure of the hose or line, the time the hose or line is open to the atmosphere during coupling and decoupling activities, the frequency with which the hose or line is purged and the flow rate during purges. You must develop a value for EF_c (or use an industry-developed value) for each combination of hose and valve fitting, to use in Equation SS–6 of this subpart. The value for EF_C must be determined for each combination of hose and valve fitting of a given diameter or size. The calculation must be recalculated annually to account for changes to the specifications of the valves or hoses that may occur throughout the year.

(e) Electrical equipment manufacturers and refurbishers must account for emissions of each insulating gas that occur as a result of unexpected events or accidental losses, such as a malfunctioning hose or leak in the flow line, during the filling of equipment or containers for disbursement by including these losses in the estimated mass of each insulating gas emitted downstream of the container or flowmeter during the period p.

(f) If the mass of each insulating gas j disbursed to customers in new equipment over the period p is determined by assuming that it is equal to the equipment's nameplate capacity or, in cases where equipment is shipped with a partial charge, equal to its partial shipping charge, equipment samples for conducting the nameplate capacity tests must be selected using the following stratified sampling strategy in this paragraph. For each make and model, group the measurement conditions to reflect predictable variability in the facility's filling practices and conditions (*e.g.,* temperatures at which equipment is filled). Then, independently select equipment samples at random from each make and model under each group of conditions. To account for variability, a certain number of these measurements must be performed to develop a robust and representative average nameplate capacity (or shipping charge) for each make, model, and group of conditions. A Student T distribution calculation should be conducted to determine how many samples are needed for each make, model, and group of conditions as a function of the relative standard deviation of the sample measurements. To determine a sufficiently precise estimate of the nameplate capacity, the number of measurements required must be calculated to achieve a precision of one percent of the true mean, using a 95 percent confidence interval. To estimate the nameplate capacity for a given make and model, you must use the lowest mean value among the different groups of conditions, or provide justification for the use of a different mean value for the group of conditions that represents the typical practices and conditions for that make and model. Measurements can be conducted using SF_6, another gas, or a liquid. Re-measurement of nameplate capacities should be conducted every five years to reflect cumulative changes in manufacturing methods and conditions over time.

* * * * *

(h) * * *

(1) Review inputs to Equation SS–2 of this subpart to ensure inputs and outputs to the company's system are included.

(2) Do not enter negative inputs and confirm that negative emissions are not calculated. However, the decrease in the inventory for each insulating gas may be calculated as negative.

(3) Ensure that for each insulating gas, the beginning-of-year inventory matches the end-of-year inventory from the previous year.

(4) Ensure that for each insulating gas, in addition to the insulating gas purchased from bulk gas distributors, the insulating gas returned from equipment users with or inside equipment and the insulating gas returned from off-site recycling are also accounted for among the total additions.

■ 112. Amend § 98.456 by revising paragraphs (a) through (k) and (n) through (s) and adding paragraphs (u) and (v) to read as follows:

§ 98.456 Data reporting requirements.

* * * * *

(a) Pounds of each insulating gas stored in containers at the beginning of the year.

(b) Pounds of each insulating gas stored in containers at the end of the year.

(c) Pounds of each insulating gas purchased in bulk.

(d) Pounds of each insulating gas returned by equipment users with or inside equipment.

(e) Pounds of each insulating gas returned to site from off site after recycling.

(f) Pounds of each insulating gas inside new equipment delivered to customers.

(g) Pounds of each insulating gas delivered to equipment users in containers.

(h) Pounds of each insulating gas returned to suppliers.

(i) Pounds of each insulating gas sent off site for destruction.

(j) Pounds of each insulating gas sent off site to be recycled.

(k) The nameplate capacity of the equipment, in pounds, delivered to customers with insulating gas inside, if different from the quantity in paragraph (f) of this section.

* * * * *

(n) The total number of fill operations for each hose and valve combination, or, F_{Ci} of Equation SS–6 of this subpart.

(o) If the mass of each insulating gas disbursed to customers in new equipment over the period p is determined according to the methods required in § 98.453(h), report the mean value of nameplate capacity in pounds for each make, model, and group of conditions.

(p) If the mass of each insulating gas disbursed to customers in new equipment over the period p is determined according to the methods required in § 98.453(h), report the number of samples and the upper and lower bounds on the 95-percent confidence interval for each make, model, and group of conditions.

(q) Pounds of each insulating gas used to fill equipment at off-site electric power transmission or distribution locations, or M_F, of Equation SS–7 of this subpart.

(r) Pounds of each insulating gas used to charge the equipment prior to leaving the electrical equipment manufacturer or refurbishment facility, or M_C, of Equation SS–7 of this subpart.

(s) The nameplate capacity of the equipment, in pounds, installed at off-site electric power transmission or distribution locations used to determine emissions from installation, or N_I, of Equation SS–7 of this subpart.

* * * * *

(u) For each unique insulating gas reported in paragraphs (a) through (j) and (o) through (r) of this section, an ID number or other appropriate descriptor.

(v) For each ID number or descriptor reported in paragraph (u) of this section for each unique insulating gas, the name (as required in § 98.3(c)(4)(iii)(G)(*1*)) and weight percent of each fluorinated gas in the insulating gas.

■ 113. Revise § 98.458 to read as follows:

§ 98.458 Definitions.

Except as specified in this section, all terms used in this subpart have the same meaning given in the CAA and subpart A of this part.

Insulating gas, for the purposes of this subpart, means any fluorinated GHG or fluorinated GHG mixture, including but not limited to SF_6 and PFCs, that is used as an insulating and/or arc-quenching gas in electrical equipment.

Subpart UU—Injection of Carbon Dioxide

■ 114. Amend § 98.470 by redesignating paragraph (c) as paragraph (d) and adding new paragraph (c) to read as follows:

§ 98.470 Definition of the source category.

* * * * *

(c) If you report under subpart VV of this part for a well or group of wells, you are not required to report under this subpart for that well or group of wells.

* * * * *

■ 115. Add subpart VV to read as follows:

Subpart VV—Geologic Sequestration of Carbon Dioxide With Enhanced Oil Recovery Using ISO 27916

Sec.

Subpart VV—Geologic Sequestration of Carbon Dioxide With Enhanced Oil Recovery Using ISO 27916

§ 98.480 Definition of the source category.

(a) This source category pertains to carbon dioxide (CO_2) that is injected in enhanced recovery operations for oil and other hydrocarbons (CO_2-EOR) in which all of the following apply:

(1) You are using the International Standards Organization (ISO) standard designated as CSA/ANSI ISO 27916:2019 (incorporated by reference, see § 98.7) as a method of quantifying geologic sequestration of CO_2 in association with EOR operations.

(2) You are not reporting under subpart UU of this part.

(3) You are not reporting under subpart RR of this part.

(b) This source category does not include wells permitted as Class VI under the Underground Injection Control program.

(c) If you are subject to only this subpart, you are not required to report emissions under subpart C of this part or any other subpart listed in § 98.2(a)(1) or (a)(2).

§ 98.481 Reporting threshold.

(a) You must report under this subpart if your CO_2-EOR project uses CSA/ANSI ISO 27916:2019 (incorporated by reference, see § 98.7) as a method of quantifying geologic sequestration of CO_2 in association with CO_2-EOR operations. There is no threshold for reporting.

(b) The requirements of § 98.2(i) do not apply to this subpart. Once a CO_2-EOR project becomes subject to the requirements of this subpart, you must continue for each year thereafter to comply with all requirements of this subpart, including the requirement to submit annual reports until the facility has met the requirements of paragraphs (b)(1) and (2) of this section and submitted a notification to discontinue reporting according to paragraph (b)(3) of this section.

(1) Discontinuation of reporting under this subpart must follow the requirements set forth under Clause 10 of CSA/ANSI ISO 27916:2019.

(2) CO_2-EOR project termination is completed when all of the following occur:

(i) Cessation of CO_2 injection.

(ii) Cessation of hydrocarbon production from the project reservoir; and

(iii) Wells are plugged and abandoned unless otherwise required by the appropriate regulatory authority.

(3) You must notify the Administrator of your intent to cease reporting and provide a copy of the CO_2-EOR project termination documentation.

§ 98.482 GHGs to report.

You must report the following from Clause 8 of CSA/ANSI ISO 27916:2019 (incorporated by reference, see § 98.7):

(a) The mass of CO_2 received by the CO_2-EOR project.

(b) The mass of CO_2 loss from the CO_2-EOR project operations.

(c) The mass of native CO_2 produced and captured.

(d) The mass of CO_2 produced and sent off-site.

(e) The mass of CO_2 loss from the EOR complex.

(f) The mass of CO_2 stored in association with CO_2-EOR.

§ 98.483 Calculating CO_2 geologic sequestration.

You must calculate CO_2 sequestered using the following quantification principles from Clause 8.2 of CSA/ANSI ISO 27916:2019 (incorporated by reference, see § 98.7).

(a) You must calculate the mass of CO_2 stored in association with CO_2-EOR (m_{stored}) in the reporting year by subtracting the mass of CO_2 loss from operations and the mass of CO_2 loss from the EOR complex from the total mass of CO_2 input (as specified in Equation VV–1 of this section).

$$m_{\text{stored}} = m_{\text{input}} - m_{\text{loss operations}} - m_{\text{loss EOR complex}} \quad \text{(Equation VV-1)}$$

Where:

m_{stored} = the annual quantity of associated storage in metric tons of CO_2 mass.

m_{input} = the total mass of CO_2 $m_{received}$ by the EOR project plus m_{native} (see Clause 8.3 and paragraph (c) of this section), metric tons. Native CO_2 produced and captured in the CO_2-EOR project (m_{native}) can be quantified and included in m_{input}.

$m_{loss\ operations}$ = the total mass of CO_2 loss from project operations (see Clauses 8.4.1 through 8.4.5 and paragraph (d) of this section), metric tons.

$m_{loss\ EOR\ complex}$ = the total mass of CO_2 loss from the EOR complex (see Clause 8.4.6), metric tons.

(b) The manner by which associated storage is quantified must assure completeness and preclude double counting. The annual mass of CO_2 that is recycled and reinjected into the EOR complex must not be quantified as associated storage. Loss from the CO_2 recycling facilities must be quantified.

(c) You must quantify the total mass of CO_2 input (m_{input}) in the reporting year according to paragraphs (c)(1) through (3) of this section.

(1) You must include the total mass of CO_2 received at the custody transfer meter by the CO_2-EOR project ($m_{received}$).

(2) The CO_2 stream received (including CO_2 transferred from another CO_2-EOR project) must be metered.

(i) The native CO_2 recovered and included as m_{native} must be documented.

(ii) CO_2 delivered to multiple CO_2-EOR projects must be allocated among those CO_2-EOR projects.

(3) The sum of the quantities of allocated CO_2 must not exceed the total quantities of CO_2 received.

(d) You must calculate the total mass of CO_2 from project operations ($m_{loss\ operations}$) in the reporting year as specified in Equation VV–2 of this section.

$$m_{\text{loss operations}} = m_{\text{loss leakage facilities}} + m_{\text{loss vent/flare}} + m_{\text{loss entrained}} + m_{\text{loss transfer}} \quad \text{(Equation VV-2)}$$

Where:

$m_{loss\ leakage\ facilities}$ = Loss of CO_2 due to leakage from production, handling, and recycling CO_2-EOR facilities (infrastructure including wellheads), metric tons.

$m_{loss\ vent/flare}$ = Loss of CO_2 from venting/flaring from production operations, metric tons.

$m_{loss\ entrained}$ = Loss of CO_2 due to entrainment within produced gas/oil/water when this CO_2 is not separated and reinjected, metric tons.

$m_{loss\ transfer}$ = Loss of CO_2 due to any transfer of CO_2 outside the CO_2-EOR project, metric tons. You must quantify any CO_2 that is subsequently produced from the EOR complex and transferred offsite.

§ 98.484 Monitoring and QA/QC requirements.

You must use the applicable monitoring and quality assurance requirements set forth in Clause 6.2 of CSA/ANSI ISO 27916:2019 (incorporated by reference, see § 98.7).

§ 98.485 Procedures for estimating missing data.

Whenever the value of a parameter is unavailable or the quality assurance procedures set forth in § 98.484 cannot be followed, you must follow the procedures set forth in Clause 9.2 of CSA/ANSI ISO 27916:2019 (incorporated by reference, see § 98.7).

§ 98.486 Data reporting requirements.

In addition to the information required by § 98.3(c), the annual report shall contain the following information, as applicable:

(a) The annual quantity of associated storage in metric tons of CO_2 (m_{stored}).

(b) The density of CO_2 if volumetric units are converted to mass in order to be reported for annual quantity of CO_2 stored.

(c) The annual quantity of CO_2 input (m_{input}) and the information in paragraphs (c)(1) and (2) of this section.

(1) The annual total mass of CO_2 received at the custody transfer meter by the CO_2-EOR project, including CO_2 transferred from another CO_2-EOR project ($m_{received}$).

(2) The annual mass of native CO_2 produced and captured in the CO_2-EOR project (m_{native}).

(d) The annual mass of CO_2 that is recycled and reinjected into the EOR complex.

(e) The annual total mass of CO_2 loss from project operations ($m_{loss\ operations}$), and the information in paragraphs (e)(1) through (4) of this section.

(1) Loss of CO_2 due to leakage from production, handling, and recycling CO_2-EOR facilities (infrastructure including wellheads) ($m_{loss\ leakage\ facilities}$).

(2) Loss of CO_2 from venting/flaring from production operations ($m_{loss\ vent/flare}$).

(3) Loss of CO_2 due to entrainment within produced gas/oil/water when this CO_2 is not separated and reinjected ($m_{loss\ entrained}$).

(4) Loss of CO_2 due to any transfer of CO_2 outside the CO_2-EOR project ($m_{loss\ transfer}$).

(f) The total mass of CO_2 loss from the EOR complex ($m_{loss\ EOR\ complex}$).

(g) Annual documentation that contains the following components as described in Clause 4.4 of CSA/ANSI ISO 27916:2019 (incorporated by reference, see § 98.7):

(1) The formulas used to quantify the annual mass of associated storage, including the mass of CO_2 delivered to the CO_2-EOR project and losses during the period covered by the documentation (see Clause 8 and Annex B).

(2) The methods used to estimate missing data and the amounts estimated as described in Clause 9.2.

(3) The approach and method for quantification utilized by the operator, including accuracy, precision, and uncertainties (see Clause 8 and Annex B).

(4) A statement describing the nature of validation or verification including the date of review, process, findings, and responsible person or entity.

(5) Source of each CO_2 stream quantified as associated storage (see Clause 8.3).

(6) A description of the procedures used to detect and characterize the total CO_2 leakage from the EOR complex.

(7) If only the mass of anthropogenic CO_2 is considered for m_{stored}, a description of the derivation and application of anthropogenic CO_2 allocation ratios for all the terms described in Clauses 8.1 to 8.4.6.

(8) Any documentation provided by a qualified independent engineer or geologist, who certifies that the documentation provided, including the mass balance calculations as well as information regarding monitoring and containment assurance, is accurate and complete.

(h) Any changes made within the reporting year to containment assurance and monitoring approaches and procedures in the EOR operations management plan.

§ 98.487 Records that must be retained.

You must follow the record retention requirements specified by § 98.3(g). In addition to the records required by § 98.3(g), you must comply with the record retention requirements in Clause 9.1 of CSA/ANSI ISO 27916:2019 (incorporated by reference, see § 98.7).

§ 98.488 EOR Operations Management Plan.

(a) You must prepare and update, as necessary, a general EOR operations management plan that provides a description of the EOR complex and engineered system (see Clause 4.3 (a)), establishes that the EOR complex is adequate to provide safe, long-term containment of CO_2, and includes site-specific and other information including:

(1) Geologic characterization of the EOR complex.

(2) A description of the facilities within the CO_2-EOR project.

(3) A description of all wells and other engineered features in the CO_2-EOR project.

(4) The operations history of the project reservoir.

(5) The information set forth in Clauses 5 and 6 of CSA/ANSI ISO 27916:2019 (incorporated by reference, see § 98.7).

(b) You must prepare initial documentation at the beginning of the quantification period, and include the following as described in the EOR operations management plan:

(1) A description of the EOR complex and engineered systems (see Clause 5).

(2) The initial containment assurance (see Clause 6.1.2).

(3) The monitoring program (see Clause 6.2).

(4) The quantification method to be used (see Clause 8 and Annex B).

(5) The total mass of previously injected CO_2 (if any) within the EOR complex at the beginning of the CO_2-EOR project (see Clause 8.5 and Annex B).

(c) The EOR operation management plan in paragraph (a) of this section and initial documentation in paragraph (b) of this section must be submitted to the Administrator with the annual report covering the first reporting year that the facility reports under this subpart. In addition, any documentation provided by a qualified independent engineer or geologist, who certifies that the documentation provided is accurate and complete, must also be provided to the Administrator.

(d) If the EOR operations management plan is updated, the updated EOR management plan must be submitted to the Administrator with the annual report covering the first reporting year for which the updated EOR operation management plan is applicable.

§ 98.489 Definitions.

Except as provided in paragraphs (a) and (b) of this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

(a) Additional terms and definitions are provided in Clause 3 of CSA/ANSI ISO 27916:2019 (incorporated by reference, see § 98.7).

(b) All references in this subpart preceded by the word Clause refer to the Clauses in CSA/ANSI ISO 27916:2019.

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Part III

Department of Energy

10 CFR Parts 429 and 431

Energy Conservation Program: Energy Conservation Standards for Dedicated-Purpose Pool Pump Motors; Proposed Rule

DEPARTMENT OF ENERGY

10 CFR Parts 429 and 431

[EERE–2017–BT–STD–0048]

RIN 1904–AF27

Energy Conservation Program: Energy Conservation Standards for Dedicated-Purpose Pool Pump Motors

AGENCY: Office of Energy Efficiency and Renewable Energy, Department of Energy.

ACTION: Notice of proposed rulemaking and announcement of public meeting.

SUMMARY: The Energy Policy and Conservation Act, as amended, prescribes energy conservation standards for various consumer products and certain commercial and industrial equipment, including electric motors. In this notice of proposed rulemaking (''NOPR''), the Department of Energy (DOE) proposes to establish energy conservation standards for dedicated-purpose pool pump motors, a category of electric motors, and also announces a public meeting to receive comment on these proposed standards and associated analyses and results.

DATES:

Comments: DOE will accept comments, data, and information regarding this NOPR no later than August 22, 2022.

Comments regarding the likely competitive impact of the proposed standard should be sent to the Department of Justice contact listed in the **ADDRESSES** section on or before July 21, 2022.

Meeting: DOE will hold a public meeting via webinar on Tuesday, July 26, 2022, from 1:00 p.m. to 4:00 p.m. See section IV, ''Public Participation,'' for webinar registration information, participant instructions and information about the capabilities available to webinar participants.

ADDRESSES: Interested persons are encouraged to submit comments using the Federal eRulemaking Portal at *www.regulations.gov*. Follow the instructions for submitting comments. Alternatively, interested persons may submit comments, identified by docket number EERE–2017–BT–STD–0048, by any of the following methods:

1. *Federal eRulemaking Portal: www.regulations.gov*. Follow the instructions for submitting comments.

2. *Email:* to *DPPMotors2017STD0048@ee.doe.gov*. Include docket number EERE–2017–BT–STD–0048 in the subject line of the message.

No telefacsimiles (''faxes'') will be accepted. For detailed instructions on submitting comments and additional information on this process, see section IV of this document.

Although DOE has routinely accepted public comment submissions through a variety of mechanisms, including the Federal eRulemaking Portal, email, postal mail and hand delivery/courier, the Department has found it necessary to make temporary modifications to the comment submission process in light of the ongoing corona virus 2019 (''COVID–19'') pandemic. DOE is currently suspending receipt of public comments via postal mail and hand delivery/courier. If a commenter finds that this change poses an undue hardship, please contact Appliance Standards Program staff at (202) 586–1445 to discuss the need for alternative arrangements. Once the COVID–19 pandemic health emergency is resolved, DOE anticipates resuming all of its regular options for public comment submission, including postal mail and hand delivery/courier.

Docket: The docket for this activity, which includes **Federal Register** notices, comments, and other supporting documents/materials, is available for review at *www.regulations.gov*. All documents in the docket are listed in the *www.regulations.gov* index. However, not all documents listed in the index may be publicly available, such as information that is exempt from public disclosure.

The docket web page can be found at *www.regulations.gov/#!docketDetail;D=EERE-2017-BT-STD-0048*. The docket web page contains instructions on how to access all documents, including public comments, in the docket. See section VII of this document for information on how to submit comments through *www.regulations.gov*.

EPCA requires the Attorney General to provide DOE a written determination of whether the proposed standard is likely to lessen competition. The U.S. Department of Justice Antitrust Division invites input from market participants and other interested persons with views on the likely competitive impact of the proposed standard. Interested persons may contact the Division at *energy.standards@usdoj.gov* on or before the date specified in the **DATES** section. Please indicate in the ''Subject'' line of your email the title and Docket Number of this proposed rulemaking.

FOR FURTHER INFORMATION CONTACT:

Mr. Jeremy Dommu, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Building Technologies Office, EE–5B, 1000 Independence Avenue SW, Washington, DC, 20585–0121. Telephone: (202) 586–9870. Email: *ApplianceStandardsQuestions@ee.doe.gov*.

Ms. Amelia Whiting, U.S. Department of Energy, Office of the General Counsel, GC–33, 1000 Independence Avenue SW, Washington, DC, 20585–0121. Telephone: (202) 586–2588. Email: *amelia.whiting@hq.doe.gov*.

For further information on how to submit a comment, review other public comments and the docket, or participate in the public meeting, contact the Appliance and Equipment Standards Program staff at (202) 287–1445 or by email: *ApplianceStandardsQuestions@ee.doe.gov*.

SUPPLEMENTARY INFORMATION: DOE proposes to maintain the following previously approved standard in part 431 and incorporate by reference it into part 429: UL 1004–10 (1004–10:2022), ''Standard for Safety for Pool Pump Motors,'' First Edition, approved February 28, 2020, including revisions through March 24, 2022.

Copies of UL 1004–10:2022 can be obtained from: Underwriters Laboratories, 333 Pfingsten Road, Northbrook, IL 60062, (841) 272–8800, or go to *https://www.ul.com*.

For a further discussion of this standard, see section VI.M of this document.

Table of Contents

I. Synopsis of the Proposed Rule

Title III, Part C[1] of the Energy Policy and Conservation Act, as amended (EPCA)[2] established the Energy Conservation Program for Certain Industrial Equipment. (42 U.S.C. 6311–6317) Such equipment includes electric motors, which include dedicated-purpose pool pump motors (''DPPP motors'' or ''DPPPMs'' or ''pool pump motors''), the subject of this proposed rulemaking. (42 U.S.C. 6311(1)(A))

Pursuant to EPCA, any new or amended energy conservation standard must be designed to achieve the maximum improvement in energy efficiency that DOE determines is technologically feasible and economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(A)) Furthermore, the new or amended standard must result in a significant conservation of energy. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3)(B))

In accordance with these and other statutory provisions discussed in this document, DOE proposes new energy conservation standards for DPPP motors. DOE is proposing performance standard for a class of DPPP motors and design requirements for certain classes of DPPP motors. The proposed performance standard, which are expressed in full-load efficiency, and proposed design requirements are shown in Table I.1 of this document. These proposed standards, if adopted, would apply to all DPPP motors listed in Table I.1 of this NOPR manufactured in, or imported into, the United States starting on the date 2 years after the publication of the final rule for this proposed rulemaking.

[1] For editorial reasons, upon codification in the U.S. Code, part C was re-designated part A–1.

[2] All references to EPCA in this document refer to the statute as amended through the Infrastructure Investment and Jobs Act, Public Law 117–58 (Nov. 15, 2021).

TABLE I.1—PROPOSED ENERGY CONSERVATION STANDARDS FOR DEDICATED PURPOSE POOL PUMP MOTORS

Motor total horsepower (THP)	Performance standard: full-load efficiency (%)	Design requirement: speed capability	Design requirement: freeze protection
THP < 0.5	69	None	None.
0.5 ≤ THP < 1.15		Variable speed control	Only for DPPP motors with freeze protection controls.
1.15 ≤ THP ≤ 5		Variable speed control	Only for DPPP motors with freeze protection controls.

DOE also proposes to require that DPPP motors greater than or equal to 0.5 THP must be variable speed control DPPP motors.[3] Finally, for DPPP motors greater than or equal to 0.5 THP, DOE proposes that DPPP motors with freeze protection controls are to be shipped with the freeze protection feature disabled, or with the following default, user-adjustable settings: (a) the default dry-bulb air temperature setting shall be no greater than 40 °F; (b) the default run time setting shall be no greater than 1 hour (before the temperature is rechecked); and (c) the default motor speed in freeze protection mode shall not be more than half of the maximum operating speed.

A. Benefits and Costs to Consumers

Table I.2 presents DOE's evaluation of the economic impacts of the proposed standards on consumers of DPPP motors, as measured by the average life-cycle cost (''LCC'') savings and the simple payback period (''PBP'').[4] The average LCC savings are positive for all equipment classes, and the PBP is less than the average lifetime of DPPP motors, which is estimated to be 4.5 years (see section IV.F.6 of this document).

TABLE I.2—IMPACTS OF PROPOSED ENERGY CONSERVATION STANDARDS ON CONSUMERS OF DPPP MOTORS

Motor total horsepower (THP)	Average LCC savings (2020$)	Simple payback period (years)
THP < 0.5	3	0.7
0.5 ≤ THP < 1.15	69	2.3
1.15 ≤ THP ≤ 5	292	0.9

DOE's analysis of the impacts of the proposed standards on consumers is described in section IV.F of this document.

B. Impact on Manufacturers

The industry net present value (''INPV'') is the sum of the discounted cash flows to the industry from the base year through the end of the analysis period (2021–2055). Using a real discount rate of 7.2 percent, DOE estimates that the INPV for manufacturers of DPPP motors in the case without standards is $798 million in 2020$. Under the proposed standards, the change in INPV is estimated to range from −23.7 percent to 12.9 percent, which is approximately −$189.3 million to $102.9 million. In order to bring products into compliance with standards, it is estimated that the industry would incur total conversion costs of $46.2 million.

DOE's analysis of the impacts of the proposed standards on manufacturers is described in section IV.J of this document. The analytic results of the manufacturer impact analysis (''MIA'') are presented in section V.B.2 of this document.

C. National Benefits and Costs [5]

DOE's analyses indicate that the proposed energy conservation standards for DPPP motors would save a significant amount of energy. Relative to the case without standards, the lifetime energy savings for DPPP motors purchased in the 30-year period that begins in the anticipated first full year of compliance with the standards (2026–2055) amount to 0.99 quadrillion British thermal units (''Btu''), or quads.[6] This represents a savings of 19.8 percent relative to the energy use of these products in the case without amended standards (referred to as the ''no-new-standards case'').

The cumulative net present value (''NPV'') of total consumer benefits of the proposed standards for DPPP motors ranges from $3.0 billion (at a 7-percent discount rate) to $6.3 billion (at a 3-percent discount rate). This NPV expresses the estimated total value of future operating-cost savings minus the estimated increased equipment costs for DPPP motors purchased in 2026–2055.

In addition, the proposed standards for DPPP motors are projected to yield significant environmental benefits. DOE estimates that the proposed standards would result in cumulative emission reductions (over the same period as for energy savings) of 36.2 million metric tons (''Mt'') [7] of carbon dioxide (''CO_2''), 15.8 thousand tons of sulfur dioxide (''SO_2''), 49.9 thousand tons of nitrogen oxides (''NO_X''), 237.2 thousand tons of methane (''CH_4''), 0.4 thousand tons of

[3] Variable speed control DPPP motor is defined in UL 1004–10:2020 (incorporated by reference, See 10 CFR 431.482 and 10 CFR 431.483). In this NOPR, DOE is proposing to reference the latest version of the UL standard, UL 1004–10:2022; see discussion in section III.A.1. Throughout this NOPR, a variable speed motor is a DPPP motor that meets the definition of ''variable speed control dedicated-purpose pool pump motor'' as defined by UL 1004–10:2022.

[4] The average LCC savings refer to consumers that are affected by a standard and are measured relative to the efficiency distribution in the no-new-standards case, which depicts the market in the compliance year in the absence of new or amended standards (*see* section IV.F.8 of this document). The simple PBP, which is designed to compare specific efficiency levels, is measured relative to the baseline product (*see* section V.B.1.a of this document).

[5] All monetary values in this document are expressed in 2020 dollars.

[6] The quantity refers to full-fuel-cycle (''FFC'') energy savings. FFC energy savings includes the energy consumed in extracting, processing, and transporting primary fuels (*i.e.,* coal, natural gas, petroleum fuels), and, thus, presents a more complete picture of the impacts of energy efficiency standards. For more information on the FFC metric, *see* section IV.H.1 of this document.

[7] A metric ton is equivalent to 1.1 short tons. Results for emissions other than CO_2 are presented in short tons.

nitrous oxide (''N_2O''), and 0.1 tons of mercury (''Hg'').[8]

DOE estimates the value of climate benefits from a reduction in greenhouse gases using four different estimates of the social cost of CO_2 (''SC–CO_2''), the social cost of methane (''SC–CH_4''), and the social cost of nitrous oxide (''SC–N_2O''). Together these represent the social cost of greenhouse gases (SC–GHG). DOE used interim SC–GHG values developed by an Interagency Working Group on the Social Cost of Greenhouse Gases (IWG).[9] The derivation of these values is discussed in section IV.L of this document. For presentational purposes, the climate benefits associated with the average SC–GHG at a 3-percent discount rate are estimated to be $1.8 billion. DOE does not have a single central SC–GHG point estimate and it emphasizes the importance and value of considering the benefits calculated using all four SC–GHG estimates.[10] DOE estimated the monetary health benefits of SO_2 and NO_X emissions reductions, also discussed in section IV.L of this document. DOE estimated the present value of the health benefits would be $1.6 billion using a 7-percent discount rate, and $3.3 billion using a 3-percent discount rate.[11] DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions.[12]

Table I.3 summarizes the economic benefits and costs expected to result from the proposed standards for DPPP motors. There are other important unquantified effects, including certain unquantified climate benefits, unquantified public health benefits from the reduction of toxic air pollutants and other emissions, unquantified energy security benefits, and distributional effects, among others.

TABLE I.3—SUMMARY OF MONETIZED ECONOMIC BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR DPPP MOTORS

[TSL 7]

	Billion 2020$
3% discount rate	
Consumer Operating Cost Savings	8.8
Climate Benefits *	1.8
Health Benefits **	3.3
Total Benefits †	13.9
Consumer Incremental Equipment Costs	2.5
Net Benefits	11.4
7% discount rate	
Consumer Operating Cost Savings	4.6
Climate Benefits * (3% discount rate)	1.8
Health Benefits **	1.6
Total Benefits †	8.0
Consumer Incremental Equipment Costs	1.5
Net Benefits	6.4

Note: This table presents the costs and benefits associated with DPPP motors shipped in 2026–2055. These results include benefits to consumers which accrue after 2055 from the products shipped in 2026–2055.

[8] DOE calculated emissions reductions relative to the no-new-standards case, which reflects key assumptions in the *Annual Energy Outlook 2021* (''*AEO2021*''). *AEO2021* represents current federal and state legislation and final implementation of regulations as of the time of its preparation. *See* section IV.K of this document for further discussion of *AEO2021* assumptions that effect air pollutant emissions.

[9] See Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide. Interim Estimates Under Executive Order 13990, Washington, DC, February 2021. (''February 2021 SC–GHG TSD''). */www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.*

[10] On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22–30087) granted the federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana* v. *Biden,* No. 21–cv–1074–JDC–KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from ''adopting, employing, treating as binding, or relying upon'' the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and presents monetized benefits where appropriate and permissible under law

[11] DOE estimates the economic value of these emissions reductions resulting from the considered TSLs for the purpose of complying with the requirements of Executive Order 12866.

[12] On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22–30087) granted the federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana* v. *Biden,* No. 21–cv–1074–JDC–KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from ''adopting, employing, treating as binding, or relying upon'' the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and present monetized benefits where appropriate and permissible under law.

* Climate benefits are calculated using four different estimates of the social cost of carbon ($SC–CO_2$), methane ($SC–CH_4$), and nitrous oxide ($SC–N_2O$) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate), as shown in Table IV.17 and Table IV.18. Together these represent the global SC–GHG. For presentational purposes of this table, the climate benefits associated with the average SC–GHG at a 3 percent discount rate are shown, but the Department does not have a single central SC–GHG point estimate. *See* section IV.L of this document for more details. On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22–30087) granted the federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana* v. *Biden,* No. 21–cv–1074–JDC–KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from ''adopting, employing, treating as binding, or relying upon'' the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and presents monetized benefits where appropriate and permissible under law.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. See section IV.L of this document for more details.

† Total and net benefits include those consumer, climate, and health benefits that can be quantified and monetized. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SC–GHG with 3-percent discount rate, but the Department does not have a single central SC–GHG point estimate. DOE emphasizes the importance and value of considering the benefits calculated using all four SC–GHG estimates.

The benefits and costs of the proposed standards can also be expressed in terms of annualized values. The monetary values for the total annualized net benefits are (1) the reduced consumer operating costs, minus (2) the increase in product purchase prices and installation costs, plus (3) the value of climate and health benefits of emission reduction, all annualized.[13] The national operating savings are domestic private U.S. consumer monetary savings that occur as a result of purchasing the covered products and are measured for the lifetime of DPPP motors shipped in 2026–2055. The benefits associated with reduced emissions achieved as a result of the proposed standards are also calculated based on the lifetime of DPPP motors shipped in 2026–2055. Total benefits for both the 3-percent and 7-percent cases are presented using the average GHG social costs with 3-percent discount rate. Estimates of SC–GHG values are presented for all four discount rates in section V.B.8 of this document. Table I.4 presents the total estimated monetized benefits and costs associated with the proposed standard, expressed in terms of annualized values.

Estimates of annualized benefits and costs of the proposed standards are shown in Table I.4 of this document. The results under the primary estimate are as follows.

Using a 7-percent discount rate for consumer benefits and costs and health benefits from reduced NO_X and SO_2 emissions benefits, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated cost of the standards proposed in this rule is $163.5 million per year in increased equipment costs, while the estimated annual benefits are $482.3 million in reduced equipment operating costs $104.2 million in GHG climate benefits, and $168.7 million in health benefits. In this case, the net benefit would amount to $591.6 million per year.

Using a 3-percent discount rate for all benefits and costs, the estimated cost of the proposed standards is $142.9 million per year in increased equipment costs, while the estimated annual benefits are $504.2 million in reduced operating costs, $104.2 million in climate benefits, and $188.9 million in health benefits. In this case, the net benefit would amount to $654.4 million per year.

TABLE I.4—ANNUALIZED MONETIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR DPPP MOTORS

[TSL 7]

	Million 2020$/year		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
3% discount rate			
Consumer Operating Cost Savings	504.2	436.2	580.9
Climate Benefits *	104.2	92.6	115.6
Health Benefits **	188.9	168.1	209.3
Total Benefits †	797.3	696.9	905.9
Consumer Incremental Equipment Costs	142.9	110.0	178.0
Net Benefits	654.4	587.0	727.9
7% discount rate			
Consumer Operating Cost Savings	482.3	424.8	546.8
Climate Benefits * (3% discount rate)	104.2	92.6	115.6
Health Benefits **	168.7	152.0	185.0
Total Benefits †	755.2	669.5	847.5

[13] To convert the time-series of costs and benefits into annualized values, DOE calculated a present value in 2026, the year used for discounting the NPV of total consumer costs and savings. For the benefits, DOE calculated a present value associated with each year's shipments in the year in which the shipments occur (*e.g.,* 2030), and then discounted the present value from each year to 2026. Using the present value, DOE then calculated the fixed annual payment over a 30-year period, starting in the compliance year, that yields the same present value.

TABLE I.4—ANNUALIZED MONETIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR DPPP MOTORS—Continued

[TSL 7]

	Million 2020$/year		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
Consumer Incremental Equipment Costs	163.5	129.2	199.0
Net Benefits	591.6	540.3	648.5

Note: This table presents the costs and benefits associated with DPPP motors shipped in 2026–2055. These results include benefits to consumers which accrue after 2055 from the products shipped in 2026–2055. The Primary, Low Net Benefits, and High Net Benefits Estimates utilize projections of energy prices from the AEO2021 Reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental equipment costs reflect a medium decline rate in the Primary Estimate, a low decline rate in the Low Net Benefits Estimate, and a high decline rate in the High Net Benefits Estimate. The methods used to derive projected price trends are explained in sections IV.F.1 and IV.H.1of this document. Note that the Benefits and Costs may not sum to the Net Benefits due to rounding.

* Climate benefits are calculated using four different estimates of the global SC–GHG (see section IV.L of this document). For presentational purposes of this table, the climate benefits associated with the average SC–GHG at a 3 percent discount rate are shown, but the Department does not have a single central SC–GHG point estimate, and it emphasizes the importance and value of considering the benefits calculated using all four SC–GHG estimates. On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22–30087) granted the federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana* v. *Biden,* No. 21–cv–1074–JDC–KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from ''adopting, employing, treating as binding, or relying upon'' the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and presents monetized benefits where appropriate and permissible under law.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. The health benefits are presented at real discount rates of 3 and 7 percent. See section IV.L of this document for more details.

† Total benefits for both the 3-percent and 7-percent cases are presented using the average SC–GHG with 3-percent discount rate, but the Department does not have a single central SC–GHG point estimate.

DOE's analysis of the national impacts of the proposed standards is described in sections IV.G.2, IV.K and IV.L of this document.

D. Conclusion

DOE has tentatively concluded that the proposed standards represent the maximum improvement in energy efficiency that is technologically feasible and economically justified, and would result in the significant conservation of energy. Specifically, with regards to technological feasibility products achieving these standard levels are already commercially available for all equipment classes covered by this proposal. As for economic justification, DOE's analysis shows that the benefits of the proposed standard exceed, to a great extent, the burdens of the proposed standards.

Using a 7-percent discount rate for consumer benefits and costs and health benefits from NO_X and SO_2 reduction, and a 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated cost of the proposed standards for DPPPM is $163.5 million per year in increased DPPPM costs, while the estimated annual benefits are $482.3 million in reduced equipment operating costs, $104.2 million in climate benefits, and $168.7 million in health benefits. The net benefit amounts to $591.6 million per year.

The significance of energy savings offered by a new or amended energy conservation standard cannot be determined without knowledge of the specific circumstances surrounding a given rulemaking.[14] For example, the United States rejoined the Paris Agreement on February 19, 2021. As part of that agreement, the United States has committed to reducing GHG emissions in order to limit the rise in mean global temperature. As such, energy savings that reduce GHG emissions have taken on greater importance. Additionally, some covered products and equipment have most of their energy consumption occur during periods of peak energy demand. The impacts of these products on the energy infrastructure can be more pronounced than products with relatively constant demand. In evaluating the significance of energy savings, DOE considers differences in primary energy and FFC effects for different covered products and equipment when determining whether energy savings are significant. Primary energy and FFC effects include the energy consumed in electricity production (depending on load shape), in distribution and transmission, and in extracting, processing, and transporting primary fuels (*i.e.,* coal, natural gas, petroleum fuels), and thus present a more complete picture of the impacts of energy conservation standards. Accordingly, DOE evaluates the significance of energy savings on a case-by-case basis.

As previously mentioned, the proposed standards would result in estimated national energy savings of 0.99 quad FFC, the equivalent of the electricity use of 9.6 million homes in one year. DOE has initially determined the energy savings from the proposed standard levels are ''significant'' within the meaning of 42 U.S.C. 6295(o)(3)(B). Finally, DOE notes that a more detailed discussion of the basis for these tentative conclusions is contained in the remainder of this document and the accompanying TSD.

DOE also considered more-stringent energy efficiency levels as potential standards, and is still considering them in this proposed rulemaking. However, DOE has tentatively concluded that the potential burdens of the more-stringent energy efficiency levels would outweigh the projected benefits.

Based on consideration of the public comments DOE receives in response to

[14] Procedures, Interpretations, and Policies for Consideration in New or Revised Energy Conservation Standards and Test Procedures for Consumer Products and Commercial/Industrial Equipment, 86 FR 70892, 70901 (Dec. 13, 2021).

this document and related information collected and analyzed during the course of this proposed rulemaking effort, DOE may adopt energy efficiency levels presented in this document that are either higher or lower than the proposed standards, or some combination of level(s) that incorporate the proposed standards in part.

II. Introduction

The following section briefly discusses the statutory authority underlying this proposed rule, as well as some of the relevant historical background related to the establishment of standards for DPPP motors.

A. Authority

EPCA authorizes DOE to regulate the energy efficiency of a number of consumer products and certain industrial equipment. Title III, Part C of EPCA, added by Public Law 95–619, Title IV, section 441(a) (42 U.S.C. 6311–6317, as codified), established the Energy Conservation Program for Certain Industrial Equipment, which sets forth a variety of provisions designed to improve energy efficiency. This equipment includes those electric motors that are DPPP motors, the subject of this document. (42 U.S.C. 6311(1)(A))

The energy conservation program under EPCA consists essentially of four parts: (1) testing, (2) labeling, (3) the establishment of Federal energy conservation standards, and (4) certification and enforcement procedures. Relevant provisions of EPCA include definitions (42 U.S.C. 6311), test procedures (42 U.S.C. 6314), labeling provisions (42 U.S.C. 6315), energy conservation standards (42 U.S.C. 6313), and the authority to require information and reports from manufacturers (42 U.S.C. 6316; 42 U.S.C. 6296).

Federal energy efficiency requirements for covered equipment established under EPCA generally supersede State laws and regulations concerning energy conservation testing, labeling, and standards. (42 U.S.C. 6316(a); 42 U.S.C. 6297) DOE may, however, grant waivers of Federal preemption for particular State laws or regulations, in accordance with the procedures and other provisions set forth under EPCA. (See 42 U.S.C. 6316(a) (applying the preemption waiver provisions of 42 U.S.C. 6297))

Subject to certain criteria and conditions, DOE is required to develop test procedures to measure the energy efficiency, energy use, or estimated annual operating cost of each covered product. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3)(A) and 42 U.S.C. 6295(r)) Manufacturers of covered equipment must use the Federal test procedures as the basis for: (1) certifying to DOE that their equipment complies with the applicable energy conservation standards adopted pursuant to EPCA (42 U.S.C. 6316(a); 42 U.S.C. 6295(s)), and (2) making representations about the efficiency of that equipment (42 U.S.C. 6314(d)). Similarly, DOE must use these test procedures to determine whether the equipment complies with relevant standards promulgated under EPCA. (42 U.S.C. 6316(a); 42 U.S.C. 6295(s)) The DOE test procedures for DPPP motors appear at title 10 of the Code of Federal Regulations (''CFR'') part 431, subpart Z.

DOE must follow specific statutory criteria for prescribing new or amended standards for covered equipment, including those electric motors that are DPPP motors. Any new or amended standard for a covered product must be designed to achieve the maximum improvement in energy efficiency that the Secretary of Energy determines is technologically feasible and economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(A) and 42 U.S.C. 6295(o)(3)(B)) Furthermore, DOE may not adopt any standard that would not result in the significant conservation of energy. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3))

Moreover, DOE may not prescribe a standard: (1) for certain equipment, including those electric motors that are DPPP motors, if no test procedure has been established for the equipment, or (2) if DOE determines by rule that the standard is not technologically feasible or economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3)(A)–(B)) In deciding whether a proposed standard is economically justified, DOE must determine whether the benefits of the standard exceed its burdens. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)) DOE must make this determination after receiving comments on the proposed standard, and by considering, to the greatest extent practicable, the following seven statutory factors:

(1) The economic impact of the standard on manufacturers and consumers of the products subject to the standard;

(2) The savings in operating costs throughout the estimated average life of the covered products in the type (or class) compared to any increase in the price, initial charges, or maintenance expenses for the covered products that are likely to result from the standard;

(3) The total projected amount of energy (or as applicable, water) savings likely to result directly from the standard;

(4) Any lessening of the utility or the performance of the covered products likely to result from the standard;

(5) The impact of any lessening of competition, as determined in writing by the Attorney General, that is likely to result from the standard;

(6) The need for national energy and water conservation; and

(7) Other factors the Secretary of Energy (''Secretary'') considers relevant.

