■ 23. Add § 721.10535 to subpart E to read as follows:

§ 721.10535 Phosphonium, tributyltetradecyl-, chloride (1:1).

(a) Chemical substance and significant new uses subject to reporting. (1) The chemical substance identified as phosphonium, tributyltetradecyl-, chloride (1:1) (PMN P–12–275; CAS No. 81741–28–8) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are:

(i) *Release to water.* Requirements as specified in § 721.90(a)(1), (b)(1), and (c)(1).

(ii) [Reserved]

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

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

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

[FR Doc. 2012–20039 Filed 8–14–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 49

[EPA–R08–OAR–2012–0479; FRL–9710–4]

Approval and Promulgation of Federal Implementation Plan for Oil and Natural Gas Well Production Facilities; Fort Berthold Indian Reservation (Mandan, Hidatsa, and Arikara Nations), ND

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is taking final action to promulgate a Reservation-specific Federal Implementation Plan in order to regulate emissions from oil and natural gas production facilities located on the Fort Berthold Indian Reservation located in North Dakota. The Federal Implementation Plan includes basic air quality regulations for the protection of communities in and adjacent to the Fort Berthold Indian Reservation. The Federal Implementation Plan requires owners and operators of oil and natural gas production facilities to reduce emissions of volatile organic compounds emanating from well completions, recompletions, and production and storage operations. This Federal Implementation Plan will be implemented by EPA, or a delegated Tribal Authority, until replaced by a Tribal Implementation Plan. EPA is proposing a Reservation-specific Federal Implementation Plan concurrently with this final rule.

DATES: This rule is effective in the CFR on August 15, 2012. This rule is effective with actual notice by EPA to the owners and operators for purposes of enforcement beginning at 5 p.m. (eastern daylight time) on August 3, 2012.

Public Hearing: EPA will hold a public hearing on the following date: September 12, 2012. The hearing will start at 1 p.m. local time and continue until 4 p.m. or until everyone has had a chance to speak. Additionally, an evening session will be held from 6 p.m. until 8 p.m. The hearing will be held at the 4 Bears Casino & Lodge, 202 Frontage Rd, New Town, ND 58763, (701) 627–4018.

ADDRESSES:

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly-available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the following locations: Air Program, U.S. Environmental Protection Agency (EPA), Region 8, Mailcode 8P–AR, 1595 Wynkoop, Denver, Colorado 80202–1129; and Environmental Division, Three Affiliated Tribes, 204 West Main, New Town, North Dakota 58763–9404. EPA requests that if at all possible, you contact the individuals listed in the **FOR FURTHER INFORMATION CONTACT** section to view the hard copy of the docket. You may view the hard copy of the docket Monday through Friday, 8 a.m. to 4 p.m., excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: Deirdre Rothery, U. S. Environmental Protection Agency, Region 8, Air Program, Mail Code 8P–AR, 1595 Wynkoop Street, Denver, Colorado 80202–1129, (303) 312–6431, *rothery.deirdre@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document, "we," "us" and "our" refer to the EPA.

Definitions

For the purpose of this document, we are giving meaning to certain words or initials as follows:

(i) The initials *APA* mean or refer to the Administrative Procedure Act.

(ii) The words or initials *Act* or *CAA* mean or refer to the Clean Air Act, unless the context indicates otherwise.

(iii) The initials *BTU* mean or refer to British Thermal Unit.

(iv) The initials *CAFOs* mean or refer to Consent Agreement Final Orders.

(v) The initials *CDPHE* mean or refer to Colorado Department of Public Health and Environment Air Pollution Control Division.

(vi) The initials *CO* mean or refer to carbon monoxide.

(vii) The words *EPA, we, us* or *our* mean or refer to the United States Environmental Protection Agency.

(viii) The words Reservation or the initials *FBIR* mean or refer to the Fort Berthold Indian Reservation.

(ix) The initials *FIP* mean or refer to Federal Implementation Plan.

(x) The initials *GOR* mean or refer to gas-to-oil ratio.

(xi) The initials *LACT* mean or refer to lease automatic custody transfer.

(xii) The initials *MDEQ* mean or refer to Montana Department of Environmental Quality.

(xiii) The initials *NAAQS* mean or refer to the National Ambient Air Quality Standards.

(xiv) The initials *NAICS* mean or refer to the North American Industry Classification System.

(xv) The initials *NDDoH* mean or refer to the North Dakota Department of Health.

(xvi) The initials *NDIC* mean or refer to the North Dakota Industrial Commission.

(xvii) The initials *NESHAP* mean or refer to National Emission Standards for Hazardous Air Pollutants.

(xviii) The initials *NMED* mean or refer to New Mexico Environment Department Air Quality Bureau.

(xix) The initials NO_X mean or refer to nitrogen oxides.

(xx) The initials NO_2 mean or refer to nitrogen dioxide.

(xxi) The initials *NSPS* mean or refer to New Source Performance Standards.

(xxii) The initials *NSR* mean or refer to new source review.

(xxiii) The initials *ODEQ* mean or refer to Oklahoma Department of Environmental Quality Air Quality Division.

(xxiv) The initials *PM* mean or refer to particulate matter.

(xxv) The initials *PSD* mean or refer to prevention of significant deterioration.

(xxvi) The initials *PTE* mean or refer to potential to emit.

(xxvii) The initials *RCT* mean or refer to Railroad Commission of Texas, Oil and Gas Division.

(xxviii) The initials *SCADA* mean or refer to Supervisory Control and Data Acquisition.

(xxix) The initials *SIP* mean or refer to State Implementation Plan.

(xxx) The initials SO_2 mean or refer to sulfur dioxide.

(xxxi) The initials *TAR* mean or refer to Tribal Authority Rule.
(xxxii) The initials *TAS* mean or refer to treatment as state.
(xxxiii) The initials *TIP* mean or refer to Tribal Implementation Plan.
(xxxiv) The initials *UDEQ* mean or refer to Utah Department of Environmental Quality.
(xxxv) The initials *VOC* mean or refer to volatile organic compound(s).
(xxxvi) The initials *VRU* mean or refer to vapor recovery unit.
(xxxvii) The initials *WDEQ* mean or refer to Wyoming Department of Environmental Quality Air Quality Division.

Table of Contents

I. Justification for This Final Rule
A. Overview
B. Rationale for the Final Rule
II. Proposed Rulemaking
III. Background
A. Today's Action
B. Purpose of the Rule
C. Development of the Rule
D. Area and Facilities Covered by the FIP
E. Effect on Permitting of Facilities
F. Registration Requirements
G. Applicability to New and Existing and Modified Facilities
H. Attainment Status
I. Benefits and Costs
IV. The Fort Berthold Indian Reservation
V. EPA's Authority To Promulgate a FIP
VI. Summary of FIP Provisions
A. Applicability
B. Compliance Schedule
C. Provisions for Delegation of Administration to the Tribes
D. General Provisions
E. Construction and Operational Control Measures
F. Control Equipment Requirements
G. Monitoring Requirements
H. Recordkeeping Requirements
I. Reporting Requirements
VII. Statutory and Executive Order

I. Justification for This Final Rule

A. Overview

In today's action, we are promulgating a Reservation-specific Federal Implementation Plan (FIP or rule) to establish enforceable control requirements for reducing volatile organic compound (VOC) emissions from oil and natural gas production activities on the Fort Berthold Indian Reservation (FBIR) in North Dakota. Specifically, we are issuing this rule to require owners and operators of oil and natural gas production facilities producing from the Bakken Pool to reduce emissions of VOCs emanating from well completions, recompletions, and production and storage operations. As explained in more detail in Section III, promulgating these Federal regulations addresses an important initial step to fill a regulatory gap with regard to controlling VOC emissions from oil and natural gas operations on the FBIR. There is no other Federal rule, including the recently finalized New Source Performance Standard (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) for the Oil and Gas Sector (NSPS OOOO and NESHAP HH), that fills this gap for the particular geologic formations that exist on the FBIR. Therefore, this rule is necessary to level the playing field, and provide the public on the FBIR the same air quality protections as the public outside the FBIR. In addition, owners and operators of oil and natural gas operations on the FBIR are provided the same benefits that owners and operators of oil and natural gas operations off the Reservation are provided by the North Dakota Department of Health (NDDoH) regulations and North Dakota Industrial Commission (NDIC) regulations in terms of effectively limiting potential to emit (PTE).[1]

B. Rationale for the Final Rule

EPA is issuing this action as a final rule. As explained in Section III., the final rule requires owners and operators of oil and natural gas production facilities on the FBIR to reduce emissions of VOC for specific types of equipment. This final rule will take effect promptly. It will be effective in the CFR on August 15, 2012. It will also be effective, with actual notice by EPA to the owners and operators, for purposes of enforcement beginning at 5 p.m. (eastern daylight time) on August 3, 2012. This final rule is also time-limited. It will be effective only until the date that EPA promulgates a final rule based on its proposal for a Reservation-specific FIP to regulate emissions from oil and natural gas production facilities located on the FBIR and that final rule takes effect. EPA is proposing a Reservation-specific FIP concurrently with this final rule. As explained in detail below, EPA finds that compelling circumstances warrant the promulgation of this final rule.

A final rule is effective with actual notice upon signature by the EPA without an opportunity for public comment. Under APA section 553, a Federal agency generally must provide for public notice and comment prior to finalizing an agency rule. However, this obligation is excused, under APA section 553(b)(3)(B), "when the agency for good cause finds (and incorporates the finding and a brief statement of reasons therefore in the rules issued) that notice and public procedure thereon are impracticable, unnecessary, or contrary to the public interest." While the good cause exception is to be narrowly construed, *Utility Solid Waste Activities Group* v. *Environmental Protection Agency*, 236 F.3d 749, 754 (D.C. Cir. 2001), it is also "an important safety valve to be used where delay would do real harm." *U.S. Steel Corp.* v. *U.S. Environmental Protection Agency*, 595 F.2d 207, 214 (5th Cir. 1979). Notice and comment are impracticable where "an agency finds that due and timely execution of its functions would be impeded by the notice otherwise required." *Utility Solid Waste Activities Group*, 236 F.3d at 754. Notice and comment are contrary to the public interest where "the interest of the public would be defeated by any requirement of advance notice." *Id.* at 755.

A brief explanation of the circumstances is helpful to understand why Notice and comment here would be both contrary to the public interest and impracticable and therefore why there is good cause to implement this final rule while the agency conducts a notice and comment rulemaking for the permanent rule. The need to address VOC emissions from coproduced natural gas from oil and natural gas production sources on the FBIR was first brought to EPA's attention approximately 12 months ago, following publication of the Review of New Sources and Modifications in Indian Country or Federal Tribal NSR Rule, promulgated on July 1, 2011, at 40 CFR 49.151 (*see* 76 FR 38748). At that time, a significant number of entities engaged in oil and natural gas production operations on the FBIR informed EPA that the emissions of regulated air pollutants, including volatile organic compounds (VOCs), from oil and natural gas production facilities were significantly larger than they had previously understood. These emissions created a public health and safety hazard and were sufficiently large that hundreds of individual facilities would potentially be required to obtain major source PSD permits unless they were able to obtain legal and practicably enforceable emission limits on the facilities' potential-to-emit.

In August 2011, EPA and the operators entered into consent agreement final orders (CAFOs), which established control requirements that restricted emissions from the oil and natural gas production facilities subject to those agreements to below major source thresholds and allowed the

[1] Depending on the emissions characteristics of a particular well, compliance with the requirements of the FIP may or may not limit the well's PTE to below the major source thresholds such that the well is not subject to major source prevention of significant (PSD) permitting and/or to national emission standards for hazardous air pollutants (NESHAP) requirements.

operators to continue to operate pending issuance of appropriate permits.

In late August 2011, the EPA Region 8 initiated a process to develop, propose and issue permits to the hundreds of sources on the FBIR (both existing and proposed new wells) and to develop a FIP. At that time, EPA lacked detailed information to develop permits (*e.g.*, information about the facilities, emissions, and possible emission controls) and therefore, hosted numerous meetings from August through November 2011 to collect the necessary information and develop complete permit applications and draft permit language.[2] The EPA drafted and proposed the first batch of permits in March 2012,[3] and explained in our April 10, 2012 letter to Chairman Hall that "[t]he comment period for these permits will end on April 23, 2012, at which time we will consider comments and finalize these permits," noting that "these completed permits will form the basis for the FIP." While we had developed an example permit to provide predictability and a framework for permitting, it was clear that each permit would need to be developed on a case-by-case basis using information submitted in each application.

We initially planned to issue all of the necessary permits before August 26, 2012, the earliest expiration date of the CAFOs. However, in May 2012, the true extent of the significant workload associated with developing and finalizing permits for more than 600 existing and new oil and natural gas production facilities became apparent. It became clear that, due to the extraordinary number of permits that needed to be issued, the need to tailor each of those permits to comport with the information in the permit application and the short timeframe remaining to complete those tasks, it would not be possible to issue all, or even a significant portion of, the final permits by August 26, 2012. Moreover, given the rapid pace of oil and gas development on the FBIR, there are likely numerous additional sources that will each need a permit in addition to sources EPA is aware of at this time. We therefore determined that the only way to ameliorate the situation in a timely manner was through this rulemaking action. We contemplated developing the FIP in addition to issuing the individual permits, but determined that promulgating the FIP should be our top priority once we realized that we could not issue all of the necessary permits in a timely manner.

Key safety provisions of the final rule require either collection and high efficiency flaring (combustion) of coproduced natural gas or that the well(s) be connected to a natural gas gathering line so that coproduced natural gas can be sold or used for another beneficial purpose. Given the accelerated development in this area and the nature of the oil and gas extracted, these requirements are necessary for both safety and protection of public health from exposure to air pollution and will avoid fire hazards and protect the public from hazardous conditions. Specifically, the requirements further a number of important goals in that regard. First, as discussed in Section III.C., VOC emissions from the natural gas that is co-produced with oil extracted from the formations are generally greater than such emissions from activities in other oil bearing formations, due to the characteristics of the produced oil. The FIP requirements for owners and operators of the oil and natural gas production facilities to reduce emissions of VOCs emanating from well completions, recompletions and production and storage operations will significantly reduce VOC emissions thereby ensuring that public health and the environment are protected. Second, the rule will result in immediate reductions in fire risks and improvements in air quality as a result of control of emissions from both new and existing oil and gas operations. Accordingly, as a result of the unique characteristics of the formations at issue, immediate application of the FIP requirements to both new and existing oil and natural gas operations is necessary to ensure that public health and the environment, continue to be protected once consent agreement final orders (CAFOs) with EPA expire.

