DEPARTMENT OF THE INTERIOR

Bureau of Land Management

43 CFR Parts 3100, 3160, and 3170

[15X.LLWO300000.L13100000.NB0000]

RIN 1004–AE14

Waste Prevention, Production Subject to Royalties, and Resource Conservation

AGENCY: Bureau of Land Management, Interior.

ACTION: Proposed rule.

SUMMARY: The Bureau of Land Management (BLM) is proposing new regulations to reduce waste of natural gas from venting, flaring, and leaks during oil and natural gas production activities on onshore Federal and Indian leases. The regulations would also clarify when produced gas lost through venting, flaring, or leaks is subject to royalties, and when oil and gas production used on site would be royalty-free. These proposed regulations would be codified at new 43 CFR subparts 3178 and 3179. They would replace the existing provisions related to venting, flaring, and royalty-free use of gas contained in the 1979 Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases, Royalty or Compensation for Oil and Gas Lost (NTL–4A), which are over 3 decades old.

DATES: Send your comments on this proposed rule to the BLM on or before April 8, 2016. The BLM is not obligated to consider any comments received after this date in making its decision on the final rule.

As explained later, the proposed rule would establish new information collection requirements that must be approved by the Office of Management and Budget (OMB). If you wish to comment on the information collection requirements in this proposed rule, please note that the OMB is required to make a decision concerning the collection of information contained in this proposed rule between 30 and 60 days after publication of this document in the **Federal Register**. Therefore, a comment to the OMB on the proposed information collection requirements is best assured of having its full effect if the OMB receives it by March 9, 2016.

ADDRESSES: *Mail:* U.S. Department of the Interior, Director (630), Bureau of Land Management, Mail Stop 2134 LM, 1849 C St. NW., Washington, DC 20240, Attention: 1004–AE14. *Personal or messenger delivery:* 20 M Street SE., Room 2134LM, Washington, DC 20003. *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions at this Web site.

Comments on the information collection burdens: *Fax:* Office of Management and Budget (OMB), Office of Information and Regulatory Affairs, Desk Officer for the Department of the Interior, fax 202–395–5806. *Electronic mail: OIRA_Submission@omb.eop.gov.* Please indicate ‘‘Attention: OMB Control Number 1004–XXXX,’’ regardless of the method used to submit comments on the information collection burdens. If you submit comments on the information collection burdens, you should provide the BLM with a copy, at one of the addresses shown earlier in this section, so that we can summarize all written comments and address them in the final rule preamble.

FOR FURTHER INFORMATION CONTACT: Eric Jones at the BLM Moab Field Office, 82 East Dogwood Ave., Moab, UT 84532, or by telephone at 435–259–2117; or Timothy Spisak at the BLM Washington Office, 20 M Street SE., Room 2134LM, Washington, DC 20003, or by telephone at 202–912–7311. For questions relating to regulatory process issues, contact Faith Bremner at 202–912–7441.

Persons who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339 to contact these individuals during normal business hours. FIRS is available 24 hours a day, 7 days a week to leave a message or question with these individuals. You will receive a reply during normal business hours.

SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Background

This proposed regulation aims to reduce the waste of natural gas from mineral leases administered by the BLM. This gas is lost during oil and gas production activities through flaring or venting of the gas, and equipment leaks. While oil and gas production technology has advanced dramatically in recent years, the BLM's requirements to minimize waste of gas have not been updated in over 30 years. The Mineral Leasing Act of 1920 (MLA) requires the BLM to ensure that lessees ‘‘use all reasonable precautions to prevent waste of oil or gas developed in the land . . . .’’ 30 U.S.C. 225. The BLM believes there are economical, cost-effective, and reasonable measures that operators should take to minimize waste, which will enhance our nation's natural gas supplies, boost royalty receipts for American taxpayers, tribes, and States, and reduce environmental damage from venting and flaring.

The BLM's onshore oil and gas management program is a major contributor to our nation's oil and gas production. The BLM manages more than 245 million acres of land and 700 million acres of subsurface estate, making up nearly a third of the nation's mineral estate. Domestic production from over 100,000 Federal onshore oil and gas wells accounts for 11 percent of the Nation's natural gas supply and 5 percent of its oil. In Fiscal Year (FY) 2014, operators produced 204.6 million barrels (bbl) of oil, 2 trillion cubic feet (Tcf) of natural gas, and 3.1 billion gallons of natural gas liquids (NGLs) from onshore Federal and Indian oil and gas leases. The production value of this oil and gas exceeded $27.2 billion and generated approximately $3.1 billion in royalties.[1]

Over the past decade, the United States has experienced a dramatic increase in oil and natural gas production due to technological advances, such as hydraulic fracturing combined with directional and/or horizontal drilling. This boost in production has brought many benefits in the form of expanded and more secure domestic oil and gas supplies, lower oil and gas prices, increased economic activity, and greater royalty revenues for Federal, State and tribal governments. At the same time, the American public has not benefited from the full potential of this increased production, due to the flaring, venting, and leakage of significant quantities of gas during the production process. According to data reported to the Office of Natural Resources Revenue (ONRR), Federal and Indian onshore lessees and operators lost 375 billion cubic feet (Bcf) of natural gas between 2009 and 2014—enough gas to serve about 5.1 million households for a year, assuming 2009 usage levels.[2]

Flaring, venting, and leaks waste a valuable resource that could be put to productive use, and deprive American taxpayers, tribes, and States of royalty revenues. In addition, the wasted gas may harm local communities and

[1] Office of Natural Resources Revenue (ONRR), Statistical Information, *http://statistics.onrr.gov/ReportTool.aspx* using Sales Year—FY2014—Federal Onshore—All States Sales Value and Revenue for Oil, NGL, and Gas products as of December 2, 2015.

[2] The Energy Information Administration (EIA), *Trends in U.S. Residential Natural Gas Consumption, http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngtrendsresidcon/ngtrendsresidcon.pdf* (reporting that in 2009, U.S. residential consumption was approximately 74 Mcf per household with natural gas service).

surrounding areas through visual and noise impacts from flaring, and regional and global air pollution problems of smog, particulate matter, toxic air pollution (such as benzene, a carcinogen) and climate change. The primary constituent of natural gas is methane, and increases in gas wasted through venting, flaring or leaks contribute to increases in atmospheric methane levels. Methane is an especially powerful greenhouse gas (GHG), with climate impacts roughly 25 times those of CO_2, if measured over a 100-year period, or 86 times those of CO_2, if measured over a 20-year period.[3] Thus, measures to conserve gas and avoid waste may significantly benefit local communities, public health, and the environment.

The BLM oversees oil and gas activities under the authority of a variety of laws, including the MLA, the Mineral Leasing Act for Acquired Lands of 1947 (MLAAL), the Federal Oil and Gas Royalty Management Act (FOGRMA), the Federal Land Policy and Management Act of 1976 (FLPMA), the Indian Mineral Leasing Act of 1938 (IMLA), the Indian Mineral Development Act of 1982 (IMDA), and the Act of March 3, 1909.[4] In particular, the MLA requires the BLM to ensure that lessees ''use all reasonable precautions to prevent waste of oil or gas developed in the land . . . .'' [5] This proposal would replace current requirements related to flaring, venting, and royalty-free use of production, which are contained in NTL–4A; amend the BLM's oil and gas regulations at 43 CFR part 3160; and add new subparts 3178 and 3179. It would apply to all Federal and Indian (other than Osage Tribe) onshore oil and gas leases as well as leases and business agreements entered into by tribes (including IMDA agreements), as consistent with those agreements and with principles of Federal Indian law.[6]

Several oversight reviews, including reviews by the Inspector General of the Department of the Interior and the Government Accountability Office (GAO), have raised concerns about waste of gas, found that the BLM's existing requirements regarding venting and flaring are insufficient, expressed concerns about the ''lack of price flexibility in royalty rates,'' [7] and identified concerns about royalty-free use of gas. These reports recommended that the BLM update its regulations to address waste prevention, afford flexibility in rate setting, and clarify policies regarding royalty-free, on-site use of oil and gas. With respect to waste, the GAO found that ''around 40 percent of natural gas estimated to be vented and flared on onshore Federal leases could be economically captured with currently available control technologies.'' [8] The GAO recommended that the BLM reduce venting and flaring of gas by revising its regulations ''to make it clear that technologies should be used where they can economically capture sources of vented and flared gas, including gas from liquid unloading, well completions, pneumatic valves, and glycol dehydrators.'' [9] The GAO further recommended that the BLM consider expanded use of infrared cameras to identify opportunities to minimize lost gas.[10]

This proposed rule would align the BLM's royalty rate for new competitive Federal oil and gas leases with the regime envisioned by the MLA, which specifies ''a rate of *not less than* 12.5 percent in amount or value of the production removed or sold from the lease.'' [11] In addition, the proposed rule would update the BLM's existing NTL–4A requirements related to venting, flaring, and royalty-free use of natural gas from onshore Federal and Indian leases. Under NTL–4A, operators must apply to the BLM on a case-by-case basis for approval to flare royalty-free, based on economic criteria. We propose to reduce the need for case-by-case applications by clarifying when flared or vented natural gas is subject to royalties. Further, with respect to venting and flaring of natural gas, we propose to: Prohibit venting, except in certain limited circumstances; limit the rate of routine flaring at development oil wells; [12] require operators to detect and repair leaks; and mandate reductions in venting from: Pneumatic controllers and pneumatic pumps that operate by releasing natural gas; storage vessels; activities to unload liquids from a well; and well drilling, completion, and testing activities. Finally, the proposed rule would require operators to submit gas capture plans with their Applications for Permits to Drill new wells.

The BLM has engaged in substantial stakeholder outreach in the course of developing this proposal. In 2014, the BLM conducted a series of forums to consult with tribal governments and solicit stakeholder views to inform the development of this proposed rule, with public meetings (some of which were livestreamed) in Colorado, New Mexico, North Dakota, and Washington, DC. [13] For each forum, we held a tribal outreach session in the morning and a public outreach session in the afternoon. We also accepted informal comments generated as a result of the public/tribal outreach sessions. Since those meetings, we have continued to consult with stakeholders throughout the rule development process, including numerous meetings and calls with State representatives, individual companies, trade associations, and non-governmental organizations (NGOs). We have also received and considered many reports, peer-reviewed studies, and letters from stakeholders providing information and views on what the BLM should propose.

The BLM conducted additional outreach with States where there is extensive oil and gas production from BLM-administered leases. We have carefully reviewed State regulations and guidance and consulted with State regulatory bodies that oversee aspects of oil and gas production to discuss their requirements and practices. The BLM intends to continue close interaction with State and tribal regulators.

The BLM is not the only entity to recognize the need to reduce flaring and

[3] See Intergovernmental Panel on Climate Change, Climate Change 2013: The Physical Science Basis, Chapter 8, *Anthropogenic and Natural Radiative Forcing,* at 714 (Table 8.7), *available at https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf.*

[4] Mineral Leasing Act, 30 U.S.C. 188–287; Mineral Leasing Act for Acquired Lands, 30 U.S.C. 351–360; Federal Oil and Gas Royalty Management Act, 30 U.S.C. 1701–1758; Federal Land Policy and Management Act of 1976, 43 U.S.C. 1701–1785; Indian Mineral Leasing Act of 1938, 25 U.S.C. 396a–g; Indian Mineral Development Act of 1982, 25 U.S.C. 2101–2108; Act of March 3, 1909, 25 U.S.C. 396.

[5] 30 U.S.C. 225.

[6] Key statutes underpinning this proposed regulation contain exceptions for the Osage Tribe. Specifically, the Osage Tribe is excepted from the application of both the Indian Mineral Leasing Act and the Federal Oil and Gas Royalty Management Act, 25 U.S.C. 396f; 43 U.S.C. 1702(3), 1702(4). The leasing of Osage Reservation lands for oil and gas mining is subject to special Bureau of Indian Affairs regulations contained in 43 CFR part 226.

[7] GAO, Oil and Gas Royalties: The Federal System for Collecting Oil and Gas Revenues Needs Comprehensive Reassessment, GAO–08–691, September 2008, 6.

[8] GAO, Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases, GAO–11–34, (Oct. 2010), 2.

[9] Ibid. at 34.

[10] Ibid. at 34.

[11] 30 U.S.C. 226(b)(1)(A) (emphasis added); *see also* 30 U.S.C. 352 (applying the MLA's leasing provisions to leases on acquired land).

[12] ''*Development oil well''* or ''*development gas well''* means a well drilled to produce oil or gas, respectively, from an established field in which hydrocarbons have been discovered and from which they are being produced at a profit or expected profit.

[13] Further information can be found at the BLM oil and gas program's outreach-events page: *http://www.blm.gov/wo/st/en/prog/energy/public_events_on_oil.html.*

venting from oil and gas production activities. Domestically, the Environmental Protection Agency (EPA) and a few individual States have been active in this area, as have some oil and gas producers. In 2012, for example, the EPA adopted Clean Air Act new source performance standards (NSPS) for certain activities in the oil and gas production sector. These regulations target reductions of volatile organic compounds (VOCs) and have the effect of reducing venting and leaks. The EPA recently proposed regulations to amend the 2012 NSPS for the oil and natural gas source category by setting standards for both methane and VOCs for certain equipment, processes and activities across this source category (40 CFR part 60 subpart OOOOa rulemaking).[14] This EPA proposal would have the effect of further reducing gas losses through venting and leaks.

In addition, several States with BLM-administered lands and mineral interests have acted in this area. Colorado has adopted comprehensive statewide regulations to limit emissions of VOCs from venting and leaks from oil and gas production activities.[15] The Colorado regulations require operators to implement leak detection and repair (LDAR) programs, replace high-bleed pneumatic controllers with low-bleed pneumatic controllers, and control emissions from storage vessels, among other things. Wyoming has adopted similar comprehensive regulations that apply in the Upper Green River Basin, a ''nonattainment area'' where air quality does not meet national ozone standards adopted by the EPA under the Clean Air Act.[16] North Dakota has also adopted an innovative program to phase down flaring by operators across the State, requiring 91 percent gas capture by 2020.[17] Pennsylvania has issued guidance that exempts oil and gas facilities from certain air quality permitting requirements if they implement changes to reduce gas loss, such as developing an LDAR program, reducing VOC emissions from storage vessels, and limiting flaring activity.[18]

The oil and gas industry has also taken voluntary actions to reduce flaring and venting. Many of these efforts have been initiated by companies participating in Natural Gas STAR, a voluntary EPA-industry partnership program that encourages oil and natural gas companies to adopt cost-effective technologies and practices that improve operational efficiency and reduce methane emissions. Twenty-six companies in the production sector currently participate in Natural Gas STAR, and they reported that they achieved about 50 Bcf of methane emissions reductions in 2013.[19] To further encourage emissions reductions from the oil and gas sector, the EPA announced, in July 2015, a voluntary program called the Natural Gas STAR Methane Challenge, in which companies would make ambitious commitments to reduce methane emissions and would track their progress in achieving those reductions.[20] In addition, six oil and gas companies have joined together to form the One Future Coalition, which aims to ''(e)nhance the energy delivery efficiency of the natural gas supply chain by limiting energy waste and by achieving a methane 'leak/loss rate' of no more than one percent.'' [21]

Given these activities, it is important to ensure that updated BLM requirements do not subject operators to conflicting or redundant requirements. Thus, in addition to our outreach to States, we are coordinating closely with the EPA as it works to finalize its 40 CFR part 60 subpart OOOOa rulemaking.