(42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(I)–(VII))

Further, EPCA establishes a rebuttable presumption that a standard is economically justified if the Secretary finds that the additional cost to the consumer of purchasing an equipment complying with an energy conservation standard level will be less than three times the value of the energy savings during the first year that the consumer will receive as a result of the standard, as calculated under the applicable test procedure. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(iii))

EPCA also contains what is known as an ''anti-backsliding'' provision, which prevents the Secretary from prescribing any amended standard that either increases the maximum allowable energy use or decreases the minimum required energy efficiency of covered equipment. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(1)) Also, the Secretary may not prescribe an amended or new standard if interested persons have established by a preponderance of the evidence that the standard is likely to result in the unavailability in the United States in any covered product type (or class) of performance characteristics (including reliability), features, sizes, capacities, and volumes that are substantially the same as those generally available in the United States. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(4))

Additionally, EPCA specifies requirements when promulgating an energy conservation standard for covered equipment that has two or more subcategories. DOE must specify a different standard level for a type or class of equipment that has the same function or intended use, if DOE determines that equipment within such group: (A) consume a different kind of energy from that consumed by other covered equipment within such type (or class); or (B) have a capacity or other performance-related feature which other equipment within such type (or class) do not have and such feature justifies a higher or lower standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(q)(1)) In determining whether a performance-related feature justifies a different standard for a group of equipment, DOE must consider such factors as the utility to the consumer of the feature and other factors DOE deems appropriate. *Id.* Any rule prescribing such a standard must include an explanation of the basis on which such higher or lower level was established. (42 U.S.C. 6316(a); 42 U.S.C. 6295(q)(2))

B. Background

1. Current Standards

DPPP motors are electric motors, which are defined as machines that convert electrical power into rotational mechanical power. 10 CFR 431.12. DOE has established test procedures, labeling requirements, and energy conservation standards for certain electric motors (10 CFR part 431 subpart B), but those requirements do not apply to DPPP motors subject to the proposed energy conservation standards. DOE has separately established test procedure for DPPP motors in 10 CFR part 431 subpart Z (''Subpart Z'').

Currently, DPPP motors that would be subject to the proposed energy conservation standards are not subject to any Federal energy conservation standards or labeling requirements because they do not fall within any of the specific classes of electric motors that are currently regulated by DOE.[15] However, DPPP motors are electric motors and, therefore, are and have been among the types of industrial equipment for which Congress has authorized DOE to establish applicable regulations under EPCA without need for DOE to undertake any additional prior administrative action. (42 U.S.C. 6311(1)(A))

2. History of Standards Rulemaking for DPPP Motors

On January 18, 2017, DOE published a direct final rule establishing energy conservation standards for DPPPs. 82 FR 5650 (the ''January 2017 Direct Final Rule'').[16] Acknowledging comments received in response to the direct final rule in support of regulating DPPP motors that would serve as replacement motors to the regulated pool pumps, DOE published a notice of public meeting on July 3, 2017, and held a public meeting on August 10, 2017, to consider potential scope, definitions, equipment characteristics, and metrics for pool pump motors. 82 FR 30845. DOE also requested comment on potential requirements for DPPP motors in a request for information (''RFI'') pertaining to test procedures for small electric motors and electric motors. 82 FR 35468 (July 31, 2017). On August 14, 2018, DOE received a petition submitted by a variety of entities (collectively, the ''Joint Petitioners'')[17] requesting that DOE issue a direct final rule to establish prescriptive standards and a labeling requirement for DPPP motors (''Joint Petition'').[18] The Joint Petitioners sought a compliance date of July 19, 2021, to align with the standards compliance date for DPPPs. (Id.) *See also* 82 FR 24218 (May 26, 2017). DOE published a notice of the Joint Petition and sought comment on whether to proceed with the proposal, as well as any data or information that could be used in DOE's determination of whether to issue a direct final rule. 83 FR 45851 (Sept. 11, 2018).[19]

On December 12, 2018, representatives from APSP, NEMA, Nidec Motors, Regal Beloit, and Zodiac met with DOE to reiterate the need for implementation of the Joint Petition. (December 2018 *Ex Parte* Meeting, No. 42 at p. 1)[20] On February 5, 2019, the Association of Pool & Spa Professionals (''APSP''), National Electrical Manufacturers Association (''NEMA''), Hayward, Pentair, Nidec Motors, Regal Beloit, WEG Commercial Motors, and Zodiac Pool Systems met with DOE to present an alternative approach to the Joint Petition, suggesting DOE propose a labeling requirement for DPPP motors. (February 2019 *Ex Parte* Meeting, No. 43 at p. 1)[21] These interested parties specifically requested that DOE base the labeling requirement on a newly-available industry standard for pool pump motors published on July 1, 2019 (UL 1004–10:2019, ''Pool Pump Motors''), a design standard that incorporates some of the proposals contained in the Joint Petition. (February 2019 *Ex Parte* Slides, No. 43 at pp. 9–10) A follow-up memorandum was submitted to DOE on March 1, 2019, providing additional information related to UL 1004–10:2019. (March 2019 *Ex Parte* Memo, No. 44) The interested parties noted the timelines and costs that would be involved in applying a label to the affected pool pump motors and the impacts flowing from past labeling efforts. (*See generally* id. at 1–3.)

On October 5, 2020, in response to the Joint Petition and the alternative recommendation presented by several of the Joint Petitioners following submission of the Joint Petition, DOE published a NOPR proposing to establish a test procedure and an accompanying labeling requirement for DPPP motors. 85 FR 62816 (''October 2020 NOPR''). Specifically, DOE proposed to incorporate by reference UL Standard 1004–10:2019 ''Outline of Investigation for Pool Pump Motors'' (''UL 1004–10:2019'') pertaining to DPPP definitions and marking requirements; require the use of CSA C747–09 (R2014), ''Energy Efficiency Test Methods for Small Motors'' (''CSA C747–09'') for testing the energy efficiency of DPPP motors; require the nameplate of a subject DPPP motor (1) to include the full-load efficiency of the motor as determined under the proposed test procedure, and (2) if the DPPP motor is certified to UL–1004–10:2019, to include the statement, ''Certified to UL 1004–10:2019''; require

[15] The current energy conservation standards at 10 CFR 431.425 apply to electric motors that satisfy nine criteria listed at 10 CFR 431.425(g), subject to the exemptions listed at 10 CFR 431.25(l). The nine criteria are as follows: (1) are single-speed, induction motors; (2) are rated for continuous duty (MG1) operation or for duty type S1 (IEC); (3) contain a squirrel-cage (MG1) or cage (IEC) rotor; (4) operate on polyphase alternating current 60-hertz sinusoidal line power; (5) are rated 600 volts or less; (6) have a 2-, 4-, 6-, or 8-pole configuration; (7) are built in a three digit or four-digit NEMA frame size (or IEC metric equivalent), including those designs between two consecutive NEMA frame sizes (or IEC metric equivalent), or an enclosed 56 NEMA frame size (or IEC metric equivalent); (8) produce at least one horsepower (0.746 kW) but not greater than 500 horsepower (373 kW), and; (9) meet all of the performance requirements of one of the following motor types: A NEMA Design A, B, or C motor or an IEC Design N or H motor. The exemptions listed at 10 CFR 431.25(l) are: (1) air-over electric motors; (2) component sets of an electric motor; (3) liquid-cooled electric motors; (4) submersible electric motors; and (5) inverter-only electric motors.

[16] DOE confirmed the adoption of the standards and the effective date and compliance date in a notice published on May 26, 2017. 82 FR 24218. DOE also established a test procedure for DPPPs. 82 FR 36858 (August 7, 2017).

[17] The Joint Petitioners are: The Association of Pool & Spa Professionals, Alliance to Save Energy, American Council for an Energy-Efficient Economy, Appliance Standards Awareness Project, Arizona Public Service, California Energy Commission, California Investor Owned Utilities, Consumer Federation of America, Florida Consumer Action Network, Hayward Industries, National Electrical Manufacturers Association, Natural Resources Defense Council, Nidec Motor Corporation, Northwest Power and Conservation Council, Pentair Water Pool and Spa, Regal Beloit Corporation, Speck Pumps, Texas ROSE (Ratepayers' Organization to Save Energy), Waterway Plastics, WEG Commercial Motors, and Zodiac Pool Systems.

[18] The Joint Petition is available at *www.regulations.gov/document?D=EERE-2017-BT-STD-0048-0014.*

[19] Docket No. EERE–2017–BT–STD–0048, available at: *www.regulations.gov/docket?D=EERE-2017-BT-STD-0048.*

[20] With respect to each of the *ex parte* communications noted in this document, DOE posted a memorandum submitted by the interested party/parties that summarized the issues discussed in the relevant meeting as well as its date and attendees, in compliance with DOE's Guidance on *Ex Parte* Communications. 74 FR 52795–52796 (Oct. 14, 2009). The memorandum of the meeting as well as any documents given to DOE employees during the meeting were added to the docket as specified in that guidance. *See Id.* at 74 FR 52796.

[21] The parenthetical reference provides a reference for information located in the docket of DOE's rulemaking to develop the test procedure and labeling requirements for DPPP motors. (Docket No. EERE–2017–BT–STD–0008, which is maintained at *www.regulations.gov/#!docketDetail;D=EERE-2017-BT-STD-0008*). The references are arranged as follows: (commenter, comment docket ID number, page of that document).

that catalogs and marketing materials include the full-load efficiency of the motor; require manufacturers to notify DOE of the subject DPPP motor models in current production (according to the manufacturer's model number) and whether the motor model is certified to UL 1004–10:2019; and require manufacturers to report to DOE the full-load efficiency of the subject DPPP motor models as determined pursuant to the proposed test procedure. 85 FR 62816, 62820. Additionally, if a DPPP motor model is certified to UL 1004–10:2019, DOE proposed to require manufacturers to report the total horsepower (''THP'') and speed configuration of the motor model as provided on the nameplate pursuant to the UL certification. *Id.*

On July 29, 2021, DOE published a final rule adopting a test procedure for DPPP motors. 86 FR 40765. (''July 2021 Final Rule''). Specifically, the test procedure requires to use CSA C747–09 (R2014), ''Energy Efficiency Test Methods for Small Motors'' (''CSA C747–09'') for testing the full-load efficiency of DPPP motors and incorporates by reference UL 1004–10:2020 ''Standard for Pool Pump Motors'' (''UL 1004–10:2020'') pertaining to definitions and scope. The new test procedure is currently located in 10 CFR part 431, subpart Z (''Subpart Z''). 86 FR 40765, 40768. DOE did not establish a labeling requirement and stated that it intends to address any such labeling and/or energy conservation standards requirement in a separate notification. *Id.*

C. Deviation From Appendix A

In accordance with section 3(a) of 10 CFR part 430, subpart C, appendix A (''appendix A''), applicable to covered equipment under 10 CFR 431.4, DOE notes that it is deviating from the provision in appendix A regarding the process for proposing new or amended energy conservation standards. Section 6(a)(1) of appendix A states that as the first step in any proceeding to consider establishing any energy conservation standard, DOE will consider initiating a rulemaking proceeding. Section 6(a)(2) of appendix A states that if the Department determines it is appropriate to proceed with a rulemaking, the preliminary stages of a rulemaking to issue an energy conservation standard that DOE will undertake will be a framework document and preliminary analysis, or an advance notice of proposed rulemaking (''ANOPR''). DOE is opting to deviate from both provisions by a publishing a NOPR without first publishing a document announcing that DOE is considering initiating a rulemaking proceeding, a framework document and preliminary analysis or an ANOPR. DOE believes that given the stakeholder involvement and information received to date regarding DPPP motors and potential standards for such equipment, there has been already been significant stakeholder engagement on this topic including: (1) the RFI on July 31, 2017, which include issues for comment relating to dedicated purpose pool pump motors (82 FR 35468); (2) the Joint Petition requesting a direct final rule to establish standards and a labeling requirement for DPPPMs, on which DOE requested comment along with any data or information that could be used in DOE's determination of whether to issue a direct final rule (83 FR 45851); (3) stakeholders engagement from substantive *ex parte* communications with DOE; and (4) the analysis conducted in support of the energy conservation standards for DPPPs, included analyses of DPPP motors comparable to the analyses conducted in support of this NOPR (*See* 82 FR 5650).

Section 6(f)(2) of appendix A states that the length of the public comment period for NOPR rulemaking documents will vary depending upon the circumstances of the particular rulemaking, but will not be less than 75 calendar days. DOE is opting to deviate from this provision in providing a 60-day comment period. DOE has tentatively that a 60-day comment period should be sufficient for stakeholders to evaluate the proposal presented in this NOPR and provide comment given the extensive stakeholder involvement to date and the prior opportunities to comment.

III. General Discussion

A. Scope of Coverage and Equipment Classes

This document covers equipment meeting the definition of DPPP motor as defined in 10 CFR 431.483 and the scope specified in 10 CFR 431.481(b). Specifically, the scope covers DPPP motors with a total THP of less than or equal to 5, but does not apply to: (i) DPPP motors that are polyphase motors capable of operating without a drive and distributed in commerce without a drive that converts single-phase power to polyphase power; (ii) waterfall pump motors; (iii) rigid electric spa pump motors, (iv) storable electric spa pump motors; (v) integral cartridge-filter pool pump motors, and (vi) integral sand-filter pool pump motors.[22]

When evaluating and establishing energy conservation standards, DOE divides covered equipment into equipment classes by the type of energy used or by capacity or other performance-related features that justify differing standards. In making a determination whether a performance-related feature justifies a different standard, DOE must consider such factors as the utility of the feature to the consumer and other factors DOE determines are appropriate. (42 U.S.C. 6316(a); 42 U.S.C. 6295(q))

DOE is proposing to establish equipment classes for DPPP motors based on THP. DOE is proposing an extra-small-size equipment corresponding to motors with a THP less than 0.5 hp, a small-size equipment class corresponding to motors with a total horsepower rating greater than or equal to 0.5 hp but less than 1.15 hp, and a standard-size equipment class corresponding to motor with a THP greater than or equal to 1.15 hp and less than or equal to 5 hp. Table III.1 provides a summary of the proposed equipment classes. See section IV.A.3 for further details on the reasoning why DOE determined these equipment classes are appropriate and justify having separate standards.

TABLE III.1—PROPOSED EQUIPMENT CLASSES FOR DPPP MOTORS

Equipment class	Motor total horsepower (Hp)
Extra-small-size	THP < 0.5
Small-size	$0.5 \leq$ THP < 1.15
Standard-size	$1.15 \leq$ THP ≤ 5

B. Test Procedure

EPCA sets forth generally applicable criteria and procedures for DOE's adoption and amendment of test procedures. (42 U.S.C. 6314(a)) Manufacturers of covered products must use these test procedures to certify to DOE that their product complies with energy conservation standards and to quantify the efficiency of their product.

As stated, DOE established subpart Z which specifies that the test procedure applies to DPPP motors with a THP of less than or equal to 5, but does not apply to: (i) DPPP motors that are polyphase motors capable of operating without a drive and distributed in commerce without a drive that converts single-phase power to polyphase power; (ii) waterfall pump motors; (iii) rigid electric spa pump motors, (iv) storable

[22] These terms are defined in UL 1004–10:2020, which is incorporated by reference in DOE's test procedure in Subpart Z of 10 CFR part 431. In this NOPR, DOE is proposing to reference the latest version of the UL standard, UL 1004–10:2022; see discussion in section III.A.1.

electric spa pump motors; (v) integral cartridge-filter pool pump motors, and (vi) integral sand-filter pool pump motors). Further, Subpart Z incorporates by reference CSA C747–09 as the energy efficiency test method for DPPP motors, with ''full-load efficiency'' as the metric.

The test procedure references UL 1004–10:2020 ''Standard for Safety for Pool Pump Motors'' for the definitions, (10 CFR 431.483) and references CSA C747–09 as the energy efficiency test method for DPPP motors (10 CFR 431.484(b)). The test procedure establishes full-load efficiency as the metric for DPPP motors. 10 CFR 431.484(b). In this NOPR, DOE is proposing to reference the latest version of the UL standard, UL 1004–10:2022, which added a definition for the term ''factory default setting''; see discussion in section III.A.1. As such, DOE is proposing product-specific enforcement requirements at 10 CFR 429.134 that require DPPPMs be tested in accordance with UL 1004–10:2022 to verify variable-speed capability and applicable freeze protection design requirements.

C. Technological Feasibility

1. General

In each energy conservation standards rulemaking, DOE conducts a screening analysis based on information gathered on all current technology options and prototype designs that could improve the efficiency of the products or equipment that are the subject of the rulemaking. As the first step in such an analysis, DOE develops a list of technology options for consideration in consultation with manufacturers, design engineers, and other interested parties. DOE then determines which of those means for improving efficiency are technologically feasible. DOE considers technologies incorporated in commercially-available products or in working prototypes to be technologically feasible. Sections 6(b)(3)(i) and 7(b)(1) of appendix A to 10 CFR part 430, subpart C (''Process Rule'').

After DOE has determined that particular technology options are technologically feasible, it further evaluates each technology option in light of the following additional screening criteria: (1) practicability to manufacture, install, and service; (2) adverse impacts on product utility or availability; (3) adverse impacts on health or safety, and (4) unique-pathway proprietary technologies. 10 CFR 431.4; Sections 6(b)(3)(ii)–(v) and 7(b)(2)–(5) of the Process Rule. Section IV.B of this document discusses the results of the screening analysis for DPPP motors, particularly the designs DOE considered, those it screened out, and those that are the basis for the standards considered in this proposed rulemaking. For further details on the screening analysis for this proposed rulemaking, see chapter 4 of the NOPR technical support document (''TSD'').

2. Maximum Technologically Feasible Levels

When DOE proposes to adopt an amended standard for a type or class of covered product, it must determine the maximum improvement in energy efficiency or maximum reduction in energy use that is technologically feasible for such product. (42 U.S.C. 6316(a); 42 U.S.C. 6295(p)(1)) Accordingly, in the engineering analysis, DOE determined the maximum technologically feasible (''max-tech'') improvements in energy efficiency for DPPP motors, using the design parameters for the most efficient products available on the market or in working prototypes. The max-tech levels that DOE determined for this proposed rulemaking are described in section IV.C.1.c of this proposed rule and in chapter 5 of the NOPR TSD.

D. Energy Savings

1. Determination of Savings

For each trial standard level (''TSL''), DOE projected energy savings from application of the TSL to DPPP motors purchased in the 30-year period that begins in the first full year of compliance with the proposed standards (2026–2055).[23] The savings are measured over the entire lifetime of DPPP motors purchased in the previous 30-year period. DOE quantified the energy savings attributable to each TSL as the difference in energy consumption between each standards case and the no-new-standards case. The no-new-standards case represents a projection of energy consumption that reflects how the market for a product would likely evolve in the absence of new energy conservation standards.

DOE used its national impact analysis (''NIA'') spreadsheet model to estimate national energy savings (''NES'') from potential amended or new standards for DPPP motors. The NIA spreadsheet model (described in section IV.H of this document) calculates energy savings in terms of site energy, which is the energy directly consumed by products at the locations where they are used. For electricity, DOE reports national energy savings in terms of primary energy savings, which is the savings in the energy that is used to generate and transmit the site electricity. DOE also calculates NES in terms of FFC energy savings. The FFC metric includes the energy consumed in extracting, processing, and transporting primary fuels (*i.e.,* coal, natural gas, petroleum fuels), and thus presents a more complete picture of the impacts of energy conservation standards.[24] DOE's approach is based on the calculation of an FFC multiplier for each of the energy types used by covered products or equipment. For more information on FFC energy savings, see section IV.H.2 of this document.

2. Significance of Savings

To adopt any new or amended standards for a covered product, DOE must determine that such action would result in significant energy savings. (42 U.S.C. 6315(a); 42 U.S.C. 6295(o)(3)(B)) The significance of energy savings offered by a new or amended energy conservation standard cannot be determined without knowledge of the specific circumstances surrounding a given rulemaking.[25] For example, the United States rejoined the Paris Agreement on February 19, 2021. As part of that agreement, the United States has committed to reducing greenhouse gas (''GHG'') emissions in order to limit the rise in mean global temperature.[26] As such, energy savings that reduce GHG emission have taken on greater importance. Additionally, some covered products and equipment have most of their energy consumption occur during periods of peak energy demand. The impacts of these products on the energy infrastructure can be more pronounced than products with relatively constant demand. In evaluating the significance of energy savings, DOE considers differences in primary energy and full-fuel-cycle (''FFC'') effects for different covered products and equipment when determining whether energy savings are significant. Primary energy and FFC effects include the energy consumed in electricity production (depending on load shape), in distribution and transmission, and in extracting, processing, and transporting primary fuels (*i.e.,* coal, natural gas, petroleum fuels), and thus present a more complete

[23] Each TSL is composed of specific efficiency levels for each product class. The TSLs considered for this NOPR are described in section V.A. DOE conducted a sensitivity analysis that considers impacts for products shipped in a 9-year period.

[24] The FFC metric is discussed in DOE's statement of policy and notice of policy amendment. 76 FR 51282 (Aug. 18, 2011), as amended at 77 FR 49701 (Aug. 17, 2012).

[25] *See* 86 FR 70892, 70901 (Dec. 13, 2021).

[26] *See* Executive Order 14008, 86 FR 7619 (Feb. 1, 2021) (''Tackling the Climate Crisis at Home and Abroad'').

picture of the impacts of energy conservation standards.

Accordingly, DOE evaluates the significance of energy savings on a case-by-case basis, taking into account the significance of cumulative FFC national energy savings, the cumulative FFC emissions reductions, and the need to confront the global climate crisis, among other factors. DOE estimates a combined total of 0.99 quads of FFC energy savings at the proposed efficiency levels for DPPP motors. This represents 19.8 percent energy savings relative to the no-new-standards case energy consumption for DPPP motors. DOE has initially determined the energy savings for the trial standard levels considered in this proposal are ''significant'' within the meaning of 42 U.S.C. 6295(o)(3)(B).

E. Economic Justification

1. Specific Criteria

As noted previously, EPCA provides seven factors to be evaluated in determining whether a potential energy conservation standard is economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(I)–(VII)) The following sections discuss how DOE has addressed each of those seven factors in this proposed rulemaking.

a. Economic Impact on Manufacturers and Consumers

In determining the impacts of a potential amended standard on manufacturers, DOE conducts an MIA, as discussed in section IV.J of this document. DOE first uses an annual cash-flow approach to determine the quantitative impacts. This step includes both a short-term assessment—based on the cost and capital requirements during the period between when a regulation is issued and when entities must comply with the regulation—and a long-term assessment over a 30-year period. The industry-wide impacts analyzed include (1) INPV, which values the industry on the basis of expected future cash flows, (2) cash flows by year, (3) changes in revenue and income, and (4) other measures of impact, as appropriate. Second, DOE analyzes and reports the impacts on different types of manufacturers, including impacts on small manufacturers. Third, DOE considers the impact of standards on domestic manufacturer employment and manufacturing capacity, as well as the potential for standards to result in plant closures and loss of capital investment. Finally, DOE takes into account cumulative impacts of various DOE regulations and other regulatory requirements on manufacturers.

For individual consumers, measures of economic impact include the changes in LCC and PBP associated with new or amended standards. These measures are discussed further in the following section. For consumers in the aggregate, DOE also calculates the national net present value of the consumer costs and benefits expected to result from particular standards. DOE also evaluates the impacts of potential standards on identifiable subgroups of consumers that may be affected disproportionately by a standard.

b. Savings in Operating Costs Compared To Increase in Price (LCC and PBP)

EPCA requires DOE to consider the savings in operating costs throughout the estimated average life of the covered product in the type (or class) compared to any increase in the price of, or in the initial charges for, or maintenance expenses of, the covered product that are likely to result from a standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(II)) DOE conducts this comparison in its LCC and PBP analysis.

The LCC is the sum of the purchase price of a product (including its installation) and the operating expense (including energy, maintenance, and repair expenditures) discounted over the lifetime of the product. The LCC analysis requires a variety of inputs, such as product prices, product energy consumption, energy prices, maintenance and repair costs, product lifetime, and discount rates appropriate for consumers. To account for uncertainty and variability in specific inputs, such as product lifetime and discount rate, DOE uses a distribution of values, with probabilities attached to each value.

The PBP is the estimated amount of time (in years) it takes consumers to recover the increased purchase cost (including installation) of a more-efficient product through lower operating costs. DOE calculates the PBP by dividing the change in purchase cost due to a more-stringent standard by the change in annual operating cost for the year that standards are assumed to take effect.

For its LCC and PBP analysis, DOE assumes that consumers will purchase the covered products in the first full year of compliance with new or amended standards. The LCC savings for the considered efficiency levels are calculated relative to the case that reflects projected market trends in the absence of new or amended standards. DOE's LCC and PBP analysis is discussed in further detail in section IV.F of this document.

c. Energy Savings

Although significant conservation of energy is a separate statutory requirement for adopting an energy conservation standard, EPCA requires DOE, in determining the economic justification of a standard, to consider the total projected energy savings that are expected to result directly from the standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(III)) As discussed in section III.D, DOE uses the NIA spreadsheet models to project national energy savings.

d. Lessening of Utility or Performance of Products

In establishing product classes and in evaluating design options and the impact of potential standard levels, DOE evaluates potential standards that would not lessen the utility or performance of the considered products. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(IV)) Based on data available to DOE, the standards proposed in this document would not reduce the utility or performance of the products under consideration in this proposed rulemaking.

e. Impact of Any Lessening of Competition

EPCA directs DOE to consider the impact of any lessening of competition, as determined in writing by the Attorney General, that is likely to result from a proposed standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(V)) It also directs the Attorney General to determine the impact, if any, of any lessening of competition likely to result from a proposed standard and to transmit such determination to the Secretary within 60 days of the publication of a proposed rule, together with an analysis of the nature and extent of the impact. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(ii)) DOE will transmit a copy of this proposed rule to the Attorney General with a request that the Department of Justice (''DOJ'') provide its determination on this issue. DOE will publish and respond to the Attorney General's determination in the final rule. DOE invites comment from the public regarding the competitive impacts that are likely to result from this proposed rule. In addition, stakeholders may also provide comments separately to DOJ regarding these potential impacts. See the **ADDRESSES** section for information to send comments to DOJ.

f. Need for National Energy Conservation

DOE also considers the need for national energy and water conservation in determining whether a new or amended standard is economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(VI)) The energy savings from the proposed standards are likely to provide improvements to the security and reliability of the Nation's energy system. Reductions in the demand for electricity also may result in reduced costs for maintaining the reliability of the Nation's electricity system. DOE conducts a utility impact analysis to estimate how standards may affect the Nation's needed power generation capacity, as discussed in section IV.M of this document.

DOE maintains that environmental and public health benefits associated with the more efficient use of energy are important to take into account when considering the need for national energy conservation. The proposed standards are likely to result in environmental benefits in the form of reduced emissions of air pollutants and greenhouse gases (''GHGs'') associated with energy production and use. DOE conducts an emissions analysis to estimate how potential standards may affect these emissions, as discussed in section IV.KIV.K; the estimated emissions impacts are reported in section V.B.6 of this document. DOE also estimates the economic value of emissions reductions resulting from the considered TSLs, as discussed in section IV.L of this document.

g. Other Factors

In determining whether an energy conservation standard is economically justified, DOE may consider any other factors that the Secretary deems to be relevant. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(VII)) To the extent DOE identifies any relevant information regarding economic justification that does not fit into the other categories described previously, DOE could consider such information under ''other factors.''

2. Rebuttable Presumption

EPCA creates a rebuttable presumption that an energy conservation standard is economically justified if the additional cost to the equipment that meets the standard is less than three times the value of the first year's energy savings resulting from the standard, as calculated under the applicable DOE test procedure. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(iii)) DOE's LCC and PBP analyses generate values used to calculate the effects that proposed energy conservation standards would have on the payback period for consumers. These analyses include, but are not limited to, the 3-year payback period contemplated under the rebuttable-presumption test.

In addition, DOE routinely conducts an economic analysis that considers the full range of impacts to consumers, manufacturers, the Nation, and the environment, as required under (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)). The results of this analysis serve as the basis for DOE's evaluation of the economic justification for a potential standard level (thereby supporting or rebutting the results of any preliminary determination of economic justification). The rebuttable presumption payback calculation is discussed in section V.B.1.c of this proposed rule.

IV. Methodology and Discussion of Related Comments

This section addresses the analyses DOE has performed for this proposed rulemaking with regard to DPPP motors. Separate subsections address each component of DOE's analyses.

DOE used several analytical tools to estimate the impact of the standards proposed in this document. The first tool is a spreadsheet that calculates the LCC savings and PBP of potential amended or new energy conservation standards. The national impacts analysis uses a second spreadsheet set that provides shipments projections and calculates national energy savings and net present value of total consumer costs and savings expected to result from potential energy conservation standards. DOE uses the third spreadsheet tool, the Government Regulatory Impact Model (''GRIM''), to assess manufacturer impacts of potential standards. These three spreadsheet tools are available on the DOE website for this proposed rulemaking: *www1.eere.energy.gov/buildings/appliance_standards/standards.aspx?productid=76.* Additionally, DOE used output from the latest version of the Energy Information Administration's (''EIA's'') *Annual Energy Outlook* (''*AEO*''), a widely known energy projection for the United States, for the emissions and utility impact analyses.

A. Market and Technology Assessment

DOE develops information in the market and technology assessment that provides an overall picture of the market for the products concerned, including the purpose of the products, the industry structure, manufacturers, market characteristics, and technologies used in the products. This activity includes both quantitative and qualitative assessments, based primarily on publicly-available information. The subjects addressed in the market and technology assessment for this proposed rulemaking include (1) a determination of the scope of the rulemaking and product classes, (2) manufacturers and industry structure, (3) existing efficiency programs, (4) shipments information, (5) market and industry trends; and (6) technologies or design options that could improve the energy efficiency of DPPP motors. The key findings of DOE's market assessment are summarized in the following sections. See chapter 3 of the NOPR TSD for further discussion of the market and technology assessment.

1. Scope of Coverage

DPPP motors are a category of electric motor used in DPPP applications. In the July 2021 Final Rule, DOE incorporated by reference UL 1004–10:2020 and referenced the definitions published in that industry standard for DPPP motors. 10 CFR 431.483; 86 FR 40765, 40768. Section 2.3 of UL 1004–10:2020 defines a DPPP motor as ''an electric motor that is single-phase or poly-phase and is designed and/or marketed for use in dedicated purpose pool pump applications''. DOE defines dedicated-purpose pool pump as comprising ''self-priming pool filter pumps, non-self-priming pool filter pumps, waterfall pumps, pressure cleaner booster pumps, integral sand-filter pool pumps, integral-cartridge filter pool pumps, storable electric spa pumps, and rigid electric spa pumps.'' 10 CFR 431.462.

With regards to scope, 10 CFR 431.481(b) specifies that the requirements in subpart Z apply to DPPP motors, as specified in paragraphs 1.2, 1.3 and 1.4 of UL 1004–10:2020. This scope covers DPPP motors with a total THP of less than or equal to 5, but does not apply to: (i) DPPP motors that are polyphase motors capable of operating without a drive and distributed in commerce without a drive that converts single-phase power to polyphase power; (ii) waterfall pump motors; (iii) rigid electric spa pump motors, (iv) storable electric spa pump motors; (v) integral cartridge-filter pool pump motors, and (vi) integral sand-filter pool pump motors. Section 1.3 and 1.4 of UL 1004–10: 2020.

Since the July 2021 Final Rule, UL 1004–10 has been updated to the ANSI approved March 24, 2022 version.[27] In the 2022 version, DOE notes that the only update was the addition of a glossary term for ''factory default setting'' in section 2.7A, which is defined as ''upon application of power

[27] *https://standardscatalog.ul.com/ProductDetail.aspx?UniqueKey=42496.*

at initial installation, the program that the unit will run without outside interference or change by the user.'' DOE understands that this definition does not change the content and requirements of UL 1004–10:2020, but only provides a clarification regarding factory default setting as it applies to the industry standard. As such, in this NOPR, DOE proposes to update the reference to the latest version of the industry standard, from UL 1004–10:2020 to UL 1004–10:2022, in sections 10 CFR 431.481(b), 10 CFR 431.482(c)(1) and 10 CFR 431.483.

DOE seeks comment on updating the UL 1004–10 reference from the 2020 version to the 2022 version.

The scope of this DPPP motors energy conservation standards rulemaking covers motors for use in the following dedicated purpose pool pump applications only: (i) self-priming pool filter pumps; (ii) non-self-priming pool filter pumps; and (iii) pressure cleaner booster pumps. The scope of the pool pump application is consistent with the scope of pool pumps that currently have performance-based standards in 10 CFR 431.465(f). Further, the DPPP motor energy conservation standards scope includes both single and polyphase motors (but excluding polyphase motors capable of operating without a drive and distributed in commerce without a drive that converts single-phase power to polyphase power) with a total THP of less than or equal to 5.

2. Market Review

To review the current market of DPPP motors incorporated in DPPPs, DOE relied on information from the DOE Compliance and Certification Database, the California Energy Commission (''CEC''), and the ENERGY STAR program.[28] (''2021 DPPP Database''). These databases included the DPPP motor speed-control capabilities, motor THP, and the weighted-efficiency factor (''WEF'') [29] of the pump with which the motor was certified. The 2021 DPPP database did not contain information related to motor efficiency or topology. To supplement the market review, DOE also reviewed general motor catalog data from 2020 and created a database which contained information regarding motor speed-control, topology, THP, motor application, and full-load efficiency (''2020 Motor Database''). To make the two databases more comparable, DOE filtered the 2020 Motor Database to analyze only motors used in DPPP applications. DOE notes that DPPPMs are electromechanically similar to general motors and use similar methods to improve the efficiency of a given motor, therefore DOE tentatively concludes that efficiencies of the 2020 Motor Database can be expected to mirror the DPPPM market. See section IV.A.4 for further discussion on the DPPP motor technology assessment.

First, DOE analyzed the distribution of motor THP and speed-control from the 2021 DPPP Database and compared this to what was observed in the January 2017 Direct Final Rule. DOE observed that the distribution of THP and speed-control has not changed significantly since 2017. Because the 2021 DPPP Database did not specifically have information related to motor efficiency or topology, DOE compared the motor efficiency data used for the January 2017 Direct Final Rule with efficiencies found in the 2020 Motor Database. In this review, DOE reviewed the range of efficiencies and average catalog efficiency for each available motor topology (capacitor-start induction-run [''CSIR''], capacitor-start capacitor-run [''CSCR''], permanent-split capacitor [''PSC''], etc.) at each THP. DOE found that the range of efficiencies and average catalog efficiency did not significantly change since 2017. DOE also reviewed the distribution of motor topology in the 2020 Motor Database and observed that it has not significantly changed since 2017. Accordingly, DOE has based its engineering analysis on the analysis conducted for the January 2017 Direct Final Rule (*see* section IV.C).

Separately, DOE also notes that the standard for DPPPs at 10 CFR 431.465(f) and the CEC performance and prescriptive standards for replacement DPPP motors, both having a compliance date starting July 19, 2021, are expected to influence the overall DPPP motor market. Specifically, in the October 2020 NOPR, DOE specified that standard-size self-priming pool filter pumps which are subject to the DOE DPPP energy conservation standards would likely require a variable-speed control motor. 85 FR 62816, 62824. Relatedly, the California standard for replacement DPPP motors requires all DPPPMs greater than or equal to 0.5 THP to be variable-speed. California Code of Federal Regulations, Title 20, Section 1605.3(g)(6)(B).

3. Equipment Classes

When evaluating and establishing energy conservation standards, DOE divides covered equipment into equipment classes by the type of energy used, or by capacity or other performance-related features that justify a different standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(q)) In determining whether capacity or another performance-related feature justifies a different standard, DOE must consider such factors as the utility of the feature to the consumer and other factors DOE deems appropriate. (*Id.*)

As discussed previously, DOE is limiting the scope of this energy conservation standard to motors used in self-priming pool filter pumps, non-self-priming pool filter pumps, and pressure cleaner booster pumps. The scope of the pool pump application is consistent with the scope of pool pumps that currently have performance-based standards in 10 CFR 431.465(f). For this energy conservation standards, DOE is dividing the DPPP motors into equipment classes based on capacity. The capacity of a dedicated-purpose pool pump motor can be expressed in terms of motor total horsepower.

Full load efficiency generally correlates with motor horsepower (*e.g.,* a 3-horsepower motor is usually more efficient than a ¼-horsepower motor). DOE found that motor efficiency varies with motor horsepower in the 2020 Motor Database. Additionally, motor horsepower dictates the maximum load that a motor can drive, which means that a motor's rated horsepower can influence and limit the end use applications where that motor can be used, which in this case is a dedicated purpose pool pump. Horsepower is a critical performance attribute of a DPPP motor, and since horsepower has a direct relationship with full load efficiency and consumer utility, DOE used this element as a criterion for distinguishing among equipment classes.

The motor capacity breakpoints developed in this NOPR align with the pump capacity breakpoints recommended by the consensus working group established under the Appliance Standards and Rulemaking

[28] DOE Compliance Certification Management System. Compliance and Certification Database. Information for DPPP products. *www.regulations.doe.gov/certification-data* (last access July 29, 2021); The California Modernized Appliance Efficiency Database System. Information for DPPP products. *https://cacertappliances.energy.ca.gov/Pages/Search/AdvancedSearch.aspx* (last access July 29, 2021); Energy Star Program. Information for DPPP products. *www.energystar.gov/productfinder/product/certified-pool-pumps/results* (last access July 29, 2021).

[29] DOE notes that while the DPPP energy conservation standards at 10 CFR 431.465(f) does not contain performance standards for the motors used in DPPPs, the DPPP performance metric of weighted energy factor (''WEF'') is directly affected by motor efficiency and the speed-control of the motor sold with the pump.

Federal Advisory Committee (the "ASRAC DPPP Working Group").[30] [31] 82 FR 5650, 5669. (Jan. 18, 2017). In the January 2017 Direct Final Rule, DOE finalized equipment classes for dedicated purpose pool pumps based on the DPPP Working Group recommendation to set the breakpoint between small-size and standard-size self-priming pool filter pumps at 0.711 hydraulic horsepower ("hhp"). 82 FR 5650, 5669.

In the Joint Petition for DPPP motors, the Joint Petitioners stated that the 0.711 hhp threshold in the DPPP standards for self-priming pool filter pumps aligns with a 1.15 THP motor threshold (1.15 THP is roughly equivalent to 0.711 hhp). Further, the Joint Petition stated that almost all motors used in non-self-priming pool filter pumps and pressure cleaner booster pumps have THPs less than 1.15 THP. (Joint Petition, No. 14 at p. 8). Finally, in the October 2020 NOPR, DOE described that DPPP motors with a total horsepower greater than or equal to 1.15 THP are primarily used in standard-size self-priming pool filter pumps (52 percent of DPPP motor applications), while pool pump motors below 1.15 THP are typically found in small-size self-priming pool filter pumps, non-self-priming pool filter pumps, and pressure cleaner booster pumps (which represent 48 percent of the DPPP motor applications).[32] 85 FR 62816, 62824. Accordingly, because full load efficiency generally correlates with motor horsepower, and the distinct utility of DPPP motors less than 1.15 THP (almost all are used in non-self-priming pool filter pumps and pressure cleaner booster pumps) is different than of DPPP motors equal to or greater than 1.15 THP (primarily used in standard-size self-priming pool filter pumps), DOE proposes to establish small-size and standard-size equipment classes based on a 1.15 THP threshold.

In the January 2017 Direct Final Rule, DOE also considered an extra-small-size equipment class for non-self-priming pool filter pumps less than 0.13 hhp. 82 FR 5650, 5672. This equipment class was ultimately merged into the small-size equipment class after DOE selected the same efficiency level for both extra-small-size and small-size non-self-priming pool filter pumps. *Id.* However, in the context of DPPP motors for this rulemaking, DOE notes that the non-self-priming pool filter DPPP motors with an hhp of less than 0.13 have different maximum efficiency potential than non-self-priming pool filter DPPP motors with an hhp of 0.13 or greater. Specifically, Table 5.6.3 in the TSD for the January 2017 Direct Final Rule ("January 2017 Direct Final Rule TSD")[33] did not consider either two-speed or variable speed motors for the extra-small-size DPPPP equipment class because both these types of motors provide inadequate flow to the pool pump. Because the distinct performance potential and utility of DPPP motors with an hhp less than 0.13, DOE proposes to include an extra-small-size equipment class for DPPP motors.

To develop the proposed motor total horsepower tier threshold for the extra-small-size equipment class, DOE considered the appropriate motor THP threshold that is applicable to the extra-small-size equipment class hydraulic horsepower threshold from the January 2017 Direct Final Rule. Based on pump fundamentals, the power out of the drive of the motor (*i.e.,* brake horsepower) is the hydraulic horsepower divided by the pump efficiency.[34] Accordingly, DOE converted the hhp to thp by dividing the hydraulic horsepower threshold for the extra-small-size equipment class (0.13 hhp limit from the January 2017 Direct Final Rule) by the hydraulic efficiency for the representative unit meeting the 0.13 hhp threshold (23 percent from Table 5.6.4 of the January 2017 Direct Final Rule TSD). This approximates to a 0.57 THP motor horsepower threshold.

As part of this proposed rulemaking, DOE collected confidential DPPP motor shipment data from manufacturers in 2018 through non-disclosure agreements ("2018 confidential DPPP motor shipments"). In reviewing that data, DOE notes there were no DPPP motor shipments at 0.57 THP; rather, the largest motor THP under 0.57 THP with any shipments was 0.5 THP. Accordingly, for this NOPR, DOE proposes to use the 0.5 THP threshold instead, and therefore proposes an extra-small-size equipment class based on the 0.5 THP threshold.

Table IV.1 provides the summary of the proposed equipment classes for DPPP motors.

TABLE IV.1—PROPOSED EQUIPMENT CLASSES FOR DPPP MOTORS

Equipment class	Motor total horsepower (Hp)
Extra-small-size	THP < 0.5
Small-size	0.5 ≤ THP < 1.15
Standard-size	1.15 ≤ THP ≤ 5

DOE seeks comments on the proposed equipment classes for DPPP motors based on motor THP thresholds.

DOE seeks comment on the proposed equipment classes for DPPP motors based on motor THP thresholds.

4. Technology Assessment and Options

The purpose of the technology assessment is to develop a preliminary list of technology options that could improve the efficiency of DPPP motors. The efficiency of a DPPP motor is dependent on motor topology, capacity, and operating speed. As previously discussed in section IV.A.2 of this document, DOE proposes to delineate equipment classes based on motor capacity (*i.e.,* motor horsepower).

a. Motor Topology

The DPPP motors covered in this proposed rulemaking include both alternating current (AC) (single and certain polyphase) induction motors and permanent magnet AC motors (also known as Electronically Commutated Motors ["ECMs"]).

In the January 2017 Direct Final Rule, DOE noted that the majority of the pool filter pumps available on the market come equipped with single-phase induction motors, of which the majority are either CSCR or PSC motors. 82 FR 5650, 5676. Based on a review of the 2020 Motor Database, DOE concludes that a majority of DPPPMs are still CSCR or PSC motors. Specifically, single-speed DPPPMs are almost exclusively PSC or CSCR and variable-speed motors are primarily ECMs.

AC induction motors have two core components: a stator and a rotor. The components work together to convert electrical energy into rotational mechanical energy. This is done by creating a rotating magnetic field in the stator, which induces a current flow in the rotor. This current flow creates an opposing magnetic field in the rotor, which creates rotational forces. Because of the orientation of these fields, the rotor field follows the stator field. The rotor is connected to a shaft that also rotates and provides the mechanical energy output.

DOE identified six categories of AC induction motors: shaded-pole, split-phase, capacitor-start (CSIR and CSCR),

[30] In accordance with the Federal Advisory Committee Act and the Negotiated Rulemaking Act (5 U.S.C. App.; 5 U.S.C. 561–570).

[31] The dedicated-purpose pool pumps energy conservation standard rulemaking docket EERE–2015–BT–STD–0008 contains all notices, public comments, public meeting transcripts, and supporting documents pertaining to this rulemaking.

[32] Estimate of DPPP motors shipments by DPPP applications for 2021. 85 FR 62816, 62824.

[33] The dedicated-purpose pool pumps energy conservation standard rulemaking TSD can be found in docket EERE–2015–BT–STD–0008–0105 (*www.regulations.gov/document/EERE-2015-BT-STD-0008-0105*).

[34] *www.sciencedirect.com/topics/engineering/hydraulic-horsepower.*

permanent-split capacitor (PSC), and polyphase. A shaded-pole motor is a single-phase induction motor provided with an auxiliary short-circuited winding or windings displaced in magnetic position from the main winding. Shaded-pole motors are typically only used in low-torque applications with power requirements less than 1/10 hp. A split-phase motor is a single-phase induction motor equipped with an auxiliary winding displaced in magnetic position from, and connected parallel to, the main winding. The term ''split-phase motor'' describes a motor to be used without impedance other than that offered by the motor windings themselves. A CSCR motor is a single-phase motor with different values of effective capacitance for the starting and running conditions. A PSC motor is another category of single-phase motor that has the same value of capacitance for both starting and running conditions. A polyphase motor is an electric motor that uses the phase changes of the electrical supply to induce a rotational magnetic field and thereby supply torque to the rotor.

Single-phase AC induction motors are inherently less efficient than polyphase AC induction motors due to the fundamental differences in how the two categories of motors operate. Three-phase power in a polyphase motor naturally produces rotation, whereas a single-phase motor requires an auxiliary winding with current and voltage out of phase of the main winding to produce a net rotating magnetic field. The more efficient polyphase AC induction motors require the end user to have access to a three-phase power source. Residential power sources are typically single-phase.