The requirements of the FIP also serve to minimize regulatory burden in a number of ways. This rule ensures that ongoing oil and gas operations (including modifications), and new operations, can occur uninterrupted in a manner consistent with the Clean Air Act (CAA), thus protecting the economic interest of both the companies and Tribes involved and the local communities. The oil and natural gas production companies operating on the FBIR entered into CAFOs with EPA which allowed them to continue existing operations and begin new ones without first complying with major source prevention of significant deterioration (PSD) new source review (NSR) requirements if applicable, which can be a very lengthy and resource-intensive process. These CAFOs are further discussed in Section III.G. The CAFOs, which contain emissions control and other requirements that are consistent with those in the rule adopted today, have been in place since August 2011 and will expire beginning on August 26, 2012,[4] a date which is rapidly approaching. In the absence of this rule, hundreds of new and existing oil and natural gas production sources on the FBIR that are subject to these CAFOs would be unable to continue to operate, construct or modify in compliance with CAA requirements without first obtaining a permit from EPA because they will have no legally and practicably enforceable requirements in place controlling VOC emissions, thus significantly disrupting ongoing economic activities and the benefits those activities bring to the communities of the Reservation.

As a result, without this final rule there will be a mixture of circumstances that will increase potential threats to human health and the environment while simultaneously impeding oil and gas development. This is because of the

[2] Resolving the challenges on the FBIR has been a top priority for EPA. The Agency has dedicated enormous resources to resolve these challenges at the Regional and National offices for nearly a year and continues to do so. EPA's efforts have included the following activities.

In late August 2011, the EPA Region 8 air permit and enforcement programs hosted a Fort Berthold Oil Production Minor NSR Permitting Process Meeting with the oil producers. Representatives from the MHA Nation were invited and attended in person and by phone. Discussions included the anticipated permitting timeline for permit applications submitted by the oil producers. Between August 23 and September 1, 2011, a draft model synthetic minor permit was sent by EPA to the meeting attendees and the Tribes in preparation for the next meeting on September 1, 2011. Then, on September 1, 2011, Region 8 hosted a permitting workshop. Representatives from the various oil producers and the MHA Nation were invited and attended. Representatives of the North Dakota Dept. of Health also participated by phone. The minor NSR permitting process was discussed, as well as questions that the companies submitted ahead of time. The group began discussions on the draft model permit and set up a workshop specifically to delve into the specific permit conditions for the following week. On September 7 and 8, 2011, EPA hosted a two-day follow-up permitting workshop. All previous meeting attendees were invited, including the MHA Nation. Participants included the oil producers and their consultants. North Dakota Department of Health representatives were also on the phone. At this meeting the group went through the draft model permit and discussed the proposed conditions and appropriate edits. Also discussed was what would constitute a complete application (administrative and technical) and the various methods of PTE calculation proposed by the companies in attendance. The EPA Region 8 hosted an additional meeting on November 30, 2011 to discuss the revised example permit, and representatives from the various oil producers and the MHA Nation were invited and attended.

[3] The draft permits that underwent a public review and comment period are available online at: *http://www.epa.gov/region8/air/permitting/pubcomment.html.*

[4] The FBIR CAFOs are included in the docket for this rule.

mix of current CAA obligations that currently apply to these wells. While many sources would first need to obtain a PSD permit to construct or would need to resolve ongoing violations to continue to operate, other sources could operate without obtaining a permit. Accordingly, sources that need to resolve permitting obligations would be delayed in construction or operation (impeding development) while those without permitting obligations would operate uncontrolled as the final rule requirements would not be in place.

In summary, this rule serves the necessary function of ensuring that a regulation is in place to control emissions of VOCs by these sources. These provisions contain legally and practicably enforceable requirements to use control measures to reduce VOC emissions such that those reductions can then be considered in calculating a source's PTE. In most cases, consideration of these emission reductions in calculating a source's PTE VOCs will result in a PTE that is below the regulatory threshold so that the source will not face a long delay in its ability to continue to operate, construct or modify. The public interest would certainly be hindered if EPA did not act now to ensure that these important public health protections are in place and that economic progress is not impeded by a lack of regulations controlling VOC emissions.

Finally, this rule is important in that while not identical to, the rule is consistent with regulations approved into North Dakota's SIP [5] under the authority of the NDDoH and regulations under the authority of the NDIC,[6] which were established for similar purposes. Accordingly, this rule ensures that consistent requirements apply to activities both inside of and within the FBIR.

The good cause exception also applies here because of the impracticability of notice and comment. EPA initially did not recognize the sheer magnitude of the volume of permit applications that it would need to process in a short time period to avoid economic disruption on the Reservation. Now that it fully comprehends the enormity of the task, EPA has determined that it would be unable to timely process more than 600 permit applications, specified to be submitted as part of the CAFOs between EPA and the oil and natural gas owners and operators by August 2012. Because of our inability to process these permits, and because of lateness at which we became fully aware of the full scope of the burden, EPA thus has had insufficient time to seek public comment before acting on the rule promulgated today.

While we have determined that notice and comment are both contrary to the public interest and impracticable, we note that the public has had several opportunities to learn about, and even comment on, the substantive requirements contained in this interim rule. The substance of many provisions in the final rule are similar to the requirements contained in the six permits for individual oil and gas production facilities on the FBIR that EPA proposed earlier this year. We received comments from the public and the sources on those proposed permits and we have taken those comments into consideration in developing the FIP requirements. The substantive requirements of the FIP are also similar to the conditions in the CAFOs under which the oil and natural gas production sources have been operating for nearly a year, and the public had notice of the CAFOs, which were posted on EPA's Internet site for public review.[7] Furthermore, the public has an additional, full opportunity to comment on the permanent rule that EPA is concurrently proposing today, which mirrors, and will replace this interim rule. By issuing this rule as a final rule, paired with a comment period on the proposal for more permanent action, EPA is providing as much opportunity for notice and comment as possible on the issues presented by this rule. EPA will expeditiously and fully, consider any comments received on the proposed rule, and once we have completed our deliberative process, will make any necessary revisions in taking final action on the proposed rule.

For the reasons discussed above, EPA finds both that there is good cause to forego notice and comment for this interim rule, and that there is good cause for this rule to take immediate effect and to take effect as described above, for those sources that receive actual notice for purposes of enforcement. Since this is not a major rule under the Congressional Review Act (CRA), the 60-day delay in effective date required for major rules under the CRA does not apply.

II. Proposed Rulemaking

We are also simultaneously publishing a parallel proposed rulemaking which seeks comment on information found within this final rule. Note that Docket Number EPA–R08–OAR–2012–0479 is being used for both the final rule and the parallel proposed rule.

III. Background

A. Today's Action

In today's action, we are promulgating a Reservation-specific FIP to establish enforceable control requirements for reducing VOC emissions from oil and natural gas production activities on the FBIR in North Dakota. Specifically, we are issuing this rule to require owners and operators of oil and natural gas production facilities producing from the Bakken Pool [8] to reduce emissions of VOCs emanating from well completions, recompletions, and production and storage operations. Oil and natural gas production facilities may also contain other VOC-emitting units that include, but are not limited to, pumps, compressors, pneumatic devices, dehydrators, and engines. This rule does not contain requirements for, or otherwise apply to, those types of equipment. If we determine at a later date that there is a need for legally and practicably enforceable control of VOC emissions from additional equipment at these oil and natural gas production facilities, or for legally and practicably enforceable control of additional regulated NSR pollutant emissions, we may propose additional FIPs or propose supplements to this FIP.

B. Purpose of the Rule

As noted above, promulgating these Federal regulations addresses an important initial step to fill a regulatory gap with regard to controlling VOC emissions from oil and natural gas operations on the FBIR. There is no other Federal rule, including the recently finalized NSPS and NESHAPs for the Oil and Gas Sector (NSPS OOOO and NESHAP HH),[9] that fills this gap for

[5] North Dakota Century Code (NDCC) (Chapter 23–25 Air Pollution Control); Air Pollution Control Rules (Article 33–15) Chapter 33–15–07 Control of Organic Compound Emissions, and Chapter 33–15–20–04 Control of Emissions from Oil and Gas Well Production Facilities. North Dakota Legislative Branch. Available online at: *http://www.legis.nd.gov/information/acdata/html/33-15.html*. Accessed May 29, 2012. Within EPA approved SIP.

[6] NDCC (Chapter 38–08 Control of Oil and Gas Resources); Article 38–08–06.4. Flaring of Gas Restricted—Imposition of Tax—Payment of Royalties—Industrial Commission Authority; and Article 43–02–03–28 Safety Regulation. Available online at: *https://www.dmr.nd.gov/oilgas/rules/rulebook.pdf*. Accessed July 5, 2012. State only rule.

[7] EPA Administrative Enforcement Dockets, available at: *http://yosemite.epa.gov/oa/rhc/epaadmin.nsf*.

[8] The Bakken Pool is defined as a compilation of crude oil formations consisting of Bakken, Sanish and Three Forks formations.

[9] The requirements in NSPS OOOO and revised NESHAP HH were finalized on April 17, 2012, but not yet promulgated and can be found at *http://www.epa.gov/airquality/oilandgas/actions.html*,

Continued

the particular geologic formations that exist on the FBIR. This is in contrast to oil and natural gas operations off the Reservation which are governed by the NDDoH regulations and NDIC regulations previously discussed. As a result of these regulations, oil and natural gas operators in NDDoH jurisdiction are provided mechanisms for establishing legally and practicably enforceable control requirements that reduce VOC emissions and allow them, in most cases, to forgo time consuming and costly preconstruction permitting requirements before being able to start operations while helping to protect air quality and prevent fires, thus addressing the two concerns that we noted above have justified this final rule.

What we are providing in the way of regulations in the FIP, and the impact that it will have on permitting is generally consistent with the approach that we have approved of in the areas surrounding the FBIR. Owners and operators of oil and natural gas operations in the NDDoH jurisdiction producing from the Bakken Pool are potentially subject to the North Dakota preconstruction permitting requirements found in the North Dakota Air Pollution Control Rules ("North Dakota Rules") at Chapter 33–15–14 (Designated Air Contaminant Sources, Permit to Construct, Minor Source Permit to Operate, Title V Permit to Operate) and Chapter 33–15–15 (Prevention of Significant Deterioration of Air Quality) if uncontrolled emissions are greater than the permitting thresholds. However, all of the owners and operators are also subject to the North Dakota Rules for the operation of oil and natural gas production operations in the State of North Dakota. The regulations found at Chapter 33–15–07 (Control of Organic Compound Emissions) provide legally and practicably enforceable control requirements and VOC emission reductions when applicable. Additionally, all of the owners and operators are subject to the NDIC regulations for well completions found at Chapter 38–08 Control of Oil and Gas Resources. In many cases, owners and operators complying with these additional North Dakota Rules and NDIC regulations, and following the NDDoH guidance (Bakken Pool Guidance)[10] do not have to obtain preconstruction permits from the NDDoH and can begin construction in a timelier manner.

Similar to the owners and operators of oil and natural gas operations producing from the Bakken Pool in NDDoH jurisdiction, the owners and operators of oil and natural gas operations producing from the Bakken Pool on the FBIR are potentially subject to the Federal preconstruction permitting requirements found in the Federal rules at 40 CFR 52.21 (Prevention of Significant Deterioration of Air Quality), and 40 CFR 49.151 through 49.161 (Federal Tribal NSR Rule). However, on the FBIR only NSPS OOOO and NESHAP HH provide legally and practicably enforceable VOC control requirements outside of the Federal preconstruction permitting requirements. Further, NSPS OOOO only applies to new and modified facilities and only to the oil storage tanks being utilized in the Bakken Pool operations. Thus, most owners and operators of oil and natural gas activities producing in the Bakken Pool must obtain preconstruction permits before production can begin, or if they are not obligated to obtain a permit face no control obligations whatsoever.

This rule will fill this regulatory gap. Consistent with the regulatory structure that exists off the FBIR, and NSPS OOOO, this rule requires VOC control requirements and emissions reductions, monitoring, recordkeeping and reporting with regard to well completions, recompletions, and production and storage operations. This rule will also, to the extent practicable, minimize the construction permitting program implementation burdens upon us and the regulated community while establishing requirements that are unambiguous and legally and practicably enforceable.

However, this rule will not eliminate any potential permitting requirements for oil and natural gas production facilities, but in many cases it will impose legally and practicably enforceable requirements that will lower PTE to a level that will allow the operators to construct without being required to obtain a PSD or Federal preconstruction permit under the Federal Tribal NSR Rule for Indian country. Specifically, where compliance with the requirements of this rule results in PTE VOCs from all pollution-emitting sources at the facility that are less than the thresholds in the PSD and Federal Tribal NSR rules, the source would not trigger permitting requirements and therefore may avoid PSD and minor source preconstruction permitting altogether. To comply with the CAA and avoid PSD or minor source preconstruction permitting altogether, a facility must calculate its PTE VOCs from all pollution-emitting sources at the facility and verify that it is less than the threshold in the PSD and Federal Tribal NSR rules. While we believe that VOC is the pollutant most likely to be emitted in quantities sufficient to require permitting, the facility may not avoid the PSD and Federal Tribal NSR permitting requirements if its emissions of any other regulated NSR pollutant are high enough to trigger PSD requirements.

Included in the docket for this rule are copies of the NDDoH rules and guidance and the NDIC regulations that we considered in this process, as well as a technical support document explaining the requirements as compared to these requirements.

C. Development of the Rule

We developed this rule in consultation with the Three Affiliated Tribes of the Mandan, Hidatsa, and Arikara Nation. As part of this consultation we evaluated the oil and natural gas activities and sources of VOC emissions that could impact air resources on the Reservation and the differences in the VOC emission reduction requirements for those facilities operating on the FBIR compared to those facilities operating in NDDoH jurisdiction. We also held a meeting with the Three Affiliated Tribes of the Mandan, Hidatsa, and Arikara Nations on June 13, 2012.