The ongoing EPA and State regulatory activities do not, however, obviate the need for the BLM, in its role as a public land manager, to update its requirements governing flaring, venting, and leaks to ensure that the public's resources and assets are not wasted and are developed in a manner that provides for long term productivity and sustainability. First, the BLM has an independent legal responsibility, and a proprietary interest as a land manager, to oversee oil and gas production activities on Federal and Indian leases. The BLM has requirements in place, but as independent reviews have pointed out, the existing requirements pre-date, and thus do not account for, significant technological developments. Updating and clarifying the regulations will make them more effective, more transparent, and easier to understand and administer, and will reduce operators' compliance burdens in some respects. The BLM must ensure that it has modern, effective requirements to govern oil and gas operations on BLM-administered leases. Second, as a practical matter, neither the EPA nor State regulations adequately address the issue of waste of gas from BLM-administered leases. The EPA regulations are directed at air pollution reduction, not waste prevention; they focus largely on new sources; and they do not address all avenues for reducing waste (for example, they do not impose flaring limits for associated gas). Similarly, no State has established a comprehensive set of requirements addressing all three avenues for waste—flaring, venting, and leaks—and only a few States have significant requirements in even one of these areas. It is wholly within the BLM's statutory authority to address flaring, venting, and leaks in its capacity as a land manager with a responsibility to ensure the longevity and long term productivity of public lands and resources, including gas resources. Part I.B. of this preamble, below, offers a summary of the proposed rule's provisions, benefits, and costs, and parts V and VI of this preamble provide more detail about those provisions (part V) and impacts (part VI). Overall, the BLM estimates that the benefits of this rule would outweigh its costs by a significant margin. Under certain assumptions, for example, the rule is expected to produce net benefits ranging from $115 million to $188 million per year (assuming the EPA finalizes 40 CFR part 60 subpart OOOOa and calculating costs and cost savings using a 7 percent discount rate) or from $138 million to $232 million per year (assuming the EPA finalizes 40 CFR part 60 subpart OOOOa and calculating costs

[14] EPA, Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, Proposed Rule, 80 FR 56593 (Sept. 18, 2015). For further information about EPA's existing and proposed NSPS standards for this source category, see Section IV.I.3 of this preamble below.

[15] Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9, Sections XII, XVII, XVIII, *available at https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9_0.pdf.*

[16] Wyoming, Nonattainment Area Regulations Ch. 8 (June 2015), *available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.*

[17] North Dakota Industrial Commission Order 24665 Policy Guidance Version 102215, *available at https://www.dmr.nd.gov/oilgas/GuidancePolicyNorthDakotaIndustrialCommissionorder24665.pdf.*

[18] Pennsylvania Department of Environmental Protection, Air Quality Permit Exemptions (Aug. 10, 2013), *available at http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf,* at 8–11.

[19] EPA Natural Gas STAR *Accomplishments, available at http://www3.epa.gov/gasstar/accomplishments/index.html.*

[20] EPA Natural Gas Star Methane Challenge, *Program Proposal, available at http://www3.epa.gov/gasstar/methanechallenge/index.html.*

[21] Maria Galluci, *Six Major Oil & Gas Firms Agree To Cut Potent Methane Emissions Ahead Of UN Climate Change Summit,* International Business Times, Sept. 23, 2014, *http://www.ibtimes.com/six-major-oil-gas-firms-agree-cut-potent-methane-emissions-ahead-un-climate-change-summit-1693517*; *http://www.gastechnology.org/CH4/Documents/Fiji-George-CH4-presentation-Sep2014.pdf*; One Future: Our Nation's Energy, 1, 6 (Sept. 2014), *http://www.gastechnology.org/CH4/Documents/Fiji-George-CH4-presentation-Sep2014.pdf.*

and cost savings using a 3 percent discount rate).[22]

B. Summary of Proposal

The proposed rule would require operators to take various actions to reduce waste of gas, establish clear criteria for when flared gas would qualify as waste and therefore be subject to royalties, and clarify the on-site uses of gas that are exempt from royalties. The BLM has identified several key points in the oil and gas production process where waste-prevention actions would be most effective and least costly. Specifically, we propose to focus on reducing waste from the following aspects of the production process: Flaring of associated gas from development oil wells; gas leaks from equipment and facilities located at the well site, as well as from compressors located on the lease; operation of high-bleed pneumatic controllers and certain pneumatic pumps; gas emissions from vessels; downhole well maintenance and liquids unloading; and well drilling and completions. The following discussion summarizes the proposed requirements applicable to each of these aspects of the production process.

These requirements would impose annual costs and yield annual benefits, but both costs and benefits are expected to vary over time. Over the first few years, compliance activity (and associated costs and gas savings) would likely be highest. During this time, some operators would have to add or improve gas-capture capability, and some would have to replace existing equipment. After these transitional years, we expect that both compliance activities and gas savings from this rule would be significantly reduced.

1. Venting and Flaring

In 2013, operators vented about 22 Bcf and flared at least 76 Bcf of natural gas from BLM-administered leases.[23] The 2013 flaring estimate, a 109 percent increase from 2009 levels,[24] represents 2.6 percent of the total production from BLM-administered leases in that year (2,901 Bcf)[25] and sufficient gas to supply over 1 million households.[26] Of this, roughly 71 Bcf came from oil wells.[27] Analysis of data supplied by the ONRR suggests that most of this was routine flaring of associated gas from development oil wells (as opposed to flaring during exploration, well testing, and emergencies). Over 90 percent of this flaring occurred in North Dakota, South Dakota, and New Mexico.[28]

The BLM is proposing to prohibit venting of natural gas, except under certain conditions, including in emergencies, as would be defined in the regulations.[29] With respect to flaring, the BLM proposes to limit the rate of routine flaring of associated gas from development oil wells and retain the current exemptions from gas capture requirements and royalties for gas flared in other situations, as long as the operator has complied with the proposed requirements to minimize such losses. These exemptions include gas lost in the normal course of well drilling and well completion; well tests; emergencies, as would be defined in the regulations;[30] and gas flared from exploration or wildcat wells, or delineation wells (wells drilled to define the boundaries of a mineral deposit).

The primary alternative to flaring associated gas from oil wells is to capture, transport, and process that gas for sale, using the same technologies that are used for natural gas production. The capture and sale of associated gas is viable where there is sufficient gas production to offset the costs of connecting to or expanding existing pipeline infrastructure. In addition, technologies for capturing and using gas without a pipeline are becoming increasingly available. This capture infrastructure may include: Separating out NGLs or liquefying the natural gas (LNG), allowing the resulting liquids to be trucked off location; converting the gas into compressed natural gas (CNG) for use on-site or to be trucked off location; and using the gas to run micro-turbines to generate power for use on-site or for sale back to the grid.

Gas is flared under a variety of circumstances. Some circumstances, such as emergencies, can occur unplanned in the course of oil and gas production. Further, in a new field, operators and the midstream processing companies that commonly build and operate gas gathering and processing infrastructure may not have sufficient information about how much gas will be produced to invest in building gathering lines and processing plants. In other instances, however, operators may decide to focus on near-term oil production rather than investing in the gas capture and transmission infrastructure that would be necessary to realize a profit from the associated gas.

On BLM-administered leases, two situations result in substantial flaring of associated gas. In some areas, there is capture infrastructure, but the rate of new well construction is outpacing the infrastructure capacity. This accounts for the majority of flaring on BLM-administered leases. In other areas, capture and processing infrastructure has not yet been built out.

Currently, under NTL–4A, operators must seek BLM approval to flare on a case-by-case basis, with limited exceptions. Operators must provide economic data with each request, demonstrating that requiring the gas to be captured would ''lead to the premature abandonment of recoverable oil reserves and ultimately to a greater loss of equivalent energy than would be recovered'' if the flaring were approved. This approach results in a substantial amount of paper-work, but does not significantly limit flaring, as BLM has commonly, although not always, approved these requests.

The BLM proposes to simplify, clarify, and strengthen its approach to reducing flaring by establishing clear parameters for when routine flaring from development wells is allowed, and by setting a limit on the rate of flaring from individual wells. As a general matter, operators would no longer have to obtain permission for flaring on a case-by-case basis, provided they stay within the proposed prescribed limit.

Specifically, we propose to limit routine flaring of associated gas from development wells to 1,800 thousand cubic feet (Mcf) per month per well, averaged across all of the producing wells on a lease. This limit is similar to requirements in Wyoming and Utah, which limit flaring to 60 Mcf/day and 1,800 Mcf/month, respectively, unless the operator obtains State approval of a higher limit.[31] The BLM estimates that this limit would reduce flaring by up to 74 percent, although there is substantial uncertainty regarding this estimate. The BLM proposes to retain the authority to allow higher rates of flaring in specific circumstances, where adhering to the proposed flaring limit would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. In making this

[22] BLM, Economic Impact and Regulatory Threshold Analysis for 43 CFR 3178 (Royalty Free Use of Production) and 43 CFR 3179 (Venting and Flaring Requirements) (2015) (hereinafter RIA) at 7.

[23] RIA at 119–120.

[24] RIA 119.

[25] RIA at 111 (Appendix A–2).

[26] See footnote 2 (assuming 2009 usage levels).

[27] RIA at 33.

[28] RIA at 122 (Appendix A–8, Table 4).

[29] See proposed 43 CFR 3179.105.

[30] Ibid.

[31] Wyoming Operational Rules, Drilling Rules Section Ch. 3, Section 39(b), *available at http://soswy.state.wy.us/Rules/RULES/9584.pdf* (60 Mcf/day); Utah R649–3–20, Gas Flaring or Venting Section 1.1, *available at* (*http://www.rules.utah.gov/publicat/code/r649/r649-003.htm#T20* (1,800 Mcf/mo.).

determination, the BLM would consider the costs of capture, and the costs and revenues of all oil and gas production on the lease. Further, the BLM proposes to create a 2-year renewable exemption from the flaring limit, available only for certain existing leases that are located a significant distance from gas processing facilities and flaring at a rate well above the proposed flaring limit. Holders of these leases have, until now, had no prior notice of the proposed flaring limit. Given the significant distance from these leases to the nearest gas capture facilities, and the leases' high rates of gas flaring, operators at these sites might have few options to meet the proposed flaring limit other than shutting in the wells. The BLM anticipates the number of leases eligible for this 2-year exemption would decline over time, as production of oil and associated gas from existing leases naturally declines.

The BLM proposes to phase in the flaring limit over the first 2 years after the rule becomes effective, in recognition of the fact that some wells are flaring at rates considerably higher than 1,800 Mcf/month, not all wells will be able to use on-site capture technologies, and connecting to gas pipeline infrastructure may take some time. We propose that in the first year after the effective date of the rule, the flaring limit per well, averaged across all of the producing wells on a lease, would be 7,200 Mcf/month. In the second year, it would be 3,600 Mcf/month. The 1,800 Mcf/month limit would apply beginning in the third year of the rule.

The BLM is also proposing that prior to drilling a new development oil well, an operator would have to evaluate the opportunities and prepare a plan to minimize waste of associated gas from that well, and the operator would need to submit this plan along with the Application for Permit to Drill or Reenter (APD). The BLM proposes to require submission of a plan with specific content, to ensure that operators have carefully considered and planned for gas capture prior to drilling.

In addition to these requirements to reduce flaring, the BLM proposes to update existing royalty provisions by more specifically defining when a loss of gas would be considered ''unavoidable'' and royalty-free, and when it would be considered ''avoidable'' and subject to royalties. A loss of gas would be deemed unavoidable when an operator has complied with all applicable requirements and taken prudent and reasonable steps to avoid waste, and the gas is lost from any of the following specified operations or sources, subject to limits specified in the proposed regulations: Emergencies; well drilling, well completion and related operations; initial production tests and subsequent well tests; exploratory coalbed methane well dewatering; leaks; venting from pneumatic devices in the normal course of operation; evaporation from storage vessels; and downhole well maintenance and liquids unloading. A loss of gas would also be deemed unavoidable when gas is flared (or, in limited circumstances, vented) from a well that is not connected to gas capture infrastructure, provided the BLM has not otherwise determined that the loss of gas is avoidable, pursuant to the provisions of the 1,800 Mcf/month limit in § 3179.6. All losses of gas not specifically found to be unavoidable would be considered avoidable and subject to royalties. Thus, royalties would apply to associated gas flared from a development well that is already connected to capture infrastructure. Under these circumstances, operators have made an economic choice to flare, and that flaring should not be considered an unavoidable consequence of oil production.

Currently, there is a backlog of requests for approval to flare royalty-free pending with the BLM. By establishing clear categories for avoidable and unavoidable losses, and thus clarifying when gas may be flared without payment of royalties, the BLM aims to reduce the number of applications for approval to flare royalty-free and thereby reduce the burden on both operators and the BLM. The BLM could then use these administrative resources to process applications for permit to drill and right-of-way applications, and to conduct inspections, among other activities.

The costs and benefits of the flaring provisions are as follows. First, the rule proposes to require the metering of flared volumes when gas flaring meets or exceeds 50 Mcf/day for a flare stack or manifold. We estimate compliance costs ranging from $1.0–1.8 million per year when the capital costs of equipment are annualized with a 7 percent discount rate, or $0.9–1.6 million per year when the capital costs of equipment are annualized with a 3 percent discount rate.[32]

We estimate that the proposed flaring limits, including the 3-year phase-in period would affect an estimated 435–885 leases in any given year. These requirements could pose total costs of about $32–68 million per year (7 percent discount rate) or $26–43 million per year (3 percent discount rate). Because these requirements would drive additional capture of gas, the flaring limits are also projected to pose total cost savings (from the value of the captured gas) of about $40–58 million per year (7 percent discount rate) or $40–64 million per year (3 percent discount rate). We also estimate that they would increase natural gas production by 2.5–5.0 Bcf per year, and increase NGL production by 36–51 million gallons per year. The net benefits of these requirements are estimated to range from negative $10 to positive $8 million per year (7 percent discount rate) or $13–30 million per year (3 percent discount rate).[33]

2. Leaks

One significant source of the 22 Bcf of gas vented from Federal and Indian leases in 2013 is leakage. The BLM estimates that up to 4.35 Bcf of natural gas was lost in 2013 as a result of leaks or other fugitive emissions at operations on BLM-administered leases.[34] Multiple studies have found that once leaks are detected, the vast majority can be repaired with a positive return to the operator. In addition, both Colorado and Wyoming (for part of the State) have recently adopted LDAR requirements for oil and gas production,[35] and EPA has adopted and proposed additional LDAR requirements for certain new and modified oil and gas production sources.[36]

The BLM believes that LDAR programs are a cost-effective means of

[32] RIA at 69.

For purposes of this analysis, we present costs and benefits using discount rates of 7% and 3% to annualize the costs of capital investments. OMB Circular A–94 (Revised) ''Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs,'' *https://www.whitehouse.gov/omb/circulars_a094/,* directs agencies to conduct baseline analyses using a discount rate of 7%, which ''approximates the marginal pretax rate of return on an average investment in the private sector in recent years.'' It also recommends that agencies show sensitivity of the discounted net present value and other outcomes using additional discount rates. The BLM chose to use a second discount rate of 3%, because the literature suggests that there is a divergence between private discount rates (considered by firms or industry) and social discount rates (considered by society), with private rates exceeding social rates. Further, it is common for regulatory impact analyses to analyze outcomes using a 3% discount rate, particularly for the environmental benefits of proposed regulations.

[33] RIA at 60.

[34] RIA at 3.

[35] Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9, Section XVII.F; Wyoming, Nonattainment Area Regulations Ch. 8, Section 6(g) (June 2015), *available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.*

[36] Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, 60 CFR subpart OOOO; 80 CFR 56593, 56660–56698.

reducing waste in oil and gas production. We are proposing to require operators to use an instrument-based approach to leak detection. Operators would be required initially to conduct semi-annual inspections at their well sites and compressor locations. If an operator finds no more than 2 leaks at a facility for two consecutive inspections, the operator may change to annual inspections at that facility. If the operator finds more than 2 leaks at a facility for two consecutive inspections, the operator must inspect for leaks quarterly. If an operator that is required to inspect for leaks quarterly finds no more than 2 leaks at a given facility in two sequential inspections, the operator could then change back to semi-annual inspections, and so forth. Once a leak is identified, the BLM proposes that the operator would be required to repair the leak as soon as practicable, but no later than 15 calendar days after discovery, absent good cause. Operators would have to verify the effectiveness of a repair within 15 calendar days of the repair, using the same method used to detect the leak. Operators would also be required to keep records documenting the dates and results of leak inspections, repairs, and follow-up inspections.