Motor topology within the single-phase AC induction motor category can also have an impact on motor efficiency. CSCR and PSC motors are typically more efficient than CSIR, split-phase, and shaded pole motors due to the presence of a run capacitor that remains connected while the motors are operating. In the notice of the Joint Petition, the recommendation included prohibiting CSIR or split phase motors for DPPPMs because (1) this would align with the DPPP standards; (2) this requirement would be consistent with certain state standards, and (3) these motors are very inefficient. (Joint Petition, No. 14 at p. 7)

In the January 2017 Direct Final Rule, DOE also noted that the pool pump market included ECMs and that ECMs are typically used in variable-speed pool filter pump applications. 82 FR 5650, 5676. Based on a review of the 2021 DPPP database, ECMs are becoming more prevalent because of the recent standards implemented by the CEC and the January 2017 Direct Final Rule standards discussed in section IV.A.2 of this NOPR.

ECMs are similar in construction to AC squirrel-cage induction motors, but feature a different rotor configuration. Instead of using conductive material in the rotor, permanent magnets are integrated into the rotor's laminations or fixed to the rotor's outer surface and do not need to be energized. The magnetic field established by the permanent magnets interacts with the field produced by windings in the stator to generate a torque. Because permanent magnet motors do not require current to be induced in rotor conductors, overall power consumption can be reduced compared to induction motors. Further, because permanent magnet motors operate at synchronous speed, they require a variable frequency drive to start rotation.

ECMs can typically achieve higher motor efficiencies than AC induction motors with similar capacities. ECMs employ rare-earth metal based permanent magnets in the rotor design to establish a magnetic field, which avoids the energy consumption observed when energizing an electro-magnetic rotor for the operation of AC induction motors. Because of the removal of rotor energy losses, ECMs often have higher full-load efficiencies than their induction counterparts. ECMs require a variable speed drive to operate, which may introduce additional losses into the motor system. Even after considering the losses from the variable speed drive and control electronics, ECMs are the most efficient motor topology currently used in dedicated-purpose pool pumps.

b. Motor Speed

Dedicated-purpose pool pumps are designed to circulate water in pool systems to facilitate pool cleaning in addition to water filtering, heating, and chlorination. Pool cleaning functions require a high flow rate, and subsequently a high motor speed, to provide the agitation necessary to stir up large debris so that the filtration system can effectively remove any contaminants. Heating functions typically require a moderate to high flow rate to ensure that heat is dissipated sufficiently and pool system components are not damaged by overheating. Water filtration is most effective at low motor speeds, as a low flow rate will ensure water bypassing the filter will be minimized.

DPPP motors exist in several configurations with different speed capabilities. Single-speed motors can operate at one predefined speed, and therefore the associated dedicated-purpose pool pump can provide only a single flow rate in any given pool system. Single-speed motors are sized to provide the minimum flow rate necessary to facilitate effective pool cleaning, and therefore pool pump functions that operate most efficiently at lower flow rates are rendered less effective.

Two-speed motors can operate at two distinct rotational speeds. Two-speed motors can be sized so that high flow functions like pool cleaning are effective at full speed operation and low flow tasks like filtration can be completed at low speed operation. Two-speed pumps can be operated by timers or other control systems to run at high speed for long enough to complete cleaning functions before switching to low speed operation for the duration of the cycle. The ability to operate at multiple speeds can provide energy savings when utilized correctly, *i.e.,* pool cleaning at high speed and filtration at lower speeds. Multi-speed motors function similarly to two-speed motors, but provide additional flexibility to maximize the effectiveness of specific pool pump functions by allowing users to program pumps to run at more than two distinct speeds.

Variable-speed motors can provide greater energy savings than two-speed or multi-speed motors due to the ability to program these motors to operate at user-defined speed settings. Variable-speed motors used in DPPP applications are typically one of two configurations: an AC induction motor paired with a variable frequency drive or a permanent magnet motor with an integral drive. Permanent magnet variable-speed motors offer improved efficiency over AC induction motors due to the incorporation of a permanent magnet rotor design in place of the powered electro-magnetic rotor design used in AC induction motors. This improvement in efficiency is particularly evident at lower speed settings, where AC induction motor efficiency drops considerably from full speed efficiency.

DOE seeks comment on the technologies considered for higher DPPP motor efficiency. DOE seeks comment on whether other motor topologies should be considered as applicable in pool pumps.

B. Screening Analysis

DOE uses the following five screening criteria to determine which technology options are suitable for further consideration in an energy conservation standards rulemaking:

(1) *Technological feasibility.* Technologies that are not incorporated in commercial products or in working prototypes will not be considered further.

(2) *Practicability to manufacture, install, and service.* If it is determined that mass production and reliable installation and servicing of a technology in commercial products could not be achieved on the scale necessary to serve the relevant market at the time of the projected compliance date of the standard, then that technology will not be considered further.

(3) *Impacts on product utility or product availability.* If it is determined that a technology would have a significant adverse impact on the utility of the product for significant subgroups of consumers or would result in the unavailability of any covered product type with performance characteristics (including reliability), features, sizes, capacities, and volumes that are substantially the same as products generally available in the United States at the time, it will not be considered further.

(4) *Adverse impacts on health or safety.* If it is determined that a technology would have significant adverse impacts on health or safety, it will not be considered further.

(5) *Unique-Pathway Proprietary Technologies.* If a design option utilizes proprietary technology that represents a unique pathway to achieving a given efficiency level, that technology will not be considered further due to the potential for monopolistic concerns.

10 CFR part 430, subpart C, appendix A, sections 6(b)(3) and 7(b).

In summary, if DOE determines that a technology, or a combination of technologies, fails to meet one or more of the listed five criteria, it will be excluded from further consideration in the engineering analysis.

In the January 2017 Direct Final Rule, DOE considered ''improved motor efficiency'' as a screened in technology option for the pool pump analysis. 82 FR 5650, 5676. This screened-in technology option considered motor topology (induction and ECM motor) and speed applications (*i.e.,* single-, dual- and variable speed). 82 FR 5650, 5676. For this DPPP motor analysis, DOE relied on and aligned with the January 2017 Direct Final Rule analysis where possible. As discussed in sections IV.A.2 and IV.A.4 of this document, the motor technologies applicable to pool pump motors analyzed in the January 2017 Direct Final Rule remain relevant and applicable in the current DPPP motor market. Therefore, DOE has initially determined that the technology options previously considered continue to be technologically feasible because they are being used or have previously been used in commercially-available products or working prototypes. DOE also finds that the technology options continue to meet the other screening criteria (*i.e.,* practicable to manufacture, install, and service and do not result in adverse impacts on consumer utility, product availability, health, or safety, unique-pathway proprietary technologies). For additional details, see chapter 4 of the NOPR TSD.

C. Engineering Analysis

The purpose of the engineering analysis is to establish the relationship between the efficiency and cost of DPPP motors. There are two elements to consider in the engineering analysis; the selection of efficiency levels to analyze (*i.e.,* the ''efficiency analysis'') and the determination of product cost at each efficiency level (*i.e.,* the ''cost analysis''). In determining the performance of higher-efficiency equipment, DOE considers technologies and design option combinations not eliminated by the screening analysis. For each equipment class, DOE estimates the baseline cost, as well as the incremental cost for the equipment at efficiency levels above the baseline. The output of the engineering analysis is a set of cost-efficiency ''curves'' that are used in downstream analyses (*i.e.,* the LCC and PBP analyses and the NIA).

1. Efficiency Analysis

DOE typically uses one of two approaches to develop energy efficiency levels for the engineering analysis: (1) relying on observed efficiency levels in the market (*i.e.,* the efficiency-level approach), or (2) determining the incremental efficiency improvements associated with incorporating specific design options to a baseline model (*i.e.,* the design-option approach). Using the efficiency-level approach, the efficiency levels established for the analysis are determined based on the market distribution of existing products (in other words, based on the range of efficiencies and efficiency level ''clusters'' that already exist on the market). Using the design option approach, the efficiency levels established for the analysis are determined through detailed engineering calculations and/or computer simulations of the efficiency improvements from implementing specific design options that have been identified in the technology assessment. DOE may also rely on a combination of these two approaches. For example, the efficiency-level approach (based on actual products on the market) may be extended using the design option approach to ''gap fill'' levels (to bridge large gaps between other identified efficiency levels) and/or to extrapolate to the max-tech level (particularly in cases where the max-tech level exceeds the maximum efficiency level currently available on the market).

For this analysis, DOE relied on the conclusions from the ''improved motor efficiency'' design option from the January 2017 Direct Final Rule. As discussed in sections IV.A.2 and IV.A.4 of this document, the motor technologies applicable to pool pump motors analyzed in the January 2017 Direct Final Rule remain relevant and applicable in the current DPPP motor market. Therefore, in line with the January 2017 Direct Final Rule, DOE considered three tiers of motor efficiency (low, medium, and high efficiency) and design requirements specifically for two-speed, multi-speed motors and variable speed motors. This is a combination of the efficiency level and design level approach discussed previously. Section 5.6.2 of the January 2017 Direct Final Rule TSD discusses that DOE presented the designs and motor efficiency assumptions to the DPPP Working Group and subsequently refined them to incorporate feedback from the DPPP Working Group.

a. Representative Units

DOE opted to use representative units for each equipment class, consistent with the January 2017 Direct Final Rule, for the engineering analysis. Representative units exemplify typical capacities in each equipment class and are used to quantify the manufacturing costs and the energy savings potential for each equipment class.

Table IV.2 details the DPPP application and associated motor THP of each representative unit considered for the analysis. The DPPP application (pump type, size and hhp) is consistent with Table 5.4.1 of the January 2017 Direct Final Rule TSD, except that DOE did not merge the extra-small-size and standard-size non self-priming pumps into one class for this NOPR. As discussed in section IV.A.3 of this document, the extra-small-size non-self-priming pool filter DPPP motors have different maximum efficiency potential than small- or standard-size equipment classes and are therefore analyzed separately.

The associated motor THP of the representative units are consistent with the motor THPs provided in Table 5.7.1 of the January 2017 Direct Final Rule TSD, with three exceptions: (1) a DPPP motor associated with self-priming filter pump application at 0.65 hhp (Representative unit 2A) was added to represent standard-size DPPP motors that are used in small-size self-priming DPPPs as DOE observed motors on the market of this size going into small-size self-priming pumps; (2) a DPPP motor associated with non-self priming filter pump at 0.87 hhp (Representative unit 6) was added to analyze standard-size DPPPMs used in non-self-priming filter pump applications to better represent THPs observed in the market; and (3) a DPPP motor of 1.125 thp instead of 1.25 thp associated with pressure cleaner booster pump (Representative unit 7) was considered so as to keep this representative unit in the small-size equipment class (EC 2), and to better represent the THP range of motors in pressure cleaner booster pumps.[35]

TABLE IV.2—REPRESENTATIVE UNITS THP AND DPPP APPLICATION

Rep. unit	Equipment class	THP	DPPP application *
1	2 (Small)	0.75	Self-priming Filter Pump, Small-size (0.44 hhp).
2	3 (Standard)	1.65	Self-priming Filter Pump, Standard-size (0.95 hhp).
2A	3 (Standard)	1.65	Self-priming Filter Pump, Small-size (0.65 hhp).
3	3 (Standard)	3.45	Self-priming Filter Pump, Standard-size (1.88 hhp).
4	1 (Extra-small)	0.22	Non Self-priming Filter Pump, Extra-Small (0.09 hhp).
5	2 (Small)	1	Non Self-priming Filter Pump, Standard-size (0.52 hhp).
6	3 (Standard)	1.5	Non Self-priming Filter Pump, Standard-size (0.87 hhp).
7	2 (Small)	1.125	Pressure Cleaner Booster Pump.

* For self-priming pumps, the terms small and standard refer to the hydraulic horsepower. Small-size designates pool pump applications with hydraulic horsepower less than 0.711 hhp, while standard-size designates pool pump applications with hydraulic horsepower greater than or equal to 0.711 hhp. DOE distinguishes extra-small non self-priming filter pumps (less than 0.13 hhp) and standard-size non self-priming filter pumps (less than 2.5 hhp and greater than 0.13 hhp).

DOE seeks comment on the proposed representative units and associated DPPP applications used for the engineering analysis.

b. Baseline Efficiency Levels

For each equipment class, DOE generally selects a baseline model as a reference point for each class, and measures changes resulting from potential energy conservation standards against the baseline. The baseline model in each equipment class represents the characteristics of an equipment typical of that class (*e.g.,* capacity, physical size). Generally, a baseline model is one that just meets current energy conservation standards, or, if no standards are in place, the baseline is typically the most common or least efficient unit on the market. Mirroring the January 2017 Direct Final Rule, this DPPP motor analysis also considered the least efficient single-speed DPPP motor on the market for each representative unit.

c. Higher Efficiency Levels

As part of DOE's analysis, the maximum available efficiency level is the highest efficiency unit currently available on the market. DOE also defines a ''max-tech'' efficiency level to represent the maximum possible efficiency for a given product.

Once the baseline was established, higher ELs were established by substituting with higher full-load efficiency DPPPMs and DPPPMs with finer levels of speed control, similar to the January 2017 Direct Final Rule. Table IV.3 details the full-load efficiency, or motor topologies and speed configurations of each EL for each representative unit. The full-load efficiencies and speed configurations being considered are consistent with Table 5.6.3 of the January 2017 Direct Final Rule TSD.

As discussed in section IV.A.4.b of this document, DPPPM have different functions, including pool cleaning, water filtering, heating, freeze protection control and chlorination, that all require different flow rates and motor speeds. Therefore, the ability to operate at multiple speeds can provide energy savings when utilized correctly. As such, there are energy savings that come from controlling the speed of the motor with two-speed, multi-speed or variable-speed capabilities. Accordingly, DOE proposes to include design requirements of speed capability as part of the engineering analysis to capture these added energy savings.[36] These design requirements are consistent with the motor speed design options considered in the January 2017 Direct Final Rule.

Further, as discussed in section IV.A.4.a of this NOPR, the efficiency of a DPPP motor is dependent on motor topology. CSCR and PSC motors are typically more efficient than CSIR, split-phase, and shaded pole motors due to the presence of a run capacitor that remains connected while the motors are operating. In the January 2017 Direct Final Rule, DOE noted that the majority of the pool filter pumps available on the market come equipped with CSCR or PSC motors. 82 FR 5650, 5676. Accordingly, DOE proposes to include design requirements based on motor topology as part of the engineering analysis to capture these added energy savings.

Table IV.3 presents the proposed performance and design requirements for the DPPPM efficiency levels. Efficiency levels 0 through 2 is consistent with Table 5.6.3 of the January 2017 Direct Final Rule TSD and represents the low-efficiency, medium-efficiency and high-efficiency performance of single-speed DPPPMs. Efficiency levels 3 through 6 incorporate certain design requirements based on motor speed capability and topology.[37]

DOE proposes that EL 3 requires motors that are two-speeds, multi-speed or variable speed, but with no restrictions on motor topology. EL 4 requires motors that are two-speeds or multi-speed, but does not allow for the low-efficiency motor topologies (split-phase, shaded-pole, CSIR)—or—requires variable speed motors. EL 5 requires motors that are two-speeds or multi-speed, but does not allow for PSC motors in addition to the other low-efficiency motor topologies—or—requires variable speed motors. Finally,

[35] The Joint Petition noted that almost all motors used in pressure cleaner booster pumps have THPs less than 1.15 THP. (Joint Petition, No. 14 at p. 8).

[36] Full-load efficiency does not capture the energy saving benefits of speed control.

[37] For the purposes of the analysis, however, DOE did consider the full-load efficiencies presented in Table 5.6.3 of the January 2017 Direct Final Rule TSD for efficiency levels 3 through 6.

EL 6 includes variable speed only, which provides the highest energy savings.

As discussed in section IV.A.3 of this document, efficiency levels 3–6 do not apply to representative unit 4 because two-speed, multi-speed and variable speed motors provide inadequate flow to the pool pump for the extra-small-size DPPPP equipment class. Further, consistent with the January 2017 Direct Final Rule, DOE only considered one speed and variable speed motors for representative unit 7 (pressure cleaner booster pump application). 82 FR 5650, 5683. Specifically, the January 2017 Direct Final Rule noted that pressure cleaner booster pumps are only operated at one speed, however the pool pump WEF metric accounts for energy savings available from adjusting the pump speed to reach the minimum required test pressure, *i.e.,* 60 feet, therefore allowing variable-speed motor applications. *Id.* Accordingly, for representative unit 7, efficiency levels 3 through 6 would require variable-speed motors only.

TABLE IV.3—PROPOSED PERFORMANCE AND DESIGN REQUIREMENTS FOR DPPPM ELs

EC	Rep. unit	Motor THP	DPPP application	EL0 (%)	EL1 (%)	EL2 (%)	EL3 *	EL4 *	EL5 *	EL6 *
1	4	0.22	Non Self-priming Filter Pump, Extra-Small (0.09 hhp).	55	69	76				
2	1	0.75	Self-priming Filter Pump, Small-size (0.44 hhp).	55	69	76	Two-speed—OR—Multi-speed—OR—Variable speed.	Two-speed/Multi-speed, not CSIR, not shaded pole, not split-phase;—OR—Variable speed.	Two-speed/Multi-speed, not CSIR, not shaded pole, not split-phase, not PSC;—OR—Variable speed.	Variable speed only.
2	5	1	Non Self-priming Filter Pump, Small-size (0.52 hhp).	55	69	76				
2	7	1.125	Pressure Cleaner Booster Pump.	55	69	76	Variable speed only.			
3	6	1.5	Non Self-priming Filter Pump (0.87 hhp).	55	69	77	Two-speed—OR—Multi-speed—OR—Variable speed.	Two-speed/Multi-speed, not CSIR, not shaded pole, not split-phase;—OR—Variable speed.	Two-speed/Multi-speed, not CSIR, not shaded pole, not split-phase, not PSC;—OR—Variable speed.	Variable speed only.
3	2	1.65	Self-priming Filter Pump, Standard-size (0.95 hhp).	55	69	77				
3	2A	1.65	Self-priming Filter Pump, Small-size (0.65 hhp).	55	69	77				
3	3	3.45	Self-priming Filter Pump, Standard-size (1.88 hhp).	75	79	84				

* includes freeze protection control design requirements.

To determine the motor input power for the energy use analysis in section IV.E, DOE also had to determine the hydraulic power of each pump. DOE calculated the relationships between flow rate of the pump and the total dynamic head required for each system curve. Once these relationships were established, the hydraulic power required for each curve was calculated using both the head and flow rate. *See* Section 5.3.1.3 of the January 2017 Direct Final Rule TSD. Each efficiency level presented has an associated Energy Factor (in Gallons/Watt-hour) and Flow (in gallons per minute) used to determine efficiency of the pump system. This energy factor considers the performance of the motor and the energy savings that come from running the motor at a lower speed. For this analysis, all pump performance curves were kept consistent with Tables 5.8.1, 5.8.2, 5.8.3 and 5.8.4 of the January 2017 Direct Final Rule TSD. For more information on how these curves were developed, see Section 5.8.2 of the January 2017 Direct Final Rule TSD.

DOE seeks comment on the efficiency levels, including the associated full load efficiencies and design requirements evaluated in the engineering analysis.

2. Cost Analysis

The cost analysis portion of the engineering analysis is conducted using one or a combination of cost approaches. The selection of cost approach depends on a suite of factors, including the availability and reliability of public information, characteristics of the regulated product, the availability and timeliness of purchasing DPPPMs on the market. The cost approaches are summarized as follows:

• *Physical teardowns:* Under this approach, DOE physically dismantles a commercially available product, component-by-component, to develop a detailed bill of materials for the product.

• *Catalog teardowns:* In lieu of physically deconstructing a product, DOE identifies each component using parts diagrams (available from manufacturer websites or appliance repair websites, for example) to develop the bill of materials for the product.

• *Price surveys:* If neither a physical nor catalog teardown is feasible (for example, for tightly integrated products such as fluorescent lamps, which are infeasible to disassemble and for which parts diagrams are unavailable) or cost-prohibitive and otherwise impractical (*e.g.,* large commercial boilers), DOE conducts price surveys using publicly available pricing data published on major online retailer websites and/or by soliciting prices from distributors and other commercial channels.

In the present case, DOE conducted the cost analysis using historical price surveys and product teardowns. DOE used feedback from manufacturers presented in the January 2017 Direct Final Rule to determine the cost of DPPP motors. Specifically, Table 5.7.1 of the January 2017 Direct Final Rule TSD presents the manufacturer production cost (''MPC'') of DPPPMs used in the analysis. However, DOE notes this cost data was in terms of *2015$.* For this evaluation, DOE updated the cost data to be representative of the market in 2020. DOE adjusted the *2015$* costs to *2020$* using the historical Bureau of Labor Statistics Producer Price Index (''PPI'') for each product's industry.[38] Finally, DOE also conducted physical teardowns to determine updated DPPP motor controller costs for variable-speed motors. DOE did not consider any added costs for the freeze protection design requirements, as these requirements do not require any additional labor, material, or technology to produce a DPPP motor meeting these requirements, and a manufacturer is able to just disable the controls to meet the requirement. Further, the January 2017 Direct Final Rule, which also adopted freeze protection controls as a prescriptive standards per the ASRAC DPPP Working Group, did not consider any added costs. 82 FR 5650, 5737.

To account for manufacturers' non-production costs and profit margin, DOE applies a non-production cost multiplier (the manufacturer markup) to the MPC. The resulting manufacturer selling price (''MSP'') is the price at which the manufacturer distributes a unit into commerce. DOE developed an average manufacturer markup of 1.37 by examining the annual Securities and Exchange Commission (SEC) 10–K reports filed by publicly-traded manufacturers primarily engaged in DPPP manufacturing and whose combined product range includes a variety of pool products. Table IV.4 lists the MSPs of each EL for DPPPMs. See TSD chapter 5 for additional detail on the engineering analysis and complete cost-efficiency results.

TABLE IV.4—MSPS IN 2020$ FOR DPPPMS

EC	Rep. unit	THP	DPPP application	EL0	EL1	EL2	EL3	EL4	EL5	EL6
1	4	0.22	Non Self-priming Filter Pump, Extra-Small (0.09 hhp)	$25	$31	$51	....	....	....	....
2	1	0.75	Self-priming Filter Pump, Small-size (0.44 hhp)	57	71	90	$93	$104	$115	$357
2	5	1	Non Self-priming Filter Pump, Small-size (0.52 hhp)	52	57	77	79	94	111	357
2	7	1.125	Pressure Cleaner Booster Pump	60	78	98	....	....	....	357
3	6	1.5	Non Self-priming Filter Pump (0.87 hhp)	68	90	108	109	128	149	357
3	2	1.65	Self-priming Filter Pump, Standard-size (0.95 hhp)	75	96	115	116	135	155	357
3	2A	1.65	Self-priming Filter Pump, Small-size (0.65 hhp)	75	96	115	116	135	155	357
3	3	3.45	Self-priming Filter Pump, Standard-size (1.88 hhp)	161	201	224	256	271	287	480

DOE seeks comment on using a 1.37 manufacturer markup for the cost analysis.

DOE seeks comment on the cost methodology and associated costs for each of efficiency levels evaluated in the engineering analysis, including any associated costs for the proposed freeze protection controls requirement.

D. Markups Analysis

The markups analysis develops appropriate markups (*e.g.,* retailer markups, distributor markups, contractor markups) in the distribution chain and sales taxes to convert the MSP estimates derived in the engineering analysis to consumer prices, which are then used in the LCC and PBP analysis and in the manufacturer impact analysis. At each step in the distribution channel, companies mark up the price of the product to cover business costs and profit margin.

DOE identified distribution channels for DPPP motors incorporated in pumps (See Table IV.5) and replacement DPPP motors sold alone (See Table IV.6). To characterize these channels, DOE referred to information collected in support of the January 2017 Direct Final Rule, which reflects the consensus of the ASRAC DPPP Working Group.

TABLE IV.5—DISTRIBUTION CHANNELS FOR DPPP MOTORS INCORPORATED IN PUMPS

Distribution channel	Fraction of shipments (%)
Replacement for an Existing Pool	
DPPP Motor Manufacturer → DPPP Manufacturer → Wholesaler → Pool Service Contractor → Consumer	75
DPPP Motor Manufacturer → DPPP Manufacturer → Pool Product Retailer → Consumer	20
New Installation for a New Pool	
DPPP Motor Manufacturer → DPPP Manufacturer → Pool Builder → Consumer	5

TABLE IV.6—DISTRIBUTION CHANNELS FOR REPLACEMENT DPPP MOTORS SOLD ALONE

Distribution channel	Fraction of shipments %
DPPP Motor Manufacturer → Wholesaler → Contractor → End-User	25
DPPP Motor Manufacturer → Wholesaler → Retailer → End-User	25
DPPP Motor Manufacturer → Pool Pump Retailer → End-User	50

DOE developed baseline and incremental markups for each actor in the distribution chain. Baseline markups are applied to the price of equipment with baseline efficiency, while incremental markups are applied

[38] Series IDs: Integral motors (<=1 hp): WPU117304, Fractional motors (<1 hp): WPU117303, Environmental Controls: WPU1181; *www.bls.gov/ppi/.*

to the difference in price between baseline and higher-efficiency models (the incremental cost increase). The incremental markup is typically less than the baseline markup and is designed to maintain similar per-unit operating profit before and after new or amended standards.[39]

To estimate average baseline and incremental markups DOE relied on several sources including: (1) for pool wholesalers, SEC form 10–K from Pool Corp;[40] (2) for pool product retailers, SEC form 10–K from several major home improvement centers[41] and U.S. Census Bureau 2017 Annual Retail Trade Survey for the miscellaneous store retailers sector (NAICS 453),[42] (3) for pool contractors and pool builders, U.S. Census Bureau 2017 Economic Census data for the plumbing, heating and air-conditioning contractor sector (NAICS 238220) and all other specialty trade contractors sector (NAICS 238990),[43] (4) for motor wholesalers, U.S. Census Bureau 2017 Annual Wholesale Trade Survey for the household appliances and electrical and electronic goods merchant wholesaler sector (NAICS 4536),[44] (5) for electrical contractor, 2020 RSMeans Electrical Cost Data,[45] (6) for motor retailers, U.S. Census Bureau 2017 Annual Retail Trade Survey for the building material and garden equipment and supplies dealers (NAICS 444), and (7) for pool pump retailers, U.S. Census Bureau 2017 Annual Retail Trade Survey for the miscellaneous store retailers sector (NAICS 453).

In addition to the markups, DOE obtained state and local taxes from data provided by the Sales Tax Clearinghouse.[46] These data represent weighted average taxes that include county and city rates. DOE derived shipment-weighted average tax values for each region considered in the analysis.

Chapter 6 of the NOPR TSD provides details on DOE's development of markups for DPPP motors.

DOE seeks comment on the distribution channels identified for DPPP motors and fraction of sales that go through each of these channels.

E. Energy Use Analysis

The purpose of the energy use analysis is to determine the annual energy consumption of DPPP motors at different efficiency levels in representative U.S. single-family homes, multi-family residences, and commercial buildings, and to assess the energy savings potential associated to each DPPP motor efficiency level. The energy use analysis estimates the range of energy use of DPPP motors in the field (*i.e.,* as they are actually used by consumers). The energy use analysis provides the basis for other analyses DOE performed, particularly assessments of the potential energy savings and the savings in consumer operating costs that could result from adoption of new standards.

1. DPPP Motor Applications

The annual energy consumption of a pool pump motor is expressed in terms of electricity consumption and depends on the DPPP motor efficiency level, pool pumping requirement, on the performance of the DPPP incorporating the motor, and on the DPPP annual operating hours. This electricity consumption is identical to the annual electricity consumption of the DPPP incorporating the motor. The pool pump motor energy consumption value is the sum of the energy consumption values in each mode of operation. Each mode of operation corresponds to a motor speed setting. Single-speed motors only have one mode of operation, while dual and variable-speed pool pump motors operate at a low- and high-speed mode. The unit energy consumption values in each mode are calculated based on the DPPP usage, which is calculated based on the pool pump system curve that the DPPP is operating on, the pump flow rate of the mode, the pump energy factor of the mode (which in turn determine the motor input power)[47] and the annual run time of the pool pump spent in that mode. DOE calculated the pool pump annual run time based on the application (residential or commercial), the assumed pool size, the assumed number of turns per day, and the sample application's geographic location, which implies the corresponding pool seasons. A typical DPPP application, characterized by the DPPP equipment class and hydraulic horsepower (hhp), was associated to each representative unit in equipment classes 1, 2, and 3 based on inputs from the engineering analysis (See Table IV.2).

2. DPPP Motor Consumer Sample

DOE created individual consumer samples for five DPPP motor markets: (1) single-family homes with a swimming pool; (2) indoor swimming pools in commercial applications; (3) single-family community swimming pools; (4) multi-family community swimming pools; and (5) outdoor swimming pools in commercial applications. DOE used the samples to determine DPPP motor annual energy consumption as well as for conducting the LCC and PBP analyses.

DOE used the Energy Information Administration's (EIA) 2015 Residential Energy Consumption Survey (RECS 2015) to establish a sample of single-family homes that have a swimming pool.[48 49] For DPPPs used in indoor swimming pools in commercial applications, DOE developed a sample using the 2012 Commercial Building Energy Consumption Survey (CBECS 2012).[50] RECS and CBECS include information such as the household or building owner demographics and the location of the household or building.

Neither RECS nor CBECS provide data on community pools or outdoor swimming pools in commercial applications, so DOE created samples based on other available data. To develop samples for DPPPs in single or multi-family communities, DOE used a combination of RECS 2009,[51] U.S. Census 2009 American Home Survey

[39] Because the projected price of standards-compliant products is typically higher than the price of baseline products, using the same markup for the incremental cost and the baseline cost would result in higher per-unit operating profit. While such an outcome is possible, DOE maintains that in markets that are reasonably competitive it is unlikely that standards would lead to a sustainable increase in profitability in the long run.

[40] U.S. Securities and Exchange Commission. *SEC 10–K Reports* for Pool Corp (2010–2017). Available at *www.sec.gov/* (Last accessed July 26, 2021.)

[41] U.S. Securities and Exchange Commission. *SEC 10–K Reports* for Home Depot, Lowe's, Wal-Mart and Costco. Available at *www.sec.gov/* (Last accessed July 26, 2021.)

[42] U.S. Census Bureau, *2017 Annual Retail Trade Survey,* available at *www.census.gov/retail/index.html* (last accessed July 26, 2021).

[43] U.S. Census Bureau, *2017 Economic Census Data,* available at *www.census.gov/econ/* (last accessed July 26, 2021).

[44] U.S. Census Bureau, *2017 Annual Wholesale Trade Survey,* available at *www.census.gov/awts* (last accessed July 26, 2021).

[45] RSMeans Electrical Cost Data, available at *www.rsmeans.com* (last accessed July 26, 2021).

[46] Sales Tax Clearinghouse Inc., State Sales Tax Rates Along with Combined Average City and County Rates (2021), available at *https://thestc.com/STrates.stm* (last accessed Feb. 14, 2021).

[47] The motor input power is equal to the DPPP flow (gallon per minute) divided by the DPPP Energy Factor (gallon per Wh) and multiplied by 60 (number of minutes in an hour).

[48] U.S. Department of Energy—Energy Information Administration. *2009 RECS Survey Data.* (Last accessed July 27, 2016.) *www.eia.gov/consumption/residential/data/2009/.*

[49] U.S. Department of Energy—Energy Information Administration. *2015 RECS Survey Data.* (Last accessed September 11, 2018.) *www.eia.gov/consumption/residential/data/2015/.*

[50] U.S. Department of Energy—Energy Information Administration. 2012 CBECS Survey Data. (Last accessed: July 27, 2016.) *www.eia.gov/consumption/commercial/data/2012/index.cfm?view=microdata.*

[51] The earlier version of RECS was used for consistency with the year of the AHS survey available with pool ownership information.

Data (2009 AHS),[52] and 2015 PK Data report.[53] To develop a sample for pool pumps in outdoor commercial swimming pools, DOE used a combination of CBECS 2012 and 2015 PK Data report.

Table IV.7 shows the estimated shares of the five DPPP markets in the existing stock based on the afore-mentioned sources. The vast majority of DPPPs are used for residential single-family swimming pools.

TABLE IV.7—FRACTION OF DPPP MOTOR APPLICATION BY MARKET

Description	Fraction of DPPP motor stock (%)
Residential Single Family Swimming Pools	95.1
Community Pools (Single Family)	0.8
Community Pools (Multi Family)	0.4
Commercial Indoor Pools	0.3
Commercial Outdoor Swimming Pools	3.4

DPPPs can be installed with either above-ground or in-ground swimming pools. DOE established separate sets of consumer samples for in-ground pools and above-ground pools by adjusting the original sample weights using data on the number of installed in-ground and above-ground pools gathered during the January 2017 Direct Final Rule, which relied on 2014 data per state provided by APSP.[54] The consumer samples for DPPP motors used in self-priming and pressure cleaner booster pumps are drawn from the in-ground pool samples; the consumer samples for motors used with non-self-priming pool pumps are obtained from the above-ground pool samples.

See chapter 7 of the NOPR TSD for more details about the creation of the consumer samples and the regional breakdowns.

DOE seeks comment on the overall methodology to develop consumer samples and on the fraction of DPPP motor existing stock across the five following markets: (1) single-family homes with a swimming pool; (2) indoor swimming pools in commercial applications; (3) single-family community swimming pools; (4) multi-family community swimming pools; and (5) outdoor swimming pools in commercial applications.

3. Self-Priming and Non-Self-Priming Pool Pump Motor Input Power

The input power of DPPP motors used in self-priming and non-self-priming pump applications was calculated based on the flow rates (gallons per minute) and typical Energy Factor (gallons per watt hour) associated to each representative unit.[55] At efficiency levels corresponding to single-speed and dual-speed motors, the flow and Energy Factor values were based on input from the engineering analysis (see section IV.C) and provided for each system curve (A, B or C).[56] For each user of self-priming and non-self-priming pool pump in the consumer sample, DOE then specified the system curve used (A, B or C) by drawing from a probability distribution in which 35 percent of the pool pumps follow curve A, 10 percent of the pool pumps follow curve B, and the remaining 55 percent follow curve C. The probability distribution was based on inputs from the ASRAC DPPP Working Group gathered during the January 2017 Direct Final Rule.[57]

At efficiency levels corresponding to variable-speed motors, the engineering analysis only provided flow and Energy Factor values for the high-speed mode on each system curve. For the low-speed mode, DOE used data on pool volume and desired time per turnover from the January 2017 Direct Final Rule technical support document to calculate a consumer-specific low-speed flow.[58] These relied on inputs from stakeholders and several other references.[59 60 61] DOE then used the equation provided by the engineering analysis to calculate the Energy Factor as a function of Q for each representative unit on each system curve.

4. Pressure Cleaner Booster Pumps Motor Input Power

The input power of DPPP motors used in pressure cleaner booster pumps was calculated using the relationship between input power and flow and the system curve provided by the engineering analysis (see section IV.C). To characterize operating flow for each consumer in the sample, DOE drew a value from a statistical distribution of flow established during the January 2017 Direct Final Rule. This distribution was developed around the test procedure test point of 10 gpm of flow rate, as recommended by the ASRAC DPPP Working Group. (Docket EERE–2015–BT–STD–0008–0092 p. 311) For single-speed pressure cleaner booster pumps, DOE then calculated the input power using the power curve from the engineering analysis. For variable-speed motors used in pressure cleaner booster pumps, DOE also calculated the pool pump motor input power in a low-speed setting. Based on information from the January 2017 Direct Final Rule, DOE used a value of 10 gpm to characterize the low-speed flow and calculate the hydraulic horsepower using the system curve.[62] Then, DOE calculated the input power using the relationship between input power and flow as provided by the engineering analysis (see section IV.C).

5. Daily Operating Hours

DOE relied on information gathered during the January 2017 Direct Final Rule to develop estimates of pool pump daily operating hours. For self-priming and non-self-priming pool filter pumps in residential applications, operating hours are calculated uniquely for each consumer based on pool size, number of turnovers per day (itself based on ambient conditions), and the pump flow rate. In commercial applications, DOE assumed these pumps operate 24 hours per day. For pressure cleaner booster pumps, operating hours are drawn from a distribution which were based on the January 2017 Direct Final Rule.[63] Table IV.8 summarizes the resulting daily

[52] U.S. Census Bureau. 2009 AHS survey data (Last accessed: September 13, 2021.) *www.census.gov/programs-surveys/ahs/data/2009/ahs-2009-public-use-file--puf-/2009-ahs-national-puf-microdata.html.*

[53] PK Data. 2015 Swimming Pool and Pool Heater Customized Report for LBNL. (Last accessed: April 30, 2016.) *www.pkdata.com/annual-reports.html/.*

[54] For more details see chapter 7 of the dedicated-purpose pool pumps January 2017 Direct Final Rule TSD, at *www.regulations.gov/document?D=EERE-2015-BT-STD-0008-0105.*

[55] The motor input power is equal to the flow (gallon per minute) divided by the Energy Factor (gallon per Wh) and multiplied by 60 (number of minutes in an hour).

[56] When a pump is tested on a system curve (such as curve C), any one of the measurements hydraulic power, P (hp), volumetric flow, Q (gpm) and total dynamic head, H (feet of water) can be used to calculate the other two measurements.

[57] For more details see chapter 7 of the dedicated-purpose pool pumps January 2017 Direct Final Rule TSD, at *www.regulations.gov/document?D=EERE-2015-BT-STD-0008-0105.*

[58] Flow (in gallon per minute) is equal to the pool volume (gallon) divided by the desired time per turnover (in minutes).

[59] CEE Residential Swimming Pool Initiative, December 2021.

[60] California Energy Commission Pool Heater CASE. (Last Accessed: July 28, 2016) *https://efiling.energy.ca.gov/GetDocument.aspx?tn=71754&DocumentContentId=8285.*

[61] Evaluation of potential best management practices—Pools, Spas, and Fountains 2010. (Last Accessed: July 28, 2016) *https://calwep.org/wp-content/uploads/2021/03/Pools-Spas-and-Fountains-PBMP-2010.pdf.*

[62] For more details see chapter 7 of the dedicated-purpose pool pumps January 2017 Direct Final Rule TSD, at *www.regulations.gov/document?D=EERE-2015-BT-STD-0008-0105.*

[63] For more details see chapter 7 of the dedicated-purpose pool pumps direct final rule TSD, at */www.regulations.gov/document?D=EERE-2015-BT-STD-0008-0105.*

operating hours during the pool operating season.

TABLE IV.8—WEIGHTED-AVERAGE DAILY OPERATING HOURS BY REPRESENTATIVE UNIT AND POOL PUMP APPLICATION

Equipment class	Representative unit	THP	Pool pump application *	Residential weighted average daily operating hours **	Commercial weighted average daily operating hours **
1	4	0.22	Non Self-priming Filter Pump, Extra-Small (0.09 hhp)	3.3	
2	1	0.75	Self-priming Filter Pump, Small-size (0.44 hhp)	9.6	
2	5	1	Non Self-priming Filter Pump, Small-size (0.52 hhp)	8.2	
2	7	1.125	Pressure Cleaner Booster Pump	2.5	2.5
3	6	1.5	Non Self-priming Filter Pump (0.87 hhp)	8.2	
3	2	1.65	Self-priming Filter Pump, Standard-size (0.95 hhp)	15.3	
3	2A	1.65	Self-priming Filter Pump, Small-size (0.65 hhp)	9.6	
3	3	3.45	Self-priming Filter Pump, Standard-size (1.88 hhp)	14.6	22.7

* For self-priming pumps, the terms small and standard refer to the hydraulic horsepower. Small-size designates pool pump applications with hydraulic horsepower less than 0.711 hhp, while standard-size designates pool pump applications with hydraulic horsepower greater than or equal to 0.711 hhp.
** During the pool operating season.

6. Annual Days of Operation

DOE calculated the annual unit energy consumption (UEC) by multiplying the daily operating hours by the annual days of operation, which depends on the number of months of pool operation. For each consumer sample, DOE assigned different annual days of operation depending on the region in which the DPPP is installed. Table IV.9 provides the assumptions of pool pump operating season based on geographical locations. This assignment was based on information collected during the January 2017 Direct Final Rule. It is based on several sources: DOE's Energy Saver website assumptions [64] and PK Data [65] that include average pool season length (*i.e.,* operating months) by state, along with discussion of the geographic distribution of pool operating days by the ASRAC DPPP Working Group. The ASRAC DPPP Working Group suggested that although some of the regions had warm weather, the pool pumps should still be operating all year long. (*See* Docket EERE–2015–BT–STD–0008–0094 pp. 191–193)

TABLE IV.9—POOL PUMP OPERATING SEASON BY GEOGRAPHICAL LOCATION

Location (states or census divisions)	Avg. months of pool use	Pool use months
CT, ME, NH, RI, VT	4	5/1–8/31
MA	4	5/1–8/31
NY	4	5/1–8/31
NJ	4	5/1–8/31
PA	4	5/1–8/31
IL	4	5/1–8/31
IN, OH	4	5/1–8/31
MI	4	5/1–8/31
WI	4	6/1–9/30
IA, MN, ND, SD	4	6/1–9/30
KS, NE	4	6/1–9/30
MO	4	6/1–9/30
VA	7	4/1–10/31
DE, DC, MD	5	5/1–9/30
GA	7	4/1–10/31
NC, SC	7	4/1–10/31
FL	12	1/1–12/31
AL, KY, MS	12	1/1–12/31
TN	12	1/1–12/31
AR, LA, OK	12	1/1–12/31
TX	12	1/1–12/31
CO	4	5/1–8/31
ID, MT, UT, WY	4	5/1–8/31
AZ	12	1/1–12/31
NV, NM	12	1/1–12/31
CA	12	1/1–12/31
OR, WA	3	6/1–8/31
AK	5	5/1–9/30
HI	12	1/1–12/31
WV	5	5/1–9/30

[64] DOE Energy Saver. (Last Accessed: April 26, 2016) *https://energy.gov/energysaver/articles/heat-pump-swimming-pool-heaters.*

[65] PK Data. 2015 Swimming Pool and Pool Heater Customized Report for LBNL. (Last accessed: April 16, 2016) *www.pkdata.com/annual-reports.html/.*

TABLE IV.9—POOL PUMP OPERATING SEASON BY GEOGRAPHICAL LOCATION—Continued

Location (states or census divisions)	Avg. months of pool use	Pool use months
New England	4	5/1–8/31
Middle Atlantic	5	5/1–9/30
East North Central	5	5/1–9/30
West North Central	4	6/1–9/30
South Atlantic	12	1/1–12/31
East South Central	12	1/1–12/31
West South Central	12	1/1–12/31
Mountain	4	5/1–8/31
Pacific	12	1/1–12/31

Chapter 7 of the NOPR TSD provides details on DOE's energy use analysis for DPPP motors.

DOE seeks comment on the overall methodology and inputs used to estimate DPPP motor energy use. Specifically, DOE seeks feedback on the average daily operating hours and annual days of operation used in the energy use analysis.

F. Life-Cycle Cost and Payback Period Analysis

DOE conducted LCC and PBP analyses to evaluate the economic impacts on individual consumers of potential energy conservation standards for DPPP motors. The effect of new energy conservation standards on individual consumers usually involves a reduction in operating cost and an increase in purchase cost. DOE used the following two metrics to measure consumer impacts:

- The LCC is the total consumer expense of an equipment over the life of that equipment, consisting of total installed cost (manufacturer selling price, distribution chain markups, sales tax, and installation costs) plus operating costs (expenses for energy use, maintenance, and repair). To compute the operating costs, DOE discounts future operating costs to the time of purchase and sums them over the lifetime of the product.
- The PBP is the estimated amount of time (in years) it takes consumers to recover the increased purchase cost (including installation) of a more-efficient equipment through lower operating costs. DOE calculates the PBP by dividing the change in purchase cost at higher efficiency levels by the change in annual operating cost for the year that amended or new standards are assumed to take effect.

For any given efficiency level, DOE measures the change in LCC relative to the LCC in the no-new-standards case, which reflects the estimated efficiency distribution of DPPP motors in the absence of new or amended energy conservation standards. In contrast, the PBP for a given efficiency level is measured relative to the baseline product.

For each considered efficiency level in each equipment class, DOE calculated the LCC and PBP for a nationally representative set of consumers. As stated previously, DOE considered five DPPP motor markets: (1) single-family homes with a swimming pool; (2) indoor swimming pools in commercial applications; (3) single-family community swimming pools; (4) multi-family community swimming pools; and (5) outdoor swimming pools in commercial applications. As described in section IV.E.2, DOE developed consumer samples from various data sources including 2009 RECS, 2009 AHS, 2015 RECS and 2012 CBECS. For each consumer in the sample, DOE determined the energy consumption for the DPPP motor and the appropriate energy price. By developing a representative sample of consumers, the analysis captured the variability in energy consumption and energy prices associated with the use of DPPP motors.

Inputs to the calculation of total installed cost include the cost of the product—which includes MSPs, retailer and distributor markups, and sales taxes—and installation costs. Inputs to the calculation of operating expenses include annual energy consumption, energy prices and price projections, repair and maintenance costs, product lifetimes, and discount rates. DOE created distributions of values for equipment lifetime, discount rates, and sales taxes, with probabilities attached to each value, to account for their uncertainty and variability.