To develop this rule, we first determined that oil and natural gas production on the FBIR from the Bakken Pool was becoming increasingly prevalent and that information regarding the nature of the fluids produced from the Bakken Pool indicated significant emissions of VOC. We accomplished this step by reviewing information provided by the NDDoH and a host of oil and natural gas operators already producing in the Bakken Pool.[11]

In order to develop appropriate requirements for the control of emissions from the production operations in the Bakken Pool, we studied the nature of the hydrocarbon liquids being produced and existing operations currently in practice. An oil well produces predominantly crude oil,

until such time that the final rule is published in the **Federal Register**.

[10] *Bakken Pool Oil and Gas Production Facilities Air Pollution Control Permitting & Compliance Guidance*, NDDoH Air Quality Division, May 2, 2011. This guidance document was developed by the Bakken VOC Task Force. The Bakken VOC Task Force was a collaboration between the NDDoH and the owners and operators of oil and gas operations producing from the Bakken Pool.

[11] The information reviewed was contained in synthetic minor NSR applications submitted to EPA, which are included in the docket for this rule.

with some natural gas dissolved in it. Each crude oil reservoir has a combination of chemical and physical qualities which makes it unique. Some crude oil types are "heavy" (high viscosity and gravity containing very little associated natural gas) and some "light" (low viscosity and gravity containing high amounts of associated natural gas). The crude oil from the Bakken Pool is a light crude oil. It contains a higher amount of lighter hydrocarbon components than is seen in heavy crude oil, and therefore has greater potential to produce natural gas in addition to oil. Because of this characteristic, the production of crude oil from the Bakken Pool wells is similar to the production of natural gas liquids from natural gas wells. Natural gas liquids contain lighter end hydrocarbons such as ethane, propane, butane, and pentane, and methane gas. In addition, methods used to extract the hydrocarbons from both natural gas wells and the Bakken Pool wells produce hydrocarbon liquids that also contain water. Therefore, similar to natural gas well production, the production methods in the Bakken Pool involve the separation of the produced liquid into hydrocarbon liquids (oil), natural gas and water.

The oil/natural gas/water emulsion being produced from each well is transported up the wellbore using an electric lifting unit, when required. The emulsion from the wells producing to this facility is transported through 2-phase separators (separators) which are an inherent component of the pipeline. The number of separators on any one production pipeline can vary from one to several. These separators reduce the pressure of the oil/natural gas/water emulsion to initiate the separation of the natural gases from the liquids. The natural gases and liquids are then sent to a 3-phase separator (heater-treater). The heater-treater reduces the pressure closer to ambient pressure and heats the leftover emulsion using a flame-arrested line heater (the heater-treater burner). The combination of higher temperatures and lower pressures allows for additional separation of the natural gas/oil/water phases from each other because of differences in densities.

Following the heater-treater, the produced oil and water are routed to storage tanks. The recovered natural gas is transferred from the heater-treater to the sales natural gas pipeline or to an emissions control unit when a natural gas sales pipeline is not available or the pipeline has a limited capacity. The oil is temporarily stored in these on-site storage tanks prior to being transferred either to tanker trucks or to a lease automatic custody transfer (LACT) unit for conveyance to a refining process plant. Separated water is temporarily stored in the on-site storage tanks prior to being loaded into tanker trucks for transport and disposal.

In addition to the natural gas recovered from the extracted wellhead fluids, low pressure natural gas is also collected from off-gassing that occurs from the storage of the produced oil and water in the on-site tanks at the facilities. This low pressure natural gas is collected via a vent line from the tanks and is either routed to an enclosed combustor, utility flare or pit flare for combustion, or is routed to a vapor recovery unit (VRU) to be injected into a natural gas sales pipeline for conveyance to a natural gas plant. In the event that pipeline injection of recoverable natural gas is temporarily infeasible and no enclosed combustor or utility flare is operational onsite, the natural gas may temporarily be routed through a closed-vent system to a pit flare.

We further identified, in the information provided, that the most prevalent sources of VOC emissions associated with oil and natural gas production come from well completions, recompletions, and production and storage operations. During well completions and recompletions there is a period of flowback of oil, natural gas, and water from newly drilled wells in order to expel drilling and reservoir fluids which vents considerable VOC emissions to the atmosphere. Large amounts of VOCs are also emitted during production when the reservoir fluids are separated into oil, natural gas and water under high pressure using heat. Finally, the transfer and storage of the produced oil and water after separation can be a source of VOC emissions if vented to the atmosphere. In other words, the separated oil and water are both under high pressure and still contain some dissolved natural gas. When the separated oil and water are subjected to atmospheric pressure during transfer to storage tanks, the dissolved natural gas comes out of the liquid. Unless a natural gas sales pipeline is available and is used to receive the evolved natural gas, it becomes a significant source of VOC emissions. Due to the high levels of VOC emissions from these specific operations, we established VOC control and emission reduction requirements in this rule for completion and recompletion operations, heater-treater systems associated with production operations, and storage tanks associated with oil and water storage operations.

Because of the experience that already existed in the Bakken Pool, we consulted with the owners and operators that are currently producing from the Bakken Pool on the FBIR and in NDDoH jurisdiction with regard to the production practices already in place. The practices currently in place are primarily due to product recovery or safety concerns and demonstrate compliance with the applicable NDIC regulations for flaring of co-produced natural gas and safety that address those concerns. These consultations provided us not only with information on the production on and off the Reservation, but also provided us with information on the existing phased approach to controlling practices occurring both from well completion and recompletions, through production operations, and ending with storage and loading operations and an appropriate timeline for installation of the controls. Components of this rule are based on these practices that are already in place off the FBIR.

In addition, we evaluated the North Dakota regulations to help identify appropriate requirements for construction and operation of the regulated equipment and the requirements for controlling VOC emissions from this equipment. The North Dakota Rules at Chapter 33–15–07 provide requirements for the construction and operation of units that separate volatile organic liquids from water, and the control of VOC emissions from such units. Specifically, Chapter 33–15–07 requires that any equipment processing, treating, storing or handling volatile organic liquids must be equipped with covers (in the case of tanks), closed vent systems and control devices, such as VRUs, enclosed combustors, or flares. Chapter 33–15–07 refers to the Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems at 40 CFR 60.690 for the control requirements and the requirements are appropriate to crude oil production operations. Chapter 33–15–07 requires the use of submerged pipe filling during storage operations to limit the evolution of natural gas from the oil and water. We determined that the VOC emission reduction requirements during the separation of the oil, natural gas, and water in this rule were relevant and appropriate as a basis for this rule. The North Dakota Rules at Chapter 33–15–20 provide requirements for the construction and operation of oil and natural gas production equipment and the control of VOC emissions from this equipment. Chapter 33–15–20 includes

requirements for storage tanks, separators and heater-treaters. While the North Dakota Rule only applies to oil or natural gas well production operations which emit sulfur or sulfur compounds to the atmosphere, we determined that the construction and control requirements were relevant and appropriate as a basis for this rule.

We also reviewed the NDIC regulations and the Bakken Pool Guidance. The NDIC regulations found in the Control of Oil and Gas Resources at Chapter 38–08 require natural gas from the heater-treaters to be routed to a natural gas gathering pipeline as soon as practicable. When a pipeline is not available, heater-treater natural gas is required to be routed to a control system or device. The Bakken Pool Guidance details the air pollution control requirements of oil and natural gas operations producing from the Bakken Pool and provides an approach that may be used by owners and operators of oil and natural gas operations producing from the Bakken Pool to demonstrate compliance with the applicable North Dakota Rules. VOC control requirements have been established within this guidance for tank emissions and heater-treater systems and much of the control equipment requirements and monitoring requirements in this rule were adapted from this guidance. Control of VOC emissions from other sources such as dehydration units, pneumatic controllers, pneumatic pumps, truck loading, etc. are also included in this guidance; however, we did not evaluate those components of oil and natural gas production operations. NDDoH identifies acceptable control systems that may be used by the owners and operators. These systems include: a ground pit flare for tank and heater-treater emissions with an assumed 90.0 percent VOC destruction efficiency; a VRU for tank emissions, designed and operated to reduce the mass content of VOC emission by at least 99.0 percent; and an enclosed combustor or utility flare for tank and heater-treater emissions designed and operated to reduce the mass content of VOC emission by at least 98.0 percent. Heater-treater natural gas must be routed to a natural gas gathering pipeline as soon as practicable. In addition, to VOC control requirements, the guidance provides extensive operating and monitoring requirements for the controls. According to the owners and operators that are producing from the Bakken Pool on the FBIR, they are already voluntarily following this guidance in the FBIR. Therefore, we determined that the VOC emission reduction requirements in this document were relevant and appropriate as a basis for establishing monitoring, recordkeeping and reporting requirements necessary for enforceability of this rule.

We also reviewed NSPS OOOO, which provides standards for oil and natural gas production from natural gas wells. However, with the exception of storage tanks and pneumatic controls, none of the production operations from the oil wells in the Bakken Pool that are covered by this rule are covered by NSPS OOOO. While this standard does not regulate the completion, recompletion, or production operations for the operations producing from the Bakken Pool, the common characteristics between natural gas production and the Bakken Pool production and the regulatory requirements specific to completion and recompletion, provided insight into feasible control requirements for these operations. In addition, the monitoring, recordkeeping and reporting requirements for production and storage operations were reviewed, and for necessary conditions to ensure legal and practicable enforceability were included in this rule. Some of the enhancements to the enforceability of the VOC reductions in this rule are derived from this standard.

Although we view the most relevant regulatory analogue to those operations that are in NDDoH's jurisdiction and producing from the Bakken Pool, we also reviewed other state oil and natural gas production-related regulations for areas that are similar to North Dakota in industry, meteorology, or air quality concerns to ensure the proposed requirements are legally and practicably enforceable, as well as reasonably achievable, because the technologies are being commonly used and regulated.

The other state air pollution agencies' rules and/or guidance that we reviewed included: Montana Department of Environmental Quality (MDEQ),[12] Wyoming Department of Environmental Quality Air Quality Division (WDEQ),[13] Colorado Department of Public Health and Environment Air Pollution Control Division (CDPHE)[14] and the Utah Department of Environmental Quality (UDEQ).[15] We also reviewed the regulations for oil and natural gas production facilities under the Texas Administrative Code, implemented by the Railroad Commission of Texas, Oil and Gas Division (RCT),[16] the New Mexico Environment Department Air Quality Bureau (NMED),[17] and the Oklahoma Department of Environmental Quality Air Quality Division (ODEQ).[18] However, we determined that it was not relevant to review state and local rules that are intended to address non-VOC pollutant emissions, nonattainment area requirements or specific localized air quality concerns unless such concerns are also present on the FBIR or control equipment requirements apply to the same emission units this rule seeks to address. Copies of all the state and local agency rules that we considered in this process and other supporting documentation are included in the docket for this rule.

Regarding state regulations and guidance for VOC destruction efficiency and monitoring of enclosed combustors and utility flares, the rule requirements

[12] MDEQ. Chapter 8 Air Quality Subchapter 16 Emission Control Requirements for Oil and Gas Well Facilities Operating Prior to Issuance of a Montana Air Quality Permit. Available online at: *http://www.deq.mt.gov/dir/legal/chapters/CH08-16.pdf.* Accessed May 29, 2012. State only rule.

[13] WDEQ Air Quality Division. Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance. Available online at: *http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf.* Accessed May 29, 2012. State only guidance.

[14] Colorado Department of Health and Environment Air Pollution Control Division. Air Quality Control Commission Regulation Number 7—Control of Ozone Via Ozone Precursors (Emissions of Volatile Organic Compounds and Nitrogen Oxides) 5–CCR 1001–9. Available online at: *http://www.cdphe.state.co.us/regulations/airregs/5CCR1001-9.pdf.* Accessed May 29, 2012. State only rule.

[15] Utah Administrative Code, Rule R307–327 Ozone Nonattainment and Maintenance Areas—Petroleum Liquid Storage, and Rule R649–3 Drilling and Operating Practices. Utah Division of Administrative Rules. Available online at: *http://www.rules.utah.gov/publicat/code.htm.* Accessed May 29, 2012. State only rule.

[16] Texas Administrative Code, Title 16 Economic Regulation, Part 1 Railroad Commission of Texas, Chapter 3 Oil and Gas Division. Utah Texas Secretary of State. Available online at: *http://www.sos.state.tx.us/tac/.* Accessed May 29, 2012. State only rule.

[17] New Mexico Administrative Code, Title 20 Environmental Protection, Chapter 2 Air Quality, Part 38 Hydrocarbon Storage Facilities and Part 61 Smoke and Visible Emissions. New Mexico Commission of Public Records, New Mexico Register. Available online at: *http://www.nmcpr.state.nm.us/nmac/_title20/T20C002.htm.* Accessed May 29, 2012. State only rule.

[18] Oklahoma Administrative Code, Title 252 Department of Environmental Quality, Chapter 100 Air Pollution Control, Subchapter 37 Control of Volatile Organic Compounds. Oklahoma Secretary of State—Office of Administrative Rules. Available online at: *http://www.sos.ok.gov/oar/online/viewCode.aspx.* Accessed May 29, 2012. EPA approved SIP sections include: 252:100–37–1, 252:200–37–3, 252:100–37–4, 252:100–37–5, 252:100–37–15, 252:100–37–16, 252:100–37–26, 252:100–37–35, 252:100–37–36, 252:100–37–37, 252:100–37–41, and 252:100–37–42; State only rule sections include: 252:100–37–2, 252:100–37–17, 252:100–37–18, 252:100–37–25, and 252:100–37–38[Revoked].

are generally consistent with all state requirements for enclosed combustors and utility flares.

When reviewing state regulations or guidance for produced oil and water storage tanks, we focused on those that might apply to the tank sizes that are typically constructed at oil and natural gas production facilities on the FBIR, primarily tanks with a storage capacity of 500 bbl each or less (approximately 21,000 gallons). The requirements for construction and emission control of produced oil and water storage tanks are fairly consistent with all state regulations and guidance reviewed, although there are varying degrees of *de minimis* natural gas throughput, storage capacities, or annual flashing emissions below which the requirements do not apply or the control equipment may be removed. The WDEQ requires 98 percent VOC reduction for tanks with a PTE greater than 10 tons per year (tpy) within 60 days of the first date of production, compared to ninety (90) days in this rule. The WDEQ also allows control equipment removal if flashing emissions decline to and are reasonably expected to remain below 8 tpy. We do not provide any *de minimis* throughput or storage capacities below which the requirements in this rule do not apply; however, as discussed previously, we allow owners or operators to use 90.0 percent control equipment after one year after the first date of production if the uncontrolled PTE VOCs emissions from the aggregate of all produced oil storage tanks and any produced water storage tanks interconnected with the produced oil storage tanks declines to less than 20 tpy.