The costs and benefits of the BLM's proposed LDAR requirements depend on the rest of the regulatory landscape. Assuming that the EPA finalizes its 40 CFR part 60 subpart OOOOa rulemaking for new and modified sources,[37] then the BLM expects that its proposed requirements would impact up to 36,700 existing wellsites, and pose total costs of about $69–70 million per year (using 7 percent and 3 percent discount rates). These requirements are also projected to result in cost savings of about $12–15 million per year (7 percent discount rate) or $15–17 million per year (3 percent discount rate), increase gas production by 3.9 Bcf per year, and reduce VOC emissions by 18,600 tons per year (tpy). We estimate they would reduce methane emissions by 67,000 tpy, producing monetized benefits of $73 million per year in 2017–2019, $87 million per year in 2020–2024, and $100 million in 2025 and 2026. Thus, we estimate that these provisions would result in net benefits of $19–21 million per year in 2017–2019, $31–35 million per year in 2020–2024, and $43–48 million in 2025 and 2026.[38]

If, for analytical purposes we assume a baseline in which EPA does not finalize its proposed LDAR requirements, we estimate the following impacts. We project that the proposed LDAR requirements would affect up to about 37,000–38,000 wellsites per year, and pose total costs of about $70–71 million per year (using 7 percent and 3 percent discount rates). These requirements are also projected to result in cost savings of about $12–18 million per year (using 7 percent and 3 percent discount rates), increase gas production by 3.9–4.0 Bcf per year, and reduce VOC emissions by 19,000 tpy. We estimate these proposed requirements would also reduce methane emissions by 68,000 tpy, producing monetized benefits of $75 million per year in 2017–2019, $88 million per year in 2020–2024, and $102 million in 2025 and 2026. Thus, we estimate that these proposed provisions would result in net benefits of $19–21 million per year in 2017–2019, $30–35 million per year in 2020–2024, and $43–48 million in 2025 and 2026.[39]

These estimates represent the maximum likely impact. As noted previously, some operators currently have LDAR programs. This analysis accounts for existing State requirements in Colorado, Utah, and Wyoming, but it does not account for existing (voluntary or required) LDAR activities conducted by operators outside of those States. If we accounted for these existing activities, then the costs, emissions reductions, incremental production, and royalty estimates resulting from this proposed rule would be less than those shown.

3. Pneumatic Controllers and Pneumatic Pumps

Pneumatic controllers and pneumatic pumps are operated by gas pressure and emit gas as part of their normal operations. We estimate that on BLM-administered leases in 2013, about 5.4 Bcf of natural gas was lost from pneumatic controllers, and about 2.5 Bcf was lost from all pneumatic pumps.[40] Further, we estimate that the proposed rule would impact up to 15,600 high bleed pneumatic controllers (pneumatic controllers with bleed rates of more than 6 standard cubic feet per hour (scf/hour)) on BLM-administered leases.[41] A recent study by the consulting firm ICF International (ICF) identified replacement of high-bleed pneumatic controllers with low-bleed pneumatic controllers (pneumatic controllers with bleed rates of 6 scf/hour or less) as one of the most inexpensive options for reducing methane, estimating that it would actually save industry $2.65 per Mcf of avoided methane emissions.[42]

EPA generally prohibits the use of new high-bleed pneumatic controllers,[43] and Colorado and Wyoming (in part of the State) have required replacement of existing high-bleed pneumatic controllers with low-bleed pneumatic controllers.[44] The State of Wyoming has regulations that require pneumatic pumps used in the Upper Green River Basin to destroy or capture emissions or be replaced by zero-emission solar-, electric-, or air-driven pumps by January 1, 2017.[45]

The BLM is proposing to require operators to replace high-bleed pneumatic controllers with low-bleed or no-bleed pneumatic controllers within 1 year of the effective date of the final rule. This requirement would apply only to pneumatic controllers that are not subject to EPA regulations. The BLM also proposes exceptions to this requirement, including where the operator demonstrates, and the BLM concurs, that replacing the controller(s) would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. In making this determination, the BLM would consider the costs of capture, and the costs and revenues of all oil and gas production on the lease.

We estimate that the proposed pneumatic controller requirements would impact up to about 15,600 existing low-bleed pneumatic devices, and pose total costs of about $6 million per year (capital costs annualized using a 7 percent discount rate) or $5 million per year (capital costs annualized using a 3 percent discount rate). Because the sale of recovered gas is expected to offset the engineering costs of new controllers, the BLM expects that

[37] The RIA includes a broader discussion of the estimates of the costs and benefits of this proposed rule if the EPA does not finalize its 40 CFR part 60 subpart OOOOa rulemaking, but the preamble omits some of those estimates to simplify the discussion. EPA's proposed requirements would apply to wells that are new, "modified," or "reconstructed" after September 18, 2015. See 40 CFR 60.14 and 60.15 for EPA's definitions of "modification" and "reconstruction."

[38] RIA at 109.

[39] RIA at 108–109.

[40] RIA at 3.

[41] RIA at 78.

[42] ICF International, Economic Analysis of Methane Emission Reduction Opportunities in the U.S. in the Onshore Oil and Natural Gas Industries, 4–4 (Mar. 2014), *available at https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf* (ICF 2014 Study) (base case assumed $4/Mcf price for recovered gas and a 10 percent discount rate/cost of capital).

[43] 40 CFR 60.5390.

[44] Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9, Section XVIII; Wyoming, Nonattainment Area Regulations Ch. 8, Section 6(f) (June 2015), *available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.*

[45] Wyoming, Nonattainment Area Regulations Ch. 8, Section 6(e) (June 2015), *available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.*

compliance with the pneumatic controller requirements would increase gas production by 2.9 Bcf per year, result in cost savings to the industry of about $9–11 million per year (using a 7 percent discount rate) or $11–12 million per year (using a 3 percent discount rate). On net, we project that the industry would save $3–5 million per year (using a 7 percent discount rate) or $6–7 million per year (using a 3 percent discount rate) under these requirements. These requirements are also projected to reduce methane emissions by 43,000 tpy, producing monetized benefits of $48 million per year in 2017–2019, $56 million per year in 2020–2024, and $65 million in 2025 and 2026. The resulting net benefits of $53–68 million per year (using a 7 percent discount rate for costs and cost savings) or net benefits of $54–73 million per year (using a 3 percent discount rate for costs and cost savings), along with a reduction in VOC emissions of about 200,000 tpy.[46]

For pneumatic pumps, the BLM is proposing to require the operator to either: (1) Replace a pneumatic chemical injection or diaphragm pump with a zero-emissions pump; or (2) Route the pneumatic chemical injection or diaphragm pump to a flare. This requirement would apply only to pneumatic pumps that are not subject to EPA regulations. In addition, an operator would be exempt from this requirement if it demonstrates, and the BLM concurs, that: (1) There is no flare already available on-site or routing to a flare device is technically infeasible; and (2) A zero-emission pneumatic pump is not a viable alternative to perform the required function. An operator would also be exempt if the operator demonstrates and the BLM concurs that replacing the pneumatic pump(s) would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. In making this determination, the BLM would consider the costs of capture, and the costs and revenues of all oil and gas production on the lease.

If the EPA finalizes its concurrent 40 CFR part 60 subpart OOOOa rulemaking, the BLM estimates that these requirements would impact up to 8,775 existing pumps, posing total costs of about $2.5 million per year. They would also increase gas production by 0.46 Bcf per year and result in cost savings of about result in cost savings of $1.5–1.9 million per year (7 percent discount rate) or $1.75–2.15 million per year (3 percent discount rate). In addition, they are projected to reduce methane emissions by about 16,000 tpy, producing monetized benefits of $18 million per year in 2017–2019, $21 million per year in 2020–2024, and $24 million in 2025 and 2026. This would result in net benefits of $17 million per year in 2017–2019, $20 million per year in 2020–2024, and $23 million in 2025 and 2026, as well as reducing VOC emissions by about 4,000 tpy.[47]

Assuming, for purposes of analysis, that EPA does not finalize the 40 CFR part 60 subpart OOOOa rulemaking, the BLM estimates that the pneumatic pump requirements would affect up to about 8,775 existing pumps and about 75 new pumps per year, posing total costs of about $2.5–2.7 million per year (using 7 percent and 3 percent discount rates). They would also increase gas production by 0.5 Bcf per year and result in cost savings of about $1.5–2.2 million per year (using 7 percent and 3 percent discount rates). In addition, they are projected to reduce methane emissions by about 16,000–17,000 tpy, producing monetized benefits of $18 million per year in 2017–2019, $22 million per year in 2020–2024, and $26 million in 2025 and 2026. This would result in net benefits of $17 million per year in 2017–2019, $21–22 million per year in 2020–2024, and $25 million in 2025 and 2026, as well as reducing VOC emissions by about 4,000 tpy.[48]

4. Storage Vessels

Vapors released from storage vessels are a lost source of energy and revenue, present safety concerns, and contribute to local air pollution and climate change. We estimate that 2.77 Bcf of natural gas was lost in 2013 from storage tank venting on Federal and Indian lands.[49] Of that volume, we estimate that 1.82 Bcf was lost from storage vessels used in natural gas production and 0.95 Bcf of gas was lost from storage vessels used in oil production.[50]

Tank vapors can be controlled by routing them to a flare or combustor, or by installing a vapor recovery unit (VRU). New and modified vessels used in oil and gas production are already subject to EPA emissions limits, which require that individual storage vessels with VOC emissions equal to or greater than 6 tpy achieve at least a 95 percent reduction in VOC emissions from baseline levels. Colorado and part of Wyoming have similar, somewhat more stringent, requirements for storage vessels.[51]

The BLM proposes to address gas losses from existing storage vessels, which are not covered by the EPA standards. The BLM believes that reducing venting from existing storage vessels, which have higher rates of venting, is a reasonably cost-effective means of reducing gas losses. Rather than establishing new and separate standards for venting from existing vessels, we have been informed by operators that it would be easier to comply if we simply require existing vessels on BLM-administered leases to meet standards that are the same as the EPA standards that already apply to new and modified vessels on those leases. Additionally, there does not appear to be a uniform conversion factor that we could use to translate the VOC standards established by EPA, Colorado, and Wyoming to a whole gas standard. Depending on the content of a vessel, the same quantity of gas released from the vessel may contain different quantities of VOCs. Thus, even though the BLM is concerned about loss of *all* hydrocarbons from vessels, not just loss of VOCs, we propose to use VOCs as a proxy for whole gas, and thus to apply the control requirement to existing vessels with at least 6 tpy of VOCs, using the same applicability threshold as EPA and Colorado.[52] (Wyoming also uses VOC emissions to determine applicability, but has a lower threshold.[53])

The BLM proposes to require that operators route VOC emissions from existing storage vessels subject to these requirements to combustion devices, continuous flares, or sales lines within 6 months after the effective date of the rule. The BLM would grant an exception to this requirement if the operator submits an economic analysis demonstrating—and the BLM agrees—that compliance would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. In making this determination, the BLM would consider the costs of capture, and the costs and revenues of all oil and gas production on the lease. Consistent with the EPA requirements for new vessels,

[46] Regulatory Impact Analysis (RIA) at 78.

[47] RIA at 82.

[48] RIA at 81.

[49] RIA at 3.

[50] RIA at 19.

[51] Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9, Sections XII.D–F; XVII.C; Wyoming, Nonattainment Area Regulations Ch. 8, Section 6(c) (June 2015), *available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.*

[52] 40 CFR 60.5395; Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9, Section XVII.C.

[53] Wyoming, Nonattainment Area Regulations Ch. 8, Section 6(c)(i)(a) (June 2015), *available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.*

these requirements would no longer apply if the uncontrolled VOC emissions fall below 4 tpy for 12 months.

The BLM estimates that the proposed requirements would affect about 300 existing storage vessels on BLM-administered leases, and pose total costs of about $6 million per year (using 7 percent and 3 percent discount rates).[54] We project that these requirements would increase gas production by 0.04 Bcf per year, resulting in cost savings of about $0.1–0.2 million per year (using 7 percent and 3 percent discount rates). They would also reduce methane emissions by 7,000 tpy, producing monetized benefits of $8 million per year in 2017–2019, $9 million per year in 2020–2024, and $11 million in 2025 and 2026. Overall, we estimate that these provisions would result in net benefits of $2 million per year in 2017–2019, $3–4 million per year in 2020–2024, and $5 million in 2025 and 2026, and reduce VOC emissions by 32,500 tpy.

5. Well Maintenance and Liquids Unloading

Over time, as pressure in a natural gas well drops, liquids often start accumulating at the bottom of the well, impeding gas production. Operators often remove or ''unload'' the liquids, but depending on the method, this process can release substantial quantities of natural gas into the environment. In particular, operators may allow the bottom-hole pressure to increase and then vent or ''blow down'' or ''purge'' the well. We estimate that 3.26 Bcf of natural gas was lost in 2013 during liquids unloading operations on Federal and Indian lands.[55]

There are a wide variety of methods for liquids unloading, and technological developments, such as automated plunger lifts, now allow liquids to be unloaded with minimal loss of gas. The BLM believes that it is reasonable to expect operators to use these available technologies to minimize gas losses, and we believe that failure to minimize losses of gas from liquids unloading now constitutes waste.

For wells drilled after the effective date of the rule, the BLM is proposing to prohibit unloading liquids by simply purging the well (except in specified circumstances). The BLM believes that it is less costly to avoid purging altogether at new wells than at existing wells. In addition, the BLM is proposing to require specified best management practices to minimize venting from liquids unloading at both new and existing wells. Specifically, the operator would be required to be on-site during well purging events, unless the well has an automatic control system, and the operator would also be required to document liquids unloading events. This would allow the BLM to verify compliance, and it would provide additional information on the amounts of gas lost through these activities on Federal and Indian lands.

We estimate that the proposed liquids unloading requirements would affect up to about 1,550 existing wells and about 25 new wells per year, posing total costs of about $6 million per year (capital costs annualized using a 7 percent discount rate) or $5–6 million per year (capital costs annualized using a 3 percent discount rate). We project that they would increase gas production by roughly 2 Bcf per year, resulting in cost savings of about $7–8 million per year (using a 7 percent discount rate) or $7–10 million per year (using a 3 percent discount rate). In addition, these requirements are projected to reduce methane emissions by 30,000 to 34,000 tpy, producing monetized benefits of $33–34 million per year in 2017–2019, $41–43 million per year in 2020–2024, and $50–51 million in 2025 and 2026. Overall, we estimate that these provisions would produce net benefits of $35–52 million per year (using a 7 percent discount rate for costs and cost savings) or $35–55 million per year (using a 3 percent discount rate for costs and cost savings), and reduce VOC emissions by about 136,000 to 156,000 tpy.[56]

6. Reduction of Waste From Drilling, Completion, and Related Operations

Substantial quantities of gas can be lost during drilling, completion, and refracturing (sometimes referred to by the broader term ''workover'') operations, and we estimate that in 2013, 2.1 Bcf of natural gas was lost during these operations on BLM-administered leases.[57] Of this, we estimate that completion emissions from hydraulically fractured (and refractured) oil wells accounted for 1.4 Bcf of the loss, emissions from hydraulically fractured gas wells accounted for about 0.7 Bcf of the loss, and all other completions accounted for a de minimis amount.[58]

The EPA currently requires new hydraulically fractured and refractured gas wells to capture or flare gas that otherwise would be released during drilling and completion operations, and EPA has announced that it plans to extend these requirements to new hydraulically fractured and refractured oil wells. Nonetheless, the BLM believes that it is appropriate for the BLM to adopt its own requirements to minimize the waste of gas during well drilling and well completion and post-completion operations at hydraulically fractured or refractured wells and wells that are not fractured. The BLM has an independent statutory obligation to minimize waste of oil and gas resources on BLM-administered leases. As proposed, the BLM waste requirements for well drilling and completions would extend to both conventional and hydraulically fractured wells, and therefore would apply to a broader set of wells than the EPA regulations propose to cover. Also, the BLM anticipates that to the extent both sets of requirements applied, the BLM believes that an operator would satisfy both sets of requirements by either capturing or flaring the gas that would otherwise be released. Thus, the BLM is also proposing to allow an operator to demonstrate that it is in compliance with EPA requirements for control of gas from well completions in lieu of compliance with the BLM requirements. The BLM is coordinating closely with the EPA on the agencies' proposals, and the BLM expects to ensure that our final requirements would not impose additional burdens on an operator that complies with any EPA requirements on new well completions.