The computer model DOE uses to calculate the LCC and PBP relies on a Monte Carlo simulation to incorporate uncertainty and variability into the analysis. The Monte Carlo simulations randomly sample input values from the probability distributions and DPPP motor user samples. For this rulemaking, the Monte Carlo approach is implemented in MS Excel together with the Crystal Ball™ add-on.[66] The model calculated the LCC and PBP for equipment at each efficiency level for 10,000 consumers per simulation run. The analytical results include a distribution of 10,000 data points showing the range of LCC savings for a given efficiency level relative to the no-new-standards case efficiency distribution. In performing an iteration of the Monte Carlo simulation for a given consumer, equipment efficiency is chosen based on its probability. If the chosen equipment efficiency is greater than or equal to the efficiency of the standard level under consideration, the LCC and PBP calculation reveals that a consumer is not impacted by the standard level. By accounting for consumers who already purchase more-efficient equipment, DOE avoids overstating the potential benefits from increasing equipment efficiency.

DOE calculated the LCC and PBP for all consumers of DPPP motors as if each were to purchase a new equipment in the expected first full year of required compliance with new standards. New standards would apply to DPPP motor manufactured 2 years after the date on which any new or amended standard is published.[67] At this time, DOE estimates publication of a final rule in the second half of 2023. Therefore, for purposes of its analysis, DOE used 2026 as the first full year of compliance with any amended standards for DPPP motors.

Table IV.10 summarizes the approach and data DOE used to derive inputs to the LCC and PBP calculations. The

[66] Crystal Ball™ is commercially-available software tool to facilitate the creation of these types of models by generating probability distributions and summarizing results within Excel, available at *www.oracle.com/technetwork/middleware/crystalball/overview/index.html* (last accessed July 6, 2021).

[67] In the Electric Motors Final Rule, DOE was informed by the statutorily mandated rulemaking schedule (see 42 U.S.C. 6313(b)) in providing a two-year lead time between the finalized rule and required compliance. 79 FR 30934, 30944 (May 29, 2014). For the purposes of this analysis, DOE is following the same 2-year lead time.

subsections that follow provide further discussion. Details of the spreadsheet model, and of all the inputs to the LCC and PBP analyses, are contained in chapter 8 of the NOPR TSD and its appendices.

TABLE IV.10—SUMMARY OF INPUTS AND METHODS FOR THE LCC AND PBP ANALYSIS *

Inputs	Source/method
Equipment Cost	Derived by multiplying MSPs by distribution channel markups and sales tax, as appropriate. Used historical data to derive a price index to project equipment costs.
Installation Costs	Baseline installation cost determined using data from manufacturer gathered during the January 2017 Direct Final Rule.
Annual Energy Use	The daily energy consumption multiplied by the number of operating days per year. *Variability:* Based on the 2009 RECS, 2009 AHS, 2015 RECS and 2012 CBECS and other data sources.
Energy Prices	*Electricity:* Based on EEI data for 2020. *Variability:* Regional energy prices determined for 9 census divisions for pool pump motors in individual single-family homes and 9 census divisions for pool pump motors in community and commercial pool pump motors. Average and marginal prices used for electricity.
Energy Price Trends	Based on *AEO2021* price projections.
Repair and Maintenance Costs	Assumed no repair or maintenance on pool pump motors.
Equipment Lifetime	*Average:* 3.6 to 5 years depending on the DPPP applications. *Variability:* Based on Weibull distribution.
Discount Rates	*Residential:* approach involves identifying all possible debt or asset classes that might be used to purchase the considered appliances, or might be affected indirectly. Primary data source was the Federal Reserve Board's Survey of Consumer Finances. *Commercial:* Calculated as the weighted average cost of capital for entities purchasing pool pumps. Primary data source was Damodaran Online.
Compliance Date	2026 (first full year).

* References for the data sources mentioned in this table are provided in the sections following the table or in chapter 8 of the NOPR TSD.

1. Equipment Cost

To calculate consumer equipment costs, DOE multiplied the MSPs developed in the engineering analysis by the distribution channel markups described previously (along with sales taxes). DOE used different markups for baseline equipment and higher-efficiency equipment, because DOE applies an incremental markup to the increase in MSP associated with higher-efficiency equipment.

To project an equipment price trend, DOE derived an inflation-adjusted index of the Producer Price Index (PPI) for integral and fractional horsepower motors and generators manufacturing over the period 1967–2020.[68] For fractional horsepower motors, the data shows a slightly downward trend before early 2000s, and then the price index increases to a small degree. For integral horsepower motors, the trend is mostly flat before early 2000s, and then the price index increases slightly. The trend is found to align with the copper and steel deflated price indices to some extent, as they are the major material used in small electric motors. Given the degree of uncertainty, DOE decided to use a constant price assumption as the default price factor index to project future DPPP motor prices. For dual-speed DPPP motors, however, DOE assumed that the timer control portion of the installation cost would be affected by price learning. DOE used PPI data on ''Automatic environmental control manufacturing'' between 1980 and 2020 to estimate the historic price trend of the electronic components in the timer control.[69] The regression performed as an exponential trend line fit results in an R-square of 0.86, with an annual price decline rate of 0.4 percent. For variable-speed DPPP motors, DOE assumed that the controls portion of the DPPP motor would be affected by price learning. Similarly, DOE used PPI data on ''Semiconductors and related device manufacturing'' between 1967 and 2020 to estimate the historic price trend of electronic components in the control.[70] The regression performed as an exponential trend line fit results in an R-square of 0.99, with an annual price decline rate of 6 percent.

DOE seeks comment on the approach and inputs used to project an equipment price trend for DPPP motors.

2. Installation Cost

Installation cost includes labor, overhead, and any miscellaneous materials and parts needed to install the equipment. During the January 2017 Direct Final Rule, DOE simplified the calculation and only accounted for the difference of installation cost by efficiency levels. For two-speed pumps, DOE included the cost of a timer control and its installation where applicable, as recommended by the ASRAC DPPP Working Group. During the January 2017 Direct Final Rule, DOE used information obtained in the manufacturer interviews to calculate the supplemental installation labor costs for two-speed and variable-speed pumps.[71] DOE retained the same estimates for this NOPR as applied to two-speed and variable speed DPPP motors.[72]

DOE seeks comment on installation costs estimates used in the LCC analysis.

3. Annual Energy Consumption

For each sampled installation, DOE determined the energy consumption for a DPPP motor at different efficiency levels using the approach described in section IV.E of this document.

4. Energy Prices

Because marginal electricity price more accurately captures the incremental savings associated with a change in energy use from higher efficiency, it provides a better representation of incremental change in consumer costs than average electricity prices. Therefore, DOE applied average electricity prices for the energy use of the DPPP motor purchased in the no-new-standards case, and marginal electricity prices for the incremental

[68] Series ID PCU 3353123353121; *www.bls.gov/ppi/.*

[69] Automatic environmental control manufacturing PPI series ID: PCU334512334512; *www.bls.gov/ppi/.*

[70] Semiconductors and related device manufacturing PPI series ID: PCU334413334413; *www.bls.gov/ppi/.*

[71] For more details see chapter 8 of the dedicated-purpose pool pumps direct final rule TSD, at *www.regulations.gov/document?D=EERE-2015-BT-STD-0008-0105.*

[72] Adjusted to $2020 and compliance year.

change in energy use associated with the other efficiency levels considered.

DOE derived electricity prices in 2020 using data from EEI Typical Bills and Average Rates reports. Based upon comprehensive, industry-wide surveys, this semi-annual report presents typical monthly electric bills and average kilowatt-hour costs to the customer as charged by investor-owned utilities. For the residential sector, DOE calculated electricity prices using the methodology described in Coughlin and Beraki (2018).[73] For the commercial sector, DOE calculated electricity prices using the methodology described in Coughlin and Beraki (2019).[74]

DOE's methodology allows electricity prices to vary by sector, region and season. In the analysis, variability in electricity prices is chosen to be consistent with the way the consumer economic and energy use characteristics are defined in the LCC analysis. For DPPP motors, regional weighted-average values for both average and marginal prices were calculated for the nine census divisions. Each EEI utility in a region was assigned a weight based on the number of consumers it serves. Consumer counts were taken from the most recent EIA's Form EAI–861 data (2020).

To estimate energy prices in future years, DOE multiplied the 2020 average regional energy prices by a projection of annual change in national-average residential and commercial energy price in *AEO 2021,* which has an end year of 2050.[75] To estimate price trends after 2050, DOE used the average annual rate of change in prices from 2040 through 2050.

See chapter 8 of the NOPR TSD for details.

5. Maintenance and Repair Costs

Repair costs are associated with repairing or replacing components that have failed in an equipment; maintenance costs are associated with maintaining the operation of the equipment. Typically, small incremental increases in equipment efficiency produce no, or only minor, changes in repair and maintenance costs compared to baseline efficiency equipment. DOE assumed that for maintenance costs, there is no change with efficiency level, and therefore DOE did not include those costs in the model. In addition, DPPP motors are not repaired and DOE assumed no repair costs.

DOE seeks comment on its decision to not include DPPP motor repair and maintenance costs in the LCC analysis.

6. Equipment Lifetime

For DPPP motors used in residential applications, DOE calculated lifetime estimates using DPPP lifetime data and rates of repair from the January 2017 Direct Final Rule, which estimated that motor replacement occurs at the halfway point in a pump's lifetime, but only for those DPPPs whose lifetime exceeds the average lifetime for the relevant equipment class.[76] The data allowed DOE to develop a survival function, which provides a distribution of lifetime ranging from a minimum of 1 year based on warranty covered period, to a maximum of 10 years, with a mean value of 5 years for self-priming pumps, to a maximum of 8 years, with a mean value of 3.6 years for non-self-priming and pressure cleaner booster pumps. These values are applicable to DPPP motors in residential applications. For commercial applications, DOE adjusted the lifetimes to account for the higher operating hours compared to residential applications, resulting in a reduced average lifetime of 3.2 years for self-priming pumps and 3.5 years for pressure cleaner booster pumps. The resulting shipments-weighted average lifetime across all DPPP motor equipment classes is 4.5 years.

DOE seeks comment on the approach and inputs used to develop DPPP motor lifetime estimates.

7. Discount Rates

In the calculation of LCC, DOE applies discount rates appropriate to consumers to estimate the present value of future operating cost savings. DOE estimated a distribution of discount rates for DPPP motors based on the opportunity cost of consumer funds.

DOE applies weighted average discount rates calculated from consumer debt and asset data, rather than marginal or implicit discount rates.[77] The LCC analysis estimates net present value over the lifetime of the equipment, so the appropriate discount rate will reflect the general opportunity cost of household funds, taking this time scale into account. Given the long time horizon modeled in the LCC analysis, the application of a marginal interest rate associated with an initial source of funds is inaccurate. Regardless of the method of purchase, consumers are expected to continue to rebalance their debt and asset holdings over the LCC analysis period, based on the restrictions consumers face in their debt payment requirements and the relative size of the interest rates available on debts and assets. DOE estimates the aggregate impact of this rebalancing using the historical distribution of debts and assets.

To establish residential discount rates for the LCC analysis, DOE identified all relevant household debt or asset classes in order to approximate a consumer's opportunity cost of funds related to appliance energy cost savings. It estimated the average percentage shares of the various types of debt and equity by household income group using data from the Federal Reserve Board's Survey of Consumer Finances [78] (''SCF'') for 1995, 1998, 2001, 2004, 2007, 2010, 2013 and 2016. Using the SCF and other sources, DOE developed a distribution of rates for each type of debt and asset by income group to represent the rates that may apply in the year in which amended standards would take effect. DOE assigned each sample household a specific discount rate drawn from one of the distributions. The average rate across all types of household debt and equity and income groups, weighted by the shares of each type, is 4.3 percent.

DOE applies weighted average discount rates calculated from consumer debt and asset data, rather than marginal or implicit discount rates.[79] DOE notes

[73] Coughlin, K. and B. Beraki. 2018. Residential Electricity Prices: A Review of Data Sources and Estimation Methods. Lawrence Berkeley National Lab. Berkeley, CA. Report No. LBNL–2001169. *https://ees.lbl.gov/publications/residential-electricity-prices-review.*

[74] Coughlin, K. and B. Beraki. 2019. Non-residential Electricity Prices: A Review of Data Sources and Estimation Methods. Lawrence Berkeley National Lab. Berkeley, CA. Report No. LBNL–2001203. *https://ees.lbl.gov/publications/non-residential-electricity-prices.*

[75] U.S. Department of Energy—Energy Information Administration. *Annual Energy Outlook 2021 with Projections to 2050.* Washington, DC. Available at *www.eia.gov/forecasts/aeo/.*

[76] For DPPPs that do not include a repair, the DPPP motor lifetime is equal to the DPPP lifetime. For DPPPs that are repaired, the DPPP motor lifetime is equal to half of the DPPP lifetime. *See* chapter 8 of the dedicated-purpose pool pumps January 2017 Direct Final Rule TSD, at *www.regulations.gov/document?D=EERE-2015-BT-STD-0008-0105.*

[77] The implicit discount rate is inferred from a consumer purchase decision between two otherwise identical goods with different first cost and operating cost. It is the interest rate that equates the increment of first cost to the difference in net present value of lifetime operating cost, incorporating the influence of several factors: transaction costs; risk premiums and response to uncertainty; time preferences; interest rates at which a consumer is able to borrow or lend. The implicit discount rate is not appropriate for the LCC analysis because it reflects a range of factors that influence consumer purchase decisions, rather than the opportunity cost of the funds that are used in purchases.

[78] U.S. Board of Governors of the Federal Reserve System. *Survey of Consumer Finances.* 1995, 1998, 2001, 2004, 2007, 2010, 2013, and 2016. (Last accessed August 8, 2019) *www.federalreserve.gov/econresdata/scf/scfindex.htm.*

[79] The implicit discount rate is inferred from a consumer purchase decision between two otherwise

that the LCC does not analyze the appliance purchase decision, so the implicit discount rate is not relevant in this model. The LCC estimates net present value over the lifetime of the product, so the appropriate discount rate will reflect the general opportunity cost of household funds, taking this time scale into account. Given the long time horizon modeled in the LCC, the application of a marginal interest rate associated with an initial source of funds is inaccurate. Regardless of the method of purchase, consumers are expected to continue to rebalance their debt and asset holdings over the LCC analysis period, based on the restrictions consumers face in their debt payment requirements and the relative size of the interest rates available on debts and assets. DOE estimates the aggregate impact of this rebalancing using the historical distribution of debts and assets.

To establish commercial discount rates for the small fraction of applications where businesses purchase and use DPPP motors, DOE estimated the weighted-average cost of capital using data from Damodaran Online.[80] The weighted-average cost of capital is commonly used to estimate the present value of cash flows to be derived from a typical company project or investment. Most companies use both debt and equity capital to fund investments, so their cost of capital is the weighted average of the cost to the firm of equity and debt financing. DOE estimated the cost of equity using the capital asset pricing model, which assumes that the cost of equity for a particular company is proportional to the systematic risk faced by that company. The average commercial discount rate is 9.8 percent.

See chapter 8 of the NOPR TSD for further details on the development of consumer discount rates.

8. Energy Efficiency Distribution in the No-New-Standards Case

To accurately estimate the share of consumers that would be affected by a potential energy conservation standard at a particular efficiency level, DOE's LCC analysis considered the projected distribution (market shares) of equipment efficiencies under the no-new-standards case (*i.e.,* the case without amended or new energy conservation standards).

To estimate the efficiency distribution of DPPP motors for 2026, DOE first established efficiency distributions in 2021. Then, as it was done in the January 2017 Direct Final Rule, DOE projected the 2026 efficiency distribution by assuming a one percent market shift from EL0–EL2 (single-speed DPPP motors) to EL 6 (variable speed DPPP motors) where applicable.

To establish the efficiency distributions of DPPP motors in 2021, DOE considered two market segments: (1) DPPP motors incorporated in DPPPs and; (2) replacement DPPP motors sold alone.

For DPPP motors incorporated in DPPPs, DOE relied on the 2021 DPPP Database that included a total of 345 models of DPPPs with weighted-energy factor (''WEF'') ratings and on the ELs developed in the January 2017 Direct Final Rule, to establish the 2021 efficiency distributions of DPPPs. DOE also used the scenario of roll-up market response to the DPPP standards as presented in the January 2017 Direct Final Rule. DOE then assumed that the distributions of DPPP motors incorporated in DPPPs would be equivalent to the 2021 efficiency distributions of DPPPs, based on the equivalent structure of the ELs used in this NOPR and in the January 2017 Direct Final Rule (*See* section III.C.1). For representative units 4 (*i.e.,* DPPP motors used in non-self-priming pumps, extra small) and 7 (*i.e.,* DPPP motors used in pressure cleaner booster pumps), the 2021 DPPP Database did not include any information specific to these DPPPs. Instead, for these representative units, DOE relied on the efficiency distributions provided in the January 2017 Direct Final Rule and applied a scenario of roll-up market response to the upcoming DPPP standards.

For replacement DPPP motors sold alone, for the U.S., not including California[81], the DPPP standards would have no impact on the DPPP motor efficiency distributions. Therefore, to establish the efficiency distributions of replacement DPPP motors sold alone, DOE relied on the 2021 no-new-standards case efficiency distributions provided in the January 2017 Direct Final Rule, which reflect efficiency distributions prior to the compliance date of the DPPP standards. DOE then assumed that the efficiency distributions of replacement DPPP motors sold alone would be equivalent to the efficiency distributions of DPPPs, based on the equivalent structure of the ELs used in this NOPR and in the January 2017 Direct Final Rule. For California, DOE applied a scenario of roll-up market response to the upcoming California replacement DPPP motor standards.[82] DOE then relied on the market shares of replacement DPPP motor sold in California[83] and in the rest of the United-States to establish the nation-wide 2021 replacement DPPP motor efficiency distributions.

The projected 2026 market shares by EL for the no-new-standards case for DPPP motors are shown in Table IV.11 by market segment. See chapter 8 of the NOPR TSD for further information on the derivation of the efficiency distributions.

TABLE IV.11—DPPP MOTORS INCORPORATED IN DPPPS 2026 NO-NEW STANDARDS CASE EFFICIENCY DISTRIBUTIONS

Equipment class	Rep. Unit	THP	DPPP application	EL0 (%)	EL1 (%)	EL2 (%)	EL3 (%)	EL4 (%)	EL5 (%)	EL6 (%)
Extra-small-size	4	0.22	Non Self-priming Filter Pump, Extra-Small (0.09 hhp).	0	67	33	....	....	....	....
Small-size	1	0.75	Self-priming Filter Pump, Small-size (0.44 hhp)	0	0	29	1	1	2	66
Small-size	5	1	Non Self-priming Filter Pump, Small-size (0.52 hhp).	0	2	47	0	5	4	41
Small-size	*7	1.125	Pressure Cleaner Booster Pump	0	79	10	....	....	....	11

identical goods with different first cost and operating cost. It is the interest rate that equates the increment of first cost to the difference in net present value of lifetime operating cost, incorporating the influence of several factors: transaction costs; risk premiums and response to uncertainty; time preferences; interest rates at which a consumer is able to borrow or lend.

[80] Damodaran Online, *Data Page: Costs of Capital by Industry Sector* (2020). (Last accessed February 1, 2021) *https://pages.stern.nyu.edu/~adamodar/*.

[81] DOE considered California separately in light of the July 2021 California standards for replacement DPPP motors adopted April 7, 2020 with an effective date July 19, 2021. See Docket #19–AAER–02 at *www.energy.ca.gov/rules-and-regulations/appliance-efficiency-regulations-title-20/appliance-efficiency-proceedings-2*.

[82] For the purposes of this analysis, DOE considered EL1 (for motors below 0.5 THP) and EL6 (for motors above 0.5 THP) as equivalent levels to the California standards.

[83] California Energy Commission, Final Analysis of Efficiency Standards for Replacement Dedicated-Purpose Pool Pump Motors, February 20, 2020. Docket 9–AAER–02 *https://efiling.energy.ca.gov/GetDocument.aspx?tn=232151* (last accessed August 2021).

TABLE IV.11—DPPP MOTORS INCORPORATED IN DPPPS 2026 NO-NEW STANDARDS CASE EFFICIENCY DISTRIBUTIONS—Continued

Equipment class	Rep. Unit	THP	DPPP application	EL0 (%)	EL1 (%)	EL2 (%)	EL3 (%)	EL4 (%)	EL5 (%)	EL6 (%)
Standard-size	6	1.5	Non Self-priming Filter Pump (0.87 hhp)	0	2	47	0	5	4	41
Standard-size	2	1.65	Self-priming Filter Pump, Standard-size (0.95 hhp)	0	0	0	0	0	0	100
Standard-size	2A	1.65	Self-priming Filter Pump, Small-size (0.65 hhp)	0	0	29	1	1	2	66
Standard-size	3	3.45	Self-priming Filter Pump, Standard-size (1.88 hhp)	0	0	0	0	0	0	100

*For Pressure cleaner booster pumps EL3, EL4, and EL5 are equivalent to EL6.

TABLE IV.12—REPLACEMENTS DPPP MOTORS SOLD ALONE 2026 NO-NEW STANDARDS CASE EFFICIENCY DISTRIBUTIONS

Equipment Class	Rep. unit	THP	DPPP Application	EL0 (%)	EL1 (%)	EL2 (%)	EL3 (%)	EL4 (%)	EL5 (%)	EL6 (%)
Extra-small-size	4	0.22	Non Self-priming Filter Pump, Extra-Small (0.09 hhp).	29	38	33	....	....	....	....
Small-size	1	0.75	Self-priming Filter Pump, Small-size (0.44 hhp)	27	9	7	1	1	1	52
Small-size	5	1	Non Self-priming Filter Pump, Small-size (0.52 hhp).	23	23	28	2	1	1	23
Small-size	*7	1.125	Pressure Cleaner Booster Pump	8	50	7	....	....	....	35
Standard-size	6	1.5	Non Self-priming Filter Pump (0.87 hhp)	23	23	28	2	1	1	23
Standard-size	2	1.65	Self-priming Filter Pump, Standard-size (0.95 hhp)	27	9	7	1	1	1	52
Standard-size	2A	1.65	Self-priming Filter Pump, Small-size (0.65 hhp)	27	9	7	1	1	1	52
Standard-size	3	3.45	Self-priming Filter Pump, Standard-size (1.88 hhp)	27	9	7	1	1	1	52

*For Pressure cleaner booster pumps EL3, EL4, and EL5 are equivalent to EL6.

DOE seeks comment on the approach and inputs used to develop no-new standards case efficiency distributions in 2021. DOE seeks feedback on the approach used to project no-new standards case efficiency distributions in future years.

9. Payback Period Analysis

The payback period is the amount of time it takes the consumer to recover the additional installed cost of more-efficient equipment, compared to baseline equipment, through energy cost savings. Payback periods are expressed in years. Payback periods that exceed the life of the equipment mean that the increased total installed cost is not recovered in reduced operating expenses.

The inputs to the PBP calculation for each efficiency level are the change in total installed cost of the equipment and the change in the first-year annual operating expenditures relative to the baseline. The PBP calculation uses the same inputs as the LCC analysis, except that discount rates are not needed.

As noted previously, EPCA establishes a rebuttable presumption that a standard is economically justified if the Secretary finds that the additional cost to the consumer of purchasing an equipment complying with an energy conservation standard level will be less than three times the value of the first year's energy savings resulting from the standard, as calculated under the applicable test procedure. (42 U.S.C. 6295(o)(2)(B)(iii)) For each considered efficiency level, DOE determined the value of the first year's energy savings by calculating the energy savings in accordance with the applicable DOE test procedure, and multiplying those savings by the average energy price projection for the year in which compliance with the new standards would be required.

G. Shipments Analysis

DOE uses projections of annual equipment shipments to calculate the national impacts of potential new energy conservation standards on energy use, NPV, and future manufacturer cash flows.[84] The shipments model takes an accounting approach, tracking market shares of each equipment class and the vintage of units in the stock. Stock accounting uses equipment shipments as inputs to estimate the age distribution of in-service equipment stocks for all years. The age distribution of in-service equipment stocks is a key input to calculations of both the NES and NPV, because operating costs for any year depend on the age distribution of the stock.

1. Base-Year Shipments

DOE estimated motor shipments by DPPP application and considered two pump pool motor market segments: (1) DPPP motors incorporated in DPPPs and; (2) replacement DPPP motors sold alone. For DPPP motors incorporated in DPPPs, DOE used the 2015 shipments of DPPPs by DPPP application from January 2017 Direct Final Rule, which were based on manufacturer interviews. For replacement DPPP motors sold alone, DOE used estimates of historical shipments of DPPPs for the period 2007–2014 and estimates of repair frequency as provided by ASRAC DPPP Working Group during the January 2017 Direct Final Rule to calculate the resulting number of failing DPPP motors each year, and corresponding replacement DPPP motor shipments by DPPP application.[85] DOE also used 2018 confidential DPPP motor shipments data and information from the 2021 DPPP database to estimate market shares of motor shipments by total horsepower and distribute DPPP motor shipments by representative unit. Table IV.13 provides the breakdown of DPPP motor shipments by market segment and representative unit.

[84] DOE uses data on manufacturer shipments as a proxy for national sales, as aggregate data on sales are lacking. In general one would expect a close correspondence between shipments and sales.

[85] DOE relied on a repair frequency of 40 percent as provided in the January 2017 Direct Final Rule. At the end-of-life of a motor, the motor is replaced (*i.e.,* pump repair) 40 percent of the time, and in the remaining 60 percent of the time, the pump is replaced by a new pump. For more details see chapter 9 of the dedicated-purpose pool pumps January 2017 Direct Final Rule TSD, at *www.regulations.gov/document?D=EERE-2015-BT-STD-0008-0105*.

TABLE IV.13—2021 SHIPMENTS OF DPPP MOTORS BY MARKET SEGMENT AND REPRESENTATIVE UNIT

Equipment class	Rep. unit*	THP	DPPP category	Represented THP range within the DPPP category	DPPP motors incorporated in pumps (thousand units)	Replacement DPPP motors sold alone (thousand units)
Small-size	1	0.75	Small Size Self-priming Filter Pump.	0.5 ≤ THP < 1.15	140.6	45.1
Standard-size	2A	1.65		1.15 ≤ THP ≤ 5	98.4	31.6
Standard-size	2	1.65	Standard Size Self-priming Filter Pump.	1.15 ≤ THP < 1.7	157.1	149.8
Standard-size	3	3.45		1.7 ≤ THP ≤ 5	246.1	234.6
Extra-small-size	4	0.22	Non Self-priming Filter Pump.	< 0.5	47.4	16.2
Small-size	5	1		0.5 ≤ THP < 1.15	279.9	95.5
Standard-size	6	1.5		1.15 ≤ THP ≤ 5	120.0	40.9
Small-size	7	1.125	Pressure Cleaner Booster Pump.	0.5 ≤ THP < 1.15	139.6	51.9

*Representative unit.

DOE seeks comment on the approach and inputs used to develop base year shipments and for DPPP motors.

2. No-New-Standards Case Shipment Projections

DOE projected shipments of DPPP motors incorporated in DPPPs and shipments of replacement DPPP motors sold alone separately.

In the no-new-standards case, DOE assumed the total shipments of DPPP motors incorporated in DPPPs was equal to the total shipments of DPPPs as projected in the January 2017 Direct Final Rule, at the trial standard level corresponding to the DPPP energy conservation standard.[86]

In the no-new-standards case, for replacement DPPP motors sold alone, DOE used the projected shipments of DPPPs and estimates of repair frequency to calculate the resulting number of failing motors each year and corresponding motor replacement sales. For replacement motors sold alone outside of California, DOE relied on repair frequency rates as provided in the January 2017 Direct Final Rule. For standard-size self-priming pump motors sold before 2021 and at efficiency levels below the DPPP standards, DOE assumed that the repair frequency would increase from 40 percent to 60 percent to calculate corresponding replacement DPPP motors sales.[87] For other categories of DPPPs, DOE relied on a 40 percent repair frequency as provided in January 2017 Direct Final Rule. These repair-replace rates were based on inputs from the ASRAC DPPP Working Group during the January 2017 Direct Final Rule. For replacement motors sold alone in California, DOE projects that with the California efficiency standards for replacement DPPP,[88] the repair frequency of standard-size self-priming pump motors will remain at its pre-2021 rate of 40 percent as estimated in the January 2017 Direct Final Rule rather than increasing to 60 percent due to the smaller price difference between replacing the entire pump and replacing the motor only.

DOE seeks comment on the approach and inputs used to develop no-new standards case shipments projections.

3. Standards-Case Shipment Projections

The standards-case shipments projections account for the effects of potential standards on shipments.

In the standards-cases for which the DPPP motor efficiency level are set below the level equivalent to the standard-size self-priming DPPP standards, DOE assumed the increase in repair frequency (*i.e.,* 60 percent) of standard-size self-priming pool pumps, which was accounted for in the no-new-standards case, was maintained for all U.S. except California (*i.e.* TSLs 1 to 5 as described in section V.A). In California, due to the California efficiency standards for replacement DPPP motors,[89] DOE estimated that the repair frequency of standard-size self-priming pump motors in California would remain at its pre-2021 rate of 40 percent in the standards-case, (same as in the no-new-standards case) because the California standards are at or above the levels equivalent to the DPPP standards at 10 CFR 431.465(f) for all equipment classes.

Outside of California, in the standards-cases for which the DPPP motor efficiency level of are set at or above the level equivalent to the standard-size self-priming DPPP standard, DOE assumed the increase in repair for standard-size self-priming pumps would no longer occur starting from the compliance year due to the smaller price difference between replacing the entire pump and replacing the motor only. Under these scenarios, DOE assumed the pumps were repaired 40 percent of the time, and new pumps were purchased 60 percent of the time to replace failed pumps (*i.e.* TSLs 6 to 8 as described in section V.A of this document).

In addition, DOE accounted for potential downsizing that could occur as a result of setting different efficiency levels that by equipment classes and THP. Specifically, DOE assumed that DPPP manufacturers may not want to incorporate variable-speed motors in DPPPs where the DPPP energy conservation standard level does not require the use of a variable speed motor. Therefore, at TSLs requiring a variable-speed motor for certain equipment classes with larger THP (*i.e.,* TSL 8, 7, 6. *See* section V.A), DOE

[86] These were calculated based on input from the ASRAC DPPP Working Group and using a repair-replace model, and accounted for price elasticity of demand. A price elasticity of −0.02 was used for standard-size self-priming pool pumps. For more details see chapter 9 of the dedicated-purpose pool pumps January 2017 Direct Final Rule TSD, at *www.regulations.gov/document?D=EERE-2015-BT-STD-0008-0105.*

[87] In the January 2017 Direct Final Rule, DOE assumed that users of standard-size self-priming pool pumps purchased before compliance year of the DPPP standards (*i.e.,* 2021), at efficiency levels below the upcoming DPPP standards, would seek to increase their pump's lifetime by performing an additional repair (*i.e.,* cheaper motor replacement with a non-variable speed motor), rather than replacing the entire pump with a more efficient and variable speed DPPP (due to the DPPP energy conversation standards at 10 CFR 431.465(f) which correspond to a variable-speed efficiency levels for these DPPPs). In the January 2017 Direct Final Rule, DOE therefore increased the repair frequency of these DPPPs from 40 percent to 60 percent. For more details see chapter 9 of the dedicated-purpose pool pumps January 2017 Direct Final Rule TSD, at *www.regulations.gov/document?D=EERE-2015-BT-STD-0008-0105.*

[88] Adopted April 7, 2020 with an effective date July 19, 2021. See Docket #19–AAER–02 at *www.energy.ca.gov/rules-and-regulations/appliance-efficiency-regulations-title-20/appliance-efficiency-proceedings-2.*

[89] Adopted April 7, 2020 with an effective date July 19, 2021. *See* Docket #19–AAER–02 at *www.energy.ca.gov/rules-and-regulations/appliance-efficiency-regulations-title-20/appliance-efficiency-proceedings-2.*

assumed that DPPP manufacturers might decide to use motors with smaller THP for DPPPs that were not required to comply with a DPPP standard level corresponding to a variable speed motor efficiency level.[90]

DOE analyzed DPPP motor THP size as a function of DPPP hydraulic horsepower in the 2021 DPPP database to estimate where such downsizing may occur. For TSL 8 and 7, DOE did not identify any possible downsizing from small-size DPPP motors to extra-small size DPPP motors. Furthermore, at TSL 8 and 7, small-size and standard-size DPPP motors are both set at EL6. Therefore, DOE did not consider any downsizing at these TSLs. At TSL 6, based on a review of the 2021 DPPP database, DOE identified representative unit 2A[91] as a candidate for downsizing.[92] Therefore at TSL 6, DOE assumed that the majority of shipments of standard-size DPPP motors used in small-size self-priming pool pumps (80 percent) would downsize to small-size DPPP motors. For standard-size DPPP motors used in standard size non-self priming pumps (*i.e.,* representative unit 5), DOE did not identify DPPP models with oversized DPPP motors in its 2021 DPPP database and did not assume any downsizing.[93]

See chapter 9 of the NOPR TSD for more detail on the shipments analysis.

DOE seeks comment on the approach and inputs used to develop the different standards case shipments projections. Specifically, at TSL 6. DOE requests information and feedback on the estimated fraction of standard-size DPPP motors used in small self-priming pool filter pumps and in non-self-priming pool filter pumps that will downsize to small-size DPPP motors.

H. National Impact Analysis

The NIA assesses the national energy savings (''NES'') and the NPV from a national perspective of total consumer costs and savings that would be expected to result from new or amended standards at specific efficiency levels.[94] (''Consumer'' in this context refers to consumers of the product being regulated.) DOE calculates the NES and NPV for the potential standard levels considered based on projections of annual product shipments, along with the annual energy consumption and total installed cost data from the energy use and LCC analyses. For the present analysis, DOE projected the energy savings, operating cost savings, product costs, and NPV of consumer benefits over the lifetime of DPPP motors sold from 2026 through 2055.

DOE evaluates the impacts of new or amended standards by comparing a case without such standards with standards-case projections. The no-new-standards case characterizes energy use and consumer costs for each product class in the absence of new or amended energy conservation standards. For this projection, DOE considers historical trends in efficiency and various forces that are likely to affect the mix of efficiencies over time. DOE compares the no-new-standards case with projections characterizing the market for each product class if DOE adopted new or amended standards at specific energy efficiency levels (*i.e.,* the TSLs or standards cases) for that class. For the standards cases, DOE considers how a given standard would likely affect the market shares of products with efficiencies greater than the standard.

DOE uses a spreadsheet model to calculate the energy savings and the national consumer costs and savings from each TSL. Interested parties can review DOE's analyses by changing various input quantities within the spreadsheet. The NIA spreadsheet model uses typical values (as opposed to probability distributions) as inputs.

Table IV.14 summarizes the inputs and methods DOE used for the NIA analysis for the NOPR. Discussion of these inputs and methods follows the table. See chapter 10 of the NOPR TSD for further details.

TABLE IV.14—SUMMARY OF INPUTS AND METHODS FOR THE NATIONAL IMPACT ANALYSIS

Inputs	Method
Shipments	Annual shipments from shipments model.
Compliance Date of Standard	2026.
Efficiency Trends	No-new-standards case: Standards cases:
Annual Energy Consumption per Unit	Annual weighted-average values are a function of energy use at each TSL.
Total Installed Cost per Unit	Annual weighted-average values are a function of cost at each TSL. Incorporates a component-based projection of future product prices based on historical data.
Annual Energy Cost per Unit	Annual weighted-average values as a function of the annual energy consumption per unit and energy prices.
Repair and Maintenance Cost per Unit	Annual values do not change with efficiency level.
Energy Price Trends	*AEO2021* projections to 2050 and extrapolation thereafter.
Energy Site-to-Primary and FFC Conversion	A time-series conversion factor based on *AEO 2021.*
Discount Rate	3 percent and 7 percent.
Present Year	2021.

1. Equipment Efficiency Trends

A key component of the NIA is the trend in energy efficiency projected for the no-new-standards case and each of the standards cases. Section IV.F.8 of this document describes how DOE developed an energy efficiency distribution for the no-new-standards case (which yields a shipment-weighted average efficiency) for each of the considered equipment classes for the first full year of anticipated compliance with an amended or new standard. To project the trend in efficiency absent amended standards for DPPP motors over the entire shipments projection period, DOE relied on the same approach described in section IV.F.8

[90] The DPPP energy conservations standards at 10 CFR 431.465(f) were set based on efficiency levels that correspond to variable speed motor DPPPs for standard size self-priming pumps. The energy conservations standards for other DPPP categories were set based on efficiency levels that correspond to single speed motor DPPPs.

[91] Representative unit 2A represents standard-size DPPP motors (*i.e.,* at or above 1.15THP) used in small-size self-priming pool filter pumps.

[92] DOE found that all DPPP models with standard-size DPPP motors in the database had a hydraulic horsepower less or equal to the hydraulic horsepower of DPPP models with small-size DPPP motors.

[93] The majority of non-self priming pool filter pump models with standards-size DPPP motors had a hydraulic horsepower greater than non-self priming pool filter pump models with small-size DPPP motors.

[94] The NIA accounts for impacts in the 50 states and U.S. territories.

and shifted 1 percent per year of the market share in the single-speed levels to the variable-speed efficiency levels. The approach is further described in chapter 10 of the NOPR TSD.

For the standards cases, DOE used a ''roll-up'' scenario to establish the shipment-weighted efficiency for the year that standards are assumed to become effective (2026). In this scenario, the market shares of products in the no-new-standards case that do not meet the standard under consideration would ''roll up'' to meet the new standard level, and the market share of products above the standard would remain unchanged.

2. National Energy Savings

The national energy savings analysis involves a comparison of national energy consumption of the considered products between each potential standards case (''TSL'') and the case with no new or amended energy conservation standards. DOE calculated the national energy consumption by multiplying the number of units (stock) of each product (by vintage or age) by the unit energy consumption (also by vintage). DOE calculated annual NES based on the difference in national energy consumption for the no-new standards case and for each higher efficiency standard case. DOE estimated energy consumption and savings based on site energy and converted the electricity consumption and savings to primary energy (*i.e.,* the energy consumed by power plants to generate site electricity) using annual conversion factors derived from *AEO2021.* Cumulative energy savings are the sum of the NES for each year over the timeframe of the analysis.

Use of higher-efficiency products is occasionally associated with a direct rebound effect, which refers to an increase in utilization of the product due to the increase in efficiency. DOE did not find any data on the rebound effect specific to DPPP motors and did not apply a rebound effect.

In 2011, in response to the recommendations of a committee on ''Point-of-Use and Full-Fuel-Cycle Measurement Approaches to Energy Efficiency Standards'' appointed by the National Academy of Sciences, DOE announced its intention to use FFC measures of energy use and greenhouse gas and other emissions in the national impact analyses and emissions analyses included in future energy conservation standards rulemakings. 76 FR 51281 (Aug. 18, 2011). After evaluating the approaches discussed in the August 18, 2011 notice, DOE published a statement of amended policy in which DOE explained its determination that EIA's National Energy Modeling System (''NEMS'') is the most appropriate tool for its FFC analysis and its intention to use NEMS for that purpose. 77 FR 49701 (Aug. 17, 2012). NEMS is a public domain, multi-sector, partial equilibrium model of the U.S. energy sector[95] that EIA uses to prepare its *Annual Energy Outlook.* The FFC factors incorporate losses in production and delivery in the case of natural gas (including fugitive emissions) and additional energy used to produce and deliver the various fuels used by power plants. The approach used for deriving FFC measures of energy use and emissions is described in appendix 10B and 13A of the NOPR TSD.

3. Net Present Value Analysis

The inputs for determining the NPV of the total costs and benefits experienced by consumers are (1) total annual installed cost, (2) total annual operating costs (energy costs and repair and maintenance costs), and (3) a discount factor to calculate the present value of costs and savings. DOE calculates net savings each year as the difference between the no-new-standards case and each standards case in terms of total savings in operating costs versus total increases in installed costs. DOE calculates operating cost savings over the lifetime of each product shipped during the projection period.

As discussed in section IV.F.1 of this document, DOE developed equipment price trends based on historical PPI data. DOE applied the same trends to project prices for each equipment class at each considered efficiency level. By 2055, which is the end date of the projection period, the average DPPP motor price is projected to drop between 0 to 51 percent depending on the efficiency level relative to 2026. DOE's projection of product prices is described in appendix 10C of the NOPR TSD.

To evaluate the effect of uncertainty regarding the price trend estimates, DOE investigated the impact of different equipment price projections on the consumer NPV for the considered TSLs for DPPP motors. In addition to the default price trend, DOE considered two equipment price sensitivity cases: (1) a high price decline case and (2) a low price decline case based on historical PPI data. The derivation of these price trends and the results of these sensitivity cases are described in appendix 10C of the NOPR TSD.

The operating cost savings are energy cost savings, which are calculated using the estimated energy savings in each year and the projected price of the appropriate form of energy. To estimate energy prices in future years, DOE multiplied the average regional energy prices by the projection of annual national-average residential and commercial energy price changes in the Reference case from *AEO2021,* which has an end year of 2050. To estimate price trends after 2050, DOE used the average annual rate of change in prices from 2020 through 2050. As part of the NIA, DOE also analyzed scenarios that used inputs from variants of the *AEO2021* Reference case that have lower and higher economic growth. Those cases have lower and higher energy price trends compared to the Reference case. NIA results based on these cases are presented in appendix 10C of the NOPR TSD.

In calculating the NPV, DOE multiplies the net savings in future years by a discount factor to determine their present value. For this NOPR, DOE estimated the NPV of consumer benefits using both a 3-percent and a 7-percent real discount rate. DOE uses these discount rates in accordance with guidance provided by the Office of Management and Budget (''OMB'') to Federal agencies on the development of regulatory analysis.[96] The discount rates for the determination of NPV are in contrast to the discount rates used in the LCC analysis, which are designed to reflect a consumer's perspective. The 7-percent real value is an estimate of the average before-tax rate of return to private capital in the U.S. economy. The 3-percent real value represents the ''social rate of time preference,'' which is the rate at which society discounts future consumption flows to their present value.

I. Consumer Subgroup Analysis

In analyzing the potential impact of new or amended energy conservation standards on consumers, DOE evaluates the impact on identifiable subgroups of consumers that may be disproportionately affected by a new or amended national standard. The purpose of a subgroup analysis is to determine the extent of any such disproportional impacts. DOE evaluates impacts on particular subgroups of consumers by analyzing the LCC

[95] For more information on NEMS, refer to *The National Energy Modeling System: An Overview 2009,* DOE/EIA–0581(2009), October 2009. Available at *www.eia.gov/analysis/pdfpages/0581(2009)index.php* (last accessed September 2, 2021).

[96] United States Office of Management and Budget. *Circular A–4: Regulatory Analysis.* September 17, 2003. Section E. Available at *obamawhitehouse.archives.gov/omb/circulars_a004_a-4/* (last accessed September 23, 2021).

impacts and PBP for those particular consumers from alternative standard levels. For this NOPR, DOE analyzed the impacts of the considered standard levels on one subgroup:[97] senior-only households. The analysis used subsets of the RECS 2015 sample composed of households that meet the criteria for the subgroup. DOE used the LCC and PBP spreadsheet model to estimate the impacts of the considered efficiency levels on this subgroup. Chapter 11 in the NOPR TSD describes the consumer subgroup analysis.

J. Manufacturer Impact Analysis

1. Overview

DOE performed an MIA to estimate the financial impacts of amended energy conservation standards on manufacturers of DPPP motors and to estimate the potential impacts of such standards on employment and manufacturing capacity. The MIA has both quantitative and qualitative aspects and includes analyses of projected industry cash flows, the INPV, investments in research and development (''R&D'') and manufacturing capital, and domestic manufacturing employment. Additionally, the MIA seeks to determine how amended energy conservation standards might affect manufacturing employment, capacity, and competition, as well as how standards contribute to overall regulatory burden. Finally, the MIA serves to identify any disproportionate impacts on manufacturer subgroups, including small business manufacturers.

The quantitative part of the MIA primarily relies on the Government Regulatory Impact Model (''GRIM''), an industry cash flow model with inputs specific to this rulemaking. The key GRIM inputs include data on the industry cost structure, unit production costs, product shipments, manufacturer markups, and investments in R&D and manufacturing capital required to produce compliant products. The key GRIM outputs are the INPV, which is the sum of industry annual cash flows over the analysis period, discounted using the industry-weighted average cost of capital, and the impact to domestic manufacturing employment. The model uses standard accounting principles to estimate the impacts of more-stringent energy conservation standards on a given industry by comparing changes in INPV and domestic manufacturing employment between a no-new-standards case and the various standards cases (''TSLs''). To capture the uncertainty relating to manufacturer pricing strategies following amended standards, the GRIM estimates a range of possible impacts under different markup scenarios.

The qualitative part of the MIA addresses manufacturer characteristics and market trends. Specifically, the MIA considers such factors as a potential standard's impact on manufacturing capacity, competition within the industry, the cumulative impact of other DOE and non-DOE regulations, and impacts on manufacturer subgroups. The complete MIA is outlined in chapter 12 of the NOPR TSD.