D. Area and Facilities Covered by the FIP

This rule will apply to any person who owns or operates an existing (constructed or modified on or after August 12, 2007), new, or modified oil and natural gas production facility [19] producing from the Bakken Pool and located on the FBIR as set forth in 40 CFR Part 49, Subpart 141—Reservation-Specific FIP for Oil & Natural Gas Production Facilities; FBIR. A more detailed description of the Reservation is provided below in Section IV.

This rulemaking is a step in addressing concerns that have been raised about the potential impacts due to increasing oil and natural gas development on the FBIR. If in the future, we become aware of air quality or permitting burden related to oil and natural gas production for other Reservations or areas of Indian Country, using our authority described in Section V. of this notice, we may propose other FIPs that are deemed necessary or appropriate.

E. Effect on Permitting of Facilities

This rule is not a permitting program. It therefore does not impose or exempt the facilities from any Federal CAA permitting requirements, including the PSD preconstruction permitting requirements at 40 CFR § 52.21 or Federal Tribal NSR Rule permitting requirements for minor sources at 40 CFR 49.151. The purpose of this rule is to provide legal and practical enforceability for the use of VOC emission controls that are already being used voluntarily by the industry and for VOC emissions reductions from those controls. Provided that the facilities are in compliance with the new rule, they may take into account the enforceable VOC emission reductions from the required controls they use when calculating their PTE for determining applicability of the permitting requirements, to the extent that the effect those controls would have on VOC emissions is legally and practicably enforceable.

Regardless of this rule, some facilities' PTE VOCs or any other regulated NSR pollutant may exceed the applicability thresholds for PSD or Federal Tribal NSR Rule permitting even after applying the legally and practicably enforceable emission reductions provided in this rule. In such cases, the owners or operators of these facilities are required to apply for and obtain the appropriate permits.

F. Registration Requirements

This rule does not exempt facilities located on the FBIR from the registration requirements of the Federal Tribal NSR Rule, promulgated on July 1, 2011. Nor does this rule impose any additional registration requirements. Again, the purpose of this rule is to provide legal and practical enforceability for the use of VOC emission controls that are already being used as an industry standard and for VOC emissions reductions from those controls. Provided that the facilities are in compliance with the provisions of this rule, facilities may include the enforceable VOC emission reductions resulting from the controls required in this rule when calculating their PTE, to the extent that the effect those controls would have on VOC emissions is legally and practicably enforceable.

If the PTE VOCs or any other regulated NSR pollutant is less than the major source thresholds in 40 CFR 52.21, but equal to or greater than the thresholds in the Federal Tribal NSR Rule, then registration is required of these facilities (40 CFR 49.160). Those facilities that must obtain a PSD permit pursuant to 40 CFR 52.21 or wish to obtain a preconstruction permit pursuant to 40 CFR 49.151 of the Federal Tribal NSR Rule, in addition to meeting the requirements of this rule, are exempt from this registration requirement.

G. Applicability to New and Existing and Modified Facilities

This rule applies to each owner or operator constructing or operating an oil and natural gas production facility that is located on the FBIR and producing from the Bakken Pool with one or more oil and natural gas wells, any one of which a well completion or recompletion operation is/was initiated on or after August 12, 2007.

For the purposes of this rule, a well completion means the process that allows for the flowback of oil and natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank. A well completion operation means any oil and natural gas well completion with hydraulic fracturing occurring at an oil and natural gas production facility. The completion date is considered the date that construction at an oil and natural gas production facility has commenced. A well recompletion operation means any oil and natural gas well completion with hydraulic refracturing occurring at an oil and natural gas production facility. The recompletion date is considered the date that a modification has occurred at an oil and natural gas production facility. The reason we selected the initiation of completions operations as the date for defining a new facility is that owners and operators use drill rigs prior to initial completion operations and this equipment is not considered a stationary source. In addition, it is not certain during the drilling operations whether a well will be a producing well. Hence it is not known whether an oil and natural gas production facility will be constructed to support that well. The outcome of a completion operation provides the well owners and operators information necessary to determine whether an oil and gas production

[19] For the purposes of this rule, an oil and gas production facility consists of all the air pollution emitting units and activities located on or integrally connected to one or more oil and gas wells that are necessary for production and separation of reservoir fluids, temporary storage of produced and produced water, and preparation of the produced oil, produced water, and produced gas for transport off-site. Additionally, August 12, 2007 is the earliest well completion date identified in the CAFOs.

facility will be constructed. Requiring compliance with this rule upon recompletion of any one well at a facility is consistent with NSPS OOOO. According to the final NSPS OOOO notice, a completion operation associated with refracturing is considered a modification under CAA section 111(a), because physical change occurs to the well resulting in emissions increases during the recompletion operation (for the purposes of this rule the process of refracturing is defined as a recompletion).

In determining the appropriate effective date and the well completion dates for this rule, we evaluated the purpose of the rule, the gaps in regulations, NSPS OOOO and the requirements and stipulations of CAFOs finalized between us and select operators on the FBIR in late August 2011 and amended, in some cases, between then and July 2012. The August 12, 2007, date is the earliest well completion date identified in the CAFOs. These orders established control requirements during the life of the orders for facilities operating on the FBIR by these companies who voluntarily entered into the agreement with us. One goal of this FIP for existing oil and natural gas production facilities is to provide a CAA compliance mechanism for those companies with CAFOs, prior to their expiration, which will occur between August 26, 2012 and August 31, 2012. Copies of all of the CAFOs can be found in the docket for the rule.

H. Attainment Status

All counties in North Dakota that coincide with the FBIR are designated as unclassifiable/attainment for all criteria pollutants under the CAA. *See* 40 CFR 81.335.

Current air quality conditions in the region of the FBIR and in western North Dakota are good, with measured ambient ozone [20] and nitrogen dioxide (NO_2) concentrations substantially lower than the current National Ambient Air Quality Standards (NAAQS) of 75 parts per billion (ppb) for 8-hour average ozone and 100 ppb for the 1-hour average NO_2. The state of North Dakota operates three air quality monitor sites in western North Dakota to characterize regional background air quality. At the Dunn Center monitoring site located, approximately 20 miles southwest of the of the FBIR, the current design values for the ozone and NO_2 NAAQS are 55 ppb and 11 ppb, respectively.

[20] VOC and NO_X are precursors to ozone.

We evaluated the impacts of changes in VOC and nitrogen oxides (NO_X) emissions from enclosed combustors and flares used for control of VOC emissions at oil and natural gas production facilities on the FBIR as part of the technical analysis for this rule. Emissions categories that are substantially controlled by this rule include VOC and NO_X.

Expected potential emissions of sulfur dioxide (SO_2) and particulate matter (PM) pollutants from enclosed combustors and flares used for control of VOC emissions at well pads are estimated to be below the Federal Tribal NSR rule permitting thresholds, and are therefore expected to have insignificant impacts on the NAAQS for these pollutants. Expected potential emissions of carbon monoxide (CO) from enclosed combustors and flares used for control of VOC emissions at well pads are expected to have an insignificant impact on the CO NAAQS because of the level and form of the CO standard in comparison to the emissions.

This rule establishes legally and practicably enforceable VOC emission reductions that reflect reductions that facilities are already routinely achieving through the installation and operation of control equipment for health, safety and market purposes. In addition, this rule does not exempt these facilities from other potentially applicable regulatory or permitting requirements. Therefore, we believe that air quality in this area will not be adversely impacted by this action.

Supporting air quality information is discussed in the Technical Support Document for this rule, found in the rule docket.

I. Benefits and Costs

Produced natural gas and natural gas emissions resulting from oil and natural gas production from the Bakken Pool underlying the FBIR have a high VOC content. Typically, the natural gases associated with the produced oil would be captured as product and injected directly into a natural gas sales pipeline. However, this is a relatively new field and while the natural gas sales pipelines are being developed, they are minimally available at this time. Currently, most produced natural gas and natural gas emissions from oil and natural gas production operations on the FBIR are routed to a combustion device such as a pit flare, utility flare, or enclosed combustor.

Uncontrolled emissions of VOC from operations at an oil and natural gas production facility consisting of a single well and associated production and storage operations were estimated to average approximately 2,165 tons per year (tpy). Of this total, approximately 1,610 tpy of VOC results from produced natural gas emissions from the heater-treater and 555 tpy of VOC is emitted from the produced oil and water storage tanks. This rule requires that emissions from the heater-treater and the storage tanks be routed to a combustion device. We estimate that, on average, the control requirements in this rule will reduce VOC emissions from an oil and natural gas production facility by approximately 2,090 tpy per well.[21]

The costs of the control equipment required by this rule depend, in part, on the number of wells associated with each oil and natural gas production facility. Generally, as the number of wells located at oil and natural gas production facilities increase, the volume of oil and natural gas production and associated emissions also increase. Multiple wells at an oil and natural gas production facility can often share control equipment if there is sufficient capacity to handle the additional produced natural gas and natural gas emissions; thus, the costs of the control equipment per well potentially decreases at oil and natural gas production facilities that consist of multiple wells. The Bureau of Land Management (BLM) has estimated that future development in the area of North Dakota encompassing the FBIR is likely to feature an average of 1.5 wells per facility.[22] Based on information from synthetic minor permit applications and environmental assessments conducted by the Bureau of Indian Affairs,[23] we believe a value of two wells per facility provides a conservative estimate of well density for future development on the FBIR.

We calculated the total annual cost for a two-well facility utilizing a pit flare, utility flare, and two enclosed combustors as control equipment. For this operating scenario, we have

[21] The Technical Support Document includes a more detailed explanation of benefits and costs. It can be found in the docket for the final rule, Docket ID: EPA–R08–OAR–2012–0479, which can be accessed at: *http://www.regulations.gov* (hereinafter referred to as TSD).

[22] October 2, 2009 Bureau of Land Management (BLM) report titled "Reasonable Foreseeable Development Scenario for Oil and Gas Activities on Bureau Managed Lands in the North Dakota Study Area." This report was supplemented on February 25, 2011 with the document titled "Revised Activity and Surface Disturbance Projections for the Reasonable Foreseeable Development Scenario for Oil and Gas Activities on Bureau Managed Lands in the North Dakota Study Area". Both documents are included in the docket for this rule and are publicly available at the following Web site: *http://www.blm.gov/mt/st/en/fo/north_dakota_field/rmp/RFD.html.*

[23] See TSD at Section 4. Reasonably Foreseeable Development.

estimated that the total annual cost of compliance with this rule would be approximately $52,000 per facility. Using the estimated average of 4,180 tpy VOC reduction from a facility consisting of two wells and associated production and storage operations, we calculated the cost effectiveness of this rule as less than $15 per ton VOC reduced.

Based on the reasonably foreseeable development in the 2011 BLM supplemental report, we estimate that a maximum of 1,000 facilities may be developed on the FBIR by 2029. Applying a maximum total annual cost impact for a two-well facility of approximately $52,000, the maximum annual cost of compliance with this rule on the oil and natural gas industry is estimated to be approximately $50 million. However, we believe this is a conservative estimate and that actual annual costs would be much lower due to factors such as increased facility well density, standard industry practice to use VOC control equipment, and anticipated pipeline infrastructure development, which is explained further in the technical support document for this rule.

IV. The Fort Berthold Indian Reservation

The Three Affiliated Tribes of the Mandan, Hidatsa, and Arikara Nations are a federally-recognized Indian tribe organized under a Constitution and By-Laws ratified by the Tribes on May 15, 1936 and approved by the Secretary of the Interior on June 29, 1936 (with relevant amendments to the Constitution and By-Laws approved by the Department of the Interior on March 11, 1985). *See* 75 FR 60813 (October 1, 2010); Constitution and By-Laws of the Three Affiliated Tribes of the Mandan, Hidatsa, and Arikara Nations. The FBIR was established pursuant to the Treaty of Fort Laramie of 1851 and addressed in subsequent agreements and Executive Orders, including the Agreement at Fort Berthold, 1866, and Executive Orders in 1868, 1870 and 1880. As described in the Tribes' Constitution and By-Laws (and as approved by the Secretary of the Interior), the FBIR currently includes all lands within the exterior boundaries of the Reservation, which is defined by the Act of March 3, 1891 (26 Statute 1032) and which includes all lands added to the Reservation by Executive Order of June 17, 1892.

Pursuant to CAA section 301(d), 42 U.S.C. 7601(d), we are authorized to treat eligible Indian tribes in the same manner as states (TAS) for purposes of implementing CAA provisions over their entire Reservation and over any other areas within their jurisdiction. *See* 63 FR 7254–57 (February 12, 1998) (explaining that CAA section 301(d) includes a delegation of authority from Congress to eligible Indian tribes to implement CAA programs over all air resources within the exterior boundaries of their Reservations). The Three Affiliated Tribes have not applied for TAS for the purpose of administering a Tribal Implementation Plan (TIP) under the CAA. There is thus currently no EPA-approved plan implementing the functions and provisions of this FIP on the FBIR. The FIP the EPA is promulgating today fills this regulatory gap and applies to all lands on the FBIR, which is defined by the Act of March 3, 1891 (26 Statute 1032) and which includes all lands added to the Reservation by Executive Order of June 17, 1892.

V. EPA's Authority To Promulgate a FIP

Section 301(d) of the CAA, 42 U.S.C. 7601(d), directs us to promulgate regulations specifying the provisions of the Act for which it is appropriate to treat Indian tribes in the same manner as states. Pursuant to this statutory directive, EPA promulgated regulations entitled, "Indian Tribes: Air Quality Planning and Management" (TAR) 63 FR 7254 (February 12, 1998). Our regulations delineate the CAA provisions for which it is appropriate to treat tribes in the same manner as a state. *See* 40 CFR 49.3, 49.4. Among those provisions for which we determined such treatment was inappropriate are CAA section 110(a)(1) (State Implementation Plan (SIP) submittal and implementation deadlines) and CAA section 110(c)(1) (directing EPA to promulgate a Federal Implementation Plan (FIP) "within 2 years" after we find that a state has failed to submit a required plan, or has submitted an incomplete plan, or within 2 years after we disapproved all or a portion of a plan). *See* 40 CFR 49.4(a), (d); 63 FR at 7262–66 (February 12, 1998).