The proposed rule would require operators to: Flare gas generated during drilling operations, capture and sell that gas, use it in operations on the lease, or inject it into the well. We estimate that the rule would apply to about 3,000 wells per year. Based on our experience in the field, however, the BLM believes that operators are already controlling gas from drilling operations as a matter of safety and operating practice. Thus, we do not estimate costs associated with this requirement. Similarly, based on our professional experience in the field, we believe that operators are already controlling gas from workover operations on conventional wells as a matter of safety and operating practice, and there should be no compliance costs for this requirement.

The proposed rule would also require operators to reduce the emissions associated with well completions by capturing and selling associated gas, flaring it, using it in operations on the lease, or injecting it. This proposal would only impact well completions and workovers/refractures on conventional oil and gas wells and

[54] RIA at 95.

[55] RIA at 3.

[56] RIA at 87.

[57] RIA at 3.

[58] RIA at 18 (Table 6).

hydraulically fractured oil wells, as EPA already covers hydraulically fractured gas wells.

If the EPA finalizes its 40 CFR part 60 subpart OOOOa rulemaking, as we expect, then as a practical matter, this rule's completion requirements will only impact conventional well completions, because the EPA will regulate completions of new and modified hydraulically fractured oil and gas wells. We estimate that the BLM rule would impact between 115–150 completions per year and pose costs to the industry of less than $430,000 per year. There would be only *de minimis* anticipated incremental production, incremental royalty, and emissions reductions.[59]

If, for purposes of analysis, we assume that EPA does not finalize its 40 CFR part 60 subpart OOOOa rulemaking, the BLM estimates that these provisions would affect about 1,250 to 1,575 completions per year and pose total costs of about $8–12 million per year (using a 7 percent discount rate) or $12 million per year (using a 3 percent discount rate). We further estimate that these provisions would increase gas production by 0.5 to 0.6 Bcf per year, resulting in cost savings of about $2–3 million per year (using 7 percent and 3 percent discount rates). This would also reduce methane emissions by 11,500 to 14,500 tpy, producing monetized benefits of $13 million per year in 2017–2019, $16–18 million per year in 2020–2024, and $21–22 million in 2025 and 2026. Overall, under this scenario, these provisions are estimated to produce net benefits of $3–15 million per year (considering the present value of costs and cost savings using a 7 percent discount rate) or net benefits of $3–13 million per year (considering the present value of costs and cost savings using a 3 percent discount rate), and reduce VOC emissions by 9,600 to 12,200 tpy.[60]

7. Royalty Provisions Governing New Competitive Leases

Finally, the BLM proposes to revise the regulations at 43 CFR 3103.3–1, which govern royalty rates applicable to onshore oil and gas leases, to make the rule text parallel to the statutory text, respond to findings and recommendations in audits from the GAO, and eliminate unnecessary provisions in the existing regulations.

The proposed revisions would do three principal things: (1) Make clear that the royalty rate on all existing leases would remain at the rate prescribed in the lease or in regulations applicable at the time of lease issuance; (2) Specify the fixed, statutory rate of 12.5 percent[61] for all noncompetitive leases issued after the effective date of the rule; and (3) Make the rule text parallel to the corresponding MLA text for competitive leases issued after the effective date of the rule.[62] The MLA text provides the BLM the flexibility to set royalty rates for these competitive leases at *or above* 12.5 percent. By contrast, the BLM's existing royalty regulation sets a flat rate of 12.5 percent for all new competitive leases.[63] Although the BLM does not currently propose to raise royalty rates, the proposed rule would allow the BLM to set a royalty rate for oil and gas produced from competitive oil and gas leases issued after the effective date of this rule of ''not less than'' 12.5 percent. The BLM is not proposing any further changes to the royalty provisions governing new competitive oil and gas wells,[64] but we are requesting comment on the use of a fluctuating royalty rate to incentivize reductions in flaring from new competitive leases. Further information about this possible approach is provided below in Section V.C. of this preamble.

C. Summary of Costs and Benefits

1. Costs

Overall, assuming that the EPA finalizes its concurrent 40 CFR part 60 subpart OOOOa rulemaking, the BLM estimates that this proposed rule will pose costs ranging from $125–161 million per year (using a 7 percent discount rate) or $117–$134 million per year (using a 3 percent discount rate) over the next 10 years.[65] These costs would include engineering compliance costs and the social cost of minor additions of carbon dioxide to the atmosphere, resulting from the on-site or downstream use of gas that is newly captured as a result of this proposed rule.[66] The engineering compliance costs presented do not include potential cost savings from the recovery and sale of natural gas (those savings are shown in the summary of benefits).

If, for analytical purposes, we assume that EPA does not finalize its concurrent 40 CFR part 60 subpart OOOOa rulemaking, these requirements would affect more sources and the costs would be somewhat higher. Under that scenario, the BLM estimates that this rule will pose costs ranging from $139–174 million per year (using a 7 percent discount rate) or $131–147 million per year (using a 3 percent discount rate) over the next 10 years.[67]

In some areas, operators have already undertaken, or plan to undertake, voluntary actions to address gas losses. To the extent that operators are already in compliance with the requirements of this proposed rule, the above estimates overstate the likely impacts of the rule.

We expect that cost impacts on individual operators would be small, even for businesses with less than 500 employees. In the RIA, we estimate that average costs for a representative small operator would increase by about $31,300–37,500, which would result in an average reduction in profit margin of 0.087–0.104 percentage points in 2020.[68]

2. Benefits

We measure the benefits of the rule as the cost savings that the industry would receive from the recovery and sale of natural gas and the environmental benefits of reducing the amount of methane (a potent GHG) and other air pollutants released into the atmosphere. As with the estimated costs, we expect benefits on an annual basis. The estimated benefits of the rule also depend on whether the EPA finalizes its 40 CFR part 60 subpart OOOOa rulemaking. Assuming that rule is in effect, the BLM estimates that this rule would result in monetized benefits of $255–329 million per year (using a 7 percent discount rate to calculate the present value of future annual cost savings, and using model averages of the social cost of methane with a 3 percent discount rate) or $255–357 million per year (using a 3 percent discount rate to calculate the present value of future annual cost savings, and using model averages of the social cost of methane with a 3 percent discount rate).[69] We estimate that the proposed rule would reduce methane emissions by 164,000–

[59] RIA at 74.

[60] RIA at 74.

[61] 30 U.S.C. 226(c)(1).

[62] 30 U.S.C. 226(b)(1)(A).

[63] 43 CFR 3103.3–1(a)(1).

[64] Note that the proposed rule would renumber current 43 CFR 3103.3–1 (a)(2) and (3) but would not otherwise change the content of those provisions. Further, the proposed rule would not alter 43 CFR 3103.3–1(b), (c), or (d). Those five provisions are reprinted in this proposed rule solely to clarify the proposed numbering of the revised § 3103.3–1, and for ease of reference. The BLM does not intend to revise those provisions, nor to invite comment on their content.

[65] RIA at 127.

[66] Some gas that would have otherwise been vented would now be combusted on-site or presumably downstream to generate electricity. As described in the RIA, the estimated value of these carbon additions would not exceed $30,000 in any given year.

[67] RIA at 127.

[68] RIA at 159. These estimates rely on 2014 company data, use a 7% discount rate, and assume the finalization of EPA's 40 CFR part 60 subpart OOOOa rulemaking.

[69] RIA at 130.

169,000 tpy, which we estimate to be worth $180–253 million per year (this social benefit is included in the monetized benefit above). We estimate that the proposed rule would reduce VOC emissions by 391,000–411,000 tpy (this benefit is not monetized in our calculations).[70]

If, for purposes of analysis, we assume that EPA does not finalize its 40 CFR part 60 subpart OOOOa rulemaking, we estimate that this proposed rule would result in monetized benefits of $270–354 million per year (using a 7 percent discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3 percent discount rate) or $270–384 million per year (using a 3 percent discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3 percent discount rate).[71] We estimate that the proposed rule would reduce methane emissions by 176,000–185,000 tpy, which we estimate to be worth $193–277 million per year (this social benefit is included in the monetized benefit above). We estimate that the proposed rule would reduce VOC emissions by 400,000–423,000 tpy (this benefit is not monetized in our calculations).[72]

Adoption of the proposed rule would also have numerous ancillary benefits. These include improved quality of life for nearby residents, who note that flares are noisy and unsightly at night; reduced release of VOCs, including benzene and other hazardous air pollutants; and reduced production of nitrogen oxides (NO_X) and particulate matter, which can cause respiratory and heart problems.

3. Net Benefits

Overall, the BLM estimates that the benefits of this rule outweigh its costs by a significant margin. The BLM expects net benefits ranging from $115–188 million per year (using a 7 percent discount rate) or $138–232 million per year (using a 3 percent discount rate). Specifically, assuming a 7 percent discount rate, we estimate the following annual net benefits:

- $115–130 million per year from 2017–2019;
- $155–156 million per year from 2020–2024; and
- $187–188 million per year from 2025–2026.

Assuming a 3 percent discount rate, we estimate the annual net benefits would be:

- $138–151 million per year from 2017–2019;
- $192–196 million per year from 2020–2024; and
- $231–232 million per year from 2025–2026.[73]

If, for purposes of analysis, we assume that the EPA does not finalize the 40 CFR part 60 subpart OOOOa rulemaking, we estimate the net benefits of this proposed rule would be somewhat higher, ranging from $119–203 million per year (costs and costs savings calculated using a 7 percent discount rate) or $139–245 million per year (costs and costs savings calculated using a 3 percent discount rate).

4. Influence on Production

The proposed rule has a number of requirements that are expected to influence the production of natural gas, NGLs, and crude oil from onshore Federal and Indian oil and gas leases.

If 40 CFR part 60 subpart OOOOa is finalized, we estimate the following incremental changes in production, noting the representative share of the total U.S. production in 2014 for context. We estimate additional natural gas production, ranging from 11.7–14.5 Bcf per year (representing 0.04–0.05 percent of the total U.S. production in 2014), the productive use of an additional 29–41 Bcf of natural gas, which we estimate would be used to generate 36–51 million gallons of NGL per year (representing 0.08–0.11 percent of the total U.S. production), and a reduction in crude oil production ranging from 0.6–3.2 million bbl per year (representing 0.02–0.10 percent of the total U.S. production). We also expect 0.5 Bcf of gas to be combusted on-site that would have otherwise been vented. Combined, the capture or combustion of gas represents 44–46 percent of the volume vented in 2013 and the capture and/or productive use of the gas 41–60 percent of the volume flared in 2013.[74]

If 40 CFR part 60 subpart OOOOa is not finalized, we estimate additional natural gas production ranging from 12–15 Bcf per year (representing 0.04–0.06 percent of the total U.S. production), the productive use of an additional 29–41 Bcf of natural gas, which we estimate would be used to generate 36–51 million gallons of NGL per year (representing 0.08–0.11 percent of the total U.S. production), and a reduction in crude oil production ranging from 0.6–3.2 million bbl per year (representing 0.02–0.10 percent of the total U.S. production). Separate from the volumes listed above, we also expect 1 Bcf of gas to be combusted on-site that would have otherwise been vented. Combined, the capture or combustion of gas represents 49–52 percent of the volume vented in 2013 and the capture and/or productive use of gas represents 41–60 percent of the volume flared in 2013.[75]

Since the relative changes in production are expected to be small, we do not expect that the proposed rule would significantly impact the price, supply, or distribution of energy.

5. Royalties

Assuming the EPA 40 CFR part 60 subpart OOOOa rulemaking is finalized, we estimate that this proposed rule would produce additional royalties of $9–11 million per year (discounted at 7 percent) or $10–16 million per year (discounted at 3 percent).[76] If, for purposes of analysis, we assume that the EPA does not finalize the 40 CFR part 60 subpart OOOOa rulemaking, we estimate that this proposed rule would result in annual incremental royalties of $9–11 million per year (discounted at 7 percent) or $11–17 million per year (discounted at 3 percent).

II. Table of Contents

[70] RIA at 133–135.
[71] RIA at 130.
[72] RIA at 133–135.
[73] RIA at 7.
[74] RIA at 140.
[75] RIA at 140.
[76] RIA at 143.

III. Public Comment Procedures

If you wish to comment on the proposed rule, you may submit your comments by any one of several methods specified (see **ADDRESSES**). If you wish to comment on the information collection requirements, you should send those comments directly to the OMB as outlined (see **ADDRESSES**); however, we ask that you also provide a copy of those comments to the BLM.

Please make your comments as specific as possible by confining them to issues for which comments are sought in this notice, and explain the basis for your comments. The comments and recommendations that will be most useful and likely to influence agency decisions are:

1. Those that are supported by quantitative information or studies; and
2. Those that include citations to, and analyses of, the applicable laws and regulations.

The BLM is not obligated to consider or include in the Administrative Record for the rule comments received after the close of the comment period (see **DATES**) or comments delivered to an address other than those listed (see **ADDRESSES**).

Comments, including names and street addresses of respondents, will be available for public review at the address listed under **ADDRESSES** during regular hours (7:45 a.m. to 4:15 p.m.), Monday through Friday, except holidays. Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

IV. Background

A. Overview

The BLM's onshore oil and gas management program is a major contributor to our nation's oil and gas production. The BLM manages more than 245 million acres of land and 700 million acres of subsurface estate, comprising nearly a third of the nation's mineral estate. Domestic production from over 100,000 Federal onshore oil and gas wells accounts for 11 percent of the Nation's natural gas supply and 5 percent of its oil. In FY 2014, the ONRR reported that operators produced 204.6 MMbbl of oil, 2 Tcf of natural gas, and 3.1 billion gallons of NGLs from onshore Federal and Indian oil and gas leases. The production value of this oil and gas exceeded $27.2 billion and generated approximately $3.1 billion in royalties.[77]

Over the past decade, the United States has experienced a dramatic increase in natural gas and oil production due to technological advances, such as hydraulic fracturing combined with directional drilling. This boost in production has brought many benefits in the form of expanded and more secure domestic supplies, lower prices, increased economic activity, and greater royalty revenues for Federal, State, and tribal governments.

At the same time, the American public has not benefited from the full potential of this increased production, as it has been accompanied by significant and growing quantities of wasted natural gas. Between 2009 and 2014, operators on BLM-administered leases wasted enough natural gas to serve 5.1 million homes for 1 year, according to data reported to ONRR.[78]

A sizeable quantity of natural gas is flared or vented in the course of exploration, development, and production activities. Commonly used well pad production equipment, such as pneumatic controllers, are designed to function by venting natural gas. Leaks and other unintentional releases across oil and gas operations account for additional waste. As discussed in the RIA, we estimate that in 2013, about 98 Bcf of natural gas was vented, flared, or leaked from oil and gas production on BLM-administered leases.[79] This represents about 3.4 percent of the total production from BLM-administered leases in that year (2,901 Bcf).[80]

This proposed rule aims to reduce wasteful venting, flaring, and leaks of natural gas from oil and natural gas production activities on onshore Federal and Indian leases. The rule would update the BLM's existing requirements

[77] ONRR, Statistical Information, *http://statistics.onrr.gov/ReportTool.aspx* using Sales Year—FY2014—Federal Onshore—All States Sales Value and Revenue for Oil, NGL, and Gas products as of December 2, 2015.