DOE conducted the MIA for this proposed rulemaking in three phases. In Phase 1 of the MIA, DOE prepared a profile of the DPPP motors manufacturing industry based on the market and technology assessment, preliminary manufacturer interviews, and publicly-available information. This included a top-down analysis of DPPP motors manufacturers that DOE used to derive preliminary financial inputs for the GRIM (*e.g.,* revenues; materials, labor, overhead, and depreciation expenses; selling, general, and administrative expenses (''SG&A''); and R&D expenses). DOE also used public sources of information to further calibrate its initial characterization of the DPPP motors manufacturing industry, including company filings of form 10–K from the SEC,[98] corporate annual reports, the U.S. Census Bureau's *Economic Census,*[99] and reports from D&B Hoovers.[100]

In Phase 2 of the MIA, DOE prepared a framework industry cash-flow analysis to quantify the potential impacts of energy conservation standards. The GRIM uses several factors to determine a series of annual cash flows starting with the announcement of the standard and extending over a 30-year period following the compliance date of the standard. These factors include annual expected revenues, costs of sales, SG&A and R&D expenses, taxes, and capital expenditures. In general, energy conservation standards can affect manufacturer cash flow in three distinct ways: (1) creating a need for increased investment, (2) raising production costs per unit, and (3) altering revenue due to higher per-unit prices and changes in sales volumes.

In addition, during Phase 2, DOE developed interview guides to distribute to manufacturers of DPPP motors in order to develop other key GRIM inputs, including product and capital conversion costs, and to gather additional information on the anticipated effects of energy conservation standards on revenues, direct employment, capital assets, industry competitiveness, and subgroup impacts.

In Phase 3 of the MIA, DOE conducted structured, detailed interviews with representative manufacturers. During these interviews, DOE discussed engineering, manufacturing, procurement, and financial topics to validate assumptions used in the GRIM and to identify key issues or concerns. See section IV.J.3 of this document for a description of the key issues raised by manufacturers during the interviews. As part of Phase 3, DOE also evaluated subgroups of manufacturers that may be disproportionately impacted by amended standards or that may not be accurately represented by the average cost assumptions used to develop the industry cash flow analysis. Such manufacturer subgroups may include small business manufacturers, low-volume manufacturers, niche players, and/or manufacturers exhibiting a cost structure that largely differs from the industry average. DOE identified one subgroup for a separate impact analysis: small business manufacturers. The small business subgroup is discussed in section VI.B, ''Review under the Regulatory Flexibility Act'' and in chapter 12 of the NOPR TSD.

2. Government Regulatory Impact Model and Key Inputs

DOE uses the GRIM to quantify the changes in cash flow due to amended standards that result in a higher or lower industry value. The GRIM uses a standard, annual discounted cash-flow analysis that incorporates manufacturer costs, markups, shipments, and industry financial information as inputs. The GRIM models changes in costs, distribution of shipments, investments, and manufacturer margins that could result from an amended energy conservation standard. The GRIM spreadsheet uses the inputs to arrive at a series of annual cash flows, beginning in 2021 (the reference year of the analysis) and continuing to 2055. DOE calculated INPVs by summing the stream of annual discounted cash flows during this period. For manufacturers of residential central air conditioners and heat pumps, DOE used a real discount rate of 7.2 percent, which was derived from industry financials and then modified according to feedback received during manufacturer interviews.

[97] DOE did not evaluate low-income consumer subgroup impacts because the sample size of the subgroup is too small for meaningful analysis.

[98] *See www.sec.gov/edgar.shtml.*

[99] *See www.census.gov/programs-surveys/asm/data.html.*

[100] *See https://app.dnbhoovers.com.*

The GRIM calculates cash flows using standard accounting principles and compares changes in INPV between the no-new-standards case and each standards case. The difference in INPV between the no-new-standards case and a standards case represents the financial impact of the amended energy conservation standard on manufacturers. As discussed previously, DOE developed critical GRIM inputs using a number of sources, including publicly available data, results of the engineering analysis, and information gathered from industry stakeholders during the course of manufacturer interviews and subsequent Working Group meetings. The GRIM results are presented in section V.B.2 of this document. Additional details about the GRIM, the discount rate, and other financial parameters can be found in chapter 12 of the NOPR TSD.

a. Manufacturer Production Costs

Manufacturing more efficient equipment is typically more expensive than manufacturing baseline equipment due to the use of more complex components, which are typically more costly than baseline components. The changes in the MPCs of covered products can affect the revenues, gross margins, and cash flow of the industry.

DOE used data from the January 2017 Direct Final Rule to determine the MSP of DPPP motors. Specifically, DOE used Table 5.7.1 of the January 2017 Direct Final Rule TSD, which estimated the MSPs of DPPP motors used in the analysis.[101] DOE adjusted the MSPs used in the January 2017 Direct Final Rule from 2015$ into 2020$. DOE also conducted physical teardowns to determine updated DPPP motor controller costs for variable-speed motors. However, DOE did not include these costs in the MIA as the motor controller costs are typically manufactured by the DPPP manufacturers not by the DPPP motor manufacturers. The MPCs and MSPs used in this MIA only account for the DPPP motors covered by this proposed rulemaking.

For a complete description of the MPCs, see chapter 5 of the NOPR TSD.

b. Shipments Projections

The GRIM estimates manufacturer revenues based on total unit shipment projections and the distribution of those shipments by efficiency level. Changes in sales volumes and efficiency mix over time can significantly affect manufacturer finances. For this analysis, the GRIM uses the NIA's annual shipment projections derived from the shipments analysis from 2021 (the reference year) to 2055 (the end year of the analysis period). See chapter 9 of the NOPR TSD for additional details.

c. Product and Capital Conversion Costs

Energy conservation standards could cause manufacturers to incur conversion costs to bring their production facilities and equipment designs into compliance. DOE evaluated the level of conversion-related expenditures that would be needed to comply with each considered efficiency level in each product class. For the MIA, DOE classified these conversion costs into two major groups: (1) product conversion costs; and (2) capital conversion costs. Product conversion costs are investments in research, development, testing, marketing, and other non-capitalized costs necessary to make product designs comply with amended energy conservation standards. Capital conversion costs are investments in property, plant, and equipment necessary to adapt or change existing production facilities such that new compliant product designs can be fabricated and assembled.

DOE assumed that DPPP motor manufacturers would not incur any capital conversion costs for efficiency levels that single-speed or dual-speed motors would be able to meet. The same production equipment currently used to manufacture single-speed and dual-speed motors would still be able to be used to manufacture more efficient single- and dual-speed motors. However, DOE did assume that DPPP motor manufacturers would incur capital conversion costs at efficiency levels that variable-speed motors would be needed to meet the analyzed energy conservation standards.

Additional production equipment would be needed to manufacture both additional variable-speed motor models and a larger production volume of variable-speed motors than are currently being produced. DOE used feedback from manufacturer interviews to estimate the cost of adding a production line to manufacture variable-speed motors. DOE then estimated the number of additional variable-speed production lines needed at each TSL, based on the increase in variable-speed shipments estimated at the analyzed TSL and the number of DPPP motor manufacturers that would need to introduce variable-speed motor models to meet the analyzed TSL.

DOE assumed that DPPP motor manufacturers would not incur any additional product conversion costs for the standard size equipment classes. All DPPP motor manufacturers currently manufacture multiple variable-speed motor models in the standard size equipment classes. Additionally, the current DOE energy conservation standard for DPPPs[102] that most commonly use the standard size DPPP motors use variable-speed motors to meet those efficiency requirements. Therefore, almost all standard size DPPP motors sold as part of a new DPPP are already variable-speed motors. However, DOE did assume that DPPP motor manufacturers would incur product conversion costs for the other equipment classes at each analyzed efficiency level.

Additional DPPP motor models would need to be introduced for the extra small-size and small-size DPPP motor equipment classes at each efficiency level analyzed. To evaluate the level of product conversion costs manufacturers would likely incur to comply with the analyzed energy conservation standards for these equipment classes, DOE used a model database to estimate the number of DPPP motor models that would have to be redesigned at each efficiency level for each equipment class. DOE estimated a redesign effort of 2 months of engineering time per model to redesign a less efficient single-speed DPPP motor into a single-speed DPPP motor capable of meeting the analyzed energy conservation standards. DOE estimated a redesign effort of 6 months of engineering time per model to redesign a single-speed or less efficient dual-speed DPPP motor into a dual-speed DPPP motor capable of meeting the analyzed energy conservation standards. Lastly, DOE estimated a redesign effort of 24 months of four engineers for DPPP motor manufacturers that do not currently produce small-size DPPP variable-speed motors to introduce one variable-speed DPPP motor model, for the analyzed energy conservation standards that would require variable-speed DPPP motor for the small-size equipment classes.

In general, DOE assumes all conversion-related investments occur between the year of publication of the final rule and the year by which manufacturers must comply with the new standard. The conversion cost figures used in the GRIM can be found in Table IV.15 and Table IV.16 and in

[101] Table 5.7.1 of the January 2017 Direct Final Rule lists DPPP motor prices as MPCs. This is because the January 2017 Direct Final Rule was for DPPPs, not DPPP motors. In the January 2017 Direct Final Rule, the selling price of the DPPP motors was part of the production costs for DPPP manufacturers. However, in this analysis the selling price of the DPPP motors is the MSP for DPPP motor manufacturers.

[102] 82 FR 5650 (January 18, 2017), compliance date of July 19, 2021.

section V.B.2.a of this document. For additional information on the estimated capital and product conversion costs, see chapter 12 of the NOPR TSD.

TABLE IV.15—DPPP MOTOR MANUFACTURER CAPITAL CONVERSION COSTS

	Equipment class	Efficiency level					
		EL 1	EL 2	EL 3	EL 4	EL 5	EL 6
Capital Conversion Costs (2020$ millions)	Extra Small (<0.5 THP)						
	Small (0.5 ≤ THP < 1.15)						20.0
	Standard (1.15 ≤ THP)						17.5

TABLE IV.16—DPPP MOTOR MANUFACTURER PRODUCT CONVERSION COSTS

	Equipment class	Efficiency level					
		EL 1	EL 2	EL 3	EL 4	EL 5	EL 6
Product Conversion Costs *(2020$ millions)*.	Extra Small (<0.5 THP)	0.0	0.2				
	Small (0.5 ≤ THP < 1.15)	0.1	0.6	3.9	4.0	4.3	8.7
	Standard (1.15 ≤ THP)						

d. Markup Scenarios

MSPs include direct manufacturing production costs (*i.e.,* labor, materials, and overhead estimated in DOE's MPCs) and all non-production costs (*i.e.,* SG&A, R&D, and interest), along with profit. To calculate the MSPs in the GRIM, DOE applied non-production cost markups to the MPCs estimated in the engineering analysis for each product class and efficiency level. Modifying these markups in the standards case yields different sets of impacts on manufacturers. For the MIA, DOE modeled two standards-case markup scenarios to represent uncertainty regarding the potential impacts on prices and profitability for manufacturers following the implementation of amended energy conservation standards: (1) a preservation of gross margin percentage markup scenario; and (2) a preservation of per-unit operating profit markup scenario. These scenarios lead to different markup values that, when applied to the MPCs, result in varying revenue and cash flow impacts.

Under the preservation of gross margin percentage scenario, DOE applied a single uniform ''gross margin percentage'' markup across all efficiency levels, which assumes that manufacturers would be able to maintain the same amount of profit as a percentage of revenues at all efficiency levels within a product class. Based on publicly available financial information for DPPP motor manufacturers and information obtained during manufacturer interviews, DOE assumed the non-production cost manufacturer markup—which includes SG&A expenses, R&D expenses, interest, and profit—to be 1.37. This manufacturer markup is consistent with the manufacturer markup DOE used in the engineering analysis (see section IV.C). Therefore, DOE assumes that this scenario represents the upper bound to industry profitability under energy conservation standards.

Under the preservation of per-unit operating profit markup scenario, DOE modeled a situation in which manufacturers are not able to increase per-unit operating profit in proportion to increases in manufacturer production costs. Under this scenario, as the MPCs increase, manufacturers are generally required to reduce the manufacturer markup to maintain a cost competitive offering in the market. Therefore, gross margin (as a percentage) shrinks in the standards cases. This manufacturer markup scenario represents the lower bound to industry profitability under new energy conservation standards.

A comparison of industry financial impacts under the two markup scenarios is presented in section V.B.2.a of this document.

3. Manufacturer Interviews

DOE conducted manufacturer interviews prior to the publication of this NOPR. In these interviews, DOE asked manufacturers to describe their major concerns regarding this rulemaking. The following section highlights manufacturer concerns that helped inform the projected potential impacts of new energy conservation standards on the industry. Manufacturer interviews are conducted under non-disclosure agreements (''NDAs''), so DOE does not document these discussions in the same way that it does public comments in the comment summaries and DOE's responses throughout the rest of this document.

Some manufacturers stated they only produce single-speed and dual-speed motors within the small-size equipment class (0.5 ≤ THP < 1.15) and no longer supply DPPP motors used in new DPPP in that range to the California market after the CEC standard took effect. These manufacturers stated that they would need to design variable-speed motor models to meet any energy conservation standard that would require a variable-speed motor for the small-size equipment class. Additionally, these manufacturers would need to build additional production lines or make significant changes to existing single-speed or dual-speed production lines to be able to meet energy conservation standards requiring variable-speed DPPP motors for this equipment class. DOE included the capital and product conversion costs necessary for these DPPP motor manufacturers to introduce variable-speed DPPP motor models for the small-size equipment class.

K. Emissions Analysis

The emissions analysis consists of two components. The first component estimates the effect of potential energy conservation standards on power sector and site (where applicable) combustion emissions of CO_2, NO_X, SO_2, and Hg. The second component estimates the impacts of potential standards on emissions of two additional greenhouse gases, CH_4 and N_2O, as well as the reductions to emissions of other gases due to ''upstream'' activities in the fuel production chain. These upstream activities comprise extraction, processing, and transporting fuels to the site of combustion.

The analysis of electric power sector emissions of CO_2, NO_X, SO_2, and Hg uses emissions factors intended to represent the marginal impacts of the change in electricity consumption associated with amended or new standards. The methodology is based on results published for the *AEO,* including a set of side cases that implement a variety of efficiency-related policies. The methodology is described in appendix 13A in the NOPR TSD. The analysis presented in this proposed rulemaking uses projections from *AEO2021.* Power sector emissions of CH_4 and N_2O from fuel combustion are estimated using Emission Factors for Greenhouse Gas Inventories published by the EPA.[103]

FFC upstream emissions, which include emissions from fuel combustion during extraction, processing, and transportation of fuels, and ''fugitive'' emissions (direct leakage to the atmosphere) of CH_4 and CO_2, are estimated based on the methodology described in chapter 15 of the NOPR TSD.

The emissions intensity factors are expressed in terms of physical units per MWh or MMBtu of site energy savings. For power sector emissions, specific emissions intensity factors are calculated by sector and end use. Total emissions reductions are estimated using the energy savings calculated in the national impact analysis.

1. Air Quality Regulations Incorporated in DOE's Analysis

DOE's no-new-standards case for the electric power sector reflects the *AEO,* which incorporates the projected impacts of existing air quality regulations on emissions. *AEO2021* generally represents current legislation and environmental regulations, including recent government actions, that were in place at the time of preparation of *AEO2021,* including the emissions control programs discussed in the following paragraphs.[104]

SO_2 emissions from affected electric generating units (''EGUs'') are subject to nationwide and regional emissions cap-and-trade programs. Title IV of the Clean Air Act sets an annual emissions cap on SO_2 for affected EGUs in the 48 contiguous States and the District of Columbia (DC). (42 U.S.C. 7651 *et seq.*) SO_2 emissions from numerous States in the eastern half of the United States are also limited under the Cross-State Air Pollution Rule (''CSAPR''). 76 FR 48208 (Aug. 8, 2011). CSAPR requires these States to reduce certain emissions, including annual SO_2 emissions, and went into effect as of January 1, 2015.[105] *AEO2021* incorporates implementation of CSAPR, including the update to the CSAPR ozone season program emission budgets and target dates issued in 2016. 81 FR 74504 (Oct. 26, 2016). Compliance with CSAPR is flexible among EGUs and is enforced through the use of tradable emissions allowances. Under existing EPA regulations, any excess SO_2 emissions allowances resulting from the lower electricity demand caused by the adoption of an efficiency standard could be used to permit offsetting increases in SO_2 emissions by another regulated EGU.

However, beginning in 2016, SO_2 emissions began to fall as a result of the Mercury and Air Toxics Standards (''MATS'') for power plants. 77 FR 9304 (Feb. 16, 2012). In the MATS final rule, EPA established a standard for hydrogen chloride as a surrogate for acid gas hazardous air pollutants (''HAP''), and also established a standard for SO_2 (a non-HAP acid gas) as an alternative equivalent surrogate standard for acid gas HAP. The same controls are used to reduce HAP and non-HAP acid gas; thus, SO_2 emissions are being reduced as a result of the control technologies installed on coal-fired power plants to comply with the MATS requirements for acid gas. In order to continue operating, coal power plants must have either flue gas desulfurization or dry sorbent injection systems installed. Both technologies, which are used to reduce acid gas emissions, also reduce SO_2 emissions. Because of the emissions reductions under the MATS, it is unlikely that excess SO_2 emissions allowances resulting from the lower electricity demand would be needed or used to permit offsetting increases in SO_2 emissions by another regulated EGU. Therefore, energy conservation standards that decrease electricity generation would generally reduce SO_2 emissions. DOE estimated SO_2 emissions reduction using emissions factors based on *AEO2021.*

CSAPR also established limits on NO_X emissions for numerous States in the eastern half of the United States. Energy conservation standards would have little effect on NO_X emissions in those States covered by CSAPR emissions limits if excess NO_X emissions allowances resulting from the lower electricity demand could be used to permit offsetting increases in NO_X emissions from other EGUs. In such case, NOx emissions would remain near the limit even if electricity generation goes down. A different case could possibly result, depending on the configuration of the power sector in the different regions and the need for allowances, such that NO_X emissions might not remain at the limit in the case of lower electricity demand. In this case, energy conservation standards might reduce NOx emissions in covered States. Despite this possibility, DOE has chosen to be conservative in its analysis and has maintained the assumption that standards will not reduce NO_X emissions in States covered by CSAPR. Energy conservation standards would be expected to reduce NO_X emissions in the States not covered by CSAPR. DOE used *AEO2021* data to derive NO_X emissions factors for the group of States not covered by CSAPR.

The MATS limit mercury emissions from power plants, but they do not include emissions caps and, as such, DOE's energy conservation standards would be expected to slightly reduce Hg emissions. DOE estimated mercury emissions reduction using emissions factors based on *AEO2021,* which incorporates the MATS.

L. Monetizing Emissions Impacts

As part of the development of this proposed rule, for the purpose of complying with the requirements of Executive Order 12866, DOE considered the estimated monetary benefits from the reduced emissions of CO_2, CH_4, N_2O, NO_X, and SO_2 that are expected to result from each of the TSLs considered. In order to make this calculation analogous to the calculation of the NPV of consumer benefit, DOE considered the reduced emissions expected to result over the lifetime of products shipped in the projection period for each TSL. This section summarizes the basis for the values used for monetizing the emissions benefits and presents the values considered in this NOPR.

On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22–30087)

[103] Available at *www.epa.gov/sites/production/files/2021-04/documents/emission-factors_apr2021.pdf* (last accessed July 12, 2021).

[104] For further information, see the Assumptions to *AEO2021* report that sets forth the major assumptions used to generate the projections in the Annual Energy Outlook. Available at *www.eia.gov/outlooks/aeo/assumptions/* (last accessed July 6, 2020).

[105] CSAPR requires states to address annual emissions of SO_2 and NO_X, precursors to the formation of fine particulate matter ($PM_{2.5}$) pollution, in order to address the interstate transport of pollution with respect to the 1997 and 2006 $PM_{2.5}$ National Ambient Air Quality Standards (''NAAQS''). CSAPR also requires certain states to address the ozone season (May–September) emissions of NO_X, a precursor to the formation of ozone pollution, in order to address the interstate transport of ozone pollution with respect to the 1997 ozone NAAQS. 76 FR 48208 (Aug. 8, 2011). EPA subsequently issued a supplemental rule that included an additional five states in the CSAPR ozone season program; 76 FR 80760 (Dec. 27, 2011) (Supplemental Rule).

granted the federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana* v. *Biden,* No. 21–cv–1074–JDC–KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from ''adopting, employing, treating as binding, or relying upon'' the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and present monetized benefits where appropriate and permissible under law. DOE requests comment on how to address the climate benefits and other non-monetized effects of the proposal.

1. Monetization of Greenhouse Gas Emissions

DOE estimates the monetized benefits of the reductions in emissions of CO_2, CH_4, and N_2O by using a measure of the SC of each pollutant (*e.g.,* SC–CO_2). These estimates represent the monetary value of the net harm to society associated with a marginal increase in emissions of these pollutants in a given year, or the benefit of avoiding that increase. These estimates are intended to include (but are not limited to) climate-change-related changes in net agricultural productivity, human health, property damages from increased flood risk, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services.

DOE exercises its own judgment in presenting monetized climate benefits as recommended by applicable Executive orders and DOE would reach the same conclusion presented in this proposed rulemaking in the absence of the social cost of greenhouse gases, including the February 2021 Interim Estimates presented by the Interagency Working Group on the Social Cost of Greenhouse Gases. DOE estimated the global social benefits of CO_2, CH_4, and N_2O reductions (*i.e.,* SC–GHGs) using the estimates presented in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 published in February 2021 by the IWG. The SC–GHGs 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–GHGs 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–GHGs therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton. The SC–GHGs is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CO_2, N_2O and CH4 emissions. As a member of the IWG involved in the development of the February 2021 SC–GHG TSD, DOE 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 SC–GHGs estimates presented here were developed over many years, using transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. Specifically, in 2009, the IWG, that included the DOE and other executive branch agencies and offices was established to ensure that agencies were using the best available science and to promote consistency in the social cost of carbon (SC–CO_2) values used across agencies. The IWG published SC–CO_2 estimates in 2010 that were developed from an ensemble of three widely cited integrated assessment models (IAMs) that estimate global climate damages using highly aggregated representations of climate processes and the global economy combined into a single modeling framework. The three IAMs were run using a common set of input assumptions in each model for future population, economic, and CO_2 emissions growth, as well as equilibrium climate sensitivity—a measure of the globally averaged temperature response to increased atmospheric CO_2 concentrations. These estimates were updated in 2013 based on new versions of each IAM. In August 2016 the IWG published estimates of the social cost of methane (SC–CH_4) and nitrous oxide (SC–N_2O) using methodologies that are consistent with the methodology underlying the SC–CO_2 estimates. The modeling approach that extends the IWG SC–CO_2 methodology to non-CO_2 GHGs has undergone multiple stages of peer review. The SC–CH_4 and SC–N_2O estimates were developed by Marten *et al.*[106] and underwent a standard double-blind peer review process prior to journal publication. In 2015, as part of the response to public comments received to a 2013 solicitation for comments on the SC–CO_2 estimates, the IWG announced a National Academies of Sciences, Engineering, and Medicine review of the SC–CO_2 estimates to offer advice on how to approach future updates to ensure that the estimates continue to reflect the best available science and methodologies. In January 2017, the National Academies released their final report, Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide, and recommended specific criteria for future updates to the SC–CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process (National Academies, 2017).[107] Shortly thereafter, in March 2017, President Trump issued Executive Order 13783, which disbanded the IWG, withdrew the previous TSDs, and directed agencies to ensure SC–CO_2 estimates used in regulatory analyses are consistent with the guidance contained in OMB's Circular A–4, ''including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates'' (E.O. 13783, Section 5(c)). Benefit-cost analyses following E.O. 13783 used SC–GHG estimates that attempted to focus on the U.S.-specific share of climate change damages as estimated by the models and were calculated using two discount rates recommended by Circular A–4, 3 percent and 7 percent. All other methodological decisions and model versions used in SC–GHG calculations remained the same as those used by the IWG in 2010 and 2013, respectively.

On January 20, 2021, President Biden issued Executive Order 13990, which re-established the IWG and directed it to ensure that the U.S. Government's estimates of the social cost of carbon and other greenhouse gases reflect the best available science and the

[106] Marten, A.L., E.A. Kopits, C.W. Griffiths, S.C. Newbold, and A. Wolverton. Incremental CH4 and N2O mitigation benefits consistent with the US Government's SC–CO2 estimates. *Climate Policy.* 2015. 15(2): pp. 272–298.

[107] National Academies of Sciences, Engineering, and Medicine. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide.* 2017. The National Academies Press: Washington, DC.

recommendations of the National Academies (2017). The IWG was tasked with first reviewing the SC–GHG estimates currently used in Federal analyses and publishing interim estimates within 30 days of the E.O. that reflect the full impact of GHG emissions, including by taking global damages into account. The interim SC–GHG estimates published in February 2021 are used here to estimate the climate benefits for this proposed rulemaking. The E.O. instructs the IWG to undertake a fuller update of the SC–GHG estimates by January 2022 that takes into consideration the advice of the National Academies (2017) and other recent scientific literature. The February 2021 SC–GHG TSD provides a complete discussion of the IWG's initial review conducted under E.O.13990. In particular, the IWG found that the SC–GHG estimates used under E.O. 13783 fail to reflect the full impact of GHG emissions in multiple ways.

First, the IWG found that the SC–GHG estimates used under E.O. 13783 fail to fully capture many climate impacts that affect the welfare of U.S. citizens and residents, and those impacts are better reflected by global measures of the SC–GHG. Examples of omitted effects from the E.O. 13783 estimates include direct effects on U.S. citizens, assets, and investments located abroad, supply chains, U.S. military assets and interests abroad, and tourism, and spillover pathways such as economic and political destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns. In addition, assessing the benefits of U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating climate impacts that affect U.S. citizens and residents. A wide range of scientific and economic experts have emphasized the issue of reciprocity as support for considering global damages of GHG emissions. If the United States does not consider impacts on other countries, it is difficult to convince other countries to consider the impacts of their emissions on the United States. The only way to achieve an efficient allocation of resources for emissions reduction on a global basis—and so benefit the U.S. and its citizens—is for all countries to base their policies on global estimates of damages. As a member of the IWG involved in the development of the February 2021 SC–GHG TSD, DOE agrees with this assessment and, therefore, in this proposed rule DOE centers attention on a global measure of SC–GHG. This approach is the same as that taken in DOE regulatory analyses from 2012 through 2016. A robust estimate of climate damages to U.S. citizens and residents does not currently exist in the literature. As explained in the February 2021 TSD, existing estimates are both incomplete and an underestimate of total damages that accrue to the citizens and residents of the U.S. because they do not fully capture the regional interactions and spillovers discussed above, nor do they include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature. As noted in the February 2021 SC–GHG TSD, the IWG will continue to review developments in the literature, including more robust methodologies for estimating a U.S.-specific SC–GHG value, and explore ways to better inform the public of the full range of carbon impacts. As a member of the IWG, DOE will continue to follow developments in the literature pertaining to this issue.

Second, the IWG found that the use of the social rate of return on capital (7 percent under current OMB Circular A–4 guidance) to discount the future benefits of reducing GHG emissions inappropriately underestimates the impacts of climate change for the purposes of estimating the SC–GHG. Consistent with the findings of the National Academies (2017) and the economic literature, the IWG continued to conclude that the consumption rate of interest is the theoretically appropriate discount rate in an intergenerational context (IWG 2010, 2013, 2016a, 2016b),[108] and recommended that discount rate uncertainty and relevant aspects of intergenerational ethical considerations be accounted for in selecting future discount rates.

Furthermore, the damage estimates developed for use in the SC–GHG are estimated in consumption-equivalent terms, and so an application of OMB Circular A–4's guidance for regulatory analysis would then use the consumption discount rate to calculate the SC–GHG. DOE agrees with this assessment and will continue to follow developments in the literature pertaining to this issue. DOE also notes that while OMB Circular A–4, as published in 2003, recommends using 3% and 7% discount rates as ''default'' values, Circular A–4 also reminds agencies that ''different regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues and the sensitivity of the benefit and cost estimates to the key assumptions.'' On discounting, Circular A–4 recognizes that ''special ethical considerations arise when comparing benefits and costs across generations,'' and Circular A–4 acknowledges that analyses may appropriately ''discount future costs and consumption benefits . . . at a lower rate than for intragenerational analysis.'' In the 2015 Response to Comments on the Social Cost of Carbon for Regulatory Impact Analysis, OMB, DOE, and the other IWG members recognized that ''Circular A–4 is a living document'' and ''the use of 7 percent is not considered appropriate for intergenerational discounting. There is wide support for this view in the academic literature, and it is recognized in Circular A–4 itself.'' Thus, DOE concludes that a 7% discount rate is not appropriate to apply to value the social cost of greenhouse gases in the analysis presented in this analysis. In this analysis, to calculate the present and annualized values of climate benefits, DOE uses the same discount rate as the rate used to discount the value of damages from future GHG emissions, for internal consistency. That approach to discounting follows the same approach that the February 2021 TSD recommends ''to ensure internal consistency—*i.e.,* future damages from climate change using the SC–GHG at 2.5 percent should be discounted to the base year of the analysis using the same 2.5 percent rate.'' DOE has also consulted the National Academies' 2017 recommendations on how SC–GHG

[108] Interagency Working Group on Social Cost of Carbon. *Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866.* 2010. United States Government. (Last accessed April 15, 2022.) *www.epa.gov/sites/default/files/2016-12/documents/scc_tsd_2010.pdf*; Interagency Working Group on Social Cost of Carbon. *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.* 2013. (Last accessed April 15, 2022.) *www.federalregister.gov/documents/2013/11/26/2013-28242/technical-support-document-technical-update-of-the-social-cost-of-carbon-for-regulatory-impact*; Interagency Working Group on Social Cost of Greenhouse Gases, United States Government. Technical Support Document: Technical Update on the Social Cost of Carbon for Regulatory Impact Analysis-Under Executive Order 12866. August 2016. (Last accessed January 18, 2022.) *www.epa.gov/sites/default/files/2016-12/documents/sc_co2_tsd_august_2016.pdf*; Interagency Working Group on Social Cost of Greenhouse Gases, United States Government. Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide. August 2016. (Last accessed January 18, 2022.) *www.epa.gov/sites/default/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf.*

estimates can ''be combined in RIAs with other cost and benefits estimates that may use different discount rates.'' The National Academies reviewed ''several options,'' including ''presenting all discount rate combinations of other costs and benefits with [SC–GHG] estimates.''

As a member of the IWG involved in the development of the February 2021 SC–GHG TSD, DOE agrees with this assessment and will continue to follow developments in the literature pertaining to this issue. While the IWG works to assess how best to incorporate the latest, peer reviewed science to develop an updated set of SC–GHG estimates, it set the interim estimates to be the most recent estimates developed by the IWG prior to the group being disbanded in 2017. The estimates rely on the same models and harmonized inputs and are calculated using a range of discount rates. As explained in the February 2021 SC–GHG TSD, the IWG has recommended that agencies to revert to the same set of four values drawn from the SC–GHG distributions based on three discount rates as were used in regulatory analyses between 2010 and 2016 and subject to public comment. For each discount rate, the IWG combined the distributions across models and socioeconomic emissions scenarios (applying equal weight to each) and then selected a set of four values recommended for use in benefit-cost analyses: an average value resulting from the model runs for each of three discount rates (2.5 percent, 3 percent, and 5 percent), plus a fourth value, selected as the 95th percentile of estimates based on a 3 percent discount rate. The fourth value was included to provide information on potentially higher-than-expected economic impacts from climate change. As explained in the February 2021 SC–GHG TSD, and DOE agrees, this update reflects the immediate need to have an operational SC–GHG for use in regulatory benefit-cost analyses and other applications that was developed using a transparent process, peer-reviewed methodologies, and the science available at the time of that process. Those estimates were subject to public comment in the context of dozens of proposed rulemakings as well as in a dedicated public comment period in 2013.

There are a number of limitations and uncertainties associated with the SC–GHG estimates. First, the current scientific and economic understanding of discounting approaches suggests discount rates appropriate for intergenerational analysis in the context of climate change are likely to be less than 3 percent, near 2 percent or lower.[109] Second, the IAMs used to produce these interim estimates do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature and the science underlying their ''damage functions''—*i.e.,* the core parts of the IAMs that map global mean temperature changes and other physical impacts of climate change into economic (both market and nonmarket) damages—lags behind the most recent research. For example, limitations include the incomplete treatment of catastrophic and non-catastrophic impacts in the integrated assessment models, their incomplete treatment of adaptation and technological change, the incomplete way in which inter-regional and intersectoral linkages are modeled, uncertainty in the extrapolation of damages to high temperatures, and inadequate representation of the relationship between the discount rate and uncertainty in economic growth over long time horizons. Likewise, the socioeconomic and emissions scenarios used as inputs to the models do not reflect new information from the last decade of scenario generation or the full range of projections. The modeling limitations do not all work in the same direction in terms of their influence on the SC–CO_2 estimates. However, as discussed in the February 2021 TSD, the IWG has recommended that, taken together, the limitations suggest that the interim SC–GHG estimates used in this final rule likely underestimate the damages from GHG emissions. DOE concurs with this assessment.

DOE's derivations of the SC–GHG (SC–CO_2, SC–N_2O, and SC–CH_4) values used for this NOPR are discussed in the following sections, and the results of DOE's analyses estimating the benefits of the reductions in emissions of these GHGs are presented in section V.B.6 of this document.

a. Social Cost of Carbon

The SC–CO_2 values used for this NOPR were generated using the values presented in the 2021 update from the IWG's February 2021 SC–GHG TSD. Table IV.17 shows the updated sets of SC–CO_2 estimates from the latest interagency update in 5-year increments from 2020 to 2050. The full set of annual values used is presented in Appendix 14–A of the NOPR TSD. For purposes of capturing the uncertainties involved in regulatory impact analysis, DOE has determined it is appropriate include all four sets of SC–CO_2 values, as recommended by the IWG.[110]

TABLE IV.17—ANNUAL SC–CO_2 VALUES FROM 2021 INTERAGENCY UPDATE, 2020–2050

[2020$ per metric ton CO_2]

Year	Discount rate and statistic			
	5%	3%	2.5%	3%
	Average	Average	Average	95th percentile
2020	14	51	76	152
2025	17	56	83	169
2030	19	62	89	187
2035	22	67	96	206
2040	25	73	103	225
2045	28	79	110	242
2050	32	85	116	260

[109] Interagency Working Group on Social Cost of Greenhouse Gases (IWG). 2021. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. February. United States Government. Available at: <*https://www.whitehouse.gov/briefing-room/blog/2021/02/26/a-return-to-science-evidence-based-estimates-of-the-benefits-of-reducing-climate-pollution/*.

[110] For example, the February 2021 TSD discusses how the understanding of discounting approaches suggests that discount rates appropriate for intergenerational analysis in the context of climate change may be lower than 3 percent.

In calculating the potential global benefits resulting from reduced CO_2 emissions, DOE used the values from the February 2021 SC–GHG TSD, adjusted to 2020$ using the implicit price deflator for gross domestic product (''GDP'') from the Bureau of Economic Analysis. DOE derived values from 2051 to 2070 based on estimates published by EPA.[111] These estimates are based on methods, assumptions, and parameters identical to the 2020–2050 estimates published by the IWG. DOE derived values after 2070 based on the trend in 2060–2070 in each of the four cases (see appendix 14A).

DOE multiplied the CO_2 emissions reduction estimated for each year by the SC–CO_2 value for that year in each of the four cases. To calculate a present value of the stream of monetary values, DOE discounted the values in each of the four cases using the specific discount rate that had been used to obtain the SC–CO_2 values in each case.

b. Social Cost of Methane and Nitrous Oxide

The SC–CH_4 and SC–N_2O values used for this NOPR were generated using the values presented in the February 2021 SC–GHG TSD. Table IV.18 shows the updated sets of SC–CH_4 and SC–N_2O estimates from the latest interagency update in 5-year increments from 2020 to 2050. The full set of annual values used is presented in Appendix 14–A of the NOPR TSD. To capture the uncertainties involved in regulatory impact analysis, DOE has determined it is appropriate to include all four sets of SC–CH_4 and SC–N_2O values, as recommended by the IWG. DOE derived values after 2050 using the approach described above for the SC–CO_2.

TABLE IV.18—ANNUAL SC–CH_4 AND SC–N_2O VALUES FROM 2021 INTERAGENCY UPDATE, 2020–2050
[2020$ per metric ton]

Year	SC–CH_4				SC–N_2O			
	Discount rate and statistic				Discount rate and statistic			
	5%	3%	2.5%	3%	5%	3%	2.5%	3%
	Average	Average	Average	95th percentile	Average	Average	Average	95th percentile
2020	670	1,500	2,000	3,900	5,800	18,000	27,000	48,000
2025	800	1,700	2,200	4,500	6,800	21,000	30,000	54,000
2030	940	2,000	2,500	5,200	7,800	23,000	33,000	60,000
2035	1,100	2,200	2,800	6,000	9,000	25,000	36,000	67,000
2040	1,300	2,500	3,100	6,700	10,000	28,000	39,000	74,000
2045	1,500	2,800	3,500	7,500	12,000	30,000	42,000	81,000
2050	1,700	3,100	3,800	8,200	13,000	33,000	45,000	88,000

DOE multiplied the CH_4 and N_2O emissions reduction estimated for each year by the SC–CH_4 and SC–N_2O estimates for that year in each of the cases. To calculate a present value of the stream of monetary values, DOE discounted the values in each of the cases using the specific discount rate that had been used to obtain the SC–CH_4 and SC–N_2O estimates in each case.

2. Monetization of Other Emissions Impacts

For the NOPR, DOE estimated the monetized value of NO_X and SO_2 emissions reductions from electricity generation using the latest benefit per ton estimates from the EPA's Benefits Mapping and Analysis Program.[112] DOE used EPA's values for $PM_{2.5}$-related benefits associated with NO_X and SO_2 and for ozone-related benefits associated with NO_X for 2025, 2030 and 2040 calculated with discount rates of 3 percent and 7 percent. DOE used linear interpolation to define values for the years not given in the 2025 to 2040 period; for years beyond 2040 the values are held constant. DOE derived values specific to the sector for DPPP motors using a method described in appendix 14B of the NOPR TSD.

DOE multiplied the site emissions reduction (in tons) in each year by the associated $/ton values, and then discounted each series using discount rates of 3 percent and 7 percent as appropriate.

M. Utility Impact Analysis

The utility impact analysis estimates several effects on the electric power generation industry that would result from the adoption of new or amended energy conservation standards. The utility impact analysis estimates the changes in installed electrical capacity and generation that would result for each TSL. The analysis is based on published output from the NEMS associated with *AEO2021.* NEMS produces the *AEO* Reference case, as well as a number of side cases that estimate the economy-wide impacts of changes to energy supply and demand. For the current analysis, impacts are quantified by comparing the levels of electricity sector generation, installed capacity, fuel consumption and emissions in the *AEO2021* Reference case and various side cases. Details of the methodology are provided in the appendices to chapters 13 and 15 of the NOPR TSD.

The output of this analysis is a set of time-dependent coefficients that capture the change in electricity generation, primary fuel consumption, installed capacity and power sector emissions due to a unit reduction in demand for a given end use. These coefficients are multiplied by the stream of electricity savings calculated in the NIA to provide estimates of selected utility impacts of potential new or amended energy conservation standards.

N. Employment Impact Analysis

DOE considers employment impacts in the domestic economy as one factor in selecting a proposed standard. Employment impacts from new or amended energy conservation standards include both direct and indirect impacts. Direct employment impacts are any changes in the number of employees of manufacturers of the products subject to standards, their suppliers, and related service firms. The MIA addresses those impacts. Indirect employment impacts are changes in national employment that occur due to

[111] See EPA, *Revised 2023 and Later Model Year Light-Duty Vehicle GHG Emissions Standards: Regulatory Impact Analysis,* Washington, DC, December 2021. Available at: *https://www.epa.gov/system/files/documents/2021-12/420r21028.pdf* (last accessed January 13, 2022).

[112] *Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 21 Sectors.* December 2 2021. *www.epa.gov/benmap/estimating-benefit-ton-reducing-pm25-precursors-21-sectors.*

the shift in expenditures and capital investment caused by the purchase and operation of more-efficient appliances. Indirect employment impacts from standards consist of the net jobs created or eliminated in the national economy, other than in the manufacturing sector being regulated, caused by (1) reduced spending by consumers on energy, (2) reduced spending on new energy supply by the utility industry, (3) increased consumer spending on the products to which the new standards apply and other goods and services, and (4) the effects of those three factors throughout the economy.

One method for assessing the possible effects on the demand for labor of such shifts in economic activity is to compare sector employment statistics developed by the Labor Department's Bureau of Labor Statistics (''BLS''). BLS regularly publishes its estimates of the number of jobs per million dollars of economic activity in different sectors of the economy, as well as the jobs created elsewhere in the economy by this same economic activity. Data from BLS indicate that expenditures in the utility sector generally create fewer jobs (both directly and indirectly) than expenditures in other sectors of the economy.[113] There are many reasons for these differences, including wage differences and the fact that the utility sector is more capital-intensive and less labor-intensive than other sectors. Energy conservation standards have the effect of reducing consumer utility bills. Because reduced consumer expenditures for energy likely lead to increased expenditures in other sectors of the economy, the general effect of efficiency standards is to shift economic activity from a less labor-intensive sector (*i.e.,* the utility sector) to more labor-intensive sectors (*e.g.,* the retail and service sectors). Thus, the BLS data suggest that net national employment may increase due to shifts in economic activity resulting from energy conservation standards.

DOE estimated indirect national employment impacts for the standard levels considered in this NOPR using an input/output model of the U.S. economy called Impact of Sector Energy Technologies version 4 (''ImSET'').[114] ImSET is a special-purpose version of the ''U.S. Benchmark National Input-Output'' (''I–O'') model, which was designed to estimate the national employment and income effects of energy-saving technologies. The ImSET software includes a computer-based I–O model having structural coefficients that characterize economic flows among 187 sectors most relevant to industrial, commercial, and residential building energy use.

DOE notes that ImSET is not a general equilibrium forecasting model, and that there are uncertainties involved in projecting employment impacts, especially changes in the later years of the analysis. Because ImSET does not incorporate price changes, the employment effects predicted by ImSET may over-estimate actual job impacts over the long run for this rule. Therefore, DOE used ImSET only to generate results for near-term timeframes (2026–2031), where these uncertainties are reduced. For more details on the employment impact analysis, see chapter 16 of the NOPR TSD.

V. Analytical Results and Conclusions

The following section addresses the results from DOE's analyses with respect to the considered energy conservation standards for DPPP motors. It addresses the TSLs examined by DOE, the projected impacts of each of these levels if adopted as energy conservation standards for DPPP motors, and the standards levels that DOE is proposing to adopt in this NOPR. Additional details regarding DOE's analyses are contained in the NOPR TSD supporting this document.

A. Trial Standard Levels

In general, DOE typically evaluates potential amended standards for products and equipment by grouping individual efficiency levels for each class into TSLs. Use of TSLs allows DOE to identify and consider manufacturer cost interactions between the equipment classes, to the extent that there are such interactions, and market cross elasticity from consumer purchasing decisions that may change when different standard levels are set.

In the analysis conducted for this NOPR, DOE analyzed the benefits and burdens of eight TSLs for DPPP motors. DOE developed TSLs that combine specific efficiency levels for each of the DPPP motor equipment classes analyzed by DOE. The TSLs that were chosen in the NOPR represent DPPPM at maximum technologically feasible (''max-tech'') energy efficiency levels and similar performance (*i.e.,* variable-speed, 2-speed, multi-speed and/or single-speed). DOE presents the results for the TSLs in this document, while the results for all efficiency levels that DOE analyzed are in the NOPR TSD.

Table V.1 presents the TSLs and the corresponding efficiency levels that DOE has identified for potential amended energy conservation standards for DPPP motors. TSL 8 represents the maximum technologically feasible (''max-tech'') energy efficiency for all equipment classes, and freeze protection control requirements for DPPP motors greater than and equal to 0.5 THP. TSL 7 represents the California CEC standards[115] and includes a variable speed requirement for DPPP motors at or above 0.5 THP, an EL1 efficiency requirement below 0.5 THP, and freeze protection control requirements for DPPP motors greater than and equal to 0.5 THP. TSL 6 represents the performance requirements included in UL 1004–10:2022, which ensures DPPP motors operate similarly to motors in DPPPs that comply with the DOE standards at 10 CFR 431.465(f) and includes a variable speed requirement for DPPP motors at or above 1.15 THP, an EL1 efficiency requirement below 1.15 THP, and freeze protection control requirements for DPPP motors greater than and equal to 1.15 THP. TSL 5 represents the 2-speed/multi-speed DPPP motor EL 5 level DPPP motor for applicable equipment classes and freeze protection control requirements for DPPP motors greater than and equal to 0.5 THP. TSL 4 represents the 2-speed/multi-speed DPPP motor EL 4 level for applicable equipment classes and freeze protection control requirements for DPPP motors greater than and equal to 0.5 THP. TSL 3 represents the 2-speed/multi-speed DPPP motor EL 3 level for applicable equipment classes and freeze protection control requirements for DPPP motors greater than and equal to 0.5 THP. TSL 2 represents the highest efficiency single-speed DPPP motor level for all equipment classes. TSL 1 represents the medium efficiency single-speed DPPP motor level for all equipment classes.