The TAR preamble clarified that by including CAA section 110(c)(1) on the § 49.4 list, "EPA is not relieved of its general obligation under the CAA to ensure the protection of air quality throughout the nation, including throughout Indian country. In the absence of an express statutory requirement, EPA may act to protect air quality pursuant to its "gap-filling" authority under the Act as a whole. *See, e.g.* CAA section 301(a)." 63 FR at 7265 (February 12, 1998). The preamble confirmed that "EPA will continue to be subject to the basic requirement to issue a FIP for affected tribal areas within some reasonable time." *Id.* (referencing § 49.11(a) which provides that the Agency will promulgate a FIP to protect tribal air quality within a reasonable time if tribal efforts do not result in adoption and approval of tribal plans or program).[24]

The preamble to the TAR set forth our view articulated in the proposed rule that, based on the "general purpose and scope of the CAA, the requirements of which apply nationally, and on the specific language of sections 301(a) and 301(d)(4), Congress intended to give to the Agency broad authority to protect tribal air resources." *Id.* at 7262. It further discussed our intent to "use its authority under the CAA 'to protect air quality throughout Indian country' by directly implementing the Act's requirements in instances where tribes choose not to develop a program, fail to adopt an adequate program or fail to adequately implement an air program." *Id.*

The NDDoH, the CAA permitting authority for areas outside of Indian country, including outside of the FBIR, has promulgated rules to control emissions from oil and natural gas production facilities. Since there is not currently an approved FIP specifically covering the reduction of VOC emissions related to natural gas emissions from oil and natural gas production facilities on the FBIR, a regulatory gap exists with regard to such facilities operating within the exterior boundaries of the Reservation. This FIP will establish legally and practicably enforceable requirements to control and reduce VOC emissions. Therefore, in this rule, we determined that it is necessary and appropriate to exercise our discretionary authority under sections 301(a) and 301(d)(4) of the CAA and 40 CFR 49.11(a) to promulgate a FIP to remedy an existing regulatory gap under the Act with respect to the FBIR.

VI. Summary of FIP Provisions

A. Applicability

This rule applies to oil and natural gas facilities producing from the Bakken Pool that are constructed and operating on the FBIR in North Dakota on or after August 12, 2007. Specifically, this rule applies to facilities on the FBIR within the Crude Petroleum and Natural Gas Extraction Industry, North American

[24] Section 49.11(a) states that the Agency, "[s]hall promulgate without unreasonable delay such federal implementation plan provisions as are necessary or appropriate to protect air quality, consistent with the provisions of sections 301(a) and 301(d)(4), if a tribe does not submit a tribal implementation plan meeting the completeness criteria of 40 CFR part 51, Appendix V, or does not receive EPA approval of a submitted tribal implementation plan." 40 CFR 49.11(a).

Industry Classification System (NAICS) Code 211111.

B. Compliance Schedule

Compliance with the rule is required no later than November 13, 2012 or upon initiation of completion or recompletion operations, whichever is later. Upon signature by the Administrator, we will post this rule on our Internet site (*http://www.epa.gov/region8/air/fbirfip.html*) and notify the owners and operators and the Tribes.

C. Provisions for Delegation of Administration to the Tribes

The provisions in § 49.141 establish the steps by which the Three Affiliated Tribes may request delegation to assist us with the administration of this rule and the process by which the Regional Administrator of EPA Region 8 may delegate to the Tribes the authority to assist with such administration of this rule. As described in the regulatory provisions, any such delegation will be accomplished through a delegation of authority agreement between the Regional Administrator and the Tribes. This section provides for administrative delegation of this federal rule and does not affect the eligibility criteria under CAA section 301(d) and 40 CFR 49.6 for TAS should the Tribes decide to seek such treatment for the purpose of administering their own EPA-approved program under Tribal law. Administrative delegation is a separate process from TAS under the TAR. Under the TAR, Indian tribes seek EPA-approval of their eligibility to run CAA programs under their own laws. The Three Affiliated Tribes would not need to seek TAS under the TAR for purposes of requesting to assist us with administration of this rule through a delegation of authority agreement. In the event such an agreement is reached, the rule would continue to operate under federal authority throughout the FBIR, and the Tribes would assist us with administration of the rule to the extent specified in the agreement.

D. General Provisions

The provisions in § 49.142 General Provisions provide: (1) Definitions that apply to this rule; (2) assurance that we will maintain its authority to require testing, monitoring, recordkeeping, and reporting in addition to that already required by an applicable requirement, in a permit to construct or permit to operate in order to ensure compliance; and (3) assurance that nothing in the rule will preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a facility would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed.

E. Construction and Operational Control Measures

The provisions in § 49.143 Construction and Operational Control Measures provide requirements to reduce VOC emissions during well completion and recompletion operations. The owner or operator must route all casinghead natural gas emissions associated with completion and recompletion operations to a utility flare or a pit flare capable of reducing the mass content of VOCs in the natural gas vented to it by at least 90.0 percent. We note that the well completion and recompletion control requirements to use pit flares or utility flares that have the capability to reduce the mass content of VOC in the natural gas emissions routed to them by at least 90.0 percent by weight are the minimum level of control that would be allowed under this rule. Owners and operators may also choose to perform reduced emission completions and recompletions,[25] which would exceed the 90.0 percent VOC emission reduction requirement. This section also requires the control of production and storage operations and imposes a timeline for installation of the controls on these operations. The owner or operator is required to reduce the mass content of VOC emissions from natural gas during oil and natural gas production and storage operations by at least 90.0 percent on the first date of production. Within ninety (90) days of the first date of production, we require the owner or operator to route the natural gas from the production and storage operations through a closed-vent system to a utility flare or equivalent combustion device capable of reducing the mass content of VOC in the natural gas vented to the device by at least 98.0 percent. The owner or operator also has the option to design their production and storage operations to recover the natural gas as product and inject it into a natural gas gathering pipeline system for sale or other beneficial purpose. For those owners or operators that choose to capture the natural gas as product rather than a pollutant to be controlled, the natural gas may temporarily be routed through a closed-vent system to an enclosed combustor, utility flare or pit flare in instances where injection of the product into the pipeline is temporarily infeasible. In these situations, the pit flare is considered an emergency standby unit used for unplanned flare events such as temporarily limited pipeline capacity, equipment breakdown and/or other upsets that are beyond a producer's control and the pit flare is used to safely burn the natural gas product that could otherwise pose a potential risk to workers, the community, or the environment. The owner or operator, however, must limit use of the pit flare in these instances to 500 hours of operation in any consecutive 12-month period. This limit on the hours of operation of the pit flare in such situations provides a balance of air quality, safety and environmental protection, to address public concerns expressed on the proposed synthetic minor NSR permits with the use of pit flares, and flexibility for the operators, to address claims that continuous injection into a natural gas sales pipeline may not be possible at all times.

The rule requires the owner or operator to route all standing, working, breathing and flashing losses from the produced oil storage tanks and any produced water storage tanks interconnected with the produced oil storage tanks through a closed vent system to either an operating system designed to recover and inject the natural gas emissions into a natural gas gathering pipeline system for sale or other beneficial use, or to an enclosed combustor or utility flare capable of reducing the mass content of VOC in the natural gas emissions vented to the device by at least 98.0 percent. We note that while NSPS OOOO requires 95% VOC reduction of emissions from storage tanks, owners and operators of oil and natural gas production facilities on the FBIR have indicated that a 98% VOC destruction efficiency in the Bakken Pool Guidance is achievable and committed in their synthetic minor NSR applications to reduce the mass content of VOC emissions routed to the enclosed combustors or utility flares used for storage tank control by at least 98.0% by weight. Since oil and natural gas production on the FBIR has higher VOC content than typical natural gas production and the overall BTU value is generally higher, this should result in more efficient VOC destruction. Therefore, we believe that a requirement of 98.0% reduction of VOC emissions during continued production operations is appropriate. However, to prevent duplicative federal requirements for

[25] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners: Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells. Office of Air and Radiation: Natural Gas Star Program. Washington, DC. Available at: *http://epa.gov/gasstar/documents/reduced_emissions_completions.pdf.* Accessed July 26, 2012.

owners and operators of storage tanks on the FBIR subject to both this rule and NSPS OOOO, storage tanks subject to and controlled under the requirements specified in 40 CFR part 60, subpart OOOO are considered to meet the storage tank control requirements of this rule. No further requirements apply for such storage tanks under this rule. In addition, like the Bakken Pool Guidance, the rule provides that if the uncontrolled PTE VOCs from the aggregate of all produced oil storage tanks and produced water storage tanks interconnected with produced oil storage tanks at an oil and natural gas production facility is less than, and reasonably expected to remain below, 20 tons in any consecutive 12-month period, then the owner or operator may use a utility flare or enclosed combustor that is capable of reducing the mass content of VOC in the natural gas emissions vented to the device by only 90.0 percent upon written approval by the EPA.[26]

The requirements to use pit flares, enclosed combustors, and utility flares are based on requirements in the North Dakota Rules at Chapters 33–15–07 and 33–15–20, and the Bakken Pool Guidance. These control devices must be operated under specific conditions as specified in § 49.144 Control Equipment Requirements and § 49.145 Monitoring Requirements. The VOC destruction efficiencies of 90.0 and 98.0 percent are the same efficiencies required in the Bakken Pool Guidance.[27]

F. Control Equipment Requirements

The provisions in § 49.144 Control Equipment Requirements require the use of covers on all produced oil and water storage tanks and the use of closed-vent systems with all VOC capture and control equipment. These requirements are derived from the North Dakota Rules at Chapter 33–15–07. Section 49.144 also specifies construction and operational requirements for the covers and closed-vent systems. The construction and operational requirements of the covers and closed-vent systems are based on the NSPS OOOO requirements and are intended to provide legal and practical enforceability. In addition, § 49.144 requires specific construction and operational requirements of pit flares, enclosed combustors, and utility flares. These requirements are derived from the Bakken Pool Guidance and have been enhanced where necessary to provide legal and practical enforceability.

The provisions in § 49.144 require that each owner and operator equip the openings on each produced oil storage tank and each produced water storage tank that is interconnected with produced oil storage tanks with a cover that ensures that natural gas emissions are efficiently routed through a closed-vent system to a vapor recovery system, an enclosed combustor, or a utility flare. Each cover and all openings on the cover (*e.g.*, access hatches, sampling ports, and gauge wells) must form a continuous barrier over the entire surface area of the produced oil and produced water in the storage tank. Each cover opening must be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the tank on which the cover is installed except during those times when it is necessary to use an opening as follows: (1) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit); or (2) to inspect or sample the material in the unit; or to inspect, maintain, repair, or replace equipment located inside the unit. These requirements are consistent with the requirements for storage tanks under NSPS OOOO and will ensure that the requirements apply to any storage tanks that are not subject to NSPS OOOO.

Each owner and operator is required to use closed-vent systems to collect and route natural gas emissions to the respective VOC control devices. All vent lines, connections, fittings, valves, relief valves, or any other appurtenance employed to contain and collect gases, and transport them to the VOC control equipment must be maintained and operated properly during any time the control equipment is operating and must be designed to operate with no detectable natural gas emissions. If a closed-vent system contains one or more bypass devices that could be used to divert all or a portion of the natural gas, from entering the VOC control devices, the owner or operator must meet one of the following options for each bypass device: (1) At the inlet to the bypass device properly install, calibrate, maintain, and operate a natural gas flow indicator capable of taking periodic readings and sounding an alarm when the bypass device is open such that the natural gas is being, or could be, diverted away from the control device and into the atmosphere; or (2) secure the bypass device valve in the non-diverting position using a car-seal or a lock-and-key type configuration. These requirements are consistent with the requirements for storage tanks under NSPS OOOO and will ensure that the requirements apply to any storage tanks that are not subject to NSPS OOOO.

Each owner or operator is required to follow the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions from each enclosed combustor or utility flare. Each enclosed combustor must have the capacity to reduce the mass content of the VOC in the natural gas routed to it by at least 98.0 percent for the minimum and maximum natural gas volumetric flow rate and British Thermal Unit (BTU) content routed to it. We note that the NSPS OOOO requires owners and operators to demonstrate that enclosed combustors and utility flares achieve the required VOC reduction by conducting performance tests. Those units that have been tested by the manufacturer in accordance with specific requirements in the rule, or that are designed and operated in accordance with applicable requirements in 40 CFR 60.18(b), satisfy the requirements of performance testing by the owner or operator. For the purposes of this rule, we require that all utility flares installed per this rule meet the requirements in 40 CFR 60.18(b), and all enclosed combustors installed per this rule must be tested according to the NSPS OOOO performance testing requirements. Until such time that compliance is required with the storage vessel requirements in the NSPS OOOO standard, however, the owner or operators can demonstrate compliance using methods specified in this rule.

We determined that certain work practice and operational requirements are also necessary for the practical enforceability of the VOC emission reduction requirement that the enclosed combustors or utility flares must achieve. Flares and combustors must be operated within specific parameters to effectively destroy VOC emissions. This was discussed in great detail in the preamble and technical support

[26] If the owner or operator receives written approval for a new method, the owner or operator must calculate potential to emit based on the new EPA-approved method.

[27] Based on our consultation with the owners and operators producing from the Bakken Pool, in addition to these particular provisions we also identified for regulating emissions from well completions and recompletions. These control operations are already being performed during these operations for product recovery or safety purposes. These consultations, provided us not only with information on the production practices occurring both on and off the Reservation, but it also provided us with information on the existing phased approach to controlling emissions from well completion and recompletions, through production operations, and ending with storage and loading operations and an appropriate timeline for installation of the controls. Those components in this section are based on these practices that are already in place.

documents to the proposed and final NSPS OOOO [15]. Therefore, each owner or operator must ensure that each enclosed combustor or utility flare is: (1) Operated at all times that natural gas is routed to it; (2) operated with a liquid knock-out system to collect any condensable vapors (to prevent liquids from going through the control device); (3) equipped with a flash-back flame arrestor; (4) equipped with a continuous burning pilot flame and thermocouple, or equipped with an electronically controlled automatic ignition system; (5) equipped with a malfunction alarm and remote notification system to detect if the pilot flame fails while natural gas is being routed through the device; (6) equipped with a continuous recording device, such as a chart recorder, data logger or similar device, or connected to a Supervisory Control and Data Acquisition (SCADA) system, to monitor and document proper operation of the enclosed combustor or utility flare; (7) maintained in a leak free condition; and (8) operated with no visible smoke emissions. These requirements are consistent with Bakken Pool Guidance.