[78] Based on an estimate of 74 Mcf of gas used per household per year. See footnote 2.

[79] RIA at 3.

[80] RIA at 111 (Appendix A–2).

related to venting, flaring, and royalty-free use of natural gas, which are over 3 decades old. The BLM proposes to clarify the circumstances under which operators may flare, or in very limited circumstances vent, natural gas produced in the course of exploration, development, and production activities, and we propose to expand the circumstances under which flared or vented natural gas would be subject to royalties. The BLM also proposes other reasonable measures to reduce wasteful venting, flaring, and leaks of natural gas from oil and gas operations on Federal and Indian leases.

The BLM expects that these regulations would benefit the public by reducing waste of a public resource, improving production accountability, increasing natural gas supplies, and increasing royalties received by Federal, State, and tribal governments. In addition, reducing venting and flaring would reduce impacts on local communities and the environment by reducing emissions of air pollutants that contribute to smog, particulate pollution, and climate change.

B. Impacts of Waste and Loss of Gas

Natural gas is a valuable resource that plays a significant role in the U.S. economy and is critical to our energy and national security. Gas that is flared, vented, or leaked into the atmosphere from production on BLM-administered leases is a lost public or tribal resource that is not available for productive use.

In addition, most of the lost gas is not currently subject to royalties, which compensate the public for the removal of publicly owned resources and help fund activities of States, localities, tribes and the Federal Government. State governments receive roughly half of the 12.5 percent royalty that the Federal Government typically collects from onshore oil and gas lessees. The BLM estimates that if captured, the gas presently lost from BLM-administered leases would provide an additional $49 million in royalties each year to the Federal Government, States, and tribes.[81]

This waste of gas through flaring can affect the quality of life for nearby residents, who note that flares are noisy and unsightly at night. Venting, flaring, and leaks of gas also contribute to local, regional, and global air pollution. VOCs and hazardous air pollutants (components of the gas, such as benzene, toluene, ethylbenzene, and xylene) are released into the atmosphere when natural gas is released through venting, flaring, or incomplete combustion at a flare. VOCs combine with sunlight and NO_X, which are created by burning fossil fuels, to form ground-level ozone, or smog, which causes a wide range of health effects. Benzene and other components of natural gas are also classified as hazardous air pollutants, which are known or suspected to cause cancer or reproductive effects.[82] Flaring of gas produces NO_X and particulate matter, both of which can cause respiratory and heart problems.[83]

Venting and leaks of natural gas in the oil and gas production process also contribute to climate change. Natural gas is primarily composed of methane, which is a potent GHG. Measured over a 100-year time-frame, methane results in more than 20 times more warming than CO_2, on a ton-per-ton basis. Over a 20-year time-frame, methane is 86 times more potent than CO_2, according to the most recent report of the Intergovernmental Panel on Climate Change.[84] Venting, flaring, and leaks also produce CO_2. As the President's Climate Action Plan recognizes, reducing methane emissions can make an important contribution to addressing climate change.[85]

C. Purpose of This Proposed Rule

The purpose of this proposed rule is to establish a comprehensive framework to give operators on Federal and tribal leases clear direction to minimize waste and losses of natural gas. This proposed rule is necessary because the BLM's existing requirements on venting and flaring are more than 3 decades old, do not reflect technological advances and current scientific understanding, have failed to deter rising losses of gas, fail in some respects to provide clear guidance to BLM staff and oil and gas operators, and do not address leaks from existing and new infrastructure.

This proposed rule would implement statutory directives to avoid waste of oil and gas resources. It would supplement the BLM's regulations contained in 43 CFR 3162.5 and 3162.7, to address prevention of waste of produced natural gas, use of produced oil and gas on a royalty-free basis, and record keeping requirements. It would also update and replace NTL–4A,[86] pertaining to venting and flaring, unavoidably and avoidably lost gas, and waste prevention. The proposed rule would ensure that operators use best practices that minimize waste from new and existing operations.

The BLM recognizes the importance of ensuring that our requirements do not subject operators to conflicting or redundant requirements. In 2012, the EPA adopted air pollution regulations for certain activities in the oil and gas production sector, and the EPA has recently proposed further regulations in that area, which would have the effect of reducing loss of gas. In addition, in response to growing concerns about venting, flaring, and leakage of gas, several States have adopted or are considering regulations to address these issues. The EPA regulations focus largely on new sources, however, and they are directed at pollution reduction, not waste prevention, so they do not address all opportunities to reduce waste. Similarly, none of the States has established a comprehensive set of requirements addressing all of the sources of lost gas that we are considering here, and many States have minimal requirements in this area. We are committed to working closely with State and tribal governments to ensure that the BLM requirements are coordinated with State and tribal requirements to the extent possible. The BLM requirements would not supersede equally effective or more stringent State and tribal requirements. We are also working closely with the EPA to coordinate our requirements, so that operators are not faced with conflicting or duplicative Federal mandates.

D. Stakeholder Outreach

Over several months of last year, the BLM conducted a series of forums to consult with tribal governments and solicit stakeholder views to inform the development of this proposed rule. We held public meetings in Denver, Colorado (March 19, 2014), Albuquerque, New Mexico (May 7,

[81] RIA at 3.

[82] The EPA has classified benzene as a known human carcinogen and reproductive effects have been reported at high exposures and observed in animal studies. U.S. EPA, *Benzene Hazard Summary (online at: http://www3.epa.gov/airtoxics/hlthef/benzene.html).*

[83] U.S. EPA, *Nitrogen Dioxide; Health* (online at: *http://www3.epa.gov/airquality/nitrogenoxides/health.html*); U.S. EPA, *Particulate Matter; Health* (online at: *http://www3.epa.gov/pm/health.html*).

[84] See Intergovernmental Panel on Climate Change, Climate Change 2013: The Physical Science Basis, Chapter 8, *Anthropogenic and Natural Radiative Forcing,* at 714 (Table 8.7), *available at https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf.*

[85] The President's Climate Action Plan, *https://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.* at 10–11 (June 2013)

[86] 44 FR 76600 (1979). The U.S. Geological Survey (USGS) issued regulations on these subjects in NTL–4A. In the early 1980's, the responsibility for Federal onshore oil and gas operations was transferred from the USGS to the Minerals Management Service (MMS). In 1983, the Secretary transferred the responsibility to the BLM. NTL–4A has remained in force through the changes in agency responsibility.

2014), Dickinson, North Dakota (May 9, 2014), and Washington, DC (May 14, 2014).[87] Each day, we held a tribal outreach session in the morning and a public outreach session in the afternoon. At the Denver, Colorado, and Washington, DC sessions, the tribal and public meetings were live streamed to allow for the greatest possible participation by interested parties. The tribal outreach sessions also served as initial consultation with Indian tribes to comply with Executive Order 13175, Consultation and Coordination with Indian tribal governments.

As part of our outreach efforts, the BLM accepted informal comments generated as a result of the public/tribal outreach sessions through May 30, 2014. A total of 29 unique comments were received: 12 from the oil and gas industry and trade associations, 6 from NGOs representing 37 organizations, 2 from government officials or elected representatives and 9 from private citizens. Two hundred and sixty comments from private citizens were part of an email campaign.

In addition, the BLM has conducted outreach to States with extensive oil and gas production on BLM-administered leases. We have carefully reviewed State regulations and guidance, and we have contacted State regulatory bodies that oversee aspects of oil and gas production to discuss their requirements and practices. We look forward to continued close interaction with State and tribal regulators.

The proposed rule reflects input gathered from the public meetings, comments, and discussions with States and tribes.

E. Existing BLM Regulations and Requirements for Preventing Natural-Gas Waste

Venting, flaring, and royalty-free uses of oil and natural gas on BLM-administered leases are currently governed by NTL–4A, which was issued by the U.S. Geological Survey on December 27, 1979, before the BLM assumed oversight responsibility for onshore oil and gas development and production. NTL–4A prohibits venting or flaring of gas well gas, and it prohibits venting or flaring of oil well gas unless approved in writing by the ''Supervisor.'' [88] Both prohibitions are subject to specified exemptions for emergencies, certain equipment malfunctions, certain well tests, and vapors from storage vessels. With respect to venting or flaring of oil well gas, NTL–4A IV.B states:

> The Supervisor may approve an application for the venting or flaring of oil well gas if justified either by the submittal of (1) an evaluation report supported by engineering, geologic, and economic data which demonstrates to the satisfaction of the Supervisor that the expenditures necessary to market or beneficially use such gas are not economically justified and that conservation of the gas, if required, would lead to the premature abandonment of recoverable oil reserves and ultimately to a greater loss of equivalent energy than would be recovered if the venting or flaring were permitted to continue or (2) an action plan that will eliminate venting or flaring of the gas within 1 year from the date of application.[89]

Thus, the key criteria under this provision in NTL–4A for approving venting or flaring (and rendering it royalty-free) are: (1) That the expenditures for capture are ''not economically justified,'' *and* they would ''lead to the premature abandonment of recoverable oil reserves''; or (2) The venting or flaring will be eliminated within 1 year.[90] NTL–4A IV.C also provides that ''(w)hen evaluating the feasibility of requiring conservation of the gas, the total leasehold production, including both oil and gas, as well as the economics of a field wide plan shall be considered . . . in determining whether the lease can be operated successfully if it is required that the gas be conserved.'' [91]

In addition, NTL–4A specifies the circumstances under which an operator owes royalties on oil and gas that is lost from a lease. It provides that gas which is ''avoidably lost'' is subject to royalties. It defines ''avoidably lost'' production as produced gas that is vented or flared without the ''prior authorization, approval, ratification, or acceptance of the Supervisor,'' or lost due to: (1) Negligence; (2) Failure to comply with lease terms, the operating plan, orders or regulations; or (3) ''(T)he failure of the lessee or operator to take all reasonable measures to prevent and/or to control the loss.'' [92] NTL–4A I further provides that no royalty is due for gas that is: (1) Used on the lease for ''beneficial purposes''; (2) Vented or flared with the Supervisor's prior authorization or approval; (3) Vented or flared pursuant to State rules or orders, when such rules have been ratified or accepted by the Supervisor; or (4) Otherwise unavoidably lost, as determined by the Supervisor.[93]

NTL–4A III. authorizes royalty-free venting or flaring of gas ''on a short-term basis'' without the need for approval under specified circumstances, including during: (1) Emergencies; (2) Well purging and evaluation tests; and (3) Initial production tests.[94] Venting or flaring is authorized during emergency situations, such as equipment failures, for up to 24 hours per incident and up to 144 cumulative hours per lease per month.[95] NTL–4A III.B. authorizes venting or flaring ''(d)uring the unloading or cleaning up of a well during drillstem, producing, routine purging, or evaluation tests, not exceeding a period of 24 hours.'' [96] In addition, NTL–4A III.C. authorizes venting or flaring during initial well evaluation tests, for up to 30 days or up to 50 million cubic feet (MMcf) of gas, whichever occurs first.[97] Finally, NTL–4A II.C. provides that gas vapors that are released from storage tanks or other low-pressure vessels are considered to be unavoidably lost, and not subject to royalties, unless the Supervisor determines that their recovery is warranted.[98]

Over the past 36 years since NTL–4A was issued, technologies and practices for oil and gas production have advanced considerably. The development of modern hydraulic fracturing and horizontal drilling techniques has been especially significant. We also now have better technologies for capturing and using gas on-site, detecting leaks, powering equipment, controlling vapors from storage vessels, removing liquids from gas wells, and many other aspects of production. Not surprisingly, NTL–4A neither reflects today's best practices and advanced technologies, nor is particularly effective in requiring their use to avoid waste. In addition, much of NTL–4A relies on broad, generalized directives. As these have been implemented in the decades since NTL–4A was issued, there has been ambiguity and variation regarding the circumstances under which venting or flaring requires prior approval, the circumstances under which venting or flaring is approved, and the circumstances under which royalties are paid on vented and flared gas. There is also some ambiguity regarding what properly constitutes royalty-free on-site use. All of these factors indicate the need to update NTL–4A.

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[87] See the BLM oil and gas program's outreach-events page: *http://www.blm.gov/wo/st/en/prog/energy/public_events_on_oil.*

[88] 44 FR 76600. (Dec. 27, 1979).

[89] Ibid.

[90] Ibid.

[91] Ibid.

[92] 44 FR at 76600. (Dec. 27, 1979).

[93] Ibid.

[94] Ibid.

[95] Ibid.

[96] Ibid.

[97] Ibid.

[98] Ibid.

NTL–4A also includes a provision for assessing the full value of avoidably lost gas and gas that is vented or flared without required approval.[99] This provision was subsequently overridden, however, by the later-enacted FOGRMA.[100] Section 308 of FOGRMA states, ''Any lessee is liable for royalty payments on oil or gas lost or wasted from a lease site when such loss or waste is due to negligence on the part of the operator of the lease, or due to the failure to comply with any rule or regulation, order or citation issued under this Act or any mineral leasing law.'' [101]

NTL–4A's ''full value'' policy has not been enforced since FOGRMA's enactment. The proposed rule would comply with FOGRMA Section 308 and require payment of royalty, rather than full value, on all oil and gas that is avoidably lost.

F. Legal Authority

With this proposed rule, the BLM aims to update the NTL–4A requirements for venting, flaring, and royalty-free uses of oil and natural gas on BLM-administered leases. The BLM's general authority to issue this proposed regulation derives from various statutes applicable to onshore Federal lands and minerals and Indian tribal and allotted lands, principally the MLA, MLAAL, FOGRMA, FLPMA, IMDA, IMLA, and the Act of March 3, 1909.[102]

The MLA rests on the fundamental principle that the public should benefit from mineral production on public lands.[103] A primary instrument for public benefit is the requirement that a lessee return a portion of the proceeds from production to the public through the payment of royalties to Federal, State, and tribal governments. For all competitively issued leases on Federal lands, the MLA requires a royalty ''at a rate of not less than 12.5 percent in amount or value of the production removed or sold from the lease.'' [104] The BLM is responsible for setting royalty rates and determining the quantity of produced oil and gas that is subject to royalties under the terms and conditions of a Federal lease. The MLA also requires the BLM to: Ensure that lessees ''use all reasonable precautions to prevent waste of oil or gas developed in the land''; [105] regulate ''all surface-disturbing activities conducted pursuant to any lease issued under (the MLA)''; [106] and ''determine reclamation and other actions as required in the interest of conservation of surface resources.'' [107]

In FLPMA, Congress declared it to be the policy of the United States that the BLM should manage the public lands ''in a manner that will protect the quality of scientific, scenic, historical, ecological, environmental, air and atmospheric, water resources, and archeological values; . . . preserve and protect certain public lands in their natural condition; . . . provide food and habitat for fish and wildlife; and . . . provide for outdoor recreation and human occupancy and use.'' [108] In addition, the BLM is required to manage public lands under principles of multiple use and sustained yield under FLPMA, which include management of the lands without permanent impairment of the quality of the environment.[109] The definition of ''multiple use'' explicitly includes the consideration of environmental resources; ''multiple use'' means a ''combination of balanced and diverse resource uses that takes into account the long-term needs of future generations for renewable and nonrenewable resources, including, but not limited to, recreation, range, timber, minerals, watershed, wildlife and fish, and natural scenic, scientific, and historical values.'' [110] Further, the statutory definition of ''multiple use'' constitutes management in a ''harmonious and coordinated'' manner ''without permanent impairment to the productivity of the land *and the quality of the environment.*'' [111] Significantly, FLPMA admonishes the Secretary to consider ''the relative values of the resources and not necessarily . . . the combination of uses that will give the greatest economic return of the greatest unit output.'' [112] FLPMA also mandates that the Secretary, ''(i)n managing the public lands . . . shall, by regulation or otherwise, take any action necessary to prevent unnecessary or undue degradation of the lands.'' [113]

The proposed rule would supplement BLM onshore lease operations regulations found at part 3160 of Title 43 of the Code of Federal Regulations (CFR). The rule would apply to all BLM-managed leases. The proposed rule would also apply to business agreements entered into by tribes (other than Osage Tribe) and agreements under the IMDA, as consistent with those agreements and with principles of Federal Indian law. Oil and gas agreements entered into under the IMDA may or may not provide for a royalty; if they do, that royalty may or may not be expressed as a percentage of the production ''removed or sold from the lease.''