[113] See U.S. Department of Commerce–Bureau of Economic Analysis. *Regional Multipliers: A User Handbook for the Regional Input-Output Modeling System (RIMS II).* 1997. U.S. Government Printing Office: Washington, DC. Available at *www.bea.gov/scb/pdf/regional/perinc/meth/rims2.pdf* (last accessed July 6, 2021).

[114] Livingston, O.V., S.R. Bender, M.J. Scott, and R.W. Schultz. *ImSET 4.0: Impact of Sector Energy Technologies Model Description and User Guide.* 2015. Pacific Northwest National Laboratory: Richland, WA. PNNL–24563.

[115] Best approximation based on the efficiency level analyzed.

TABLE V.1–TRIAL STANDARD LEVELS FOR DPPP MOTORS

TSL	TSL1	TSL2	TSL3	TSL4	TSL5	TSL6	TSL7	TSL8
Extra Small (<0.5 THP)	EL 1	EL 2	EL 2	EL 2	EL 2	EL 1	EL 1	EL 2.
Small Size (0.5 ≤ THP < 1.15)	EL 1	EL 2	EL 3*	EL 4*	EL 5*	EL 1	EL 6*	EL 6.*
Standard Size (1.15 ≤ THP ≤ 5)	EL 1	EL 2	EL 3*	EL 4*	EL 5*	EL 6*	EL 6*	EL 6.*

* Includes freeze protection control requirements.

B. Economic Justification and Energy Savings

1. Economic Impacts on Individual Consumers

DOE analyzed the economic impacts on DPPP motor consumers by considering the effects that potential standards at each TSL would have on the LCC and PBP. DOE also examined the impacts of potential standards on selected consumer subgroups. These analyses are discussed in the following sections.

a. Life-Cycle Cost and Payback Period

In general, higher-efficiency equipment affects consumers in two ways: (1) purchase price increases and (2) annual operating costs decrease. Inputs used for calculating the LCC and PBP include total installed costs (*i.e.,* equipment price plus installation costs), and operating costs (*i.e.,* annual energy use, energy prices, energy price trends, repair costs, and maintenance costs). The LCC calculation also uses product lifetime and a discount rate. Chapter 8 of the NOPR TSD provides detailed information on the LCC and PBP analyses.

Table V.2 through Table V.7 of this NOPR show the LCC and PBP results for the TSLs considered for the three DPPP motor equipment classes. In the first of each pair of tables, the simple payback is measured relative to the baseline equipment. In the second table, impacts are measured relative to the efficiency distribution in the no-new-standards case in the compliance year (see section IV.F.8 of this document). Because some consumers purchase products with higher efficiency in the no-new-standards case, the average savings are less than the difference between the average LCC of the baseline equipment and the average LCC at each TSL. The savings refer only to consumers who are affected by a standard at a given TSL. Those who already purchase a product with efficiency at or above a given TSL are not affected. Consumers for whom the LCC increases at a given TSL experience a net cost.

TABLE V.2–AVERAGE LCC AND PBP RESULTS FOR EXTRA SMALL-SIZE DPPP MOTORS

TSL	Efficiency level	Average costs (2020$)				Simple payback (years)	Average lifetime (years)
		Installed cost	First year's operating cost	Lifetime operating cost	LCC		
1, 6, 7	1	$61	$58	$192	$253	0.7	3.6
2–5, 8	2	92	53	175	267	2.1	3.6

Note: The results for each TSL are calculated assuming that all consumers use products at that efficiency level. The PBP is measured relative to the baseline product.

TABLE V.3—AVERAGE LCC SAVINGS RELATIVE TO THE NO-NEW-STANDARDS CASE FOR EXTRA SMALL-SIZE DPPP MOTORS

TSL	Efficiency level	Life-cycle cost savings	
		Average LCC savings* (2020$)	Percent of consumers that experience net cost (%)
1,6,7	1	$3	0
2–5,8	2	(6)	54

* The savings represent the average LCC for affected consumers.

TABLE V.4–AVERAGE LCC AND PBP RESULTS FOR SMALL-SIZE DPPP MOTORS

TSL	Efficiency level	Average costs (2020$)				Simple payback (years)	Average lifetime (years)
		Installed cost	First year's operating cost	Lifetime operating cost	LCC		
1, 6	1	$131	$205	$726	$857	0.3	4.5
2	2	162	186	660	822	0.7	4.5
3	3	308	199	721	1,029	3.3	4.5
4	4	330	171	620	950	2.5	4.5
5	5	354	162	586	940	2.5	4.5

TABLE V.4–AVERAGE LCC AND PBP RESULTS FOR SMALL-SIZE DPPP MOTORS—Continued

TSL	Efficiency level	Average costs (2020$)				Simple payback (years)	Average lifetime (years)
		Installed cost	First year's operating cost	Lifetime operating cost	LCC		
7, 8	6	493	92	358	852	2.3	4.5

Note: The results for each TSL are calculated assuming that all consumers use products at that efficiency level. The PBP is measured relative to the baseline product.

TABLE V.5—AVERAGE LCC SAVINGS RELATIVE TO THE NO-NEW-STANDARDS CASE FOR SMALL-SIZE DPPP MOTORS

TSL	Efficiency level	Life-cycle cost savings	
		Average LCC savings * (2020$)	Percent of consumers that experience net cost (%)
1, 6	1	$11	0
2	2	20	11
3	3	(38)	42
4	4	3	36
5	5	7	38
7,8	6	69	30

* The savings represent the average LCC for affected consumers.

TABLE V.6—AVERAGE LCC AND PBP RESULTS FOR STANDARD-SIZE DPPP MOTORS

TSL	Efficiency level	Average costs (2020$)				Simple payback (years)	Average lifetime (years)
		Installed cost	First year's operating cost	Lifetime operating cost	LCC		
1	1	$251	$576	$2,406	$2,657	0.4	4.5
2	2	282	531	2,218	2,500	0.5	4.5
3	3	444	358	1,515	1,958	0.7	4.5
4	4	472	317	1,341	1,813	0.7	4.5
5	5	502	286	1,210	1,712	0.7	4.5
6–8	6	609	246	1,086	1,695	0.9	4.5

Note: The results for each TSL are calculated assuming that all consumers use products at that efficiency level. The PBP is measured relative to the baseline product.

TABLE V.7—AVERAGE LCC SAVINGS RELATIVE TO THE NO-NEW-STANDARDS CASE FOR STANDARD-SIZE DPPP MOTORS

TSL	Efficiency level	Life-cycle cost savings	
		Average LCC savings * (2020$)	Percent of consumers that experience net cost
1	1	$32	0
2	2	50	0
3	3	120	15
4	4	156	13
5	5	176	13
6–8	6	292	2

* The savings represent the average LCC for affected consumers.

b. Consumer Subgroup Analysis

In the consumer subgroup analysis, DOE estimated the impact of the considered TSLs on senior-only households. Table V.8 through Table V.13 compare the average LCC savings and PBP at each efficiency level for the consumer subgroup, with similar metrics for the entire consumer sample for DPPP motors. The average LCC savings and PBP for senior-only households at the considered efficiency levels are not substantially different from the average for all households. Chapter 11 of the NOPR TSD presents the complete LCC and PBP results for the subgroup.

TABLE V.8—COMPARISON OF AVERAGE LCC SAVINGS AND PBP FOR CONSUMER SUBGROUP AND ALL HOUSEHOLDS FOR EQUIPMENT CLASS 1 EXTRA SMALL MOTORS

TSL	Average life-cycle cost savings (2020$)		Simple payback period (years)	
	Senior-only households	All households	Senior-only households	All households
1, 6, 7	$3	$3	0.7	0.7
2–5, 8	−6	−6	2.1	2.1

TABLE V.9—COMPARISON OF FRACTION OF CONSUMERS EXPERIENCING NET BENEFIT AND NET COST FOR CONSUMER SUBGROUP AND ALL HOUSEHOLDS FOR EQUIPMENT CLASS 1 EXTRA SMALL MOTORS

TSL	Percent of consumers that experience net cost (%)		Percent of consumers that experience net benefit (%)	
	Senior-only households	All households	Senior-only households	All households
1, 6, 7	0	0	8	8
2–5, 8	54	54	11	12

TABLE V.10—COMPARISON OF AVERAGE LCC SAVINGS AND PBP FOR CONSUMER SUBGROUP AND ALL HOUSEHOLDS FOR EQUIPMENT CLASS 2 SMALL MOTORS

TSL	Average life-cycle cost savings (2020$)		Simple payback period (years)	
	Senior-only households	All households	Senior-only Households	All households
1, 6	$11	$11	0.3	0.3
2	18	20	0.7	0.7
3	(40)	(38)	3.7	3.3
4	(2)	3	2.7	2.5
5	1	7	2.7	2.5
7,8	53	69	2.4	2.3

TABLE V.11—COMPARISON OF FRACTION OF CONSUMERS EXPERIENCING NET BENEFIT AND NET COST FOR CONSUMER SUBGROUP AND ALL HOUSEHOLDS FOR EQUIPMENT CLASS 2 SMALL MOTORS

TSL	Percent of consumers that experience net cost (%)		Percent of consumers that experience net benefit (%)	
	Senior-only households	All households	Senior-only households	All households
1, 6	0	0	6	6
2	11	11	25	25
3	42	42	10	10
4	36	36	16	16
5	38	38	18	18
7, 8	31	30	25	26

TABLE V.12—COMPARISON OF AVERAGE LCC SAVINGS AND PBP FOR CONSUMER SUBGROUP AND ALL HOUSEHOLDS FOR EQUIPMENT CLASS 3 STANDARD SIZE MOTORS

TSL	Average life-cycle cost savings (2020$)		Simple payback period (years)	
	Senior-only households	All households	Senior-only households	All households
1	$28	$32	0.4	0.4
2	45	50	0.5	0.5
3	108	120	0.8	0.7
4	140	156	0.8	0.7
5	157	176	0.8	0.7
6–8	259	292	1.0	0.9

TABLE V.13—COMPARISON OF FRACTION OF CONSUMERS EXPERIENCING NET BENEFIT AND NET COST FOR CONSUMER SUBGROUP AND ALL HOUSEHOLDS FOR EQUIPMENT CLASS 3 STANDARD SIZE MOTORS

TSL	Percent of consumers that experience net cost (%)		Percent of consumers that experience net benefit (%)	
	Senior-only households	All households	Senior-only households	All households
1	0	0	8	8
2	0	0	12	12
3	15	15	18	18
4	13	13	21	21
5	13	13	22	23
6–8	2	2	18	19

c. Rebuttable Presumption Payback

As discussed in section III.E.2 of this document, EPCA establishes a rebuttable presumption that an energy conservation standard is economically justified if the increased purchase cost for a product that meets the standard is less than three times the value of the first-year energy savings resulting from the standard. In calculating a rebuttable presumption payback period for each of the considered TSLs, DOE used discrete values, and, as required by EPCA, based the energy use calculation on the DOE test procedure for DPPP motors. In contrast, the PBPs presented in section V.B.1.a were calculated using distributions that reflect the range of energy use in the field.

Table V.14 presents the rebuttable-presumption payback periods for the considered TSLs for DPPP motors. While DOE examined the rebuttable-presumption criterion, it considered whether the standard levels considered for the NOPR are economically justified through a more detailed analysis of the economic impacts of those levels, pursuant to 42 U.S.C. 6295(o)(2)(B)(i), that considers the full range of impacts to the consumer, manufacturer, Nation, and environment. The results of that analysis serve as the basis for DOE to definitively evaluate the economic justification for a potential standard level, thereby supporting or rebutting the results of any preliminary determination of economic justification.

TABLE V.14—REBUTTABLE-PRESUMPTION PAYBACK PERIODS

[years]

Equipment class	Trial standard level							
	1	2	3	4	5	6	7	8
Extra-Small	0.8	2.4	2.4	2.4	2.4	0.8	0.8	2.4
Small-Size	0.3	0.7	3.0	2.4	2.4	0.3	2.9	2.9
Standard-Size	0.4	0.5	0.7	0.7	0.7	1.1	1.1	1.1

2. Economic Impacts on Manufacturers

DOE performed an MIA to estimate the impact of amended energy conservation standards on manufacturers of DPPP motors. The following section describes the expected impacts on manufacturers at each considered TSL. Chapter 12 of the NOPR TSD explains the analysis in further detail.

a. Industry Cash Flow Analysis Results

In this section, DOE provides GRIM results from the analysis, which examines changes in the industry that would result from a standard. Table V.15 and Table V.16 summarize the estimated financial impacts (represented by changes in INPV) of potential amended energy conservation standards on manufacturers of DPPP motors, as well as the conversion costs that DOE estimates manufacturers of DPPP motors would incur at each TSL.

As discussed in section IV.J.2.d of this document, DOE modeled two manufacturer markup scenarios to evaluate a range of cash flow impacts on the DPPP motor industry: (1) the preservation of gross margin percentage markup scenario and (2) the preservation of operating profit. DOE considered the preservation of gross margin percentage scenario by applying a ''gross margin percentage'' markup for each product class across all efficiency levels. As MPCs increase with efficiency, this scenario implies that the absolute dollar markup will increase. DOE assumed a manufacturer markup of 1.37 for DPPP motors. This manufacturer markup is with the same as the one DOE assumed in the engineering analysis and the no-new-standards case of the GRIM. Because this scenario assumes that a manufacturer's absolute dollar markup would increase as MPCs increase in the standards cases, it represents the upper-bound to industry profitability under potential new energy conservation standards.

The preservation of operating profit scenario reflects manufacturers' concerns about their inability to maintain margins as MPCs increase to reach more-stringent efficiency levels. In this scenario, while manufacturers make the necessary investments required to convert their facilities to produce compliant products, operating profit does not change in absolute dollars and decreases as a percentage of revenue.

Each of the modeled manufacturer markup scenarios results in a unique set of cash-flows and corresponding industry values at each TSL. In the following discussion, the INPV results refer to the difference in industry value between the no-new-standards case and each standards case resulting from the sum of discounted cash-flows from 2021 through 2055. To provide perspective on the short-run cash-flow impact, DOE includes in the discussion of results a comparison of free cash flow between the no-new-standards case and the standards case at each TSL in the year before new standards are required.

TABLE V.15—MANUFACTURER IMPACT ANALYSIS FOR DPPP MOTORS UNDER THE PRESERVATION OF GROSS MARGIN MARKUP SCENARIO

	Units	No-new-standards case	Trial standard level *							
			1	2	3	4	5	6	7	8
INPV	2020$ millions	798	800	804	823	829	835	826	901	901
Change in INPV	2020$ millions		1.8	6.3	25.3	31.1	37.7	28.4	102.9	103.6
	%		0.2	0.8	3.2	3.9	4.7	3.6	12.9	13.0
Product Conversion Costs	2020$ millions		0.1	0.8	6.2	6.2	6.5	0.1	8.7	8.8
Capital Conversion Costs	2020$ millions				6.4	6.4	6.4	15.4	37.5	37.5
Total Investment Required **	2020$ millions		0.1	0.8	12.6	12.6	12.9	15.5	46.2	46.3

* Numbers in parentheses indicate a negative number.
** Numbers may not sum exactly due to rounding.

TABLE V.16—MANUFACTURER IMPACT ANALYSIS FOR DPPP MOTORS UNDER THE PRESERVATION OF GROSS MARGIN MARKUP SCENARIO

	Units	No-new-standards case	Trial standard level *							
			1	2	3	4	5	6	7	8
INPV	2020$ millions	798	797	795	770	768	765	704	608	608
Change in INPV	2020$ millions		(0.6)	(3.0)	(28.0)	(30.1)	(32.8)	(93.4)	(189.3)	(189.7)
	%		(0.1)	(0.4)	(3.5)	(3.8)	(4.1)	(11.7)	(23.7)	(23.8)
Product Conversion Costs	2020$ millions		0.1	0.8	6.2	6.2	6.5	0.1	8.7	8.8
Capital Conversion Costs	2020$ millions				6.4	6.4	6.4	15.4	37.5	37.5
Total Investment Required **	2020$ millions		0.1	0.8	12.6	12.6	12.9	15.5	46.2	46.3

* Numbers in parentheses indicate a negative number.
** Numbers may not sum exactly due to rounding.

At TSL 1, DOE estimates that impacts on INPV will range from −$0.6 million to $1.8 million, or a change in INPV of −0.1 to 0.2 percent. At TSL 1, industry free cash-flow is $33.8 million, which is a decrease of less than $0.1 million compared to the no-new-standards case value of $33.9 million in 2025, the year leading up to the proposed standards.

TSL 1 would set the energy conservation standard for all equipment classes at EL 1. DOE estimates that 93 percent of extra small size DPPP motors, 95 percent of small size DPPP motors, and 87 percent of standard size DPPP motors already meet or exceed the efficiency levels analyzed at TSL 1. At TSL 1, DOE estimates that manufacturers will incur approximately $0.1 million in product conversion costs, as some single speed DPPP motor models will need to be redesigned to comply with the standard. DOE also estimates that DPPP motor manufacturers will incur minimal to no capital conversion costs at TSL 1.

At TSL 1, the shipment-weighted average MPC for all DPPP motors increases by 1.0 percent relative to the no-new-standards case shipment-weighted average MPC for all DPPP motors in 2026. In the preservation of gross margin markup scenario, manufacturers are able to fully pass on this slight cost increase to consumers. The slight increase in shipment-weighted average MPC for DPPP motors outweighs the $0.1 million in conversion costs, causing a slightly positive change in INPV at TSL 1 under the preservation of gross margin markup scenario.

Under the preservation of operating profit markup scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments. In this scenario, the 1.0 percent shipment-weighted average MPC increase results in a reduction in the manufacturer markup after the analyzed compliance year. This reduction in the manufacturer markup and the $0.1 million in conversion costs incurred by manufacturers cause a slightly negative change in INPV at TSL 1 under the preservation of operating profit markup scenario.

At TSL 2, DOE estimates that impacts on INPV will range from −$3.0 million to $6.3 million, or a change in INPV of −0.4 percent to 0.8 percent. At TSL 2, industry free cash-flow is $33.6 million, which is a decrease of approximately $0.3 million compared to the no-new-standards case value of $33.9 million in 2025, the year leading up to the proposed standards.

TSL 2 would set all equipment classes at EL 2, which is max-tech for the extra small size DPPP motors. DOE estimates 33 percent of extra small size DPPP motors, 73 percent of small size DPPP motors, and 81 percent of standard size DPPP motors already meet or exceed the efficiency levels analyzed at TSL 2. At TSL 2, DOE estimates that manufacturers will incur approximately $0.8 million in product conversion costs, as many single speed DPPP motor models will need to be redesigned to comply with the set efficiency level. DOE also estimates that DPPP motor manufacturers will incur minimal to no capital conversion costs at TSL 2.

At TSL 2, the shipment-weighted average MPC for all DPPP motors increases by 2.8 percent relative to the no-new-standards case shipment-weighted average MPC for all DPPP motors in 2026. In the preservation of gross margin markup scenario, the slight increase in shipment-weighted average MPC for DPPP motors outweighs the $0.8 million in conversion costs, causing a slightly positive change in INPV at TSL 2 under the preservation of gross margin markup scenario.

Under the preservation of operating profit markup scenario, the 2.8 percent shipment-weighted average MPC increase results in a reduction in the manufacturer markup after the analyzed compliance year. This reduction in the manufacturer markup and the $0.8 million in conversion costs incurred by manufacturers cause a slightly negative change in INPV at TSL 2 under the preservation of operating profit markup scenario.

At TSL 3, DOE estimates that impacts on INPV will range from −$28.0 million to $25.3 million, or a change in INPV of −3.5 percent to 3.2 percent. At TSL 3, industry free cash-flow is $28.8 million, which is a decrease of approximately $5.1 million compared to the no-new-standards case value of $33.9 million in 2025, the year leading up to the proposed standards.

TSL 3 would set extra small size DPPP motors at EL 2 (max-tech) and set EL 3 for small and standard size DPPP motors. DOE estimates that 33 percent of extra small size DPPP motors, 44 percent of small size DPPP motors, and 70 percent of standard size DPPP motors already meet or exceed the efficiency levels analyzed at TSL 3. At TSL 3, DOE estimates that manufacturers will incur approximately $6.2 million in product conversion costs, as small and standard sized single speed DPPP motors will most likely be unable to comply with the standard and would need to be redesigned into dual-speed or variable-speed DPPP motor models. DOE also estimates that DPPP motor manufacturers will incur $6.4 million in capital conversion costs at TSL 3, to accommodate this increase in dual-speed and variable-speed DPPP motor manufacturing production capacity.

At TSL 3, the shipment-weighted average MPC for all DPPP motors increases by 11.5 percent relative to the no-new-standards case shipment-weighted average MPC for all DPPP motors in 2026. In the preservation of gross margin markup scenario, the moderate increase in shipment-weighted average MPC for DPPP motors outweighs the $12.6 million in conversion costs, causing a slightly positive change in INPV at TSL 3 under the preservation of gross margin markup scenario.

Under the preservation of operating profit markup scenario, the moderate 11.5 percent shipment-weighted average MPC increase results in a reduction in the manufacturer markup after the analyzed compliance year. This reduction in the manufacturer markup and the $12.6 million in conversion costs incurred by manufacturers cause a slightly negative change in INPV at TSL 3 under the preservation of operating profit markup scenario.

At TSL 4, DOE estimates that impacts on INPV will range from −$30.1 million to $31.1 million, or a change in INPV of −3.8 percent to 3.9 percent. At TSL 4, industry free cash-flow is $28.8 million, which is a decrease of approximately $5.1 million compared to the no-new-standards case value of $33.9 million in 2025, the year leading up to the proposed standards.

TSL 4 would set extra small size DPPP motors at EL 2 (max-tech), and small size and standard size DPPP motors at EL 4. DOE estimates that 33 percent of extra small DPPP motors, 43 percent of small size DPPP motors, and 69 percent already meet or exceed the efficiency levels analyzed at TSL 4. At TSL 4, DOE estimates that manufacturers will incur approximately $6.2 million in product conversion costs as, in addition to single-speed motors most likely not being able to comply with the standards, some dual-speed DPPP motor models will need to be redesigned for higher efficiency. DOE also estimates that DPPP motor manufacturers will incur $6.4 million in capital conversion costs at TSL 4, to accommodate this increase in dual-speed and variable-speed DPPP motor manufacturing production capacity.

At TSL 4, the shipment-weighted average MPC for all DPPP motors increases by 13.5 percent relative to the no-new-standards case shipment-weighted average MPC for all DPPP motors in 2026. In the preservation of gross margin markup scenario, the moderate increase in shipment-weighted average MPC for DPPP motors outweighs the $12.6 million in conversion costs, causing a slightly positive change in INPV at TSL 4 under the preservation of gross margin markup scenario.

Under the preservation of operating profit markup scenario, the moderate 13.5 percent shipment-weighted average MPC increase results in a reduction in the manufacturer markup after the analyzed compliance year. This reduction in the manufacturer markup and the $12.6 million in conversion costs incurred by manufacturers causing a slightly negative change in INPV at TSL 4 under the preservation of operating profit markup scenario.

At TSL 5, DOE estimates that impacts on INPV will range from −$32.8 million to $37.7 million, or a change in INPV of −4.1 percent to 4.7 percent. At TSL 5, industry free cash-flow is $28.7 million, which is a decrease of approximately $5.2 million compared to the no-new-standards case value of $33.9 million in 2025, the year leading up to the proposed standards.

TSL 5 would set extra small size DPPP motors at EL 2 (max-tech), and small and standard size DPPP motors at EL 5. DOE estimates that 33 percent of extra small size DPPP motors, 41 percent of small size DPPP motors, and 67 percent of standard size DPPP motors already meet or exceed the efficiency levels analyzed at TSL 5. At TSL 5, DOE estimates that manufacturers will incur approximately $6.5 million in product conversion costs as, in addition to single-speed motors not being able to comply with the standard, many dual-speed DPPP motor models will need to be redesigned for higher efficiency. DOE also estimates that DPPP motor manufacturers will incur $6.4 million in capital conversion costs at TSL 5, to accommodate this increase in dual-speed and variable-speed DPPP motor manufacturing production capacity.

At TSL 5, the shipment-weighted average MPC for all DPPP motors increases by 15.7 percent relative to the no-new-standards case shipment-weighted average MPC for all DPPP motors in 2025. In the preservation of gross margin markup scenario, the moderate increase in shipment-weighted average MPC for DPPP motors outweighs the $12.9 million in conversion costs, causing a slightly positive change in INPV at TSL 5 under the preservation of gross margin markup scenario.

Under the preservation of operating profit markup scenario, the 15.7 percent shipment-weighted average MPC increase results in a reduction in the manufacturer markup after the analyzed compliance year. This reduction in manufacturer markup and the $12.9 million in conversion costs incurred by manufacturers cause a slightly negative change in INPV at TSL 5 under the preservation of operating profit markup scenario.

At TSL 6, DOE estimates that impacts on INPV will range from −$93.4 million to $28.4 million, or a change in INPV of −11.7 percent to 3.6 percent. At TSL 6, industry free cash-flow is $26.9 million, which is a decrease of approximately $7.0 million compared to the no-new-standards case value of $33.9 million in 2025, the year leading up to the proposed standards.

TSL 6 would set extra small size and small size DPPP motors at EL 1 and standard size DPPP motors at EL 6 (max-tech). DOE estimates 93 percent of extra small size DPPP motors, 95 percent of small size DPPP motors, and 66 percent of standard size DPPP motors already meet the efficiency levels analyzed at TSL 6. At TSL 6, DOE estimates that manufacturers will incur approximately $0.1 million in product conversion costs as some pool filter pumps that use standard size motors downsize to a smaller sized single speed motors—necessitating redesign costs for standard size motor models. DOE also estimates that DPPP motor manufacturers will incur $15.4 million in capital conversion costs at TSL 6, to accommodate this increase in variable-speed DPPP motor manufacturing production capacity, for the standard size DPPP motors.

At TSL 6, the shipment-weighted average MPC for all DPPP motors significantly increases by 18.9 percent relative to the no-new-standards case shipment-weighted average MPC for all DPPP motors in 2026. In the preservation of gross margin markup scenario, the large increase in shipment-weighted average MPC for DPPP motors outweighs the $15.5 million in conversion costs, causing a slightly positive change in INPV at TSL 6 under the preservation of gross margin markup scenario.

Under the preservation of operating profit markup scenario, the 18.9 percent shipment-weighted average MPC increase results in a reduction in the manufacturer markup after the analyzed compliance year. This reduction in manufacturer markup and the $15.5 million in conversion costs incurred by manufacturers cause a moderately negative change in INPV at TSL 6 under the preservation of operating profit markup scenario.

At TSL 7, DOE estimates that impacts on INPV will range from −$189.3 million to $102.9 million, or a change in INPV of −23.7 percent to 12.9 percent. At TSL 7, industry free cash-flow is $13.9 million, which is a decrease of approximately $20.0 million compared to the no-new-standards case value of $33.9 million in 2025, the year leading up to the proposed standards.

TSL 7 would set extra small size DPPP motors at EL 1; and small and standard size DPPP motors at EL 6, which is max-tech for both equipment classes. DOE estimates 93 percent of extra small size DPPP motors, 39 percent of small size DPPP motors, and 66 percent of standard size DPPP motors already meet the efficiency levels analyzed at TSL 7. At TSL 7, DOE estimates that manufacturers will incur approximately $8.7 million in product conversion costs. At TSL 7, most DPPP motor manufacturers would need to introduce variable-speed small size DPPP motor models into the market. DOE also estimates that DPPP motor manufacturers will incur $37.5 million in capital conversion costs at TSL 7, to accommodate a significant increase in variable-speed DPPP motor manufacturing production capacity for both the small size and standard size DPPP motors.

At TSL 7, the shipment-weighted average MPC for all DPPP motors significantly increases by 45.0 percent relative to the no-new-standards case shipment-weighted average MPC for all DPPP motors in 2026. In the preservation of gross margin markup scenario, the large increase in shipment-weighted average MPC for DPPP motors outweighs the $46.2 million in conversion costs, causing a moderately positive change in INPV at TSL 7 under the preservation of gross margin markup scenario.

Under the preservation of operating profit markup scenario, the 45.0 percent shipment-weighted average MPC increase results in a significant reduction in the manufacturer markup after the analyzed compliance year. This large reduction in manufacturer markup and the significant $46.2 million in conversion costs incurred by manufacturers cause a significantly negative change in INPV at TSL 7 under the preservation of operating profit markup scenario.

At TSL 8, DOE estimates that impacts on INPV will range from −$189.7 million to $103.6 million, or a change in INPV of −23.8 percent to 13.0 percent. At TSL 8, industry free cash-flow is $13.9 million, which is a decrease of approximately $20.0 million compared to the no-new-standards case value of $33.9 million in 2025, the year leading up to the proposed standards.

TSL 8 would set extra small size DPPP motors at EL 2 (max-tech); and small and standard size DPPP motors at EL 6, which is max-tech for both equipment classes. DOE estimates 33 percent of extra small size DPPP motors, 39 percent of small size DPPP motors, and 66 percent of standard size DPPP motors already meet the efficiency levels analyzed at TSL 8. At TSL 8, DOE estimates that manufacturers will incur approximately $8.8 million in product conversion costs. At TSL 8, most DPPP motor manufacturers would need to introduce variable-speed small size DPPP motor models into the market. DOE also estimates that DPPP motor manufacturers will incur $37.5 million in capital conversion costs at TSL 8, to accommodate a significant increase in variable-speed DPPP motor manufacturing production capacity for both the small size and standard size DPPP motors.

At TSL 8, the shipment-weighted average MPC for all DPPP motors significantly increases by 45.2 percent relative to the no-new-standards case shipment-weighted average MPC for all DPPP motors in 2026. In the preservation of gross margin markup scenario, the large increase in shipment-weighted average MPC for DPPP motors outweighs the $46.3 million in conversion costs, causing a moderately positive change in INPV at TSL 8 under the preservation of gross margin markup scenario.

Under the preservation of operating profit markup scenario, the 45.2 percent shipment-weighted average MPC increase results in a significant reduction in the manufacturer markup after the analyzed compliance year. This large reduction in manufacturer markup and the significant $46.3 million in conversion costs incurred by manufacturers cause a significantly negative change in INPV at TSL 8 under the preservation of operating profit markup scenario.

b. Direct Impacts on Employment

To quantitatively assess the potential impacts of new energy conservation standards on direct employment in the DPPP motors industry, DOE used the GRIM to estimate the domestic labor expenditures, number of direct employees, and non-production employees in the no-new-standards case and in each of the standards cases during the analysis period.

Production employees are those who are directly involved in fabricating and assembling products within an original equipment manufacturer facility. Workers performing services that are closely associated with production operations, such as materials handling tasks using forklifts, are included as production labor, as well as line supervisors.

DOE used the GRIM to calculate the number of production employees from labor expenditures. DOE used statistical data from the U.S. Census Bureau's 2019 Annual Survey of Manufacturers (''ASM'') and the results of the engineering analysis to calculate industry-wide labor expenditures. Labor expenditures related to product manufacturing depend on the labor intensity of the product, the sales volume, and an assumption that wages remain fixed in real terms over time. The total labor expenditures in the GRIM were then converted to domestic production employment levels by dividing production labor expenditures by the annual payment per production worker.

Non-production employees account for those workers that are not directly engaged in the manufacturing of the covered product. This could include sales, human resources, engineering, and management. DOE estimated non-production employment levels by multiplying the number of DPPP motor production workers by a scaling factor. The scaling factor is calculated by taking the ratio of the total number of employees, and the total number of production workers associated with the industry NAICS code 335312, which covers DPPP motor manufacturing.

Using the GRIM, DOE estimates that there would be approximately 675 domestic production workers and approximately 352 non-production workers for DPPP motors in 2026 in the absence of new energy conservation standards. Table V.17 shows the range of the impacts of energy conservation standards on U.S. production of DPPP motors.

TABLE V.17—TOTAL NUMBER OF DOMESTIC DPPP MOTOR WORKERS IN 2026

	No-new-standards case	Trial standard level							
		1	2	3	4	5	6	7	8
Domestic Production Workers in 2026	675	678	684	728	736	746	757	904	905
Production Workers in 2026	352	354	357	380	384	389	395	472	472
Total Direct Employment in 2026	1,027	1,032	1,041	1,108	1,120	1,135	1,152	1,376	1,377
Potential Changes in Total Direct Employment in 2026	....	0–5	0–14	0–81	0–93	0–108	(169)–125	(279)–349	(279)–350

The direct employment impacts shown in Table V.17 represent the potential changes in direct employment that could result following the compliance date for the DPPP motors covered in this proposed rulemaking. Employment could increase or decrease due to the labor content of the equipment being manufactured domestically or if manufacturers decided to move production facilities abroad because of the new standards. At the less severe end of the range, DOE assumes that all manufacturers continue to manufacture the same scope of the equipment domestically after compliance with the analyzed new standards. The other end of the range assumes that some domestic manufacturing either is eliminated or moves abroad due to the analyzed new standards.

DOE assumes that for DPPP motors, manufacturing is only potentially negatively impacted at TSLs that would most likely require variable-speed DPPP motors. At these TSLs, the maximum number of employees that could be eliminated are the number of domestic employees that would be manufacturing single-speed and dual-speed DPPP motors in the absence of new energy conservation standards. DOE estimated that there would be approximately 72 domestic production employees involved in the production of single-speed and dual-speed small-size DPPP motors and 38 non-production employees (for a total of 110 total employees) in 2026 in the absence of new DPPP motor standards. DOE also estimated that there would be approximately 111 domestic production employees involved in the production of single-speed and dual-speed standard-size DPPP motors and 58 non-production employees (for a total of 169 total employees) in 2026 in the absence of new DPPP motor standards. However, DOE notes that motors used in DPPPs are frequently used in other non-DPPP applications and motor manufacturers may choose to continue to manufacture single-speed and dual-speed motors (even at TSL 6, TSL 7, and TSL 8) that would be allowed to be used in other non-DPPP applications. If manufacturers choose to do this there would likely not be a significant impact on the overall domestic motor employment.

c. Impacts on Manufacturing Capacity

DOE did not identify any significant capacity constraints for the design options being evaluated for this NOPR. The design options evaluated for this NOPR are available as equipment that is on the market currently. The materials used to manufacture DPPP motor models at all efficiency levels are widely available on the market. While there were a limited number of small size variable-speed DPPP motor models currently on the market, all manufacturers are capable of manufacturing standard size variable-speed DPPP motor models and would be able to manufacture small size variable-speed DPPP motor models if they choose to make the investments described in section IV.J.2.c of this document. As a result, DOE does not anticipate that the industry will likely experience any capacity constraints directly resulting from energy conservation standards at any of the TSLs considered.

d. Impacts on Subgroups of Manufacturers

As discussed in section IV.J.1 of this document, using average cost assumptions to develop an industry cash-flow estimate may not be adequate for assessing differential impacts among manufacturer subgroups. Small manufacturers, niche manufacturers, and manufacturers exhibiting a cost structure substantially different from the industry average could be affected disproportionately. DOE used the results of the industry characterization to group manufacturers exhibiting similar characteristics. Consequently, DOE identified small business manufacturers as a subgroup for a separate impact analysis.

For the small business subgroup analysis, DOE applied the small business size standards published by the Small Business Administration (''SBA'') to determine whether a company is considered a small business. The size standards are codified at 13 CFR part 121. To be categorized as a small business under NAICS code 335312, ''Motor and Generator Manufacturing,'' a DPPP motor manufacturer and its affiliates may employ a maximum of 1,250 employees. The 1,250-employee threshold includes all employees in a business's parent company and any other subsidiaries. Based on this classification, DOE identified one potential manufacturers that could qualify as domestic small businesses.

e. Cumulative Regulatory Burden

One aspect of assessing manufacturer burden involves looking at the cumulative impact of multiple DOE standards and the product-specific regulatory actions of other Federal agencies that affect the manufacturers of a covered product or equipment. While any one regulation may not impose a significant burden on manufacturers, the combined effects of several existing or impending regulations may have serious consequences for some manufacturers, groups of manufacturers, or an entire industry. Assessing the impact of a single regulation may overlook this cumulative regulatory burden. In addition to energy conservation standards, other regulations can significantly affect manufacturers' financial operations. Multiple regulations affecting the same manufacturer can strain profits and lead companies to abandon product lines or markets with lower expected future returns than competing products. For these reasons, DOE conducts an analysis of cumulative regulatory burden as part of its rulemakings pertaining to appliance efficiency.

DOE is aware that DPPP motor manufacturers produce other products or equipment that are subject to DOE's energy conservation standards. DOE has ongoing rulemakings for some of these other products or equipment that DPPP motor manufactures produce, including electric motors [116] and distribution transformers.[117] None of these equipment have proposed or adopted energy conservation standards that require compliance within 3 years of the estimated compliance date (2026) for DPPP motors in this NOPR. If DOE proposes or finalizes any energy conservation standards for this equipment prior to finalizing energy conservation standards for DPPP motors, DOE will include the energy conservation standards for these other equipment as part of the cumulative regulatory burden for this DPPP motor proposed rulemaking.

DOE requests information regarding the impact of cumulative regulatory burden on manufacturers of DPPP motors associated with multiple DOE standards or product-specific regulatory actions of other Federal agencies.

3. National Impact Analysis

This section presents DOE's estimates of the national energy savings and the NPV of consumer benefits that would result from each of the TSLs considered as potential amended standards.

a. Significance of Energy Savings

To estimate the energy savings attributable to potential amended standards for DPPP motors, DOE compared their energy consumption under the no-new-standards case to their anticipated energy consumption under each TSL. The savings are measured over the entire lifetime of products purchased in the 30-year period that begins in the first full year of anticipated compliance with amended standards (2026–2055). Table V.18 presents DOE's projections of the national energy savings for each TSL considered for DPPP motors. The savings were calculated using the approach described in section IV.H of this document.

TABLE V.18—CUMULATIVE NATIONAL ENERGY SAVINGS FOR DPPP MOTORS; 30 YEARS OF SHIPMENTS

[2026–2055]

	Trial standard levels							
	1	2	3	4	5	6	7	8
	(quads)							
Primary energy	0.09	0.15	0.41	0.53	0.61	0.65	0.95	0.95
FFC energy	0.09	0.15	0.43	0.55	0.63	0.67	0.99	0.99

OMB Circular A–4 [118] requires agencies to present analytical results, including separate schedules of the monetized benefits and costs that show the type and timing of benefits and costs. Circular A–4 also directs agencies to consider the variability of key elements underlying the estimates of benefits and costs. For this proposed rulemaking, DOE undertook a sensitivity analysis using 9 years, rather than 30 years of shipments. The choice of a 9-year period is a proxy for the timeline in EPCA for the review of certain energy conservation standards and potential revision of and compliance with such revised standards.[119] The review timeframe established in EPCA is generally not synchronized with the equipment lifetime, product manufacturing cycles, or other factors specific to DPPP motors. Thus, such results are presented for informational purposes only and are not indicative of any change in DOE's analytical methodology. The NES sensitivity analysis results based on a 9-year analytical period are presented in Table V.19. The impacts are counted over the lifetime of DPPP motors purchased in 2026–2034.

TABLE V.19—CUMULATIVE NATIONAL ENERGY SAVINGS FOR DPPP MOTORS; 9 YEARS OF SHIPMENTS

[2026–2034]

	Trial standard levels							
	1	2	3	4	5	6	7	8
	(quads)							
Primary energy	0.03	0.05	0.14	0.18	0.20	0.20	0.29	0.29
FFC energy	0.03	0.05	0.15	0.19	0.21	0.20	0.30	0.30

[116] *www.regulations.gov/docket/EERE-2020-BT-STD-0007.*

[117] *www.regulations.gov/docket/EERE-2019-BT-STD-0018.*

[118] U.S. Office of Management and Budget. *Circular A–4: Regulatory Analysis.* September 17, 2003. *https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/* (last accessed July 6, 2021).

[119] Section 325(m) of EPCA requires DOE to review its standards at least once every 6 years, and requires, for certain products, a 3-year period after any new standard is promulgated before compliance is required, except that in no case may any new standards be required within 6 years of the compliance date of the previous standards. While adding a 6-year review to the 3-year compliance period adds up to 9 years, DOE notes that it may undertake reviews at any time within the 6 year period and that the 3-year compliance date may yield to the 6-year backstop. A 9-year analysis period may not be appropriate given the variability that occurs in the timing of standards reviews and the fact that for some products, the compliance period is 5 years rather than 3 years.

b. Net Present Value of Consumer Costs and Benefits

DOE estimated the cumulative NPV of the total costs and savings for consumers that would result from the TSLs considered for DPPP motors. In accordance with OMB's guidelines on regulatory analysis,[120] DOE calculated NPV using both a 7-percent and a 3-percent real discount rate. Table V.20 shows the consumer NPV results with impacts counted over the lifetime of products purchased in 2026–2055.

TABLE V.20 CUMULATIVE NET PRESENT VALUE OF CONSUMER BENEFITS FOR DPPP MOTORS; 30 YEARS OF SHIPMENTS

[2026–2055]

Discount rate	Trial standard level							
	1	2	3	4	5	6	7	8
	(billion 2020$)							
3 percent	0.7	1.1	1.4	2.3	2.7	5.4	6.3	6.3
7 percent	0.4	0.6	0.7	1.1	1.3	2.7	3.0	3.0

The NPV results based on the aforementioned 9-year analytical period are presented in Table V.21. The impacts are counted over the lifetime of products purchased in 2026–2034. As mentioned previously, such results are presented for informational purposes only and are not indicative of any change in DOE's analytical methodology or decision criteria.

TABLE V.21—CUMULATIVE NET PRESENT VALUE OF CONSUMER BENEFITS FOR DPPP MOTORS; 9 YEARS OF SHIPMENTS

[2026–2034]

Discount rate	Trial standard level							
	1	2	3	4	5	6	7	8
	(billion 2020$)							
3 percent	0.3	0.5	0.6	1.0	1.2	2.0	2.1	2.1
7 percent	0.22	0.3	0.4	0.7	0.8	1.4	1.3	1.3

The previous results reflect the use of a default trend to estimate the change in price for DPPP motors over the analysis period (see section IV.F.1 of this document). DOE also conducted a sensitivity analysis that considered one scenario with a lower rate of price decline than the reference case and one scenario with a higher rate of price decline than the reference case. The results of these alternative cases are presented in appendix 10C of the NOPR TSD. In the high-price-decline case, the NPV of consumer benefits is higher than in the default case. In the low-price-decline case, the NPV of consumer benefits is lower than in the default case.

c. Indirect Impacts on Employment

It is estimated that that amended energy conservation standards for DPPP Motors would reduce energy expenditures for consumers of those products, with the resulting net savings being redirected to other forms of economic activity. These expected shifts in spending and economic activity could affect the demand for labor. As described in section IV.N of this document, DOE used an input/output model of the U.S. economy to estimate indirect employment impacts of the TSLs that DOE considered. There are uncertainties involved in projecting employment impacts, especially changes in the later years of the analysis. Therefore, DOE generated results for near-term timeframes (2026–2031), where these uncertainties are reduced.

The results suggest that the proposed standards would be likely to have a negligible impact on the net demand for labor in the economy. The net change in jobs is so small that it would be imperceptible in national labor statistics and might be offset by other, unanticipated effects on employment. Chapter 16 of the NOPR TSD presents detailed results regarding anticipated indirect employment impacts.

4. Impact on Utility or Performance of Products

As discussed in section IV.C.1.b of this document, DOE has tentatively concluded that the standards proposed in this NOPR would not lessen the utility or performance of the DPPP motors under consideration in this rulemaking. Manufacturers of these products currently offer units that meet or exceed the proposed standards.

5. Impact of Any Lessening of Competition

DOE considered any lessening of competition that would be likely to result from new or amended standards. As discussed in section III.E.1.e of this NOPR, the Attorney General determines the impact, if any, of any lessening of competition likely to result from a proposed standard, and transmits such determination in writing to the Secretary, together with an analysis of the nature and extent of such impact. To assist the Attorney General in making this determination, DOE has provided DOJ with copies of this NOPR and the accompanying TSD for review. DOE will consider DOJ's comments on the proposed rule in determining whether to proceed to a final rule. DOE will publish and respond to DOJ's comments in that document. DOE invites comment

[120] U.S. Office of Management and Budget. *Circular A–4: Regulatory Analysis.* September 17, 2003. *www.whitehouse.gov/omb/circulars_a004_a-4/* (last accessed July 6, 2021).

from the public regarding the competitive impacts that are likely to result from this proposed rule. In addition, stakeholders may also provide comments separately to DOJ regarding these potential impacts. See the **ADDRESSES** section for information to send comments to DOJ.