Section 49.144 requires that each owner or operator limit the use of pit flares to: the control natural gas emissions during well completion operations; the control VOC emissions in the event the natural gas that is being recovered for sale or other beneficial purpose must be diverted to an emergency control device because injection into the pipeline is temporarily infeasible and the enclosed combustor or utility flare installed at the oil and natural gas production facility is not operational; or use when total uncontrolled PTE VOCs from all produced oil storage tanks and any produced water storage tanks interconnected with produced oil storage tanks at an oil and natural gas production facility have declined to less than, and are reasonably expected to stay below, 20 tons in any consecutive 12-month period. Each pit flare must be operated to reduce the mass content of VOC in the natural gas routed to it by at least 90 percent and must be operated with no visible smoke emissions.[28] Each pit flare must be equipped with an electronically controlled automatic ignition system with malfunction alarm and remote notification system if the pilot flame fails. Each pit flare must be visually inspected for the presence of a pilot flame any time natural gas is being routed to it and if the pilot flame fails, it must be relit as soon as safely possible and the automatic ignition system must be repaired or replaced before the pit flare is used again.

As North Dakota has done in the Bakken Pool Guidance, § 49.144 allows owners or operators of oil and natural gas production facilities to use control devices other than an enclosed combustor or utility flare, provided they are capable of achieving at least a 98.0 percent VOC destruction efficiency and upon our written approval. This provision will allow for owner or operators to take advantage of technological advances in VOC emission control for the oil and natural gas production industry and will provide us with valuable information on any new control technologies.

G. Monitoring Requirements

Section 49.145 Monitoring Requirements requires each owner or operator conduct certain monitoring that we determined is necessary for the practical enforceability of the VOC emission reduction requirements, including but not limited to: (1) Monitoring of the hours of operation of each pit flare used to control VOC emissions in the event the natural gas that is being recovered for sale or other beneficial purpose must be diverted to an emergency control device because injection into the pipeline is temporarily infeasible and the enclosed combustor or utility flare installed at the oil and natural gas production facility is not operational; (2) Monitoring of the number of barrels of oil produced at the facility each time the oil is unloaded from the produced oil storage tanks; (3) Monitoring of the volume of natural gas from the heater-treater sent to each enclosed combustor, utility flare, and pit flare at all times; (4) Monitoring of the volume of standing, working, breathing, and flashing losses from the produced oil and produced water storage tanks sent to each vapor recovery system, enclosed combustor, utility flare, and pit flare at all times; (5) Directly measuring, or calculating using EPA approved models, various parameters (i.e., product throughput, enclosed combustor flame presence, temperature, etc.) related to the proper operation of emissions units and required control devices to assure compliance with the emissions reduction requirements and operational limitations; and (6) Visibility monitoring for detecting visible smoke from enclosed combustors, utility flares, and pit flares.

These requirements are derived from the Bakken Pool Guidance in conjunction with NSPS OOOO. The monitoring, recordkeeping and reporting requirements for the covers, close-vent systems, pit flares, enclosed combustors, and utility flares are based, in part, on the requirements in the Bakken Pool Guidance. Specifically, our review and determination that these requirements are appropriate, as well as the Bakken Pool Guidance provides the basis for monitoring the flares and enclosed combustors. The monitoring of the covers and closed-vent systems, in addition to the recordkeeping and reporting requirements are based on the NSPS OOOO requirements for these units and are intended to provide legal and practical enforceability.

H. Recordkeeping Requirements

Section 49.146 Record Keeping Requirements requires that each owner or operator of an oil and natural gas production facility keep specific records to be made available upon our request, in lieu of voluminous reporting requirements. The records that must be kept include, but are not limited to, all required measurements, monitoring, and deviations or exceedances of rule requirements and corrective actions taken, as well as any manufacturer specifications and guarantees or engineering analyses. These record keeping requirements were derived independently of the North Dakota Rules and Bakken Pool Guidance and provide legal and practical enforceability to the control and emission reduction requirements of this rule.

I. Reporting Requirements

Section 49.147 Reporting Requirements requires that each owner or operator of an oil and natural gas production facility prepare and submit an annual report, beginning one year after this rule becomes effective covering the period for the previous calendar year. The report must include a summary of required records identifying each oil and natural gas production well completion or recompletion operation for each facility conducted during the reporting period, an identification of the first date of production for each oil and natural gas production well at each facility that commenced operation during the reporting period, and a summary of deviations or exceedances of any requirements of the FIP and the corrective measures taken. Additionally,

[28] Owners and operators of oil and natural gas production facilities on the FBIR have indicated that a 90.0% VOC destruction efficiency in the Bakken Pool Guidance is achievable using a pit flare and committed in their synthetic minor NSR applications to reduce the mass content of VOC emissions routed to a pit flare by at least 90.0% by weight.

a report must be submitted for any performance test we require.

We decided not to require owners or operators to register their oil and natural gas production facilities, because the Federal Tribal NSR Rule at 40 CFR 49.151 already requires registration of existing minor sources and such a requirement in this rule would be redundant.

These reporting requirements were derived independently of the North Dakota Rules and Bakken Pool Guidance and provide legal and practical enforceability to the control and emission reduction requirements of this rule.

VII. Statutory and Executive Order

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

This action is not a "significant regulatory action" under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011).

B. Paperwork Reduction Act

This action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* Burden is defined at 5 CFR 1320.3(b).

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant adverse economic impact on small entities, since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives "which minimize any significant economic impact of the rule on small entities." 5 U.S.C. 603 and 604. Thus, an agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect on all of the small entities subject to the rule.

This rule will not have a significant economic impact on a substantial number of small entities due to the reduced regulatory requirement, and thus the regulatory burden, to obtain Federal CAA permits that this rule provides. We continue to be interested in the potential impacts of this rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act (UMRA)

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to State, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more (adjusted for inflation) in any one year. Before promulgating an EPA rule for which a written statement is needed, Section 205 of UMRA generally requires us to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of Section 205 of UMRA do not apply when they are inconsistent with applicable law. Moreover, Section 205 of UMRA allows us to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before we establish any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under Section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

Under Title II of UMRA, we determined that this rule does not contain a federal mandate that may result in expenditures that exceed the inflation-adjusted UMRA threshold of $100 million by State, local, or Tribal governments or the private sector in any one year. In addition, this rule does not contain a significant federal intergovernmental mandate as described by section 203 of UMRA nor does it contain any regulatory requirements that might significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

Federalism (64 FR 43255, August 10, 1999) revokes and replaces Executive Orders 12612 (Federalism) and 12875 (Enhancing the Intergovernmental Partnership). Executive Order 13132 requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." "Policies that have federalism implications" is defined in the Executive Order to include regulations that 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." Under Executive Order 13132, we may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or we consult with State and local officials early in the process of developing regulations. We also may not issue a regulation that has federalism implications and that preempts State law unless the Agency consults with State and local officials early in the process of developing regulations.

This rule 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, as specified in Executive Order 13132, because it regulates under the CAA certain stationary sources in Indian country that are not subject to approved CAA programs of the State of North Dakota. Thus, Executive Order 13132 does not apply to this action. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between us and State and local governments, we specifically solicit comment on this rule from State and local officials.

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

Executive Order 13175, entitled "Consultation and Coordination with Indian Tribal Governments" (65 FR 67249, November 6, 2000), requires us to develop an accountable process to ensure "meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications." "Policies that have Tribal implications" is defined in the Executive Order to include regulations that have "substantial direct effects on one or more Indian Tribes, on the relationship between the Federal government and the Indian Tribes, or on the distribution of power and responsibilities between the Federal government and Indian Tribes."

Under Section 5(b) of Executive Order 13175, we may not issue a regulation that has Tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by Tribal governments, or we consult with Tribal officials early in the process of developing the proposed regulation. Under Section 5(c) of Executive Order 13175, we may not issue a regulation that has Tribal implications and that preempts Tribal law, unless the Agency consults with Tribal officials early in the process of developing the proposed regulation.

We concluded that this final rule will have tribal implications. However, it will neither impose substantial direct compliance costs on tribal governments, nor preempt tribal law. These regulations would affect the FBIR community by filling a gap in air quality regulations and thus creating a level of air quality protection not previously provided under the CAA. The gap-filling approach used in this rule would create Federal requirements similar to those that are already in place in areas adjacent to the Reservation covered by the proposal. Finally, although Tribal governments are encouraged to partner with us on the implementation of these regulations, they are not required to do so. Since this final rule will neither impose substantial direct compliance costs on Tribal governments, nor preempt Tribal law, the requirements of Sections 5(b) and 5(c) of the Executive Order do not apply to this rule.

Consistent with EPA policy, the EPA consulted with Tribal officials and representatives of the Three Affiliated Tribes of the Mandan, Hidatsa and Arikara Nations early in the process of developing this regulation to permit them to have meaningful and timely input into its development.

Tribal consultation with the Three Affiliated Tribes of the Mandan, Hidatsa, and Arikara Nation was first initiated on February 17, 2012 when we mailed a letter inviting the Tribes to consult on the first group of synthetic minor permits being issued on the Reservation under the Tribal NSR Rule. Then, on March 29, 2012, EPA senior management and the Chairman of the Tribes along with other government officials met via conference call to discuss the proposed FIP to be developed for the FBIR. We formally invited the Tribes to consult about the FIP in a letter dated April 10, 2012 to Chairman Tex Hall, of the Three Affiliated Tribes of the Mandan, Hidatsa, and Arikara Nation Council.

We again met with members of the Three Affiliated Tribes of the Mandan, Hidatsa, and Arikara Nation Council on June 13, 2012 in New Town to consult and receive input from the Tribes as we developed the FIP. In attendance from the Council were the vice Chairman and two council members. The Tribes' legal counsel was also in attendance. The purpose of the consultation was twofold: (1) Update the Tribes on EPA's efforts to develop the FIP so that the air quality on the FBIR is protected and oil and natural gas development continues; and (2) discuss the Tribes' preferences regarding involvement in the FIP process. We provided information on our plan to prepare a FIP to ensure air quality protection while preventing delays in oil and natural gas production. EPA solicited the Tribes' input on the FIP development. The Council members present at the consultation meeting indicated that they strongly desired the FIP rule to be consistent with North Dakota's requirements for oil and natural gas production facilities in order to keep a level playing field for development and continue uninterrupted development of a key economic resource for the Tribe. The Council members expressed interest in the future delegation of the FIP so that the Tribes can implement the rule in place of EPA. The Council members also expressed interest in providing the Tribes' assistance in setting up a public hearing for the rule.

As noted above, the Three Affiliated Tribes of the Mandan, Hidatsa and Arikara Nations have indicated preliminary interest in seeking administrative delegation of the Tribal NSR rule to assist us with administration of that rule. We will continue to work with the Tribes if administrative delegation is something the Tribes decide to pursue.

Information containing the consultation process is contained in the docket for this rule.

For purposes of the proposed rule, EPA specifically solicits additional comments on the proposed action from tribal officials.

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

EPA interprets E.O. 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the E.O. has the potential to influence the regulation. This action is not subject to E.O. 13045 because it implements specific standards established by Congress in statutes. In addition, this rule requires control and reduction of emissions of VOCs, which will have a beneficial effect on children's health by reducing air pollution.

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

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

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs us to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, and business

practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs us to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking does not involve technical standards. Therefore, we are not considering the use of any voluntary consensus standards.

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

Executive Order 12898 (59 FR 7629, February 16, 1994), establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

We determined that this rule will not have disproportionately high and adverse human health or environmental effects on minority, low income and indigenous populations because it is in compliance with the National Ambient Air Quality Standards and provides environmental protection for all affected populations including any minority, low income, and indigenous populations.

K. Congressional Review Act

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. Section 808 allows the issuing agency to make a rule effective sooner than otherwise provided by the CRA if the agency makes a good cause finding that notice and public procedure is impracticable, unnecessary or contrary to the public interest. This determination must be supported by a brief statement. 5 U.S.C. 808(2). As stated previously, EPA has made such a good cause finding, including the reasons therefore, and the rule is effective in the CFR August 15, 2012. This rule is effective with actual notice for purposes of enforcement beginning at 5 p.m. (Eastern Daylight Time) on August 3, 2012. This action is not a "major rule" as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 49

Environmental protection, Administrative practice and procedure, Air pollution control, Indians, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: August 1, 2012.

Lisa P. Jackson,

Administrator.

40 CFR part 49 is amended as follows:

PART 49—[AMENDED]

■ 1. The authority citation for part 49 continues to read as follows:

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

PART 49—INDIAN COUNTRY: AIR QUALITY PLANNING AND MANAGEMENT

Subpart C—General Federal Implementation Plan Provisions

■ 2. Add §§ 49.140 through 49.147 and an undesignated center heading to appear immediately before the newly added § 49.140 to read as follows:

Federal Implementation Plan for Oil and Natural Gas Production Facilities, Fort Berthold Indian Reservation (Mandan, Hidatsa and Arikara Nations) in EPA Region 8

§ 49.140 Introduction.

(a) *What is the purpose of §§ 49.140 through 49.147?* Sections 49.140 through 49.147 establish legally and practicably enforceable requirements to control and reduce VOC emissions from well completion operations, well recompletion operations, production operations, and storage operations at existing, new and modified oil and natural gas production facilities.

(b) *Am I subject to §§ 49.140 through 49.147?* Sections 49.140 through 49.147 apply to each owner or operator constructing or operating an oil and natural gas production facility producing from the Bakken Pool with one or more oil and natural gas wells, for any one of which completion or recompletion operations are/were performed on or after August 12, 2007, that is located on the Fort Berthold Indian Reservation, which is defined by the Act of March 3, 1891 (26 Statute 1032) and which includes all lands added to the Reservation by Executive Order of June 17, 1892 (the "Fort Berthold Indian Reservation").

(c) *When must I comply with §§ 49.140 through 49.147?* Compliance with *§§ 49.140 through 49.147* is required no later than November 13, 2012 or upon initiation of completion or recompletion operations, whichever is later.

§ 49.141 Delegation of authority of administration to the tribes.