The BLM's authority to require royalty payments derives from the above-quoted provision in the MLA: ''A lease shall be conditioned upon the payment of a royalty at a rate of not less than 12.5 percent in amount or value of the *production removed or sold from the lease.*'' [114] As established in several judicial decisions, the phrase ''production removed or sold from the lease'' exempts from royalty payments production that is used on the lease for lease operations.[115] Thus, operators may use oil or gas on the lease royalty-free to support the productivity of the lease. For example, a lessee may use produced gas to power the production infrastructure.

The proposed rule does not use the terms ''beneficial purpose'' and ''beneficial use,'' which are used in NTL–4A. Over the years, those terms appear to have been applied inconsistently within the BLM, creating confusion for some in the industry regarding when production may be used royalty-free. Instead of referencing beneficial purposes or use, the proposed rule would directly address the royalty-free treatment of various uses of lease production, and would identify the situations in which prior written BLM approval would be required for royalty-free treatment.

The BLM, through NTL–4A, has long read the MLA to exempt from royalty payments production that is ''unavoidably lost'' in the course of production.[116] Under NTL–4A, in

[99] Ibid.

[100] 30 U.S.C. 1701 *et seq.*

[101] 30 U.S.C. 1756.

[102] See footnote 4.

[103] *See, e.g., California Co.* v. *Udall,* 296 F.2d 384, 388 (D.C. Cir. 1961) (noting that the MLA was ''intended to promote wise development of . . . natural resources and to obtain for the public a reasonable financial return on assets that 'belong' to the public''). The Indian Mineral Leasing Act also had the similar purpose of securing for Indian tribes ''the greatest return on their property.'' *Kerr-McGee* v. *Navajo Tribe of Indians,* 731 F.2d 597, 601 n.3 (internal quotation mark omitted).

[104] 30 U.S.C. 226(b)(1)(A) and (c)(1); 30 U.S.C. 352 (applying that requirement to leases on acquired land). The same royalty provision is included in the lease instruments for leases of Indian tribal and allotted lands under applicable regulations, although that rate is set at no less than 16–2/3%, absent approval of the Secretary. 25 CFR 211.41, 212.41.

[105] 30 U.S.C. 225.

[106] 30 U.S.C. 226(g).

[107] Ibid.

[108] Ibid. 1701(a)(8).

[109] 43 U.S.C. 1702(c), 1732(a).

[110] Ibid. (emphasis added).

[111] Ibid. (emphasis added).

[112] Ibid.

[113] Ibid. 1732(b).

[114] 30 U.S.C. 226(b)(1)(A) (emphasis added).

[115] *See Marathon Oil Co.* v. *Andrus,* 452 F. Supp. 548, 522–23 (D. Wyo. 1978); *Gulf Oil Corp.* v. *Andrus,* 460 F. Supp. 15, 18 (C.D. Cal. 1978).

[116] 44 FR 76600.

determining when production is unavoidably versus avoidably lost, the BLM has generally considered the technical and economic feasibility of preventing the loss of gas. Under NTL–4A, the BLM deems a loss of gas ''avoidable''—and charges associated royalties—if it determines that such loss occurred as a result of: (1) Negligence on the part of the lessee or operator; (2) The failure of the lessee or operator to take all reasonable measures to prevent and/or to control the loss; and/or (3) The failure of the lessee or operator to comply fully with the applicable lease terms and regulations, appropriate provisions of the approved operating plan, or the prior written orders of the BLM.[117] If, on the other hand, the loss of gas is not the result of operator negligence and results from certain specified circumstances, such as emergencies, well tests, and production tests, or if the BLM determines that venting from storage tanks is ''warranted,'' the BLM deems the loss ''unavoidable'' and does not charge associated royalties.[118] As discussed below, however, the BLM has not always been consistent in applying this distinction between ''unavoidably'' and ''avoidably'' lost gas, creating significant confusion for both operators and regulators. The proposed rule seeks to clarify the distinction, and thereby limit the need for operators to submit, and BLM to process, applications for approval of royalty-free use of gas.

G. Concerns About Loss of Gas Identified Through Oversight

Several oversight reviews have raised concerns about waste of gas, found that the BLM's existing requirements regarding venting and flaring are insufficient, and have identified concerns about royalty-free use of gas. They recommended that the BLM update its regulations and guidance on royalty-free use and waste prevention. These include reviews by the Subcommittee on Royalty Management of the Royalty Policy Committee (RPC), which is a Federal advisory committee to the Department of the Interior; the Inspector General of the Department of the Interior; and the GAO.

The RPC's December 2007 report entitled, *Mineral Revenue Collection from Federal and Indian Lands and the Outer Continental Shelf,* includes specific recommendations to the BLM and the former Minerals Management Service (MMS (which was subsequently divided into ONRR, the Bureau of Ocean Energy Management (BOEM), and the Bureau of Safety and Environmental Enforcement.)) The report emphasized the need for enhanced verification of production accountability, and it recommended that the BLM update relevant pre-1983 (remnant U.S. Geological Survey and MMS) rules. In recognition of those needs, the BLM began a process to implement the recommendations to improve production accountability oversight. This proposed rule—along with other separately proposed rules dealing with site security and oil and gas measurement—responds to recommendations in the RPC's report. A March 2010 report by the Department of the Interior Inspector General also recommended that the BLM clarify its requirements for royalty-free use of gas.[119]

In October 2010, the GAO issued a report entitled, *Federal Oil and Gas Leases—Opportunities Exist to Capture Vented and Flared Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases.* For this audit, the GAO examined the amounts of natural gas being vented and flared on Federal oil and gas leases, and evaluated the potential for additional capture of natural gas using available technologies. The GAO also evaluated what the associated potential increases in royalty payments and decreases in GHG emissions would be from any additional gas capture.

The GAO found that ''around 40 percent of natural gas estimated to be vented and flared on onshore Federal leases could be economically captured with currently available control technologies.'' [120] The GAO further found that ''Interior's oversight efforts to minimize these losses have several limitations, including that its regulations and guidance do not address'' new capture technologies and some significant sources of lost gas.[121] As the GAO noted, BLM guidance is over 30 years old and does not address venting and flaring reduction technologies that have advanced since it was issued, such as automated plunger lift technologies that reduce the amount of gas vented during liquid unloading operations or low-bleed pneumatic devices that can replace the functions of high-bleed pneumatic devices.[122]

The GAO recommended that ''to help reduce venting and flaring of gas by addressing limitations'' in the regulations, the ''BLM should revise its guidance to operators to make it clear that technologies should be used where they can economically capture sources of vented and flared gas, including gas from liquid unloading, well completions, pneumatic valves, and glycol dehydrators.''[123] The GAO further recommended that the BLM should ''assess the potential use of venting and flaring reduction technologies to minimize the waste of natural gas'' before production occurs, and that the BLM should consider expanded use of infrared cameras to improve reporting and identify opportunities to minimize lost gas.[124] This proposed regulation responds to these recommendations as well.

In addition, multiple public advocacy organizations have recently raised concerns about the waste of gas in oil and gas production operations, and recent State regulatory actions to reduce venting and flaring indicate that some States share these concerns as well.[125]

H. Volumes of Lost Natural Gas

1. Data Sources on Lost Gas

While concerns have been growing over rising quantities of lost gas, there is no single definitive estimate on the volume of these losses from Federal and Indian leases. One relevant source of information for estimating the volumes of waste is the Oil and Gas Operations Report Part B (OGOR–B) that producers from BLM-administered leases file each month with ONRR to report quantities of gas removed from their leases. Another key source of information is the EPA Inventory of Greenhouse Gas Emissions and Sinks (2015) (''EPA GHG Inventory''), which is an annual report that estimates the total national GHG emissions and removals associated with human activities across the United States. Additional information is drawn from the EPA Greenhouse Gas Reporting Program (GHGRP), which collects GHG data from large emitting facilities, suppliers of fossil fuels and industrial gases that result in GHG emissions when used. Additional emissions quantification data was presented by ICF in a publication entitled, *Onshore Petroleum and Natural Gas Operations on Federal and Tribal Lands in the United States.*[126] With respect to oil and gas production, some of these sources estimate releases of natural gas, while

[117] Ibid.

[118] Ibid. at 76,601.

[119] Department of the Interior, Inspector General, *BLM and MMS Beneficial Use Deductions* (March 2010), *https://www.doioig.gov/sites/doioig.gov/files/2010-I-00171.pdf.*

[120] GAO–11–34, Oct. 2010, 2.

[121] Ibid. at 34.

[122] Ibid. at 27.

[123] Ibid. at 34.

[124] Ibid. at 34.

[125] See discussion in Section I.1 of this preamble.

[126] ICF, Onshore Petroleum and Natural Gas Operations on Federal and Tribal Lands in the United States (June 2015) (SHORT FORM—ICF 2015).

others estimate methane emissions. Natural gas is primarily composed of methane, however, and translating back and forth between the two types of estimates is a relatively straightforward calculation.

The data collected by ONRR includes operators' estimates of gas vented and flared-during production from each Federal and Indian lease. These data do not include any estimates of natural gas lost through leaks, or from routine operation of pneumatic devices, storage vessels, compressors, or glycol dehydrators (equipment that circulates the chemical glycol in gas to absorb moisture). In addition, the GAO found that there is variation across BLM offices as to whether operators must report certain other types of natural gas losses on their OGOR-Bs. Specifically, operators varied in whether they included quantities of vented or flared gas where the BLM had authorized the venting or flaring or where the quantities were under the BLM's permissible limits. Operators are also not always required to meter the quantities of vented or flared gas reported on their OGOR-Bs. Instead they may use BLM-approved methods to estimate the quantities to be reported. So while the ONRR data are highly relevant, they provide information about a subset of gas wasted and there is some uncertainty regarding the accuracy of the estimates the data do include. In reviewing these data, the GAO found that they ''likely underestimate venting and flaring because they do not account for all sources of lost gas.''[127]

For purposes of this proposed rule, ONRR provided the BLM with 6 years of vented and flared volumes reported on the OGOR-Bs. The data analyzed included gas flared and vented from both oil wells and gas wells from 2009 through 2014. During this period, operators reported that they vented or flared a total of 375 Bcf of natural gas, or about 2.6 percent of the 14.6 Tcf of natural gas that was produced from BLM-administered leases from 2009 through 2014. This is enough natural gas to supply about 5 million households—or every household in the States of Colorado, Montana, New Mexico, Utah, and Wyoming—for 1 year.[128] These data are reported by operators on BLM-administered leases, but the production is actually derived from lands with various ownership patterns. Of the vented and flared gas reported to ONRR, 15.2 percent came from wells extracting only Federal minerals; 9.0 percent from Indian ownership, and 75.8 percent from mixed ownership (some combination of Federal, Indian, fee (private) and State land). While all of the natural gas flared or vented from the Federal and Indian lands categories originates from the Federal and Indian mineral estates, only a portion of the natural gas flared or vented from the mixed ownership category originates from the Federal and Indian mineral estates.

Data in the EPA GHG Inventory can be used to calculate a more complete estimate of gas losses from venting and leaks from BLM-administered leases, which is discussed in more detail in the Regulatory Impact Analysis (RIA) for this rule. Using data from the GHG Inventory, we estimate that about 167 Bcf of natural gas was released or vented to the atmosphere from all U.S. onshore oil and gas leases in 2013, the most recent year for which estimates are currently available. In that year, production from Federal and Indian leases accounted for 12.7 percent of the U.S. natural gas production and 7.43 percent of the U.S. crude oil production.[129] Because we expect the national emissions level to be generally representative of what we would expect on Federal and Indian lands, we derived emissions estimates largely by applying the Federal and Indian share of production to the national emissions estimate.[130] The analysis of these data sources indicates that roughly 22 Bcf of natural gas was lost from BLM-administered leases through venting and leaks in 2013.

In addition, the ONRR data indicate that operators reported flaring 76 Bcf of natural gas from BLM-administered leases in 2013 (the most recent year for which data are available). Of this, ONRR estimates that about 44 Bcf was gas from the Federal and Indian mineral estate (as opposed to gas from State or private mineral estates that is being extracted through a well that is producing from a mix of Federal, Indian, State or private mineral estates).[131]

Thus, for purposes of this proposal, our best estimate is that 98 Bcf of natural gas was vented, leaked, or flared from BLM-administered leases in 2013,[132] of which 66 Bcf originated from the Federal and Indian mineral estates.[133] The 66 Bcf of vented or flared gas represents about 2.3 percent of total Federal and Indian production from these leases in 2013, and is enough gas to supply almost 900,000 homes each year.[134] This is consistent with ICF's estimate that fugitive sources, vented emissions and flared emissions from Federal and Indian onshore leases amounted to 66 Bcf of natural gas in 2013.

Based on available data, the problem of natural gas loss on BLM-administered leases is also growing. The total amounts of annual reported flaring from Federal and Indian leases increased by 109 percent from 2009 through 2013.[135] During this period, reported volumes of flared oil-well gas increased by 292 percent, while reported volumes of flared gas-well gas decreased by 75 percent.[136] The reduction in flaring at gas wells coincides with the adoption of EPA air pollution requirements limiting emissions from gas wells hydraulically fractured after August 2011.

Another indicator of the increase of flaring on Federal and Indian lands is the increase of applications to vent or flare received by the BLM. In 2005, the BLM received just 50 applications to vent or flare gas. In 2011, the BLM received 622 applications, and this doubled again within 3 years to 1,248 applications in 2014. BLM field offices indicate that most of the additional applications were for flaring in New Mexico, Montana, the Dakotas, and, to a lesser extent, Wyoming.[137]

In addition to considering the quantity of gas that is lost now, it is also important to consider the potential future quantities of lost gas, and to evaluate the future sources of such losses. One source of information on this question is a study by ICF entitled, *Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries,* issued in March 2014. The ICF Study estimated methane emissions from onshore oil and gas production in 2018 based on a 2011 baseline. It found that absent regulation, emissions are projected to grow 4.5 percent from 2011 through 2018, and almost 90 percent of emissions in 2018 would come from sources that were already operating prior to 2012.[138] Based on this information, the BLM believes that it is important for the proposal to address waste from both new sources and

[127] GAO–11–34, Oct. 2010.

[128] Using U.S. Census Bureau Total Households as of 2013 (latest data available).

[129] Based on updated EIA production crossed against ONRR Federal production data.

[130] For additional detail on these calculations, see RIA App. 7.

[131] RIA at 19.

[132] That is, 22 Bcf vented or leaked (per EPA GHG Inventory data), and 76 Bcf flared (per ONRR data).

[133] RIA at 3.

[134] Based on an estimate of 74 Mcf of gas used per household per year. See footnote 2.

[135] RIA at 201.

[136] Ibid.

[137] BLM data extracted from AFMSS in response to media inquiry, October 2014.

[138] ICF 2014 Study.

sources that already exist at the time of the final rule.

2. Additional Information on Loss Estimates

The BLM developed the emissions estimates discussed in the preamble and RIA using the best data available at the time. Some of the data produced by EPA and ONRR, such as the EPA estimates of the quantities of gas lost through leaks, and emergency releases reported to ONRR by the operators, rely on emissions factors, which have been developed by the EPA. These emissions factors are usually based on representative measured data and are applied to activity data to calculate estimated emissions. The ONRR relies primarily on self-reporting by industry, subject to agency audits.