6. Need of the Nation To Conserve Energy

Enhanced energy efficiency, where economically justified, improves the Nation's energy security, strengthens the economy, and reduces the environmental impacts (costs) of energy production. Reduced electricity demand due to energy conservation standards is also likely to reduce the cost of maintaining the reliability of the electricity system, particularly during peak-load periods. Chapter 15 in the NOPR TSD presents the estimated impacts on electricity generating capacity, relative to the no-new-standards case, for the TSLs that DOE considered in this rulemaking.

Energy conservation resulting from potential energy conservation standards for DPPP motors is expected to yield environmental benefits in the form of reduced emissions of certain air pollutants and greenhouse gases. Table V.22 provides DOE's estimate of cumulative emissions reductions expected to result from the TSLs considered in this rulemaking. The emissions were calculated using the multipliers discussed in section IV.K. of this document. DOE reports annual emissions reductions for each TSL in chapter 13 of the NOPR TSD.

TABLE V.22—CUMULATIVE EMISSIONS REDUCTION FOR DPPP MOTORS SHIPPED IN 2026–2055

	Trial standard level							
	1	2	3	4	5	6	7	8
Power Sector Emissions								
CO_2 (million metric tons)	3.1	5.3	14.9	19.2	21.8	23.0	33.8	33.9
CH_4 (thousand tons)	0.3	0.4	1.2	1.6	1.8	1.9	2.8	2.8
N_2O (thousand tons)	0.04	0.06	0.17	0.22	0.25	0.26	0.39	0.39
NO_X (thousand tons)	1.3	2.3	6.4	8.3	9.4	9.9	14.5	14.5
SO_2 (thousand tons)	1.4	2.4	6.9	8.9	10.1	10.7	15.6	15.7
Hg (tons)	0.01	0.01	0.04	0.05	0.06	0.06	0.10	0.10
Upstream Emissions								
CO_2 (million metric tons)	0.2	0.4	1.0	1.3	1.5	1.6	2.4	2.4
CH_4 (thousand tons)	21.5	36.2	102.4	132.1	150.5	159.9	234.4	234.9
N_2O (thousand tons)	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
NO_X (thousand tons)	3.2	5.5	15.4	19.9	22.7	24.1	35.4	35.4
SO_2 (thousand tons)	0.02	0.03	0.08	0.11	0.12	0.13	0.19	0.19
Hg (tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total FFC Emissions								
CO_2 (million metric tons)	3.3	5.6	15.9	20.5	23.4	24.7	36.2	36.3
CH_4 (thousand tons)	21.7	36.6	103.7	133.6	152.3	161.8	237.2	237.7
N_2O (thousand tons)	0.04	0.06	0.18	0.23	0.26	0.27	0.40	0.40
NO_X (thousand tons)	4.6	7.7	21.9	28.2	32.1	34.0	49.9	50.0
SO_2 (thousand tons)	1.5	2.5	7.0	9.0	10.2	10.8	15.8	15.9
Hg (tons)	0.01	0.01	0.04	0.05	0.06	0.07	0.10	0.10

As part of the analysis for this proposed rulemaking, DOE estimated monetary benefits likely to result from the reduced emissions of CO_2 that DOE estimated for each of the considered TSLs for DPPP motors. Section IV.L of this document discusses the SC–CO_2 values that DOE used. Table V.23 presents the value of CO_2 emissions reduction at each TSL for each of the SC–CO_2 cases. The time-series of annual values is presented for the proposed TSL in chapter 14 of the NOPR TSD.

TABLE V.23—PRESENT VALUE OF CO_2 EMISSIONS REDUCTION FOR DPPP MOTORS SHIPPED IN 2026–2055

TSL	SC–CO_2 case			
	Discount rate and statistics			
	5%	3%	2.5%	3%
	Average	Average	Average	95th Percentile
	(Million 2020$)			
1	34	140	216	427
2	58	237	366	721
3	165	671	1,034	2,040
4	212	863	1,331	2,626
5	241	983	1,516	2,990
6	250	1,028	1,587	3,128

TABLE V.23—PRESENT VALUE OF CO_2 EMISSIONS REDUCTION FOR DPPP MOTORS SHIPPED IN 2026–2055—Continued

TSL	SC–CO_2 case			
	Discount rate and statistics			
	5%	3%	2.5%	3%
	Average	Average	Average	95th Percentile
	(Million 2020$)			
7	367	1,508	2,329	4,590
8	367	1,511	2,334	4,599

As discussed in section IV.L.2, DOE estimated the climate benefits likely to result from the reduced emissions of CH_4 and N_2O that DOE estimated for each of the considered TSLs for DPPP motors. Table V.24 presents the value of the CH_4 emissions reduction at each TSL, and Table V.25 presents the value of the N_2O emissions reduction at each TSL. The time-series of annual values is presented for the proposed TSL in chapter 14 of the NOPR TSD.

TABLE V.24—PRESENT VALUE OF METHANE EMISSIONS REDUCTION FOR DPPP MOTORS SHIPPED IN 2026–2055

TSL	SC–CH_4 case			
	Discount rate and statistics			
	5%	3%	2.5%	3%
	Average	Average	Average	95th Percentile
	(Million 2020$)			
1	10	28	38	74
2	17	47	64	124
3	48	132	181	351
4	62	170	234	453
5	70	194	266	516
6	73	205	282	546
7	108	301	414	800
8	108	301	415	802

TABLE V.25—PRESENT VALUE OF NITROUS OXIDE EMISSIONS REDUCTION FOR DPPP MOTORS SHIPPED IN 2026–2055

TSL	SC–N_2O case			
	Discount rate and statistics			
	5%	3%	2.5%	3%
	Average	Average	Average	95th Percentile
	(Million 2020$)			
1	0.1	0.5	0.8	1.4
2	0.2	0.9	1.4	2.4
3	0.7	2.6	3.9	6.8
4	0.9	3.3	5.0	8.7
5	1.0	3.7	5.7	10.0
6	1.0	3.9	6.0	10.4
7	1.5	5.7	8.8	15.3
8	1.5	5.8	8.8	15.3

DOE is well aware that scientific and economic knowledge about the contribution of CO_2 and other GHG emissions to changes in the future global climate and the potential resulting damages to the world economy continues to evolve rapidly. Thus, any value placed on reduced GHG emissions in this proposed rulemaking is subject to change. That said, because of omitted damages, DOE agrees with the IWG that these estimates most likely underestimate the climate benefits of greenhouse gas reductions. DOE, together with other Federal agencies, will continue to review methodologies for estimating the monetary value of reductions in CO_2 and other GHG emissions. This ongoing review will consider the comments on this subject that are part of the public record for this and other rulemakings, as well as other methodological assumptions and issues. DOE notes that the proposed standards would be economically justified even without inclusion of monetized benefits of reduced GHG emissions.

DOE also estimated the monetary value of the health benefits associated with NO_X emissions reductions anticipated to result from the considered TSLs for DPPP motors. The dollar-per-ton values that DOE used are discussed in section IV.L of this document. Table V.26 presents the present value for NO_X emissions reduction for each TSL calculated using 7-percent and 3-percent discount rates.

TABLE V.26—PRESENT VALUE OF NO_X EMISSIONS REDUCTION FOR DPPP MOTORS SHIPPED IN 2026–2055

TSL	3% Discount rate	7% Discount rate
	(Million 2020$)	
1	107	214
2	182	363
3	514	1,026
4	659	1,321
5	750	1,504
6	761	1,575
7	1,118	2,312
8	1,120	2,316

DOE also estimated the monetary value of the health benefits associated with SO_2 emissions reductions anticipated to result from the considered TSLs for DPPP motors. The dollar-per-ton values that DOE used are discussed in section IV.L of this document. Table V.27 presents the present value for SO_2 emissions reduction for each TSL calculated using 7-percent and 3-percent discount rates.

TABLE V.27—PRESENT VALUE OF SO_2 EMISSIONS REDUCTION FOR DPPP MOTORS SHIPPED IN 2026–2055

TSL	3% Discount rate	7% Discount rate
	(Million 2020$)	
1	46	91
2	79	155
3	222	437
4	285	562
5	324	640
6	327	666
7	480	977
8	481	979

The benefits of reduced CO_2, CH_4, and N_2O emissions are collectively referred to as climate benefits. The benefits of reduced SO_2 and NO_X emissions are collectively referred to as health benefits. For the time series of estimated monetary values of reduced emissions, see chapter 14 of the NOPR TSD.

DOE has not considered the monetary benefits of the reduction of Hg for this final rule. Not all the public health and environmental benefits from the reduction of greenhouse gases, NO_X, and SO_2 are captured in the values above, and additional unquantified benefits from the reductions of those pollutants as well as from the reduction of Hg, direct PM, and other co-pollutants may be significant.

7. Other Factors

The Secretary of Energy, in determining whether a standard is economically justified, may consider any other factors that the Secretary deems to be relevant. (42 U.S.C. 6295(o)(2)(B)(i)(VII))

8. Summary of Economic Impacts

Table V.28 presents the NPV values that result from adding the estimates of the potential economic benefits resulting from reduced GHG and NO_X and SO_2 emissions to the NPV of consumer benefits calculated for each TSL considered in this proposed rulemaking. The consumer benefits are domestic U.S. monetary savings that occur as a result of purchasing the covered DPPP motors, and are measured for the lifetime of products shipped in 2026–2055. The climate benefits associated with reduced GHG emissions resulting from the adopted standards are global benefits, and are also calculated based on the lifetime of DPPP motors shipped in 2026–2055.

TABLE V.28—CONSUMER NPV COMBINED WITH PRESENT VALUE OF CLIMATE AND HEALTH BENEFITS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7	TSL 8
3% discount rate for Consumer NPV and Health Benefits (billion 2020$)								
5% Average SC–GHG case	1.1	1.7	3.1	4.4	5.1	8.0	10.1	10.0
3% Average SC–GHG case	1.2	1.9	3.7	5.2	6.0	8.9	11.4	11.4
2.5% Average SC–GHG case	1.3	2.0	4.1	5.7	6.6	9.5	12.3	12.3
3% 95th percentile SC–GHG case	1.5	2.4	5.3	7.2	8.3	11.3	15.0	15.0
7% discount rate for Consumer NPV and Health Benefits (billion 2020$)								
5% Average SC–GHG case	0.6	0.9	1.6	2.4	2.7	4.1	5.1	5.1

TABLE V.28—CONSUMER NPV COMBINED WITH PRESENT VALUE OF CLIMATE AND HEALTH BENEFITS—Continued

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7	TSL 8
3% Average SC–GHG case	0.7	1.1	2.2	3.1	3.6	5.0	6.4	6.4
2.5% Average SC–GHG case	0.8	1.3	2.6	3.6	4.2	5.7	7.4	7.4
3% 95th percentile SC–GHG case	1.0	1.7	3.8	5.2	5.9	7.5	10.0	10.0

C. Conclusion

When considering new or amended energy conservation standards, the standards that DOE adopts for any type (or class) of covered product must be designed to achieve the maximum improvement in energy efficiency that the Secretary determines is technologically feasible and economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(A)) In determining whether a standard is economically justified, the Secretary must determine whether the benefits of the standard exceed its burdens by, to the greatest extent practicable, considering the seven statutory factors discussed previously. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)) The new or amended standard must also result in significant conservation of energy. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3)(B))

For this NOPR, DOE considered the impacts of potential new standards for DPPP motors at each TSL, beginning with the maximum technologically feasible level, to determine whether that level was economically justified. Where the max-tech level was not justified, DOE then considered the next most efficient level and undertook the same evaluation until it reached the highest efficiency level that is both technologically feasible and economically justified and saves a significant amount of energy.

To aid the reader as DOE discusses the benefits and/or burdens of each TSL, tables in this section present a summary of the results of DOE's quantitative analysis for each TSL. In addition to the quantitative results presented in the tables, DOE also considers other burdens and benefits that affect economic justification. These include the impacts on identifiable subgroups of consumers who may be disproportionately affected by a national standard and impacts on employment.

DOE also notes that the economics literature provides a wide-ranging discussion of how consumers trade off upfront costs and energy savings in the absence of government intervention. Much of this literature attempts to explain why consumers appear to undervalue energy efficiency improvements. There is evidence that consumers undervalue future energy savings as a result of (1) a lack of information, (2) a lack of sufficient salience of the long-term or aggregate benefits, (3) a lack of sufficient savings to warrant delaying or altering purchases, (4) excessive focus on the short term, in the form of inconsistent weighting of future energy cost savings relative to available returns on other investments, (5) computational or other difficulties associated with the evaluation of relevant tradeoffs, and (6) a divergence in incentives (for example, between renters and owners, or builders and purchasers). Having less than perfect foresight and a high degree of uncertainty about the future, consumers may trade off these types of investments at a higher than expected rate between current consumption and uncertain future energy cost savings.

In DOE's current regulatory analysis, potential changes in the benefits and costs of a regulation due to changes in consumer purchase decisions are included in two ways. First, if consumers forego the purchase of a product in the standards case, this decreases sales for product manufacturers, and the impact on manufacturers attributed to lost revenue is included in the MIA. Second, DOE accounts for energy savings attributable only to products actually used by consumers in the standards case; if a standard decreases the number of products purchased by consumers, this decreases the potential energy savings from an energy conservation standard. DOE provides estimates of shipments and changes in the volume of product purchases in chapter 9 of the NOPR TSD. However, DOE's current analysis does not explicitly control for heterogeneity in consumer preferences, preferences across subcategories of products or specific features, or consumer price sensitivity variation according to household income.[121]

While DOE is not prepared at present to provide a fuller quantifiable framework for estimating the benefits and costs of changes in consumer purchase decisions due to an energy conservation standard, DOE is committed to developing a framework that can support empirical quantitative tools for improved assessment of the consumer welfare impacts of appliance standards. DOE has posted a paper that discusses the issue of consumer welfare impacts of appliance energy conservation standards, and potential enhancements to the methodology by which these impacts are defined and estimated in the regulatory process.[122] DOE welcomes comments on how to more fully assess the potential impact of energy conservation standards on consumer choice and how to quantify this impact in its regulatory analysis in future rulemakings.

1. Benefits and Burdens of TSLs Considered for DPPP Motors Standards

Table V.29 and Table V.30 summarize the quantitative impacts estimated for each TSL for DPPP motors. The national impacts are measured over the lifetime of DPPP motors purchased in the 30-year period that begins in the anticipated first full year of compliance with amended standards (2026–2055). The energy savings, emissions reductions, and value of emissions reductions refer to full-fuel-cycle results. DOE exercises its own judgment in presenting monetized climate benefits as recommended in applicable Executive orders and DOE would reach the same conclusion presented in this notice in the absence of the social cost of greenhouse gases, including the February 2021 Interim Estimates presented by the Interagency Working Group on the Social Cost of Greenhouse Gases. The efficiency levels contained in each TSL are described in section V.A of this document.

[121] P.C. Reiss and M.W. White. Household Electricity Demand, Revisited. *Review of Economic Studies*. 2005. 72(3): pp. 853–883. doi: *10.1111/0034–6527.00354*.

[122] Sanstad, A.H. *Notes on the Economics of Household Energy Consumption and Technology Choice*. 2010. Lawrence Berkeley National Laboratory. Available at: *www1.eere.energy.gov/buildings/appliance_standards/pdfs/consumer_ee_theory.pdf (last accessed April 15, 2021).*

TABLE V.29—SUMMARY OF ANALYTICAL RESULTS FOR DPPP MOTORS TSLS: NATIONAL IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7	TSL 8
Cumulative FFC National Energy Savings								
Quads	0.09	0.15	0.43	0.55	0.63	0.67	0.99	0.99
Cumulative FFC Emissions Reduction								
CO_2 (million metric tons)	3.3	5.6	15.9	20.5	23.4	24.7	36.2	36.3
CH_4 (thousand tons)	21.7	36.6	103.7	133.6	152.3	161.8	237.2	237.7
N_2O (thousand tons)	0.04	0.06	0.18	0.23	0.26	0.27	0.40	0.40
SO_2 (thousand tons)	4.6	7.7	21.9	28.2	32.1	34.0	49.9	50.0
NO_X (thousand tons)	1.5	2.5	7.0	9.0	10.2	10.8	15.8	15.9
Hg (tons)	0.01	0.01	0.04	0.05	0.06	0.07	0.10	0.10
Present Value of Benefits and Costs (3% discount rate, billion 2020$)								
Consumer Operating Cost Savings	0.8	1.4	3.9	5.0	5.7	5.9	8.8	8.8
Climate Benefits *	0.2	0.3	0.8	1.0	1.2	1.2	1.8	1.8
Health Benefits **	0.3	0.5	1.5	1.9	2.1	2.2	3.3	3.3
Total Benefits †	1.3	2.2	6.2	7.9	9.0	9.4	13.9	13.9
Consumer Incremental Product Costs	0.1	0.3	2.5	2.8	3.1	0.5	2.5	2.5
Consumer Net Benefits	0.7	1.1	1.4	2.3	2.7	5.4	6.3	6.3
Total Net Benefits	1.2	1.9	3.7	5.2	6.0	8.9	11.4	11.4
Present Value of Benefits and Costs (7% discount rate, billion 2020$)								
Consumer Operating Cost Savings	0.4	0.7	2.1	2.7	3.1	3.1	4.6	4.6
Climate Benefits *	0.2	0.3	0.8	1.0	1.2	1.2	1.8	1.8
Health Benefits **	0.2	0.3	0.7	0.9	1.1	1.1	1.6	1.6
Total Benefits †	0.8	1.3	3.6	4.7	5.3	5.4	8.0	8.0
Consumer Incremental Product Costs	0.1	0.2	1.4	1.6	1.7	0.4	1.5	1.6
Consumer Net Benefits	0.4	0.6	0.7	1.1	1.3	2.7	3.0	3.0
Total Net Benefits	0.7	1.1	2.2	3.1	3.6	5.0	6.4	6.4

Note: This table presents the costs and benefits associated with DPPP motors shipped in 2026–2055. These results include benefits to consumers which accrue after 2055 from the products shipped in 2026–2055.

* Climate benefits are calculated using four different estimates of the social cost of carbon (SC–CO_2), methane (SC–CH_4), and nitrous oxide (SC–N_2O) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate), as shown in Table V.23 through Table V.25. Together these represent the global SC–GHG. For presentational purposes of this table, the climate benefits associated with the average SC–GHG at a 3 percent discount rate are shown, but the Department does not have a single central SC–GHG point estimate. See section IV.L of this document for more details. On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22–30087) granted the federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana* v. *Biden,* No. 21–cv–1074–JDC–KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from ''adopting, employing, treating as binding, or relying upon'' the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and presents monetized benefits where appropriate and permissible under law.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. The health benefits are presented at real discount rates of 3 and 7 percent. See section IV.L of this document for more details.

† Total and net benefits include consumer, climate, and health benefits. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SC–GHG with 3-percent discount rate, but the Department does not have a single central SC–GHG point estimate. DOE emphasizes the importance and value of considering the benefits calculated using all four SC–GHG estimates.

TABLE V.30—SUMMARY OF ANALYTICAL RESULTS FOR DPPP MOTORS TSLS: MANUFACTURER AND CONSUMER IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7	TSL 8
Manufacturer Impacts								
Industry NPV (million 2020$) (No-new-standards case INPV = 798)	797–800	795–804	770–823	768–829	765–835	704–826	608–901	608–901
Industry NPV *(% change)*	(0.1)–0.2	(0.4)–0.8	(3.5)–3.2	(3.8)–3.9	(4.1)–4.7	(11.7)–3.6	(23.7)–12.9	(23.8)–13.0
Consumer Average LCC Savings (2020$)								
Extra Small-Size	3	(6)	(6)	(6)	(6)	3	3	(6)
Small-Size	11	20	(38)	3	7	11	69	69
Standard-Size	32	50	120	156	176	292	292	292
Shipment-Weighted Average *	19	32	30	68	78	129	161	161
Consumer Simple PBP (years)								
Extra Small-Size	0.7	2.1	2.1	2.1	2.1	0.7	0.7	2.1
Small-Size	0.3	0.7	3.3	2.5	2.5	0.3	2.3	2.3
Standard-Size	0.4	0.5	0.7	0.7	0.7	0.9	0.9	0.9
Shipment-Weighted Average *	0.4	0.6	2.2	1.7	1.8	0.6	1.7	1.7
Percent of Consumers that Experience a Net Cost								
Extra Small-Size	0%	54%	54%	54%	54%	0%	0%	54%
Small-Size	0%	11%	42%	36%	38%	0%	30%	30%
Standard-Size	0%	0%	15%	13%	13%	2%	2%	2%
Shipment-Weighted Average *	0%	8%	31%	27%	28%	1%	17%	19%

Parentheses indicate negative (−) values.

* Weighted by shares of each equipment class in total projected shipments in 2026.

DOE first considered TSL 8, which represents the max-tech efficiency levels. TSL 8 would save an estimated 0.99 quads of FFC energy, an amount DOE considers significant. Under TSL 8, the NPV of consumer benefit would be $3.0 billion using a discount rate of 7 percent, and $6.3 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 8 are 36.3 Mt of CO_2, 15.9 thousand tons of SO_2, 50.0 thousand tons of NO_X, 0.1 ton of Hg, 237.7 thousand tons of CH_4, and 0.4 thousand tons of N_2O. The estimated monetary value of the climate benefits from reduced GHG emissions (associated with the average SC–GHG at a 3-percent discount rate) at TSL 8 is $1.8 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 8 is $1.6 billion using a 7-percent discount rate and $3.3 billion using a 3-percent discount rate. Using a 7-percent discount rate for consumer benefits and costs, health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated total NPV at TSL 8 is $6.4 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 8 is $11.4 billion. The estimated total NPV is provided for additional information, however DOE primarily relies upon the NPV of consumer benefits when determining whether a proposed standard level is economically justified.

At TSL 8, the average LCC impact is a savings of −$6 for extra small-size DPPP motors, $69 for small size DPPP motors, and $292 for standard-size DPPP motors. The simple payback period is 2.1 years for extra small-size DPPP motors, 2.3 years for small-size DPPP motors, and 0.9 years for standard-size DPPP motors. The fraction of consumers experiencing a net LCC cost is 54 percent for extra small-size DPPP motors, 30 percent for small-size DPPP motors, and 2 percent for standard-size DPPP motors.

At TSL 8, the projected change in manufacturer INPV ranges from a decrease of $189.7 million to an increase of $103.6 million, which correspond to a decrease of 23.8 percent and an increase of 13.0 percent, respectively. DOE estimates that industry must invest $46.3 million to comply with standards set at TSL 8. DOE estimates that approximately 33 percent of extra-small size DPPP motor shipments, 39 percent of small size DPPP motor shipments, and 66 percent of standard size DPPP motor shipments would meet the efficiency levels analyzed at TSL 8.

The Secretary tentatively concludes that at TSL 8 for DPPP motors, the benefits of energy savings, positive NPV of consumer benefits, emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the economic burden on some consumers, including average negative LCC for extra small-size DPPP motors, including those consumers in senior-only households. Consequently, the Secretary has tentatively concluded that TSL 8 is not economically justified.

DOE then considered TSL 7, which would save an estimated 0.99 quads of FFC energy, an amount DOE considers significant. Under TSL 7, the NPV of consumer benefit would be $3.0 billion using a discount rate of 7 percent, and $6.3 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 7 are 36.2 Mt of CO_2, 15.8 thousand tons of SO_2, 49.9 thousand tons of NO_X, 0.1 tons of Hg, 237.2 thousand tons of CH_4, and 0.4 thousand tons of N_2O. The estimated monetary value of the climate benefits from reduced GHG emissions (associated with the average SC–GHG at a 3-percent discount rate) at TSL 7 is $1.8 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 7 is $1.6 billion using a 7-percent discount rate and $3.3 billion using a 3-percent discount rate.

Using a 7-percent discount rate for consumer benefits and costs and health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated total NPV at TSL 7 is $6.4 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 7 is $11.4 billion. The estimated total NPV is provided for additional information, however DOE primarily relies upon the NPV of consumer benefits when determining whether a proposed standard level is economically justified.

At TSL 7, the average LCC impact is a savings of $3 for extra small-size DPPP motors, $69 for small size DPPP motors, and $292 for standard-size DPPP motors. The simple payback period is 0.7 years for extra small-size DPPP motors, 2.3 years for small-size DPPP motors, and 0.9 years for standard-size DPPP motors. The fraction of consumers experiencing a net LCC cost is zero percent for extra small-size DPPP motors, 30 percent for small-size DPPP motors, and 2 percent for standard-size DPPP motors.

At TSL 7, the projected change in manufacturer INPV ranges from a decrease of $193.3 million to an increase of $102.9 million, which represent a decrease of 23.7 percent and an increase of 12.9 percent, respectively. DOE estimates that industry must invest $46.2 million to comply with standards set at TSL 7. DOE estimates that approximately 93 percent of extra-small size DPPP motor shipments, 39 percent of small size DPPP motor shipments, and 66 percent of standard size DPPP motor shipments would meet the efficiency levels analyzed at TSL 7.

After considering the analysis and weighing the benefits and burdens, the Secretary has tentatively concluded that at TSL 7 for DPPP motors, the benefits of energy savings, positive NPV of consumer benefits, emission reductions, the estimated monetary value of the emissions reductions, and positive average LCC savings would outweigh the negative impacts on some consumers and on manufacturers, including the $46.2 million in conversion costs that could result in a reduction in INPV for manufacturers of up to 23.8 percent.

As stated, DOE conducts the walk-down analysis to determine the TSL that represents the maximum improvement in energy efficiency that is technologically feasible and economically justified as required under EPCA. The walk-down is not a comparative analysis, as a comparative analysis would result in the maximization of net benefits instead of energy savings that are technologically feasible and economically justified, which would be contrary to the statute. 86 FR 70892, 70908. Although DOE has not conducted a comparative analysis to select the proposed energy conservation standards, DOE notes at TSL 7, average LCC savings are positive for all equipment classes which is not the case at TSL 8.

Although DOE considered proposed amended standard levels for DPPP motors by grouping the efficiency levels for each equipment category into TSLs, DOE evaluates all analyzed efficiency levels in its analysis. TSL 8 represents the max-tech energy efficiency for all equipment classes. As discussed previously, the max-tech level for extra small DPPPM would lead to average negative LCC for extra small-size DPPP motors, including those consumers in senior-only households. The benefits of max-tech efficiency levels for extra small DPPPM do not outweigh the negative impacts to consumers. DOE has tentatively concluded that TSL 8 is not economically justified.

Therefore, based on the previous considerations, DOE proposes to adopt the energy conservation standards for DPPP motors at TSL 7. The proposed amended energy conservation standards for DPPP motors, which are expressed as performance and design requirements are shown in Table V.31 of this document.

TABLE V.31—PROPOSED ENERGY CONSERVATION STANDARDS FOR DPPP MOTORS

Motor total horsepower (THP)	Performance standard: full-load efficiency (%)	Design requirement: speed capability	Design requirement: freeze protection
THP < 0.5	69	None	None.
0.5 ≤ THP < 1.15		Variable speed control	Only for DPPP motors with freeze protection controls.
1.15 ≤ THP ≤ 5		Variable speed control	Only for DPPP motors with freeze protection controls.

2. Annualized Benefits and Costs of the Proposed Standards

The benefits and costs of the proposed standards can also be expressed in terms of annualized values. The annualized net benefit is (1) the annualized national economic value (expressed in 2020$) of the benefits from operating products that meet the proposed standards (consisting primarily of operating cost savings from using less energy, minus increases in product purchase costs, and (2) the annualized monetary value of the climate and health benefits from emission reductions.

Table V.32 shows the annualized values for DPPP motors under TSL 7, expressed in 2020$. The results under the primary estimate are as follows.

Using a 7-percent discount rate for consumer benefits and costs and health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated cost of the standards proposed in this rule is $163.5 million per year in increased equipment costs, while the estimated annual benefits are $482.3 million in reduced equipment operating costs, $104.2 million in climate benefits, and $168.7 million in health benefits. In this case, the net benefit would amount to $591.6 million per year.

Using a 3-percent discount rate for all benefits and costs, the estimated cost of the proposed standards is $142.9 million per year in increased equipment costs, while the estimated annual benefits are $504.2 million in reduced operating costs $104.2 million in climate benefits, and $188.9 million in health benefits. In this case, the net benefit would amount to $654.4 million per year.

TABLE V.32—ANNUALIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR DPPP MOTORS

[TSL 7]

	Million 2020$/year		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
3% discount rate			
Consumer Operating Cost Savings	504.2	436.2	580.9
Climate Benefits *	104.2	92.6	115.6
Health Benefits **	188.9	168.1	209.3
Total Benefits †	797.3	696.9	905.9
Consumer Incremental Equipment Costs	142.9	110.0	178.0
Net Benefits	654.4	587.0	727.9
7% discount rate			
Consumer Operating Cost Savings	482.3	424.8	546.8
Climate Benefits * (3% discount rate)	104.2	92.6	115.6
Health Benefits **	168.7	152.0	185.0
Total Benefits †	755.2	669.5	847.5
Consumer Incremental Equipment Costs	163.5	129.2	199.0
Net Benefits	591.6	540.3	648.5

Note: This table presents the costs and benefits associated with DPPP motors shipped in 2026–2055. These results include benefits to consumers which accrue after 2055 from the products shipped in 2026–2055. The Primary, Low Net Benefits, and High Net Benefits Estimates utilize projections of energy prices from the AEO2021 Reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental equipment costs reflect a medium decline rate in the Primary Estimate, a low decline rate in the Low Net Benefits Estimate, and a high decline rate in the High Net Benefits Estimate. The methods used to derive projected price trends are explained in sections IV.F.1 and IV.H.1of this document. Note that the Benefits and Costs may not sum to the Net Benefits due to rounding.

* Climate benefits are calculated using four different estimates of the SC–GHG). For presentational purposes of this table, the climate benefits associated with the average SC–GHG at a 3 percent discount rate are shown, but the Department does not have a single central SC–GHG point estimate, and it emphasizes the importance and value of considering the benefits calculated using all four SC–GHG estimates. On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22–30087) granted the federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana* v. *Biden,* No. 21–cv–1074–JDC–KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from ''adopting, employing, treating as binding, or relying upon'' the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and presents monetized benefits where appropriate and permissible under law.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. The health benefits are presented at real discount rates of 3 and 7 percent. See section IV.L of this document for more details.

† Total benefits for both the 3-percent and 7-percent cases are presented using the average SC–GHG with 3-percent discount rate, but the Department does not have a single central SC–GHG point estimate.

VI. Procedural Issues and Regulatory Review

A. Review Under Executive Orders 12866 and 13563

Executive Order (''E.O.'') 12866, ''Regulatory Planning and Review,'' as supplemented and reaffirmed by E.O. 13563, ''Improving Regulation and Regulatory Review, 76 FR 3821 (Jan. 21, 2011), requires agencies, to the extent permitted by law, to (1) propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify); (2) tailor regulations to impose the least burden on society, consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, the costs of cumulative regulations; (3) select, in choosing among alternative regulatory approaches, those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity); (4) to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt; and (5) identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public. DOE emphasizes as well that E.O. 13563 requires agencies to use the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible. In its guidance, OIRA has emphasized that such techniques may include identifying changing future compliance costs that might result from technological innovation or anticipated behavioral changes. For the reasons stated in the preamble, this proposed regulatory action is consistent with these principles.

Section 6(a) of E.O. 12866 also requires agencies to submit ''significant regulatory actions'' to the Office of Information and Regulatory Affairs (''OIRA'') for review. OIRA has determined that this proposed regulatory action constitutes a ''significant regulatory action'' under section 3(f) of E.O. 12866. Accordingly, pursuant to section 6(a)(3)(C) of E.O. 12866, DOE has provided to OIRA an assessment, including the underlying analysis, of benefits and costs anticipated from the proposed regulatory action, together with, to the extent feasible, a quantification of those costs; and an assessment, including the underlying analysis, of costs and benefits of potentially effective and reasonably feasible alternatives to the planned regulation, and an explanation why the planned regulatory action is preferable to the identified potential alternatives. A summary of the potential costs and benefits of the regulatory action is presented in Table VI.1.

TABLE VI.1—ANNUALIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR DPPP MOTORS

[TSL 7]

	Million 2020$/year		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
3% discount rate			
Consumer Operating Cost Savings	504.2	436.2	580.9
Climate Benefits *	104.2	92.6	115.6
Health Benefits **	188.9	168.1	209.3
Total Benefits †	797.3	696.9	905.9
Consumer Incremental Equipment Costs	142.9	110.0	178.0
Net Benefits	654.4	587.0	727.9
7% discount rate			
Consumer Operating Cost Savings	482.3	424.8	546.8
Climate Benefits * (3% discount rate)	104.2	92.6	115.6
Health Benefits **	168.7	152.0	185.0

TABLE VI.1—ANNUALIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR DPPP MOTORS—Continued

[TSL 7]

	Million 2020$/year		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
Total Benefits †	755.2	669.5	847.5
Consumer Incremental Equipment Costs	163.5	129.2	199.0
Net Benefits	591.6	540.3	648.5

Note: This table presents the costs and benefits associated with DPPP motors shipped in 2026–2055. These results include benefits to consumers which accrue after 2055 from the products shipped in 2026–2055. The Primary, Low Net Benefits, and High Net Benefits Estimates utilize projections of energy prices from the AEO2021 Reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental equipment costs reflect a medium decline rate in the Primary Estimate, a low decline rate in the Low Net Benefits Estimate, and a high decline rate in the High Net Benefits Estimate. The methods used to derive projected price trends are explained in sections IV.F.1 and IV.H.1of this document. Note that the Benefits and Costs may not sum to the Net Benefits due to rounding.

* Climate benefits are calculated using four different estimates of the global SC–GHG (see section IV.L of this notice). For presentational purposes of this table, the climate benefits associated with the average SC–GHG at a 3 percent discount rate are shown, but the Department does not have a single central SC–GHG point estimate, and it emphasizes the importance and value of considering the benefits calculated using all four SC–GHG estimates. On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22–30087) granted the federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana* v. *Biden,* No. 21–cv–1074–JDC–KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from ''adopting, employing, treating as binding, or relying upon'' the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and presents monetized benefits where appropriate and permissible under law.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. The health benefits are presented at real discount rates of 3 and 7 percent. See section IV.L of this document for more details.

† Total benefits for both the 3-percent and 7-percent cases are presented using the average SC–GHG with 3-percent discount rate, but the Department does not have a single central SC–GHG point estimate.

B. Review Under the Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires preparation of an initial regulatory flexibility analysis (''IRFA'') for any rule that by law must be proposed for public comment, unless the agency certifies that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities. As required by E.O. 13272, ''Proper Consideration of Small Entities in Agency Rulemaking,'' 67 FR 53461 (Aug. 16, 2002), DOE published procedures and policies on February 19, 2003, to ensure that the potential impacts of its rules on small entities are properly considered during the rulemaking process. 68 FR 7990. DOE has made its procedures and policies available on the Office of the General Counsel's website (*energy.gov/gc/office-general-counsel*). DOE has prepared the following IRFA for the products that are the subject of this rulemaking.

For manufacturers of DPPP motors, the SBA has set a size threshold, which defines those entities classified as ''small businesses'' for the purposes of the statute. DOE used the SBA's small business size standards to determine whether any small entities would be subject to the requirements of the rule. (*See* 13 CFR part 121.) The size standards, listed by respective North American Industry Classification System Codes (''NAICS'') and industry descriptions, are available at *www.sba.gov/document/support—table-size-standards.* Manufacturing of DPPP motors is classified under NAICS 335312, ''Motor and Generator Manufacturing.'' The SBA sets a threshold of 1,250 employees or fewer for an entity in this category to be considered as a small business. This threshold includes employees of the entity itself as well as any parent, subsidiary, or sister organizations.

1. Description of Reasons Why Action Is Being Considered

On January 18, 2017, DOE published a direct final rule establishing energy conservation standards for DPPPs. (82 FR 5650) Following this, DOE received feedback from manufacturers in support of regulating DPPP motors that would serve as replacement motors to the regulated pool pumps. On August 14, 2018, DOE received a petition submitted by a variety of entities (collectively, the ''Joint Petitioners'') requesting that DOE issue a direct final rule to establish prescriptive standards and a labeling requirement for DPPP motors (''Joint Petition'').[123] On February 5, 2019, the Association of Pool & Spa Professionals (''APSP''), National Electrical Manufacturers Association (''NEMA''), Hayward, Pentair, Nidec Motors, Regal Beloit, WEG Commercial Motors, and Zodiac Pool Systems met with DOE to present an alternative approach to the Joint Petition, suggesting DOE propose a labeling requirement for DPPP motors. (February 2019 *Ex Parte* Meeting, No. 43 at p. 1)

On October 5, 2020, in response to the Joint Petition and the alternative recommendation, DOE published a NOPR proposing to establish a test procedure and an accompanying labeling requirement for DPPP motors. Following this, on July 29, 2021, DOE published a final rule adopting a test procedure for DPPP motors. 86 FR 40765. DOE did not establish a labeling requirement and stated that it intends to address any such labeling and/or energy conservation standards requirement in a separate notification.

2. Objectives of, and Legal Basis for, Rule

As discussed previously in section II.A, EPCA authorizes DOE to regulate

[123] The Joint Petition is available at *www.regulations.gov/document?D=EERE-2017-BT-STD-0048-0014.*

the energy efficiency of a number of consumer products and certain industrial equipment. Title III, Part C of EPCA, added by Public Law 95–619, Title IV, section 441(a) (42 U.S.C. 6311–6317, as codified), established the Energy Conservation Program for Certain Industrial Equipment, which sets forth a variety of provisions designed to improve energy efficiency. This equipment includes those electric motors that are DPPP motors, the subject of this document. (42 U.S.C. 6311(1)(A))

DOE must follow specific statutory criteria for prescribing new or amended standards for covered equipment, including those electric motors that are DPPP motors. Any new or amended standard for a covered product must be designed to achieve the maximum improvement in energy efficiency that the Secretary of Energy determines is technologically feasible and economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(A) and 42 U.S.C. 6295(o)(3)(B)) Furthermore, DOE may not adopt any standard that would not result in the significant conservation of energy. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3))

3. Description on Estimated Number of Small Entities Regulated

DOE reviewed the potential standard levels considered in this NOPR under the provisions of the Regulatory Flexibility Act and the procedures and policies published on February 19, 2003. During its market survey, DOE used publicly available information to identify potential small manufacturers. DOE's research involved industry trade association membership directories (*e.g.,* AHRI), information from previous rulemakings, individual company websites, and market research tools (*e.g.,* D&B Hoover's reports) to create a list of companies that manufacture DPPP motors.

As previously stated, manufacturing of DPPP motors is classified under NAICS 335312, ''Motor and Generator Manufacturing,'' for which the SBA sets a threshold of 1,250 employees or fewer for an entity to be considered as a small business. DOE screened out companies that do not offer products impacted by this rulemaking, do not meet the definition of a ''small business,'' or are foreign owned and operated.

DOE identified five companies manufacturing DPPP motors for the domestic market, of those DOE determined that one company met the SBA definition of a small business. DOE contacted this small business regarding a discussion of potential DPPP motor standards, but the small business was not interested in discussing potential impacts of energy conservation standards on DPPP motors.

4. Description and Estimate of Compliance Requirements Including Differences in Cost, if Any, for Different Groups of Small Entities

DOE reviewed the website and catalog offerings of the identified small business and determined that the manufacturer offers extra small sized DPPP motors that would meet requirements under the proposed standards as well as standard sized DPPP motors that are capable of variable speed. The small business is expected to need to introduce one variable speed, small sized DPPP motor model in order to comply with the energy conservation standards proposed in this NOPR.

There are two types of costs the small business could incur due to the proposed standards for DPPP motors: product conversion costs and capital conversion costs. Product conversion costs are investments in R&D, testing, marketing, and other non-capitalized costs necessary to make equipment designs comply with new energy conservation standards. Capital conversion costs are investments in property, plant, and equipment necessary to adapt or change existing production facilities such that new compliant equipment designs can be fabricated and assembled.

DOE anticipates that the small business will incur approximately $1.1 million in product conversion costs—accounting for the compensation of four full-time engineers for 24 months of product design and testing work—and approximately $2.5 million in capital conversion costs to build a suitable production line to manufacture one small size DPPP motor model that would comply with the energy conservation standards for the small size DPPP motors proposed in this NOPR. Therefore, this small business would incur a total of approximately $3.6 million in conversion costs. DOE was able to identify an annual revenue estimate of approximately $28.2 million for the small business.[124] The $3.6 million in conversion cost represents 12.8 percent of the estimated annual revenue of the small business.

DOE assumes that all DPPP motor manufacturers would spread these costs over the five-year compliance timeframe, as standards are expected to require compliance approximately five years after the publication of a final rule. Therefore, DOE assumes that this small business would incur on average about $720,000 or approximately 2.6 percent of its annual revenue in each of the five years leading up to the compliance date.

DOE requests comment on its findings that there is one domestic small business that manufactures DPPP motors and on its estimate of the potential impacts on this small business.

5. Duplication, Overlap, and Conflict With Other Rules and Regulations

DOE is not aware of any rules or regulations that duplicate, overlap, or conflict with the rule being considered.

DOE has established test procedures, labeling requirements, and energy conservation standards for certain electric motors (10 CFR part 431 subpart B), but those requirements do not apply to DPPP motors subject to the proposed energy conservation standards requirements because they do not fall within any of the specific classes of electric motors that are currently regulated by DOE.

6. Significant Alternatives to the Rule

The discussion in the previous section analyzes impacts on small businesses that would result from DOE's proposed rule, represented by TSL 7. In reviewing alternatives to the proposed rule, DOE examined energy conservation standards set at lower efficiency levels. While TSL 1 through TSL 6 would reduce the impacts on small business manufacturers, it would come at the expense of a reduction in energy savings. TSL 1 through TSL 6 achieve 91 percent to 32 percent lower energy savings compared to the energy savings at TSL 7.

Based on the presented discussion, establishing standards at TSL 7 balances the benefits of the energy savings at TSL 7 with the potential burdens placed on DPPP motor manufacturers, including small business manufacturers. Accordingly, DOE does not propose one of the other TSLs considered in the analysis, or the other policy alternatives examined as part of the regulatory impact analysis and included in chapter 17 of the NOPR TSD.

Additional compliance flexibilities may be available through other means. EPCA provides that a manufacturer whose annual gross revenue from all of its operations does not exceed $8 million may apply for an exemption from all or part of an energy conservation standard for a period not longer than 24 months after the effective date of a final rule establishing the standard. (42 U.S.C. 6295(t)). Additionally, manufacturers subject to DOE's energy efficiency standards may

[124] The small business's annual revenue estimate is taken from D&B Hoovers (*app.avention.com*).

apply to DOE's Office of Hearings and Appeals for exception relief under certain circumstances. Manufacturers should refer to 10 CFR part 430, subpart E, and 10 CFR part 1003 for additional details.

C. Review Under the Paperwork Reduction Act

DOE's certification and compliance activities ensure accurate and comprehensive information about the energy and water use characteristics of covered products and covered equipment sold in the United States. Manufacturers of all covered products and covered equipment with applicable standards must submit a certification report before a basic model is distributed in commerce, annually thereafter, and if the basic model is redesigned in such a manner to increase the consumption or decrease the efficiency of the basic model such that the certified rating is no longer supported by the test data. Additionally, manufacturers must report when production of a basic model has ceased and is no longer offered for sale as part of the next annual certification report following such cessation. DOE requires the manufacturer of any covered product or covered equipment to establish, maintain, and retain the records of certification reports, of the underlying test data for all certification testing, and of any other testing conducted to satisfy the requirements of 10 CFR part 429, 10 CFR part 430, and/or 10 CFR part 431. Certification reports provide DOE and consumers with comprehensive, up-to date efficiency information and support effective enforcement.

DOE is not proposing certification or reporting requirements for DPPPM in this NOPR. Were DOE to establish energy conservation standards for DPPPM, certification of compliance would not be required until such time as DOE establishes such energy conservation standards and manufacturers are required to comply with those standards. DOE may consider proposals to establish certification requirements and reporting for DPPPM under a separate rulemaking regarding appliance and equipment certification.

DOE will address changes to OMB Control Number 1910–1400 at that time, as necessary. 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.

D. Review Under the National Environmental Policy Act of 1969

DOE is analyzing this proposed regulation in accordance with the National Environmental Policy Act of 1969 (''NEPA'') and DOE's NEPA implementing regulations (10 CFR part 1021). DOE's regulations include a categorical exclusion for rulemakings that establish energy conservation standards for consumer products or industrial equipment. 10 CFR part 1021, subpart D, appendix B5.1. DOE anticipates that this proposed rulemaking qualifies for categorical exclusion B5.1 because it is a rulemaking that establishes energy conservation standards for consumer products or industrial equipment, none of the exceptions identified in categorical exclusion B5.1(b) apply, no extraordinary circumstances exist that require further environmental analysis, and it otherwise meets the requirements for application of a categorical exclusion. *See* 10 CFR 1021.410. DOE will complete its NEPA review before issuing the final rule.