(a) *What is the purpose of this section?* The purpose of this section is to establish the process by which the Regional Administrator may delegate to the Mandan, Hidatsa and Arikara Nations the authority to assist the EPA with administration of this Federal implementation plan (FIP). This section provides for administrative delegation and does not affect the eligibility criteria under 40 CFR 49.6 for treatment in the same manner as a State.

(b) *How does the Tribe request delegation?* In order to be delegated authority to assist us with administration of this FIP, the authorized representative of the Mandan, Hidatsa and Arikara Nations must submit a request to the Regional Administrator that:

(1) Identifies the specific provisions for which delegation is requested;

(2) Includes a statement by the Mandan, Hidatsa and Arikara Nations' legal counsel (or equivalent official) that includes the following information:

(i) A statement that the Mandan, Hidatsa and Arikara Nations are an Indian Tribe recognized by the Secretary of the Interior;

(ii) A descriptive statement demonstrating that the Mandan, Hidatsa and Arikara Nations are currently carrying out substantial governmental duties and powers over a defined area and that meets the requirements of § 49.7(a)(2); and

(iii) A description of the laws of the Mandan, Hidatsa and Arikara Nations that provide adequate authority to carry out the aspects of the rule for which delegation is requested.

(3) Demonstrates that the Mandan, Hidatsa and Arikara Nations have, or will have, adequate resources to carry out the aspects of the rule for which delegation is requested.

(c) *How is the delegation of administration accomplished?* (1) A Delegation of Authority Agreement will set forth the terms and conditions of the delegation, will specify the rule and provisions that the Mandan, Hidatsa and Arikara Nations shall be authorized to implement on behalf of the EPA, and shall be entered into by the Regional Administrator and the Mandan, Hidatsa and Arikara Nations. The Agreement will become effective upon the date that both the Regional Administrator and the authorized representative of the Mandan, Hidatsa and Arikara Nations have signed the Agreement. Once the

delegation becomes effective, the Mandan, Hidatsa and Arikara Nations will be responsible, to the extent specified in the Agreement, for assisting us with administration of the FIP and shall act as the Regional Administrator as that term is used in these regulations. Any Delegation of Authority Agreement will clarify the circumstances in which the term "Regional Administrator"' found throughout the FIP is to remain the EPA Regional Administrator and when it is intended to refer to the "Mandan, Hidatsa and Arikara Nations," instead.

(2) A Delegation of Authority Agreement may be modified, amended, or revoked, in part or in whole, by the Regional Administrator after consultation with the Mandan, Hidatsa and Arikara Nations.

(d) *How will any delegation of authority agreement be publicized?* The Regional Administrator shall publish a notice in the **Federal Register** informing the public of any delegation of authority agreement with the Mandan, Hidatsa and Arikara Nations to assist us with administration of all or a portion of the FIP and will identify such delegation in the FIP. The Regional Administrator shall also publish an announcement of the delegation of authority agreement in local newspapers.

§ 49.142 General provisions.

(a) *Definitions.* As used in §§ 49.140 through 49.147, all terms not defined herein shall have the meaning given them in the Act, in subpart A and subpart OOOO of 40 CFR part 60, in the Prevention of Significant Deterioration regulations at 40 CFR 52.21, or in the Federal Minor New Source Review Program in Indian Country at 40 CFR 49.151. The following terms shall have the specific meanings given them.

(1) *Bakken Pool* means Oil produced from the Bakken, Three Forks, and Sanish Formations.

(2) *Breathing losses* means natural gas emissions from fixed roof tanks resulting from evaporative losses during storage.

(3) *Casinghead natural gas* means the associated natural gas that naturally dissolves out of reservoir fluids during well completion operations and recompletion operations due to the pressure relief that occurs as the reservoir fluids travel up the well casinghead.

(4) *Closed vent system* means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport natural gas from a piece or pieces of equipment to a control device or back to a process.

(5) *Enclosed combustor* means a thermal oxidation system with an enclosed combustion chamber that maintains a limited constant temperature by controlling fuel and combustion air.

(6) *Existing facility* means an oil and natural gas production facility that begins actual construction prior to the effective date of the "Federal Implementation Plan for Oil and Natural Gas Production Facilities, Fort Berthold Indian Reservation (Mandan, Hidatsa and Arikara Nations)".

(7) *Flashing losses* means natural gas emissions resulting from the presence of dissolved natural gas in the produced oil and the produced water, both of which are under high pressure, that occurs as the produced oil and produced water is transferred to storage tanks or other vessels that are at atmospheric pressure.

(8) *Modified facility* means a facility which has undergone the addition, completion, or recompletion of one or more oil and natural gas wells, and/or the addition of any associated equipment necessary for production and storage operations at an existing facility.

(9) *New facility* means an oil and natural gas production facility that begins actual construction after the effective date of the "Federal Implementation Plan for Oil and Natural Gas Production Facilities, Fort Berthold Indian Reservation (Mandan, Hidatsa and Arikara Nations)".

(10) *Oil* means hydrocarbon liquids.

(11) *Oil and natural gas production facility* means all of the air pollution emitting units and activities located on or integrally connected to one or more oil and natural gas wells that are necessary for production operations and storage operations.

(12) *Oil and natural gas well* means a single well that extracts subsurface reservoir fluids containing a mixture of oil, natural gas, and water.

(13) *Owner or operator* means any person who owns, leases, operates, controls, or supervises an oil and natural gas production facility.

(14) *Permit to construct or construction permit* means a permit issued by the Regional Administrator pursuant to 40 CFR 49.151, 52.10 or 52.21, or a permit issued by a Tribe pursuant to a program approved by the Administrator under 40 CFR part 51, subpart I, authorizing the construction or modification of a stationary source.

(15) *Permit to operate or operating permit* means a permit issued by the Regional Administrator pursuant to 40 CFR part 71, or by a Tribe pursuant to a program approved by the Administrator under 40 CFR part 51 or 40 CFR part 70, authorizing the operation of a stationary source.

(16) *Pit flare* means an ignition device, installed horizontally or vertically and used in oil and natural gas production operations to combust produced natural gas and natural gas emissions.

(17) *Produced natural gas* means natural gas that is separated from extracted reservoir fluids during production operations.

(18) *Produced oil* means oil that is separated from extracted reservoir fluids during production operations.

(19) *Produced oil storage tank* means a unit that is constructed primarily of non-earthen materials (such as steel, fiberglass, or plastic) which provides structural support and is designed to contain an accumulation of produced oil.

(20) *Produced water* means water that is separated from extracted reservoir fluids during production operations.

(21) *Produced water storage tank* means a unit that is constructed primarily of non-earthen materials (such as steel, fiberglass, or plastic) which provides structural support and is designed to contain an accumulation of produced water.

(22) *Production operations* means the extraction and separation of reservoir fluids from an oil and natural gas well, using separators and heater-treater systems. A separator is a pressurized vessel designed to separate reservoir fluids into their constituent components of oil, natural gas and water. A heater-treater is a unit that heats the reservoir fluid to break oil/water emulsions and to reduce the oil viscosity. The water is then typically removed by using gravity to allow the water to separate from the oil.

(23) *Regional Administrator* means the Regional Administrator of EPA Region 8 or an authorized representative of the Regional Administrator.

(24) *Standing losses* means natural gas emissions from fixed roof tanks as a result of evaporative losses during storage.

(25) *Storage operations* means the transfer of produced oil and produced water to storage tanks, the filling of the storage tanks, the storage of the produced oil and produced water in the storage tanks, and the draining of the produced oil and produced water from the storage tanks.

(26) *Supervisory Control and Data Acquisition (SCADA) system* generally refers to industrial control computer systems that monitor and control

industrial infrastructure or facility-based processes.

(27) *Utility flare* means thermal oxidation system using an open (without enclosure) flame. An enclosed combustor as defined in §§ 49.140 through 49.147 is not considered a flare.

(28) *Visible Smoke emissions* means a pollutant generated by thermal oxidation in a flare or enclosed combustor and occurring immediately downstream of the flame. Visible smoke occurring within, but not downstream of, the flame, is not considered to constitute visible smoke emissions.

(29) *Well completion* means the process that allows for the flowback of oil and natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

(30) *Well completion operation* means any oil and natural gas well completion using hydraulic fracturing occurring at an oil and natural gas production facility.

(31) *Well recompletion operation* means any oil and natural gas well completion using hydraulic refracturing occurring at an oil and natural gas production facility.

(32) *Working losses* means natural gas emissions from fixed roof tanks resulting from evaporative losses during filling and emptying operations.

(b) *Requirement for testing.* The Regional Administrator may require that an owner or operator of an oil and natural gas production facility demonstrate compliance with the requirements of the "Federal Implementation Plan for Oil and Natural Gas Production Facilities, Fort Berthold Indian Reservation (Mandan, Hidatsa and Arikara Nations)" by performing a source test and submitting the test results to the Regional Administrator. Nothing in the "Federal Implementation Plan for Oil and Natural Gas Production Facilities, Fort Berthold Indian Reservation (Mandan, Hidatsa and Arikara Nations)" limits the authority of the Regional Administrator to require, in an information request pursuant to section 114 of the Act, an owner or operator of an oil and natural gas production facility subject to the "Federal Implementation Plan for Oil and Natural Gas Production Facilities, Fort Berthold Indian Reservation (Mandan, Hidatsa and Arikara Nations)" to demonstrate compliance by performing testing, even where the facility does not have a permit to construct or a permit to operate.

(c) *Requirement for monitoring, recordkeeping, and reporting.* Nothing in "Federal Implementation Plan for Oil and Natural Gas Production Facilities, Fort Berthold Indian Reservation (Mandan, Hidatsa and Arikara Nations)" precludes the Regional Administrator from requiring monitoring, recordkeeping and reporting, including monitoring, recordkeeping and reporting in addition to that already required by an applicable requirement, in a permit to construct or permit to operate in order to ensure compliance.

(d) *Credible evidence.* For the purposes of submitting reports or establishing whether or not an owner or operator of an oil and natural gas production facility has violated or is in violation of any requirement, nothing in the "Federal Implementation Plan for Oil and Natural Gas Production Facilities, Fort Berthold Indian Reservation (Mandan, Hidatsa and Arikara Nations)" shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a facility would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed.

§ 49.143 Construction and operational control measures.

(a) Each owner or operator must operate and maintain all liquid and gas collection, storage, processing and handling operations, regardless of size, so as to minimize leakage of natural gas emissions to the atmosphere.

(b) During all oil and natural gas well completion operations or recompletion operations at an oil and natural gas production facility and prior to the first date of production of each oil and natural gas well, each owner or operator must, at a minimum, route all casinghead natural gas to a utility flare or a pit flare capable of reducing the mass content of VOC in the natural gas emissions vented to it by at least 90.0 percent or greater and operated as specified in § 49.144 and § 49.145.

(c) Beginning with the first date of production from any one oil and natural gas well at an oil and natural gas production facility, each owner or operator must, at a minimum, route all natural gas emissions from production operations and storage operations to a control device capable of reducing the mass content of VOC in the natural gas emissions vented to it by at least 90.0 percent or greater and operated as specified in § 49.144 and § 49.145.

(d) Within ninety (90) days of the first date of production from any oil and natural gas well at an oil and natural gas production facility, each owner or operator must:

(1) Route the produced natural gas from the production operations through a closed-vent system to:

(i) An operating system designed to recover and inject all the produced natural gas into a natural gas gathering pipeline system for sale or other beneficial purpose; or

(ii) A utility flare or equivalent combustion device capable of reducing the mass content of VOC in the produced natural gas vented to the device by at least 98.0 percent or greater and operated as specified in § 49.144 and § 49.145.

(2) Route all standing, working, breathing, and flashing losses from the produced oil storage tanks and any produced water storage tank interconnected with the produced oil storage tanks through a closed-vent system to:

(i) An operating system designed to recover and inject the natural gas emissions into a natural gas gathering pipeline system for sale or other beneficial purpose; or

(ii) An enclosed combustor or utility flare capable of reducing the mass content of VOC in the natural gas emissions vented to the device by at least 98.0 percent or greater and operated as specified in § 49.144(c) and § 49.145.

(iii) If the uncontrolled potential to emit VOCs from the aggregate of all produced oil storage tanks and produced water storage tanks interconnected with produced oil storage tanks at an oil and natural gas production facility is less than, and reasonably expected to remain below, 20 tons in any consecutive 12-month period, then, upon written approval by the EPA the owner or operator may use a pit flare, an enclosed combustor or a utility flare that is capable of reducing the mass content of VOC in the natural gas emissions from the storage tanks vented to the device by only 90.0 percent.

(e) In the event that pipeline injection of all or part of the natural gas collected in an operating system designed to recover and inject natural gas becomes temporarily infeasible and there is no operational enclosed combustor or utility flare at the facility, the owner or operator must route the natural gas that cannot be injected through a closed-vent system to a pit flare operated as specified in § 49.144 and § 49.145.

(f) Produced oil storage tanks and any produced water storage tanks interconnected with produced oil storage tanks subject to and controlled under the requirements specified in 40 CFR part 60, subpart OOOO are considered to meet the requirements of

§ 49.143(d)(2). No further requirements apply for such storage tanks under § 49.143(d)(2).

§ 49.144 Control equipment requirements.

(a) *Covers.* Each owner or operator must equip all openings on each produced oil storage tank and produced water storage tank interconnected with produced oil storage tanks with a cover to ensure that all natural gas emissions are efficiently being routed through a closed-vent system to a vapor recovery system, an enclosed combustor, a utility flare, or a pit flare.

(1) Each cover and all openings on the cover (*e.g.,* access hatches, sampling ports, pressure relief valves (PRV), and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the produced oil and produced water in the storage tank.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.,* covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit; or

(iii) To inspect, maintain, repair, or replace equipment located inside the unit.

(3) Each thief hatch cover shall be weighted and properly seated.

(4) Each PRV shall be set to release at a pressure that will ensure that natural gas emissions are routed through the closed-vent system to the vapor recovery system, the enclosed combustor, or the utility flare under normal operating conditions.

(b) *Closed-vent systems.* Each owner or operator must meet the following requirements for closed-vent systems:

(1) Each closed-vent system must route all produced natural gas and natural gas emissions from production and storage operations to the natural gas sales pipeline or the control devices required by paragraph (a) of this section.

(2) All vent lines, connections, fittings, valves, relief valves, or any other appurtenance employed to contain and collect natural gas, vapor, and fumes and transport them to a natural gas sales pipeline and any VOC control equipment must be maintained and operated properly at all times.