Annually, EPA reviews new information as it becomes available, and the GHG Inventory continues to be refined to reflect new information available. For example, EPA notes the availability of new data in its GHG Inventory, including data and information that are becoming available through EPA's GHGRP and external studies, allowing EPA to re-evaluate and make updates to GHG Inventory data, as applicable.

Several recently completed academic studies aim to improve our understanding of the quantity of natural gas and petroleum system emissions, and more such studies are underway. In general, there are two major types of studies related to oil and gas GHG data: So-called ''bottom up'' studies that focus on measurement or quantification of emissions from specific activities, processes, and equipment (*e.g.,* EPA's Greenhouse Gas Reporting Program data and many of the series of studies being conducted by the Environmental Defense Fund, academic researchers, and industry, discussed below), and ''top down'' studies that focus on verification of estimates at the regional scale through methods such as airborne mass balance, atmospheric transport models, and enhancement ratios with well-constrained pollutants, along with approaches such as inverse modeling (*e.g.,* National Oceanic and Atmospheric Administration (NOAA) verification studies), which measure atmospheric levels of emissions and attempt to allocate contribution among potential sources. The first type of study can lead to direct improvements to or verification of inventory estimates. The second type of study can provide general indications of potential over- and under-estimates in existing data. Several of these recent studies are discussed below.

An article published last year in the peer-reviewed journal *Science* reviewed 20 years of technical literature on natural gas emissions in the U.S. and Canada and compared various emissions estimates from top down (*e.g.,* aircraft) and bottom up (*e.g.,* inventory) studies. The authors found that inventories consistently underestimate actual methane emissions.[139] Similarly, a study published in May 2014 by researchers from NOAA and the University of Colorado, Boulder, estimated methane emissions from oil and gas production areas using atmospheric hydrocarbons gathered while flying over the Denver-Julesberg Basin. This study estimated that hourly methane emissions from oil and gas sources in that basin are three times higher than would be expected based on estimates derived from data reported under the EPA GHGRP.[140]

Beginning in 2012, the Environmental Defense Fund began working with about 100 universities, research institutions and companies on a multi-pronged scientific research effort to develop a clearer picture of methane losses across the U.S. natural gas supply chain. Several studies from this effort, in addition to the NOAA and *Science* studies discussed above, are particularly relevant to this rulemaking.

For example, researchers at the University of Texas, Austin, in Phase 1 of their production studies, published in September 2013, found that methane emissions from equipment leaks and pneumatic devices were larger than previously thought.[141] The study focused on methane emissions at 190 sites (focusing on ongoing production activity and well completion emissions) operated by nine natural gas companies. It also found that emissions from well completions were smaller than previously thought (apparently due to the EPA's requirement for reduced emission completions, which can reduce venting from well completions by 99 percent).[142] Phase II of the study, which looked at wells operated by 10 companies, found that for emissions from liquids unloading and pneumatic devices, a small percentage of sources account for the majority of the emissions from these categories.[143] Nineteen percent of pneumatic devices produced 95 percent of the emissions that were attributable to the devices, while 20 percent of wells that vented during liquids unloading produced 65 to 83 percent of the emissions from those sources.[144] The study further found that average emissions from pneumatic controllers are higher than EPA's previous estimates, which are the basis for the emissions factors used in calculating gas waste.[145]

A February 2015 study from Colorado State University, entitled *Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results,*[146] found wide variations in the amount of methane leaking at gathering and processing facilities. Another study, *Analyzing Methane Emissions from Upstream Oil and Gas Production Operations,*[147] conducted by researchers at the Houston Advanced Research Center and the EPA, analyzed fence line data on methane emissions at well production sites. It found that unpredictable events, such as malfunctions and leaks, likely have a strong influence on emissions rates.[148] In addition, a recent study questions the accuracy of the sampler used in the University of Texas and other studies. The new study, published in the journal Energy Science & Engineering, asserts that the University of Texas researchers used a sampler that can fail under certain conditions, leading to ''severe'' underreporting of natural gas emissions.[149] Other sources of information also reinforce concerns about the volumes of lost gas. In October 2014, an analysis of satellite measurements from 2002–2012 by

[139] A. R. Brandt et al., *Methane Leaks from North American Natural Gas Systems, Science,* 733 (Feb. 14, 2014), *http://www.sciencemag.org/content/343/6172/733.full.*

[140] Gabrielle Pétron et al., A new look at methane and nonmethane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin, Journal of Geophysical Research: Atmospheres, 6836 (June 3, 2014), *http://onlinelibrary.wiley.com/doi/10.1002/2013JD021272/pdf.*

[141] David T. Allen et al., *Measurements of Methane Emissions at Natural Gas Production Sites in the United States,* 17768 (Oct. 2013), The Proceedings of the National Academy of Sciences of the United States of America, 17768 (Oct. 2013), *http://www.pnas.org/content/110/44/17768.full.pdf.*

[142] Ibid, 17769–70.

[143] David T. Allen et al., Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers, 636 (Dec. 9, 2014), Environmental Science and Technology, available at *http://pubs.acs.org/doi/abs/10.1021/es5040156.*

[144] Ibid.

[145] Ibid. at 638.

[146] Austin L. Mitchell et al., *Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results,* 3219 (Feb. 2015), Environmental Science and Technology, *available at http://pubs.acs.org/doi/abs/10.1021/es5052809.*

[147] Birmur Guven et. al., *Analyzing Methane Emissions from Upstream Oil and Gas Production Operations,* (Nov. 2014).

[148] Ibid.

[149] Howard, Touché, University of Texas study underestimates national methane emissions at natural gas production sites due to instrument sensor failure, Energy Science & Engineering (Aug. 4, 2015).

scientists from the National Aeronautics and Space Administration (NASA) and the University of Michigan identified a 2,500-square-mile (about half the size of the State of Connecticut) concentration of methane located over the Four Corners area in Arizona, Colorado, New Mexico, and Utah.[150] The study's lead author indicated that the emissions likely come from natural gas production and processing equipment (although not from hydraulic fracturing, as much of the data predates its upsurge) in the San Juan Basin in New Mexico, which produces natural gas from conventional gas production, oil production, and coalbed methane.[151]

On the other hand, another recent study found that methane measurements taken by aircraft in some natural gas production basins track well with the EPA's GHG Inventory estimates.[152] Data indicate that emissions from gas production activities vary from basin to basin. This variation may be due to characteristics of the natural gas, the amount of natural gas processing that is necessary, and the condition of the natural gas gathering, compression and transportation system. Also, some of the older studies may tend to overestimate current losses in some respects, as recent EPA and State regulations, as well as voluntary actions by industry, have substantially reduced the volumes of gas lost from some sources, such as gas well completions.

Most recently, a new study by Zavala et al., published in the *Proceedings of the National Academy of Sciences,* developed new techniques to reconcile bottom up and top down estimates of methane emissions from oil and gas production in the Barnett Shale region in Texas.[153] This study found that in this region, methane emissions from oil and gas production and processing are almost twice as high as would be estimated based on the EPA GHG Inventory, and are 3.5 times higher than would be estimated based on EPA GHGRP data.[154] It further found that the emissions from these sources in this region are dominated by a relatively small number of high emitters, with, at any given time, 2 percent of the facilities contributing half of the emissions, and 10 percent contributing 90 percent of the emissions.[155]

The BLM expects that additional studies will use bottom-up and top-down data comparisons to continue to refine emissions estimates for these sources. The presence, distribution, and effect of super-emitters, which are often defined as sources with exceptionally high emissions as compared to similar sources (essentially malfunctioning equipment), is also being further studied. Overall, these studies and alternative sources of data suggest that the BLM's estimates of lost gas likely underestimate, and potentially substantially underestimate, the extent of the problem.

I. Examples of and Gaps in Existing Waste-Reduction and Related Efforts

1. State Activities

In developing the proposed rule, we have consulted with State regulators and reviewed State requirements related to waste of oil and gas resources. Like the MLA, most State laws and regulations prohibit or encourage prevention of waste of these resources. But specific State requirements, and the outcomes they produce, vary widely. This variability reinforces the need for this rule to update standards for oil and gas operations on Federal and Indian lands. In developing the proposed rule, we also looked to some of the most effective State approaches as models. In particular, we have drawn on new requirements recently adopted by Colorado and North Dakota to address rising rates of flaring, resource losses, and other impacts. Below we summarize how several States have approached these issues.

(a) Alaska

The State of Alaska adopted regulations in the 1970s to address high rates of flaring.[156] Since then, the State has prohibited venting or flaring of gas except in narrowly defined circumstances: Testing a well before regular production; fuel that maintains a continuous flare; de minimis venting of gas incidental to normal oil field operations; and flaring or venting gas for no more than 1 hour during an emergency or operational upset.[157] The practical effect of this prohibition has been widespread reinjection of associated gas into the field for conservation and oil recovery purposes.[158] Alaska estimates that roughly 0.4 percent of gas production is flared, which is far lower than in most other States.[159]

(b) Colorado

The State of Colorado has reduced venting and flaring through air quality regulations directed at emissions of hydrocarbons and VOCs from the oil and natural gas industry.[160] The Colorado Department of Public Health and Environment, Air Quality Control Commission has instituted regulations similar in many ways to the EPA's existing NSPS for new and modified hydraulically fractured gas wells and gas processing facilities.[161] The Colorado regulation includes some aspects of EPA's NSPS, and expands on the EPA standards in other areas. For example, the Colorado rule requires reduced emissions completions for most oil and gas well completions and recompletions, whereas EPA's NSPS currently applies only to hydraulically fractured or refractured gas well completions in developed gas fields. Colorado has also adopted some requirements that are independent of the EPA NSPS. For instance, under the reduced emissions completion process, operators must minimize venting ''to the maximum extent practicable.'' [162]

In addition to requiring green completions, Colorado's rules: Establish requirements for pneumatic controllers;[163] require a comprehensive LDAR program;[164] set standards for liquids unloading;[165] establish emission standards for storage vessels;[166] and require storage tank emissions management (STEM) plans, which would identify strategies to minimize emissions from storage vessels during normal operations.[167] BLM has several memoranda of understanding with the Colorado Oil and Gas Conservation

[150] NASA news release, Oct. 9, 2014 available at *http://www.nasa.gov/press/2014/october/satellite-data-shows-us-methane-hot-spot-bigger-than-expected/#.VLbQ0PnF9sE.*

[151] Ibid.

[152] Jeff Peischl, T. B. Ryerson, K. C. Aikin, J. A. de Gouw, J. B. Gilman, J. S. Holloway, B. M. Lerner, R. Nadkarni, J. A. Neuman, J. B. Nowak, M. Trainer, C. Warneke, D. D. Parrish, Quantifying atmospheric methane emissions from the Haynesville, Fayetteville, and northeastern Marcellus shale gas production regions, Journal of Geophysical Research: Atmospheres, 120 (5), pp. 2119–2139.

[153] Zavala-Araiza et al., *Reconciling divergent estimates of oil and gas methane emissions,* Proceedings of the National Academy of Sciences, vol. 112, no. 51, 15597–15602 (Dec. 22, 2015).

[154] Ibid. at 15599.

[155] Ibid. at 15600.

[156] Alaska Administrative Code Title 20—Chapter 25 235, Gas Disposition, *available at http://doa.alaska.gov/ogc/Regulations/RegIndex.html.*

[157] Ibid.

[158] Telephone call with BLM staff and State of Alaska, Oil and Gas Conservation Commission (April 30, 2015).

[159] Ibid.

[160] Colorado Air Quality Control Commission Regulations, Regulation 7, Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions (Emissions of Volatile Organic Compounds and Nitrogen Oxides).

[161] For further information about EPA's NSPS standards for this source category, see Section IV.I.3 of this preamble below.

[162] Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9, Sections XII, XVIII.

[163] Ibid. at Section XVIII.

[164] Ibid. at Section XVII.F.

[165] Ibid. at Section XVII.H.

[166] Ibid. at Sections XII.D–F; XVII.C.

[167] Ibid. at Section XVII.C.2.

Commission regarding permitting, inspection, and enforcement relating to oil and gas activities on BLM lands.[168]

(c) Montana

The State of Montana has had limits on venting and flaring in place since the 1970s. Produced gas vented to the atmosphere at a rate exceeding 20 Mcf per day that continues for more than 72 hours must be burned.[169] After completion of a gas well, no gas may be permitted to escape, except gas required for periodic testing or cleaning of the well bore.[170] If, after well completion, the operator intends to flare gas production in excess of 100 Mcf per day, the operator must obtain a variance from the oil and gas board.[171] The operator must submit a production test and a statement justifying the need for a variance, including information such as potential human exposure; relative isolation of location; measures to restrict public access to the location; low gas volume; and low BTU content.[172] The board may elect to restrict production until the gas is marketed or otherwise beneficially used.[173]

(d) North Dakota

North Dakota has experienced a rapid increase in oil production in recent years. A byproduct of this development is more natural gas being produced than can be processed and transported to market through existing pipeline infrastructure. Without access to a market, much of the associated natural gas continues to be flared.

In March 2013, the North Dakota Industrial Commission adopted a policy to reduce flaring, and it followed this with an enforceable order adopted in July 2014 and modified in September 2015.[174] The policy and order require well operators to meet flaring reduction targets according to a prescribed time line.[175] The gas capture requirements for each operator include a target of capturing at least 74 percent of production by October 2014.[176] The target then rises over time to a target of capturing at least 91 percent of production by October 2020.[177] The operator may show compliance with the target at each well, or on a field, county, or statewide basis.[178]

North Dakota's policy includes additional requirements intended to help operators reach the targets.[179] One component of the policy requires that all applications for permits to drill be accompanied by gas capture plans.[180] The State's goal is to ensure that options for capturing any natural gas discovered are fully evaluated before a well is drilled. North Dakota also requires the gas capture plan to be provided to midstream processing companies so they can plan accordingly.[181]

The policy provides for oil production to be restricted from wells where the operator does not meet the flaring reduction targets.[182] Production is restricted to no more than 200 bbl of oil per day for those wells capturing more than 60 percent of the gas production, but less than the applicable target percentage.[183] Production is restricted to no more than 100 bbl of oil per day from those wells capturing less than 60 percent of produced gas.

(e) Pennsylvania

In August 2013, the Pennsylvania Department of Environmental Protection issued guidance that exempted from certain air quality permitting requirements oil and gas exploration, development, and production facilities and associated equipment and operations that implemented the following: An LDAR program consistent with relevant EPA regulations; VOC emission controls on all storage tanks; a 2.7 tpy limit on VOC emissions from all facility sources; certain limitations on flaring activities; and hourly, daily, seasonal, and annual limits on NOx emissions.[184]

(f) Utah

The Utah Department of Environmental Quality issued a General Approval Order on June 5, 2014, that applies to new and modified oil and gas well sites and tank batteries. Among other provisions, this order requires pneumatic controllers to be low bleed or route the emissions to a flare or capture device; pneumatic pumps route emissions to a flare or capture device; and requires operators to inspect for leaks at least annually, and more frequently for sources with greater throughput levels.[185]

(g) Wyoming

The Wyoming Department of Environmental Quality adopted regulations in June 2015, to reduce emissions of VOCs from storage vessels, pneumatic controllers, pneumatic pumps, glycol dehydrators, and leaks in the Upper Green River Basin nonattainment area.[186] Among other things, the rule requires emissions from vessels with uncontrolled VOC emissions from flashing of 4 tpy or more to be controlled by 98 percent,[187] emissions from pneumatic pumps to be controlled by 98 percent,[188] high-bleed pneumatic controllers to be replaced with low-bleed controllers,[189] and operators to establish LDAR programs with at least quarterly inspections.[190]

2. Voluntary Industry Efforts

The oil and gas industry has also recognized concerns about the rising quantities of flared and vented gas, and has begun to take voluntary steps to reduce gas losses. For example, oil and gas companies developed the technologies for green completions.[191] Individual companies voluntarily use some of the approaches proposed here to reduce their natural gas losses through venting, flaring, and leaks and boost profitability.