E. Review Under Executive Order 13132

E.O. 13132, ''Federalism,'' 64 FR 43255 (Aug. 10, 1999), imposes certain requirements on Federal agencies formulating and implementing policies or regulations that preempt State law or that have federalism implications. The Executive order requires agencies to examine the constitutional and statutory authority supporting any action that would limit the policymaking discretion of the States and to carefully assess the necessity for such actions. The Executive order also requires agencies to have an accountable process to ensure meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications. On March 14, 2000, DOE published a statement of policy describing the intergovernmental consultation process it will follow in the development of such regulations. 65 FR 13735. DOE has examined this proposed rule and has tentatively determined that it 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. EPCA governs and prescribes Federal preemption of State regulations as to energy conservation for the equipment that are the subject of this proposed rule. States can petition DOE for exemption from such preemption to the extent, and based on criteria, set forth in EPCA. (42 U.S.C. 6316(a) and (b); 42 U.S.C. 6297) Therefore, no further action is required by Executive Order 13132.

F. Review Under Executive Order 12988

With respect to the review of existing regulations and the promulgation of new regulations, section 3(a) of E.O. 12988, ''Civil Justice Reform,'' imposes on Federal agencies the general duty to adhere to the following requirements: (1) eliminate drafting errors and ambiguity, (2) write regulations to minimize litigation, (3) provide a clear legal standard for affected conduct rather than a general standard, and (4) promote simplification and burden reduction. 61 FR 4729 (Feb. 7, 1996). Regarding the review required by section 3(a), section 3(b) of E.O. 12988 specifically requires that executive agencies make every reasonable effort to ensure that the regulation: (1) clearly specifies the preemptive effect, if any, (2) clearly specifies any effect on existing Federal law or regulation, (3) provides a clear legal standard for affected conduct while promoting simplification and burden reduction, (4) specifies the retroactive effect, if any, (5) adequately defines key terms, and (6) addresses other important issues affecting clarity and general draftsmanship under any guidelines issued by the Attorney General. Section 3(c) of Executive Order 12988 requires Executive agencies to review regulations in light of applicable standards in section 3(a) and section 3(b) to determine whether they are met or it is unreasonable to meet one or more of them. DOE has completed the required review and determined that, to the extent permitted by law, this proposed rule meets the relevant standards of E.O. 12988.

G. Review Under the Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (''UMRA'') requires each Federal agency to assess the effects of Federal regulatory actions on State, local, and Tribal governments and the private sector. Public Law 104–4, section 201 (codified at 2 U.S.C. 1531). For a proposed regulatory action likely to result in a rule that may cause the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector of $100 million or more in any one year (adjusted annually for inflation), section 202 of UMRA requires a Federal agency to publish a written statement that estimates the resulting costs, benefits, and other effects on the national economy. (2 U.S.C. 1532(a), (b)) The UMRA also requires a Federal agency to develop an effective process to permit timely input by elected officers of State, local, and Tribal governments on a proposed ''significant intergovernmental mandate,'' and requires an agency plan for giving notice and opportunity for timely input to potentially affected small governments before establishing any requirements that might significantly or uniquely affect them. On March 18, 1997, DOE published a statement of policy on its process for intergovernmental consultation under UMRA. 62 FR 12820. DOE's policy statement is also available at *energy.gov/sites/prod/files/gcprod/documents/umra_97.pdf.*

Although this proposed rule does not contain a Federal intergovernmental mandate, it may require expenditures of $100 million or more in any one year by the private sector. Such expenditures may include: (1) investment in research and development and in capital expenditures by DPPPM manufacturers in the years between the final rule and the compliance date for the new standards and (2) incremental additional expenditures by consumers to purchase higher-efficiency DPPPM, starting at the compliance date for the applicable standard.

Section 202 of UMRA authorizes a Federal agency to respond to the content requirements of UMRA in any other statement or analysis that accompanies the proposed rule. (2 U.S.C. 1532(c)) The content requirements of section 202(b) of UMRA relevant to a private sector mandate substantially overlap the economic analysis requirements that apply under section 325(o) of EPCA and Executive Order 12866. The **SUPPLEMENTARY INFORMATION** section of this NOPR and the TSD for this proposed rule respond to those requirements.

Under section 205 of UMRA, the Department is obligated to identify and consider a reasonable number of regulatory alternatives before promulgating a rule for which a written statement under section 202 is required. (2 U.S.C. 1535(a)) DOE is required to select from those alternatives the most cost-effective and least burdensome alternative that achieves the objectives of the proposed rule unless DOE publishes an explanation for doing otherwise, or the selection of such an alternative is inconsistent with law. As required by 42 U.S.C. 6295(o)(A) through 42 U.S.C. 6316(a), this proposed rule would establish energy conservation standards for DPPPM that are designed to achieve the maximum improvement in energy efficiency that DOE has determined to be both technologically feasible and economically justified. A full discussion of the alternatives considered by DOE is presented in chapter 17 of the TSD for this proposed rule.

H. Review Under the Treasury and General Government Appropriations Act, 1999

Section 654 of the Treasury and General Government Appropriations Act, 1999 (Pub. L. 105–277) requires Federal agencies to issue a Family Policymaking Assessment for any rule that may affect family well-being. This proposed rule would not have any impact on the autonomy or integrity of the family as an institution. Accordingly, DOE has concluded that it is not necessary to prepare a Family Policymaking Assessment.

I. Review Under Executive Order 12630

Pursuant to E.O. 12630, ''Governmental Actions and Interference with Constitutionally Protected Property Rights,'' 53 FR 8859 (Mar. 15, 1988), DOE has determined that this proposed rule would not result in any takings that might require compensation under the Fifth Amendment to the U.S. Constitution.

J. Review Under the Treasury and General Government Appropriations Act, 2001

Section 515 of the Treasury and General Government Appropriations Act, 2001 (44 U.S.C. 3516 note) provides for Federal agencies to review most disseminations of information to the public under information quality guidelines established by each agency pursuant to general guidelines issued by OMB. OMB's guidelines were published at 67 FR 8452 (Feb. 22, 2002), and DOE's guidelines were published at 67 FR 62446 (Oct. 7, 2002). Pursuant to OMB Memorandum M–19–15, Improving Implementation of the Information Quality Act (April 24, 2019), DOE published updated guidelines which are available at *www.energy.gov/sites/prod/files/2019/12/f70/DOE%20Final%20Updated%20IQA%20Guidelines%20Dec%202019.pdf.* DOE has reviewed this NOPR under the OMB and DOE guidelines and has concluded that it is consistent with applicable policies in those guidelines.

K. Review Under Executive Order 13211

E.O. 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use,'' 66 FR 28355 (May 22, 2001), requires Federal agencies to prepare and submit to OIRA at OMB, a Statement of Energy Effects for any proposed significant energy action. A ''significant energy action'' is defined as any action by an agency that promulgates or is expected to lead to promulgation of a final rule, and that (1) is a significant regulatory action under Executive Order 12866, or any successor order; and (2) is likely to have a significant adverse effect on the supply, distribution, or use of energy, or (3) is designated by the Administrator of OIRA as a significant energy action. For any proposed significant energy action, the agency must give a detailed statement of any adverse effects on energy supply, distribution, or use should the proposal be implemented, and of reasonable alternatives to the action and their expected benefits on energy supply, distribution, and use.

DOE has tentatively concluded that this regulatory action, which proposes energy conservation standards for DPPPM, is not a significant energy action because the proposed standards are not likely to have a significant adverse effect on the supply, distribution, or use of energy, nor has it been designated as such by the Administrator at OIRA. Accordingly, DOE has not prepared a Statement of Energy Effects on this proposed rule.

L. Information Quality

On December 16, 2004, OMB, in consultation with the Office of Science and Technology Policy (''OSTP''), issued its Final Information Quality Bulletin for Peer Review (''the Bulletin''). 70 FR 2664 (Jan. 14, 2005). The Bulletin establishes that certain scientific information shall be peer reviewed by qualified specialists before it is disseminated by the Federal Government, including influential scientific information related to agency regulatory actions. The purpose of the Bulletin is to enhance the quality and credibility of the Government's scientific information. Under the Bulletin, the energy conservation standards rulemaking analyses are ''influential scientific information,'' which the Bulletin defines as ''scientific information the agency reasonably can determine will have, or does have, a clear and substantial impact on important public policies or private sector decisions.'' 70 FR 2664, 2667.

In response to OMB's Bulletin, DOE conducted formal peer reviews of the energy conservation standards development process and the analyses that are typically used and has prepared a report describing that peer review.[125]

[125] The 2007 ''Energy Conservation Standards Rulemaking Peer Review Report'' is available at the following website: *energy.gov/eere/buildings/downloads/energy-conservation-standards-rulemaking-peer-review-report-0* (last accessed 10/27/21).

Generation of this report involved a rigorous, formal, and documented evaluation using objective criteria and qualified and independent reviewers to make a judgment as to the technical/scientific/business merit, the actual or anticipated results, and the productivity and management effectiveness of programs and/or projects. Because available data, models, and technological understanding have changed since 2007, DOE has engaged with the National Academy of Sciences to review DOE's analytical methodologies to ascertain whether modifications are needed to improve the Department's analyses. DOE is in the process of evaluating the resulting report.[126]

M. Description of Materials Incorporated by Reference

In this NOPR, DOE is proposing to incorporate by reference the standard published by UL, titled, Standard For Pool Pump Motors, UL 1004–10:2022. UL 1004–10:2022 establishes definitions for certain pool pump motors, and includes test requirements to verify variable-speed capability and applicable freeze protection design requirements. UL 1004–10 is readily available at UL's website at *https://www.shopulstandards.com/ProductDetail.aspx?productId=UL1004-10_1_S_20200228.*

VII. Public Participation

A. Participation in the Webinar

The time and date of the webinar meeting are listed in the **DATES** section at the beginning of this document. Webinar registration information, participant instructions, and information about the capabilities available to webinar participants will be published on DOE's website: *www.energy.gov/eere/buildings/public-meetings-and-comment-deadlines* Participants are responsible for ensuring their systems are compatible with the webinar software.

B. Procedure for Submitting Prepared General Statements for Distribution

Any person who has an interest in the topics addressed in this document, or who is representative of a group or class of persons that has an interest in these issues, may request an opportunity to make an oral presentation at the webinar. Such persons may submit to *ApplianceStandardsQuestions@ee.doe.gov.* Persons who wish to speak should include with their request a computer file in WordPerfect, Microsoft Word, PDF, or text (ASCII) file format that briefly describes the nature of their interest in this rulemaking and the topics they wish to discuss. Such persons should also provide a daytime telephone number where they can be reached.

Persons requesting to speak should briefly describe the nature of their interest in this rulemaking and provide a telephone number for contact. DOE requests persons selected to make an oral presentation to submit an advance copy of their statements at least two weeks before the webinar. At its discretion, DOE may permit persons who cannot supply an advance copy of their statement to participate, if those persons have made advance alternative arrangements with the Building Technologies Office. As necessary, requests to give an oral presentation should ask for such alternative arrangements.

C. Conduct of the Webinar

DOE will designate a DOE official to preside at the webinar and may also use a professional facilitator to aid discussion. The meeting will not be a judicial or evidentiary-type public hearing, but DOE will conduct it in accordance with section 336 of EPCA (42 U.S.C. 6306). A court reporter will be present to record the proceedings and prepare a transcript. DOE reserves the right to schedule the order of presentations and to establish the procedures governing the conduct of the webinar. There shall not be discussion of proprietary information, costs or prices, market share, or other commercial matters regulated by U.S. anti-trust laws. After the webinar and until the end of the comment period, interested parties may submit further comments on the proceedings and any aspect of the rulemaking.

The public meeting will be conducted in an informal, conference style. DOE will present a general overview of the topics addressed in this proposed rulemaking, allow time for prepared general statements by participants, and encourage all interested parties to share their views on issues affecting this proposed rulemaking. Each participant will be allowed to make a general statement (within time limits determined by DOE), before the discussion of specific topics. DOE will allow, as time permits, other participants to comment briefly on any general statements.

At the end of all prepared statements on a topic, DOE will permit participants to clarify their statements briefly. Participants should be prepared to answer questions by DOE and by other participants concerning these issues. DOE representatives may also ask questions of participants concerning other matters relevant to this proposed rulemaking. The official conducting the public meeting will accept additional comments or questions from those attending, as time permits. The presiding official will announce any further procedural rules or modification of the previous procedures that may be needed for the proper conduct of the public meeting.

A transcript of the public meeting will be included in the docket, which can be viewed as described in the *Docket* section at the beginning of this document and will be accessible on the DOE website. In addition, any person may buy a copy of the transcript from the transcribing reporter.

D. Submission of Comments

DOE will accept comments, data, and information regarding this proposed rule before or after the public meeting, but no later than the date provided in the **DATES** section at the beginning of this proposed rule. Interested parties may submit comments, data, and other information using any of the methods described in the **ADDRESSES** section at the beginning of this document.

Submitting comments via *www.regulations.gov.* The *www.regulations.gov* web page will require you to provide your name and contact information. Your contact information will be viewable to DOE Building Technologies staff only. Your contact information will not be publicly viewable except for your first and last names, organization name (if any), and submitter representative name (if any). If your comment is not processed properly because of technical difficulties, DOE will use this information to contact you. If DOE cannot read your comment due to technical difficulties and cannot contact you for clarification, DOE may not be able to consider your comment.

However, your contact information will be publicly viewable if you include it in the comment itself or in any documents attached to your comment. Any information that you do not want to be publicly viewable should not be included in your comment, nor in any document attached to your comment. Otherwise, persons viewing comments will see only first and last names, organization names, correspondence containing comments, and any documents submitted with the comments.

[126] The report is available at *www.nationalacademies.org/our-work/review-of-methods-for-setting-building-and-equipment-performance-standards.*

Do not submit to *www.regulations.gov* information for which disclosure is restricted by statute, such as trade secrets and commercial or financial information (hereinafter referred to as Confidential Business Information (''CBI'')). Comments submitted through *www.regulations.gov* cannot be claimed as CBI. Comments received through the website will waive any CBI claims for the information submitted. For information on submitting CBI, see the Confidential Business Information section.

DOE processes submissions made through *www.regulations.gov* before posting. Normally, comments will be posted within a few days of being submitted. However, if large volumes of comments are being processed simultaneously, your comment may not be viewable for up to several weeks. Please keep the comment tracking number that *www.regulations.gov* provides after you have successfully uploaded your comment.

Submitting comments via email. Comments and documents submitted via email also will be posted to *www.regulations.gov.* If you do not want your personal contact information to be publicly viewable, do not include it in your comment or any accompanying documents. Instead, provide your contact information in a cover letter. Include your first and last names, email address, telephone number, and optional mailing address. The cover letter will not be publicly viewable as long as it does not include any comments.

Include contact information each time you submit comments, data, documents, and other information to DOE. No telefacsimiles (''faxes'') will be accepted.

Comments, data, and other information submitted to DOE electronically should be provided in PDF (preferred), Microsoft Word or Excel, or text (ASCII) file format. Provide documents that are not secured, that are written in English, and that are free of any defects or viruses. Documents should not contain special characters or any form of encryption and, if possible, they should carry the electronic signature of the author.

Campaign form letters. Please submit campaign form letters by the originating organization in batches of between 50 to 500 form letters per PDF or as one form letter with a list of supporters' names compiled into one or more PDFs. This reduces comment processing and posting time.

Confidential Business Information. Pursuant to 10 CFR 1004.11, any person submitting information that he or she believes to be confidential and exempt by law from public disclosure should submit via email two well-marked copies: one copy of the document marked ''confidential'' including all the information believed to be confidential, and one copy of the document marked ''non-confidential'' with the information believed to be confidential deleted. DOE will make its own determination about the confidential status of the information and treat it according to its determination.

It is DOE's policy that all comments may be included in the public docket, without change and as received, including any personal information provided in the comments (except information deemed to be exempt from public disclosure).

E. Issues on Which DOE Seeks Comment

Although DOE welcomes comments on any aspect of this proposal, DOE is particularly interested in receiving comments and views of interested parties concerning the following issues:

(1) DOE seeks comment on updating the UL 1004–10 reference from the 2020 version to the 2022 version.

(2) DOE seeks comment on the proposed equipment classes for DPPP motors based on motor THP thresholds.

(3) DOE seeks comment on the technologies considered for higher DPPP motor efficiency. DOE seeks comment on whether other motor topologies should be considered as applicable in pool pumps.

(4) DOE seeks comment on the proposed representative units and associated DPPP applications used for the engineering analysis.

(5) DOE seeks comment on the efficiency levels, including the associated full load efficiencies and design requirements evaluated in the engineering analysis.

(6) DOE seeks comment on using a 1.37 manufacturer markup for the cost analysis.

(7) DOE seeks comment on the cost methodology and associated costs for each of efficiency levels evaluated in the engineering analysis, including any associated costs for the proposed freeze protection controls requirement.

(8) DOE seeks comment on the distribution channels identified for DPPP motors and fraction of sales that go through each of these channels.

(9) DOE seeks comment on the overall methodology to develop consumer samples and on the fraction of DPPP motor existing stock across the five following markets: (1) single-family homes with a swimming pool; (2) indoor swimming pools in commercial applications; (3) single-family community swimming pools; (4) multi-family community swimming pools; and (5) outdoor swimming pools in commercial applications.

(10) DOE seeks comment on the overall methodology and inputs used to estimate DPPP motor energy use. Specifically, DOE seeks feedback on the average daily operating hours and annual days of operation used in the energy use analysis.

(11) DOE seeks comment on the approach and inputs used to project an equipment price trend for DPPP motors.

(12) DOE seeks comment on installation costs estimates used in the LCC analysis.

(13) DOE seeks comment on its decision to not include DPPP motor repair and maintenance costs in the LCC analysis.

(14) DOE seeks comment on the approach and inputs used to develop DPPP motor lifetime estimates.

(15) DOE seeks comment on the approach and inputs used to develop no-new standards case efficiency distributions in 2021. DOE seeks feedback on the approach used to project no-new standards case efficiency distributions in future years.

(16) DOE seeks comment on the approach and inputs used to develop base year shipments and for DPPP motors.

(17) DOE seeks comment on the approach and inputs used to develop no-new standards case shipments projections.

(18) DOE seeks comment on the approach and inputs used to develop the different standards case shipments projections. Specifically, at TSL 6. DOE requests information and feedback on the estimated fraction of standard-size DPPP motors used in small self-priming pool filter pumps and in non-self-priming pool filter pumps that will downsize to small-size DPPP motors.

(19) DOE requests information regarding the impact of cumulative regulatory burden on manufacturers of DPPP motors associated with multiple DOE standards or product-specific regulatory actions of other Federal agencies.

(20) DOE requests comment on its findings that there is one domestic small business that manufactures DPPP motors and on its estimate of the potential impacts on this small business.

Additionally, DOE welcomes comments on other issues relevant to the conduct of this proposed rulemaking that may not specifically be identified in this document.

VIII. Approval of the Office of the Secretary

The Secretary of Energy has approved publication of this notice of proposed rulemaking and announcement of public meeting.

List of Subjects

10 CFR Part 429

Administrative practice and procedure, Confidential business information, Energy conservation, Household appliances, Incorporation by reference, Reporting and recordkeeping requirements.

10 CFR Part 431

Administrative practice and procedure, Confidential business information, Energy conservation test procedures, Incorporation by reference, and Reporting and recordkeeping requirements.

Signing Authority

This document of the Department of Energy was signed on May 25, 2022, by Kelly J. Speakes-Backman, Principal Deputy Assistant Secretary for Energy Efficiency and Renewable Energy, pursuant to delegated authority from the Secretary of Energy. That document with the original signature and date is maintained by DOE. For administrative purposes only, and in compliance with requirements of the Office of the Federal Register, the undersigned DOE Federal Register Liaison Officer has been authorized to sign and submit the document in electronic format for publication, as an official document of the Department of Energy. This administrative process in no way alters the legal effect of this document upon publication in the **Federal Register**.

Signed in Washington, DC, on May 26, 2022.

Treena V. Garrett,

Federal Register Liaison Officer, U.S. Department of Energy.

For the reasons set forth in the preamble, DOE proposes to amend parts 429 and 431 of chapter II, title 10 of the Code of Federal Regulations, as set forth below:

PART 429—CERTIFICATION, COMPLIANCE, AND ENFORCEMENT FOR CONSUMER PRODUCTS AND COMMERCIAL AND INDUSTRIAL EQUIPMENT

■ 1. The authority citation for part 429 continues to read as follows:

Authority: 42 U.S.C. 6291–6317; 28 U.S.C. 2461 note.

■ 2. Amend § 429.4 by revising paragraph (a) and adding paragraph (g) to read as follows:

§ 429.4 Materials incorporated by reference.

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, DOE must publish a document in the **Federal Register** and the material must be available to the public. All approved material is available for inspection at DOE, and at the National Archives and Records Administration (NARA). Contact DOE at: the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Building Technologies Program, Sixth Floor, 950 L'Enfant Plaza SW, Washington, DC 20024, (202) 586–9127, *Buildings@ee.doe.gov, www.energy.gov/eere/buildings/building-technologies-office.* For information on the availability of this material at NARA, email: *fr.inspection@nara.gov,* or go to: *www.archives.gov/federal-register/cfr/ibr-locations.html.* The material may be obtained from the sources in the following paragraphs of this section:

* * * * *

(g) *UL.* Underwriters Laboratories, 333 Pfingsten Road, Northbrook, IL 60062, (841) 272–8800, or go to *https://www.ul.com.*

(1) UL 1004–10:2022, ''Standard for Safety for Pool Pump Motors,'' First Edition, Dated February 28, 2020, including revisions through March 24, 2022; IBR approved for § 429.134.

(2) [Reserved]

■ 3. Amend § 429.134 by adding paragraph (s) to read as follows:

§ 429.134 Product-specific enforcement provisions.

* * * * *

(s) *Dedicated-purpose pool pump motors.*

(1) To verify the dedicated-purpose pool pump motor variable speed capability, a test in accordance with Section 5 of UL 1004–10:2022 (incorporated by reference, see § 429.4) will be conducted.

(2) To verify that dedicated-purpose pool pump motor comply with the applicable freeze protection design requirements, a test in accordance with Section 6 of UL 1004–10:2022 will be conducted.

PART 431—ENERGY EFFICIENCY PROGRAM FOR CERTAIN COMMERCIAL AND INDUSTRIAL EQUIPMENT

■ 4. The authority citation for part 431 continues to read as follows:

Authority: 42 U.S.C. 6291–6317; 28 U.S.C. 2461 note.

■ 5. Section 431.481(b) is revised to read as follows:

§ 431.481 Purpose and scope.

* * * * *

(b) *Scope.* The requirements of this subpart apply to dedicated-purpose pool pump motors, as specified in paragraphs 1.2, 1.3 and 1.4 of UL 1004–10:2022 (incorporated by reference, see § 431.482).

* * * * *

■ 6. Section 431.482 is amended by revising paragraphs (a) and (c)(1) to read as follows:

§ 431.482 Materials incorporated by reference.

(a) Certain material is incorporated by reference into this subpart with the approval of the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, DOE must publish a document in the **Federal Register** and the material must be available to the public. All approved material is available for inspection at DOE, and at the National Archives and Records Administration (NARA). Contact DOE at: the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Building Technologies Program, Sixth Floor, 950 L'Enfant Plaza SW, Washington, DC 20024, (202) 586–9127, *Buildings@ee.doe.gov, https://www.energy.gov/eere/buildings/building-technologies-office.* For information on the availability of this material at NARA, email: *fr.inspection@nara.gov,* or go to: *www.archives.gov/federal-register/cfr/ibr-locations.html.* The material may be obtained from the sources in the following paragraphs of this section:

* * * * *

(c) * * *

(1) UL 1004–10 (1004–10:2022), ''Standard for Safety for Pool Pump Motors,'' First Edition, Dated February 28, 2020, including revisions through March 24, 2022; IBR approved for §§ 431.481 and 431.483.

* * * * *

■ 7. Section 431.483 is revised to read as follows:

§ 431.483 Definitions.

The definitions applicable to this subpart are defined in Section 2 ''Glossary'' of UL 1004–10:2022 (incorporated by reference, see § 431.482). In addition, the following definition applies:

Basic model means all units of dedicated purpose pool pump motors manufactured by a single manufacturer, that are within the same equipment class, have electrical characteristics that are essentially identical, and do not have any differing physical or functional characteristics that affect energy consumption or efficiency.

■ 8. Section 431.485 is added to subpart Z to read as follows:

§ 431.485 Energy conservation standards.

(a) For the purpose of paragraph (b) of this section, ''THP'' means dedicated-purpose-pool pump motor total horsepower.

(b) Each dedicated-purpose pool pump motor manufactured starting on [*date 24 months after date of final rule publication in the* **Federal Register**] with a THP less than 0.5 THP, must have a full-load efficiency that is not less than 69 percent.

(c) All dedicated-purpose pool pump motors manufactured starting on [*date 24 months after date of final rule publication in the* **Federal Register**] with a THP greater than or equal to 0.5 THP must be a variable speed control dedicated-purpose pool pump motor.

(d) For all dedicated-purpose pool pump motors with a THP greater than or equal to 0.5 THP, distributed in commerce with freeze protection controls, the motor must be shipped with freeze protection disabled or with the following default, user-adjustable settings:

(1) The default dry-bulb air temperature setting is no greater than 40 °F;

(2) The default run time setting shall be no greater than 1 hour (before the temperature is rechecked); and

(3) The default motor speed (in revolutions per minute, or rpm) in freeze protection mode shall not be more than half of the maximum operating speed.

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Part IV

The President

Executive Order 14075—Advancing Equality for Lesbian, Gay, Bisexual, Transgender, Queer, and Intersex Individuals

Federal Register
Vol. 87, No. 118
Tuesday, June 21, 2022

Presidential Documents

Title 3—

The President

Executive Order 14075 of June 15, 2022

Advancing Equality for Lesbian, Gay, Bisexual, Transgender, Queer, and Intersex Individuals

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered as follows:

Section 1. *Policy.* Our Nation has made great strides in fulfilling the fundamental promises of freedom and equality for lesbian, gay, bisexual, transgender, queer, and intersex (LGBTQI+) Americans, owing to the leadership of generations of LGBTQI+ individuals. In spite of this historic progress, LGBTQI+ individuals and families still face systemic discrimination and barriers to full participation in our Nation's economic and civic life. These disparities and barriers can be the greatest for transgender people and LGBTQI+ people of color. Today, unrelenting political and legislative attacks at the State level—on LGBTQI+ children and families in particular—threaten the civil rights gains of the last half century and put LGBTQI+ people at risk. These attacks defy our American values of liberty and dignity, corrode our democracy, and threaten basic personal safety. They echo the criminalization that LGBTQI+ people continue to face in some 70 countries around the world. The Federal Government must defend the rights and safety of LGBTQI+ individuals.

It is therefore the policy of my Administration to combat unlawful discrimination and eliminate disparities that harm LGBTQI+ individuals and their families, defend their rights and safety, and pursue a comprehensive approach to delivering the full promise of equality for LGBTQI+ individuals, consistent with Executive Order 13988 of January 20, 2021 (Preventing and Combating Discrimination on the Basis of Gender Identity or Sexual Orientation).

The Federal Government must take action to address the significant disparities that LGBTQI+ youth face in the foster care system, the misuse of State and local child welfare agencies to target LGBTQI+ youth and families, and the mental health needs of LGBTQI+ youth. My Administration must safeguard LGBTQI+ youth from dangerous practices like so-called ''conversion therapy''—efforts to suppress or change an individual's sexual orientation, gender identity, or gender expression—a discredited practice that research indicates can cause significant harm, including higher rates of suicide-related thoughts and behaviors by LGBTQI+ youth. The Federal Government must strengthen the supports for LGBTQI+ students in our Nation's schools and other education and training programs. It must also address the discrimination and barriers that LGBTQI+ individuals and families face by expanding access to comprehensive health care, including reproductive health; protecting the rights of LGBTQI+ older adults; and preventing and addressing LGBTQI+ homelessness and housing instability. Through these actions, the Federal Government will help ensure that every person—regardless of who they are or whom they love—has the opportunity to live freely and with dignity.

Sec. 2. *Addressing Harmful and Discriminatory Legislative Attacks on LGBTQI+ Children, Youth, and Families.* (a) The Secretary of Health and Human Services (HHS) shall, as appropriate and consistent with applicable law, use the Department of HHS's authorities to protect LGBTQI+ individuals' access to medically necessary care from harmful State and local laws and practices, and shall promote the adoption of promising policies and practices to support health equity, including in the area of mental health care, for

LGBTQI+ youth and adults. Within 200 days of the date of this order, the Secretary of HHS shall develop and release sample policies for States to safeguard and expand access to health care for LGBTQI+ individuals and their families, including mental health services.

(b) The Secretary of Education shall, as appropriate and consistent with applicable law, use the Department of Education's authorities to support LGBTQI+ students, their families, educators, and other school personnel targeted by harmful State and local laws and practices, and shall promote the adoption of promising policies and practices to support the safety, well-being, and rights of LGBTQI+ students. Within 200 days of the date of this order, the Secretary of Education shall develop and release sample policies for supporting LGBTQI+ students' well-being and academic success in schools and educational institutions.

Sec. 3. *Addressing Exposure to So-Called Conversion Therapy.* (a) The Secretary of HHS shall establish an initiative to reduce the risk of youth exposure to so-called conversion therapy. As part of that initiative, the Secretary of HHS shall, as appropriate and consistent with applicable law:

(i) consider whether to issue guidance clarifying for HHS programs and services agencies that so-called conversion therapy does not meet criteria for use in federally funded health and human services programs;

(ii) increase public awareness of the harms and risks associated with so-called conversion therapy for LGBTQI+ youth and their families;

(iii) increase the availability of technical assistance and training to health care and social service providers on evidence-informed promising practices for supporting the health, including mental health, of LGBTQI+ youth, and on the dangers of so-called conversion therapy; and

(iv) seek funding opportunities for providers of evidence-based trauma-informed services to better support survivors of so-called conversion therapy.

(b) The Federal Trade Commission is encouraged to consider whether so-called conversion therapy constitutes an unfair or deceptive act or practice, and to issue such consumer warnings or notices as may be appropriate.

(c) To address so-called conversion therapy around the world, within 180 days of the date of this order, the Secretary of State, in collaboration with the Secretary of the Treasury, the Secretary of HHS, and the Administrator of the United States Agency for International Development, shall develop an action plan to promote an end to its use around the world. In developing the action plan, the Secretary of State shall consider the use of United States foreign assistance programs and the United States voice and vote in multilateral development banks and international development institutions of which the United States is a shareholder or donor to take appropriate steps to prevent the use of so-called conversion therapy, as well as to help ensure that United States foreign assistance programs do not use foreign assistance funds for so-called conversion therapy. To further critical data collection, the Secretary of State shall instruct all United States Embassies and Missions worldwide to submit additional information on the practice and incidence of so-called conversion therapy as part of the Country Reports on Human Rights Practices.

Sec. 4. *Promoting Family Counseling and Support of LGBTQI+ Youth as a Public Health Priority of the United States.* (a) ''Family counseling and support programs'' are defined for the purposes of this order as voluntary programs in which families and service providers may elect to participate that seek to prevent or reduce behaviors associated with family rejection of LGBTQI+ youth by providing developmentally appropriate support, counseling, or information to parents, families, caregivers, child welfare and school personnel, or health care professionals on how to support an LGBTQI+ youth's safety and well-being.

(b) The Secretary of HHS shall seek to expand the availability of family counseling and support programs in federally funded health, human services, and child welfare programs by:

(i) considering whether to issue guidance regarding the extent to which Federal funding under Title IV–B and IV–E of the Social Security Act, 42 U.S.C. Ch. 7, may be used to provide family counseling and support programs;

(ii) considering funding opportunities for programs that implement family counseling and support models;

(iii) considering opportunities through the Centers for Disease Control and Prevention (CDC) and the National Institutes of Health to increase Federal research into the impacts of family rejection and family support on the mental health and long-term well-being of LGBTQI+ individuals; and

(iv) ensuring that HHS data, investments, resources, and partnerships related to the CDC Adverse Childhood Experiences program address the disparities faced by LGBTQI+ children and youth.

Sec. 5. *Addressing Discrimination and Barriers Faced by LGBTQI+ Children, Youth, Parents, Caretakers, and Families in the Child Welfare System and Juvenile Justice Systems.* (a) The Secretary of HHS shall consider how to use the Department's authorities to strengthen non-discrimination protections on the basis of sex, including sexual orientation, gender identity, and sex characteristics, in its programs and services, consistent with Executive Order 13988 and applicable legal requirements.

(b) The Secretary of HHS shall direct the Assistant Secretary for Family Support to establish an initiative to partner with State child welfare agencies to help address and eliminate disparities in the child welfare system experienced by LGBTQI+ children, parents, and caregivers, including: the over-representation of LGBTQI+ youth in the child welfare system, including over-representation in congregate placements; disproportionately high rates of abuse, and placements in unsupportive or hostile environments faced by LGBTQI+ youth in foster care; disproportionately high rates of homelessness faced by LGBTQI+ youth who exit foster care; and discrimination faced by LGBTQI+ parents, kin, and foster and adoptive families. The initiative, as appropriate and consistent with applicable law, shall also take actions to:

(i) seek funding opportunities for programs and services that improve outcomes for LGBTQI+ children in the child welfare system;

(ii) provide increased training and technical assistance to State child welfare agencies and child welfare personnel on promising practices to support LGBTQI+ youth in foster care and LGBTQI+ parents and caregivers;

(iii) develop sample policies for supporting LGBTQI+ children, parents, and caregivers in the child welfare system;

(iv) promote equity and inclusion for LGBTQI+ foster and adoptive parents in their interactions with the child welfare system;

(v) evaluate the rate of child removals from LGBTQI+ families of origin, in particular families that include LGBTQI+ women of color, and develop proposals to address any disproportionate rates of child removals faced by such families;

(vi) assess and improve the responsible collection and use of data on sexual orientation and gender identity in the child welfare system to measure and address inequities faced by LGBTQI+ children, parents, and caregivers, while safeguarding the privacy, safety, and civil rights of LGBTQI+ youth; and

(vii) advance policies that help to prevent the placement of LGBTQI+ youth in foster and congregate care environments that will be hostile to their gender identity or sexual orientation.

(c) The Attorney General shall establish a clearinghouse within the Office of Juvenile Justice and Delinquency Prevention to provide effective training, technical assistance, and other resources for jurisdictions seeking to better serve LGBTQI+ youth using a continuum-of-care framework. The clearinghouse shall include juvenile justice and delinquency prevention programs addressing the needs, including mental health needs, of LGBTQI+ youth.

Sec. 6. *Reviewing Eligibility Standards for Federal Benefits and Programs.* (a) Within 180 days of the date of this order, the Secretary of HHS shall conduct a study on the impact that current Federal statutory and regulatory eligibility standards have on the ability of LGBTQI+ and other households as determined by the Secretary to access Federal benefits and programs for families, and shall produce a public report with findings and recommendations that could increase LGBTQI+ and such other households' participation in and eligibility for Federal benefits and programs for families.

(b) Within 100 days of the release of the recommendations required by subsection (a) of this section, the Director of the Office of Management and Budget (OMB) shall coordinate with executive departments and agencies (agencies) that administer programs that establish eligibility standards for participation by families to complete a review of agencies' current eligibility standards for families. Such agencies shall seek opportunities, consistent with applicable law, to adopt more inclusive eligibility standards in line with the recommendations in the report produced pursuant to subsection (a) of this section.

Sec. 7. *Safeguarding Access to Health Care and Other Health Supports for LGBTQI+ Individuals*. The Secretary of HHS shall establish an initiative to address the health disparities facing LGBTQI+ youth and adults, take steps to prevent LGBTQI+ suicide, and address the barriers and exclusionary policies that LGBTQI+ individuals and families face in accessing quality, affordable, comprehensive health care, including mental health care, reproductive health care, and HIV prevention and treatment. As part of that initiative, the Secretary of HHS shall, as appropriate and consistent with applicable law:

(a) seek funding opportunities related to health, including mental health, for LGBTQI+ individuals, especially youth, including resources for the Nation's suicide prevention and crisis support services to support LGBTQI+ individuals;

(b) promote expanded access to comprehensive health care for LGBTQI+ individuals, including by working with States on expanding access to gender-affirming care;

(c) issue guidance through the Substance Abuse and Mental Health Services Administration and the Office of the Assistant Secretary for Health, within 100 days of the date of this order, on providing evidence-informed mental health care and substance use treatment and support services for LGBTQI+ youth; and

(d) develop and issue a report, within 1 year of the date of this order, and after consultation with medical experts, medical associations, and individuals with lived expertise, on promising practices for advancing health equity for intersex individuals.

Sec. 8. *Supporting LGBTQI+ Students in our Nation's Schools and Educational Institutions.* The Secretary of Education shall establish a Working Group on LGBTQI+ Students and Families, which shall lead an initiative to address discrimination against LGBTQI+ students and strengthen supports for LGBTQI+ students and families. Through that Working Group, the Secretary of Education shall, as appropriate and consistent with applicable law:

(a) review, revise, develop, and promote guidance, technical assistance, training, promising practices, and sample policies for States, school districts, and other educational institutions to promote safe and inclusive learning environments in which all LGBTQI+ students thrive and to address bullying of LGBTQI+ students;

(b) identify promising practices for helping to ensure that school-based health services and supports, especially mental health services, are accessible to and supportive of LGBTQI+ students;

(c) seek funding opportunities for grantees and programs that will improve educational and health outcomes, especially mental health outcomes, for LGBTQI+ students and other underserved students; and

(d) seek to strengthen supportive services for LGBTQI+ students and families experiencing homelessness, including those provided by the National Center for Homeless Education.

Sec. 9. *Preventing and Ending LGBTQI+ Homelessness and Housing Instability.* (a) The Secretary of Housing and Urban Development (HUD) shall establish a Working Group on LGBTQI+ Homelessness and Housing Equity, which shall lead an initiative that aims to prevent and address homelessness and housing instability among LGBTQI+ individuals, including youth, and households. As part of that initiative, the Secretary of HUD shall, as appropriate and consistent with applicable law:

(i) identify and address barriers to housing faced by LGBTQI+ individuals, including youth, and families that place them at high risk of housing instability and homelessness;

(ii) provide guidance and technical assistance to HUD contractors, grantees, and programs on effectively and respectfully serving LGBTQI+ individuals, including youth, and families;

(iii) develop and provide guidance, sample policies, technical assistance, and training to Continuums of Care, established pursuant to HUD's Continuum of Care Program; homeless service providers; and housing providers to improve services and outcomes for LGBTQI+ individuals, including youth, and families who are experiencing or are at risk of homelessness, and to ensure compliance with the Fair Housing Act, 42 U.S.C. 3601 *et seq.,* and HUD's 2012 and 2016 Equal Access Rules; and

(iv) seek funding opportunities, including through the Youth Homelessness Demonstration Program, for culturally appropriate services that address barriers to housing for LGBTQI+ individuals, including youth, and families, and the high rates of LGBTQI+ youth homelessness.

(b) The Secretary of HHS, through the Assistant Secretary for Family Support, shall, as appropriate and consistent with applicable law:

(i) use agency guidance, training, and technical assistance to implement non-discrimination protections on the basis of sexual orientation and gender identity in programs established pursuant to the Runaway and Homeless Youth Act (Public Law 110–378), and ensure that such programs address LGBTQI+ youth homelessness; and

(ii) coordinate with youth advisory boards funded through the Runaway and Homeless Youth Training and Technical Assistance Center and the National Runaway Safeline to seek input from LGBTQI+ youth who have experienced homelessness on improving federally funded services and programs.

Sec. 10. *Strengthening Supports for LGBTQI+ Older Adults.* The Secretary of HHS shall address discrimination, social isolation, and health disparities faced by LGBTQI+ older adults, including by:

(a) developing and publishing guidance on non-discrimination protections on the basis of sex, including sexual orientation, gender identity, and sex characteristics, and other rights of LGBTQI+ older adults in long-term care settings;

(b) developing and publishing a document parallel to the guidance required by subsection (a) of this section in plain language, titled "Bill of Rights for LGBTQI+ Older Adults," to support LGBTQI+ older adults and providers in understanding the rights of LGBTQI+ older adults in long-term care settings;

(c) considering whether to issue a notice of proposed rulemaking to clarify that LGBTQI+ individuals are included in the definition of "greatest social need" for purposes of targeting outreach, service provision, and funding under the Older Americans Act, 42 U.S.C. 3001 *et seq.;* and

(d) considering ways to improve and increase appropriate data collection on sexual orientation and gender identity in surveys on older adults, including by providing technical assistance to States on the collection of such data.

Sec. 11. *Promoting Inclusive and Responsible Federal Data Collection Practices.* (a) Advancing equity and full inclusion for LGBTQI+ individuals requires that the Federal Government use evidence and data to measure and address the disparities that LGBTQI+ individuals, families, and households face, while safeguarding privacy, security, and civil rights.

(b) To advance the responsible and effective collection and use of data on sexual orientation, gender identity, and sex characteristics (SOGI data), the Co-Chairs of the Interagency Working Group on Equitable Data established in Executive Order 13985 of January 20, 2021 (Advancing Racial Equity and Support for Underserved Communities Through the Federal Government), shall, within 30 days of the date of this order, establish a subcommittee on SOGI data to coordinate with agencies on strengthening the Federal Government's collection of SOGI data to advance equity for LGBTQI+ individuals. Within 120 days of the date of this order, the subcommittee shall, in coordination with the Director of OMB, develop and release a Federal Evidence Agenda on LGBTQI+ Equity, which shall:

(i) describe disparities faced by LGBTQI+ individuals that could be better understood through Federal statistics and data collection;

(ii) identify, in coordination with agency Statistical Officials, Chief Science Officers, Chief Data Officers, and Evaluation Officers, Federal data collections where improved SOGI data collection may be important for advancing the Federal Government's ability to measure disparities facing LGBTQI+ individuals; and

(iii) identify practices for all agencies engaging in SOGI data collection to follow in order to safeguard privacy, security, and civil rights, including with regard to appropriate and robust practices of consent for the collection of this data and restrictions on its use or transfer.

(c) Within 200 days of the date of this order, the head of each agency that conducts relevant programs or statistical surveys related to the Federal Evidence Agenda on LGBTQI+ Equity shall submit to the Co-Chairs of the Interagency Working Group on Equitable Data a SOGI Data Action Plan, which shall detail how the agency plans to use SOGI data to advance equity for LGBTQI+ individuals and shall identify how the agency plans to implement the recommendations in the Federal Evidence Agenda on LGBTQI+ Equity.

(d) To support implementation of agency SOGI Data Action Plans, the head of each agency shall include in the agency's annual budget submission to the Director of OMB a request for any necessary funding increases to support improved SOGI data practices.

(e) Within 180 days of the date of this order, to support agencies in appropriately collecting and using SOGI data, the Director of OMB, through the Chief Statistician of the United States, shall publish a report with recommendations for agencies on the best practices for the collection of SOGI data on Federal statistical surveys, including strategies to preserve data privacy and safety.

(f) On an annual basis, the Director of OMB, through the Chief Statistician of the United States, shall evaluate the efficacy of SOGI data practices across agencies, and shall consider whether to update reports, guidance, or directives based upon the latest evidence and research as needed.

Sec. 12. *Reporting.* Within 1 year of the date of this order:

(a) The Attorney General shall submit a report to the President through the Assistant to the President for Domestic Policy (APDP) detailing progress in implementing section 5 of this order;

(b) The Secretary of HHS shall submit a report to the President through the APDP detailing progress in implementing sections 2 through 7 and 9 through 11 of this order;

(c) The Secretary of Education shall submit a report to the President through the APDP detailing progress in implementing sections 2, 8, and 11 of this order;

(d) The Secretary of HUD shall submit a report to the President through the APDP detailing progress in implementing sections 9 and 11 of this order;

(e) The Secretary of State shall submit a report to the President through the APDP detailing progress in implementing section 3 of this order;

(f) The Director of OMB shall submit a report to the President through the APDP detailing progress in implementing sections 6 and 11 of this order; and

(g) The Director of OMB, through the Chief Statistician of the United States, shall submit a report to the President through the APDP detailing progress in implementing section 11 of this order.

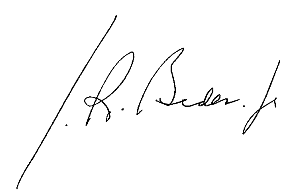
Sec. 13. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



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LIST OF PUBLIC LAWS

This is a continuing list of public bills from the current session of Congress which have become Federal laws. This list is also available online at *https://www.archives.gov/federal-register/laws*.

The text of laws is not published in the **Federal Register** but may be ordered in "slip law" (individual pamphlet) form from the Superintendent of Documents, U.S. Government Publishing Office, Washington, DC 20402 (phone, 202–512–1808). The text will also be made available at *https://www.govinfo.gov*. Some laws may not yet be available.

S. 3580/P.L. 117–146
Ocean Shipping Reform Act of 2022 (June 16, 2022; 136 Stat. 1272)

H.R. 3613/P.L. 117–147
To designate the facility of the United States Postal Service located at 202 Trumbull Street in Saint Clair, Michigan, as the "Corporal Jeffrey Robert Standfest Post Office Building". (June 16, 2022; 136 Stat. 1287)

S. 4160/P.L. 117–148
Supreme Court Police Parity Act of 2022 (June 16, 2022; 136 Stat. 1288)

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