(3) Each closed-vent system must be designed to operate with no detectable natural gas emissions.

(4) If any closed-vent system contains one or more bypass devices that could be used to divert all or a portion of the natural gas emissions, from entering a natural gas sales pipeline and/or any control devices, the owner or operator must meet one of the following requirements for each bypass device:

(i) At the inlet to the bypass device that could divert the natural gas emissions away from a natural gas sales pipeline or a control device and into the atmosphere, properly install, calibrate, maintain, and operate a natural gas flow indicator that is capable of taking continuous readings and sounding an alarm when the bypass device is open such that natural gas emissions are being, or could be, diverted away from a natural gas sales pipeline or a control device and into the atmosphere;

(ii) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration;

(iii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements applicable to bypass devices.

(c) *Enclosed combustors and utility flares.* Each owner or operator must meet the following requirements for enclosed combustors and utility flares:

(1) For each enclosed combustor or utility flare, the owner or operator must follow the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions;

(2) For each enclosed combustor or utility flare, the owner or operator must ensure there is sufficient capacity to reduce the mass content of VOC in the produced natural gas and natural gas emissions routed to it by at least 98.0 percent for the minimum and maximum natural gas volumetric flow rate and BTU content routed to the device;

(3) Each enclosed combustor or utility flare must be operated to reduce the mass content of VOC in the produced natural gas and natural gas emissions routed to it by at least 98.0 percent;

(4) The owner or operator must ensure that each utility flare is designed and operated in accordance with the requirements of 40 CFR 60.18(b) for such flares.

(5) The owner or operator must ensure that each enclosed combustor is:

(i) A model demonstrated by a manufacturer to the meet the VOC destruction efficiency requirements of §§ 49.140 through 49.147 using the procedure specified in 40 CFR part 60, subpart OOOO at § 60.5413(d) by the due date of the first annual report as specified in § 49.147(b); or

(ii) Demonstrated to meet the VOC destruction efficiency requirements of §§ 49.140 through 49.147 using EPA approved performance test methods specified in 40 CFR part 60, subpart OOOO at § 60.5413(b) by the due date of the first annual report as specified in § 49.147(b); or

(iii) Until such time that 40 CFR part 60, subpart OOOO is promulgated, demonstrated to meet the VOC destruction efficiency requirements of §§ 49.140 through 49.147 by using the EPA approved performance test methods specified in 40 CFR part 63, subpart HH at § 63.772(e)(1)(i) through (iii) for hazardous air pollutants, by the due date of the first annual report as specified in § 49.147(b).

(6) The owner or operator must ensure that each enclosed combustor and utility flare is:

(i) Operated properly at all times that natural gas is routed to it;

(ii) Operated with a liquid knock-out system to collect any condensable vapors (to prevent liquids from going through the control device);

(iii) Equipped with a flash-back flame arrestor;

(iv) Equipped with one of the following:

(A) A continuous burning pilot flame, a thermocouple, and a malfunction alarm and remote notification system if the pilot flame fails.

(B) An electronically controlled auto-ignition system with a malfunction alarm and remote notification system if the pilot flame fails while produced natural gas or natural gas emissions are flowing to the enclosed combustor or utility flare;

(v) Equipped with a continuous recording device, such as a chart recorder, data logger or similar device, or connected to a Supervisory Control and Data Acquisition (SCADA) system, to monitor and document proper operation of the enclosed combustor or utility flare;

(vi) Maintained in a leak-free condition; and

(vii) Operated with no visible smoke emissions.

(d) *Pit Flares.* Each owner or operator must meet the following requirements for pit flares:

(1) The owner or operator must develop written operating instructions, operating procedures and maintenance schedules to ensure good air pollution control practices for minimizing emissions from the pit flare based on the site-specific design.

(2) The owner or operator must only use a pit flare for the following operations:

(i) To control produced natural gas and natural gas emissions during well completion operations or recompletion operations;

(ii) To control natural gas emissions in the event that natural gas recovered for pipeline injection must be diverted to an emergency control device because injection is temporarily infeasible and the enclosed combustor or utility flare installed at the oil and natural gas production facility is not operational. Use of the pit flare for this situation is limited to a maximum of 500 hours in any twelve (12) consecutive months during periods when pipeline injection has become temporarily infeasible and no enclosed combustor or utility flare installed at the facility is operational; or

(iii) Control of standing, working, breathing, and flashing losses from the produced oil storage tanks and any produced water storage tank interconnected with the produced oil storage tanks if the uncontrolled potential VOC emissions from the aggregate of all produced oil storage tanks and produced water storage tanks interconnected with produced oil storage tanks is less than, and reasonably expected to remain below, 20 tons in any consecutive 12-month period.

(3) The owner or operator must only use the pit flare under the following conditions and limitations:

(i) The pit flare is operated to reduce the mass content of VOC in the produced natural gas and natural gas emissions routed to it by at least 90.0 percent;

(ii) The pit flare is operated in accordance with the site-specific written operating instructions, operating procedures, and maintenance schedules to ensure good air pollution control practices for minimizing emissions;

(iii) The pit flare is operated with no visible smoke emissions;

(iv) The pit flare is equipped with an electronically controlled auto-ignition system with a malfunction alarm and remote notification system if the pilot flame fails;

(v) The pit flare is visually inspected for the presence of a pilot flame anytime produced natural gas or natural gas emissions are being routed to it. Should the pilot flame fail, the flame must be relit as soon as safely possible and the electronically controlled auto-ignition system must be repaired or replaced before the pit flare is utilized again; and

(vi) The owner or operator does not deposit or cause to be deposited into a flare pit any oil field fluids or oil and natural gas wastes other than those designed to go to the pit flare.

(e) *Other Control Devices.* Upon written approval by the EPA, the owner or operator may use control devices other than those listed above that are capable of reducing the mass content of VOC in the natural gas routed to it by at least 98.0 percent, provided that:

(1) In operating such control devices, the owner or operator must follow the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions; and

(2) The owner or operator must ensure there is sufficient capacity to reduce the mass content of VOC in the produced natural gas and natural gas emissions routed to such other control devices by at least 98.0 percent for the minimum and maximum natural gas volumetric flow rate and BTU content routed to each device.

(3) The owner or operator must operate such a control device to reduce the mass content of VOC in the produced natural gas and natural gas emissions routed to it by at least 98.0 percent.

§ 49.145 Monitoring requirements.

(a) Each owner and operator must measure the barrels of oil produced at the oil and natural gas production facility each time the oil is unloaded from the produced oil storage tanks using the methodologies of tank gauging or positive displacement metering system, as appropriate, as established by the US Department of the Interior's Bureau of Land Management at 43 CFR part 3160, in the "Onshore Oil and Gas Operations; Federal and Indian Oil & Gas Leases; Onshore Oil and Gas Order No. 4; Measurement of Oil."

(b) Each owner or operator must monitor the hours that each pit flare is operated to control natural gas emissions in the event that natural gas recovered for pipeline injection must be diverted to an emergency control device because injection is temporarily infeasible and the enclosed combustor or utility flare installed at the oil and natural gas production facility is not operational.

(c) Each owner or operator must monitor the volume of produced natural gas sent to each enclosed combustor, utility flare, and pit flare at all times. Methods to measure the volume include, but are not limited to, direct measurement and gas-to-oil ratio (GOR) laboratory analyses.

(d) Each owner or operator must monitor the volume of standing, working, breathing, and flashing losses from the produced oil and produced water storage tanks sent to each vapor recovery system, enclosed combustor, utility flare, and pit flare at all times. Methods to measure the volume include, but are not limited to, direct measurement or GOR laboratory analyses.

(e) Each owner or operator must perform quarterly visual inspections of tank thief hatches, covers, seals, PRVs, and closed vent systems to ensure proper condition and functioning and repair any damaged equipment. The quarterly inspections must be performed while the produced oil and produced water storage tanks are being filled.

(f) Each owner or operator must perform quarterly visual inspections of the peak pressure and vacuum values in each closed vent system and control system for the produced oil and produced water storage tanks to ensure that the pressure and vacuum relief set-points are not being exceeded in a way that has resulted, or may result, in venting and possible damage to equipment. The quarterly inspections must be performed while the produced oil and produced water storage tanks are being filled.

(g) Each owner or operator must monitor the operation of each enclosed combustor, utility flare, and pit flare to confirm proper operation as follows:

(1) Continuously monitor the enclosed combustor, utility flare, and pit flare operation, using a malfunction alarm and remote notification system for failures, and checking the system for proper operation whenever an operator is on site, at a minimum quarterly;

(2) Continuously monitor all variable operational parameters specified in the written operating instructions and procedures;

(3) Using EPA Reference Method 22 of 40 CFR part 60, Appendix A, confirm that no visible smoke emissions are present, except for periods not to exceed a total of 2 minutes during any hour, during operation of any enclosed combustor, utility flare, or pit flare whenever an operator is on site; at a minimum quarterly. The observation period shall be 1 hour; and

(4) Respond to any observation of improper monitoring equipment operation or any pilot flame failure alarm and ensure the monitoring equipment is returned to proper operation and/or the pilot flame is relit as soon as practicable and safely possible after an observation or an alarm sounds.

(h) Where sufficient to meet the monitoring and recordkeeping requirements in § 49.145 and § 49.146, the owner or operator may use a

Supervisory Control and Data Acquisition (SCADA) system to monitor and record the required data in §§ 49.140 through 49.147.

§ 49.146 Recordkeeping requirements.

(a) Each owner or operator must maintain the following records:

(1) The measured barrels of oil produced at the oil and natural gas production facility each time the oil is unloaded from the produced oil storage tanks;

(2) The volume of produced natural gas sent to each enclosed combustor, utility flare, and pit flare at all times;

(3) The volume of natural gas emissions from the produced oil storage tanks and produced water storage tanks sent to each enclosed combustor, utility flare, and pit flare at all times;

(4) For each oil and natural gas well completion operation and recompletion operation at an oil and natural gas production facility:

(i) Records identifying each oil and natural gas well completion operation and recompletion operation for each oil and natural gas production facility; and

(ii) The latitude and longitude location of the oil and natural gas well; the date, time, and duration of flowback from the oil and natural gas well; the date, time, and duration of any venting of produced natural gas from the oil and natural gas well; and specific reasons for each instance of venting in lieu of capture or combustion. The duration must be specified in hours.

(5) For each enclosed combustor, utility flare, and pit flare at an oil and natural gas production facility:

(i) Written, site-specific designs, operating instructions, operating procedures and maintenance schedules;

(ii) Records of all required monitoring of operations;

(iii) Records of any deviations from the operating parameters specified by the written site-specific designs, operating instructions, and operating procedures. The records must include the enclosed combustor, utility flare, or pit flare's total operating time during which a deviation occurred, the date, time and length of time that deviations occurred, and the corrective actions taken and any preventative measures adopted to operate the device within that operating parameter;

(iv) Records of any instances in which the pilot flame is not present or the monitoring equipment is not functioning in the enclosed combustor, the utility flare, or the pit flare, the date and times of the occurrence, the corrective actions taken, and any preventative measures adopted to prevent recurrence of the occurrence;

(v) Records of any instances in which a recording device installed to record data from the enclosed combustor, utility flare, or pit flare is not operational; and

(vi) Records of any time periods in which visible smoke emissions are observed emanating from the enclosed combustor, utility flare, or pit flare.

(6) For each pit flare at an oil and natural gas production facility, a demonstration of compliance with the use restrictions set forth in § 49.144(d)(2)(ii) is made by keeping records in a log book, or similar recording system, during each period of time that the pit flare is operating. The records must contain the following information:

(i) Date and time the pit flare was started up and subsequently shut down;

(ii) Total hours operated when pipeline injection was temporarily infeasible for the current calendar month plus the previous consecutive eleven (11) calendar months; and

(iii) Brief descriptions of the justification for each period of operation.

(7) Records of any instances in which any closed-vent system or control device was bypassed or down, the reason for each incident, its duration, and the corrective actions taken and any preventative measures adopted to avoid such bypasses or downtimes; and

(8) Documentation of all produced oil storage tank and produced water storage tank inspections required in § 49.145(d) and (e). All inspection records must include, at a minimum, the following information:

(i) The date of the inspection;

(ii) The findings of the inspection;

(iii) Any adjustments or repairs made as a result of the inspections, and the date of the adjustment or repair; and

(iv) The inspector's name and signature.

(b) Each owner or operator must keep all records required by this section onsite at the facility or at the location that has day-to-day operational control over the facility and must make the records available to the EPA upon request.

(c) Each owner or operator must retain all records required by this section for a period of at least five (5) years from the date the record was created.

§ 49.147 Notification and reporting requirements.

(a) Each owner or operator must submit any documents required under this section to: U.S. Environmental Protection Agency, Region 8 Office of Enforcement, Compliance & Environmental Justice, Air Toxics and Technical Enforcement Program, 8ENF–AT, 1595 Wynkoop Street, Denver, Colorado 80202. Documents may be submitted electronically to *r8airreport@epa.gov.*

(b) Each owner and operator must submit an annual report containing the information specified in paragraphs (b)(1) through (4) of this section. The annual report must cover the period for the previous calendar year. The initial annual report is due 1 year after the first date of production for the first oil and natural gas well at each oil and natural gas production facility or 1 year after August 15, 2012, whichever is later. Subsequent annual reports are due on the same date each year as the initial annual report. If you own or operate more than one oil and natural gas production facility, you may submit one report for multiple oil and natural gas production facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (4) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. The EPA may approve a common schedule on which reports required by §§ 49.140 through 49.147 may be submitted as long as the schedule does not extend the reporting period.

(1) The company name and the address of the oil and natural gas production facility or facilities.

(2) An identification of each oil and natural gas production facility being included in the annual report.

(3) The beginning and ending dates of the reporting period.

(4) For each oil and natural gas production facility, the information in paragraphs (b)(4)(i) through (iii) of this section.

(i) A summary of all required records identifying each oil and natural gas well completion or recompletion operation for each oil and natural gas production facility conducted during the reporting period;

(ii) An identification of the first date of production for each oil and natural gas well at each oil and natural gas production facility that commenced production during the reporting period; and

(iii) A summary of cases where construction or operation was not performed in compliance with the requirements specified in § 49.143, § 49.144, or § 49.145 for each oil and natural gas well at each oil and natural gas production facility, and the corrective measures taken.

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