Many of these efforts have been initiated by companies participating in Natural Gas STAR, a voluntary EPA-industry partnership program that encourages oil and natural gas companies to adopt cost-effective technologies and practices that improve operational efficiency and reduce methane emissions. Twenty-six companies in the production sector currently participate in Natural Gas STAR. Partners in this program have

[168] The MOUs are *available at http://cogcc.state.co.us/gov.html#/federal.*

[169] Administrative Rules of Montana, Section 36.22.1221(1).

[170] Ibid. at 36.22.1219.

[171] Ibid. at 36.22.1220(1–2).

[172] Ibid. at 36.22.1221(2).

[173] Ibid. at 36.22.1221(3).

[174] North Dakota Industrial Commission Order No. 24665 (July 1, 2014), *available at https://www.dmr.nd.gov/oilgas/or24665.pdf;* North Dakota Industrial Commission Order No. 24665 Policy/Guidance Version 102215, *available at https://www.dmr.nd.gov/oilgas/GuidancePolicyNorthDakotaIndustrialCommissionorder24665.pdf.*

[175] Ibid.

[176] Ibid.

[177] Ibid.

[178] Ibid.

[179] Ibid.

[180] Ibid.

[181] Ibid.

[182] Ibid.

[183] Ibid.

[184] Pennsylvania Department of Environmental Protection, Air Quality, *Air Quality Permit Exemptions, http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf* (August 10, 2013) at 8–11.

[185] State of Utah, Department of Environmental Quality, Division of Air Quality, *Approval Order: General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery,* DAQE–AN1492500001–14 (June, 5, 2014).

[186] Wyoming, Nonattainment Area Regulations Ch. 8 (June 2015), *available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.*

[187] Ibid. at Section 6(c)(i)(A).

[188] Ibid. at Section 6(e).

[189] Ibid. at Section 6(f).

[190] Ibid. at Section 6(g).

[191] *See, e.g.,* EPA, Lessons Learned from Natural Gas STAR Partners, *Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells, available at http://www3.epa.gov/gasstar/documents/reduced_emissions_completions.pdf.*

pioneered some of what are now the most widely-used, innovative technologies and practices to reduce methane emissions. These include green completions for hydraulically fractured wells, artificial lift systems for well maintenance, pneumatic controllers and pumps with no or low gas releases, and infrared cameras for leak detection. Natural Gas STAR partners from the oil and gas production sector reported that they achieved about 50 Bcf of methane emissions reductions in 2013.[192]

To further encourage emissions reductions from the oil and gas sector, the EPA announced, in July 2015, a voluntary program called the Natural Gas STAR Methane Challenge, in which companies would make ambitious commitments to reduce methane emissions and would track their progress in achieving those reductions.[193]

In addition, six oil and gas companies have joined together to form the One Future Coalition, which aims to ''(e)nhance the energy delivery efficiency of the natural gas supply chain by limiting energy waste and by achieving a methane 'leak/loss rate' of no more than one percent.'' [194] These companies aim ''to develop yearly, sliding-scale emission intensity goals for the entire value chain and each sector within the value chain,'' and use a flexible approach to achieve reductions.[195]

3. EPA Air Quality Requirements

While EPA does not regulate waste of oil and gas resources, certain air pollution regulations applicable to the oil and gas production sector have the co-benefit of also reducing waste of natural gas. Because the air pollutants regulated by EPA are contained in natural gas, many of the control options for reducing emissions operate by limiting the release (and hence loss) of natural gas. To the extent that EPA rules under the Clean Air Act address some aspects of the waste issue, the BLM intends to coordinate its requirements with the EPA as far as possible, to ensure that industry is not burdened by duplicative or conflicting requirements. The EPA rules will include both standards that EPA adopted in 2012, which are largely focused on natural gas wells and infrastructure, and the 40 CFR part 60 subpart OOOOa rulemaking, which addresses additional categories of new and modified sources in the oil and gas production sector.

In 2012, EPA adopted NSPS to limit the release of VOCs from new and modified hydraulically-fractured natural gas wells, certain new or modified sources located at well sites, natural gas processing plants, or natural gas gathering and boosting stations.[196] These standards require new hydraulically fractured gas wells to use a process termed a ''reduced emission completion'' or ''green completion'' to capture natural gas that would otherwise be released in the well-completion process.[197] EPA estimated that this requirement reduces VOC emissions from the hydraulic fracturing process by 95 percent.[198] EPA allows for flaring instead of green completions for new exploratory or delineation wells, on the assumption that these types of wells are generally not near pipeline infrastructure to transport captured gas. EPA also does not require green completions for wells where there is not sufficient pressure to route the gas to a gathering line, instead allowing operators to flare the gas that would otherwise be released.

The 2012 standards also require operators to use certain types of new and modified equipment at natural gas processing plants and gathering and boosting stations. The standards limit VOC emissions from centrifugal compressors and establish maintenance requirements for reciprocating compressors.[199] The standards also apply to new and modified high-bleed pneumatic controllers powered by natural gas, which are defined as pneumatic controllers that emit more than 6 scf/hour.[200] The standards limit the bleed rate for pneumatic controllers at well sites and gathering and boosting stations to 6 scf/hour, and they require zero VOC emissions from pneumatic controllers located at processing plants.[201] In practice, this standard requires operators to replace high-bleed pneumatic controllers with low-bleed or no-bleed devices. New, modified, and reconstructed storage vessels at these locations (including well sites) are also covered by the 2012 requirements.[202] They require new storage vessels with VOC emissions of at least 6 tpy to reduce those emissions by at least 95 percent.[203] In addition, the 2012 standards strengthened existing leak detection standards for natural gas processing plants.[204]

On September 18, 2015, EPA published a notice of proposed rulemaking that proposes NSPS standards to be codified as 40 CFR part 60 subpart OOOOa.[205] The EPA proposes to establish both methane and VOC standards for several emission sources not covered by the 2012 NSPS, including hydraulically fractured oil well completions, pneumatic pumps, and fugitive emissions from well sites and compressor stations. In addition, the EPA proposed methane standards for certain emission sources that are currently regulated for VOCs but not for methane, and proposed to extend VOC standards and create methane standards for equipment used widely in the industry.[206]

In addition, the EPA proposed to issue Control Technique Guidelines (CTGs), which States could adopt in nonattainment areas to reduce methane emissions from *existing* sources in the oil and gas production sector.[207]

4. Need for BLM Requirements

While the proposed EPA standards are expected to reduce methane emissions from certain new and modified oil and gas production facilities, they would not be sufficient to meet the goals of BLM's proposed rule for several reasons. First, the proposed EPA regulations do not include any provisions to reduce flaring of associated gas during normal production operations. Second, even with respect to the natural gas waste from venting, the EPA regulations would apply only to new and modified sources, whereas this proposal would reach existing sources as well. In States that choose to adopt the CTGs, those guidelines would apply to existing sources, but the guidelines are designed to reduce emissions in nonattainment

[192] EPA Natural Gas STAR, *Accomplishments, http://www3.epa.gov/gasstar/accomplishments/index.html.*

[193] EPA Natural Gas Star Methane Challenge, *Program Proposal, http://www3.epa.gov/gasstar/methanechallenge/index.html.*

[194] International Business Times, ''Six Major Oil and Gas Firms Agree to Cut Potent Methane Emissions Ahead of UN Climate Change Summit, (Sept. 23, 2014), *http://www.ibtimes.com/six-major-oil-gas-firms-agree-cut-potent-methane-emissions-ahead-un-climate-change-summit-1693517; http://www.gastechnology.org/CH4/Documents/Fiji-George-CH4-presentation-Sep2014.pdf.*

[195] Our Nation's Energy (ONE) Future Coalition, *http://www.gastechnology.org/CH4/Documents/fiji-George-CH4-presentation-Sep2014.pdf.*

[196] U.S. EPA, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule, 77 FR 49490 (Aug. 16, 2012).

[197] 40 CFR 60.5375.

[198] U.S. EPA, Overview of Final Amendments to Air Regulations for the Oil and Natural Gas Sector, Fact Sheet, *available at http://www3.epa.gov/airquality/oilandgas/pdfs/20120417fs.pdf.*

[199] 40 CFR 60.5380; 40 CFR 60.5385.

[200] 40 CFR 60.5390.

[201] Ibid.

[202] 40 CFR 60.5395.

[203] Ibid.

[204] 40 CFR 60.5400.

[205] 80 FR 56593, Sept. 18, 2015.

[206] Ibid.

[207] Ibid.

areas, and very little oil and gas is produced from BLM-administered leases in such areas. Third, because the EPA's legal authorities differ from those of the BLM, the proposed EPA regulations do not cover all BLM-regulated activities, such as well maintenance and liquids unloading.

Similarly, of the States with extensive oil and gas operations on BLM-administered leases, only one has comprehensive requirements to reduce flaring, and only one has comprehensive statewide requirements to control losses from venting and leaks. Moreover, State regulations do not apply to BLM-administered oil and gas leases on Indian lands, and States do not have a statutory mandate to reduce waste of Federal oil and gas.

In addition, the BLM has regulated oil and gas operations on Federal and Indian leases for decades to prevent waste, conserve resources, and protect public lands. The BLM has the responsibility and experience to ensure that these valuable public resources are extracted in a safe manner, while minimizing harm to local communities and the environment and ensuring fair returns to Federal taxpayers and tribes. We have existing requirements that are intended to serve these purposes, but NTL–4A is over 3 decades old and is no longer adequate in meeting these goals. Thus, the proposed rule would update NTL–4A, and would do so in coordination with the concurrent EPA rulemaking. In addition, the proposed rule would make provision for State and tribal programs that address flaring or venting.

V. Discussion of the Proposed Rule

The proposed rule would require operators to limit waste of gas through flaring and venting, clarify the situations in which flared gas would be subject to royalties, conform the royalty terms applicable to competitive leases with the corresponding statutory language, and clarify the on-site uses of gas that are exempt from royalties. In addition, the BLM is proposing to require operators to record and report information related to venting and flaring of gas, and is taking comment on how best to make this information more available to the public. This section of the preamble also includes a discussion of how today's proposal relates to the planning process for lands subject to BLM administration, although this rule would not make any regulatory changes to the planning process itself.

A. Measures To Reduce Waste

The BLM has identified several key points in the production process where waste-prevention actions would be most effective and least costly. Specifically, we propose to focus on reducing waste from the following: Flaring of associated gas from producing oil wells; gas leaks from equipment and facilities located at the well site, as well as from compressors located on the lease; operation of high-bleed pneumatic controllers and certain pneumatic pumps; gas emissions from storage vessels; well maintenance and liquids unloading; and well drilling and completions. Based on the available data regarding methane emissions and the numbers and types of sources of gas losses from Federal and Indian leases, we believe that these aspects of the production process offer the best opportunities for reducing waste.

To the extent that EPA completes regulations that would have the effect of reducing waste from these sources, the BLM proposes to take EPA's requirements into account in finalizing this proposed rule to avoid conflict or burdensome duplication.

In addition, the BLM requests public comments on the scope of this proposed rule, including whether there are other aspects of the production process that might provide sufficient opportunities for economical and cost-effective waste reduction to warrant inclusion in this regulation. We also request comment on whether we could achieve additional economical and cost-effective waste reduction from any of the sources of waste that we are addressing here. In addition, we request comment on the cost-effectiveness of the changes we are proposing to each aspect of the production process, taking into account the full range of private and public benefits achieved through waste reduction. We also request comment on how we could lower costs of the measures that we are proposing here.

1. Venting or Flaring of Associated Gas From Producing Oil Wells.

As discussed earlier in Section II.H. of this preamble, operators currently vent gas under some circumstances, and they also flare large quantities of natural gas that is produced at oil wells (commonly called ''associated gas'' or ''casinghead gas''). Operators have an economic incentive to capture and sell the flared gas, or to use it on-site. Nonetheless, substantial flaring occurs under a variety of circumstances.

(a) Quantities of Gas Vented or Flared

BLM analysis of ONRR data shows that operators reported venting about 22 Bcf and flaring at least 76 Bcf of natural gas from BLM-administered leases in 2013 (with about 44 Bcf estimated to be Federal and Indian minerals).[208] Of that total volume of flared gas, 71 Bcf was flared oil-well gas while about 5 Bcf was flared gas-well gas. Most of the flared oil-well gas volume appears to be associated gas flaring, with the balance coming from other sources such as well testing and emergency flaring. Flared gas represents 2.6 percent of the total gas production from BLM-administered leases in 2013, enough to supply over 1 million households.[209]

According to ONRR data, 91 percent of flared oil-well gas from BLM-administered leases occurred in three States: North Dakota, South Dakota, and New Mexico. In 2013, the volumes of flared oil-well gas from BLM-administered leases in these States were about 42 Bcf, 15 Bcf, and 8 Bcf, respectively.[210] The data also show that these volumes have increased dramatically since 2009, while oil production increased in North Dakota and either remained relatively constant or declined in New Mexico and South Dakota. For example, between 2009 and 2013, flared oil-well gas in New Mexico increased by 2.3 percent, even as oil production decreased by 3 percent, and in South Dakota flaring increased by 1.3 percent even as oil production fell by 45 percent.[211] Meanwhile, the increase in oil-well gas flaring in North Dakota appears to have tracked closely with the increase in oil production (each increased by roughly 350 percent over that period).[212]

(b) Technologies To Address Flaring

The primary means to avoid flaring of associated gas from oil wells is to capture, transport, and process that gas for sale, using the same technologies that are used for natural gas wells. While industry continues to reduce the cost and improve the reliability of this technology, it is long-established and well understood. The capture and sale of associated gas can pay for itself where there is sufficient gas production relative to costs of connecting to or expanding existing infrastructure. The costs of installing equipment and pipelines for capture and transport can range from $400,000 to $1 million per mile for a 4-inch natural gas pipeline.[213] In some cases, line capacity can be

[208] RIA at 3.

[209] Based on an estimate of 74 Mcf of gas used per household per year. See footnote 2.

[210] RIA at 203.

[211] Ibid.

[212] Ibid.

[213] Pipeline and Gas Journal, *Billions Needed to Meet Long-Term Natural Gas Infrastructure Supply, Demands (April 2009) http://pipelineandgasjournal.com/billions-needed-meet-long-term-natural-gas-infrastructure-supply-demands?page=4.*

increased by adding more compressors to boost pressure. Similarly, industry has long used some of this gas on-site to pneumatically control equipment or fuel various types of equipment, including such items as drilling rigs, artificial lift equipment or heater/treater equipment.

In addition, the recent increase in flaring has encouraged entrepreneurs to develop new technologies and applications designed to capture smaller amounts of gas and put them to productive uses where building a pipeline to connect to the market is impractical. Companies are beginning to experiment with and deploy several technologies as potential alternatives to the traditional pipeline systems that capture associated gas. These include: Separating out NGLs, which are often quite valuable, and trucking them off location; using the gas to run micro-turbines to generate power; and using small integrated gas compressors to convert the gas into CNG that can be used on-site or trucked off location for use as transportation fuel or conversion to chemicals. In addition, there are other promising and innovative approaches that are either in development or in the earlier stages of deployment.[214]

Natural gas contains hydrocarbons that can exist in liquid phase without being in a high pressure or low temperature environment. These are referred to as NGLs. Higher NGL concentrations in a gas stream reflect higher heating (Btu) value and a higher combined commodity value when the NGLs are separated from the remaining gas stream. Although NGLs are typically stripped and fractionated into their various components (*e.g.,* propane, butane, etc.) at a gas processing plant, well-site equipment capable of stripping NGLs into a mixed liquid is available. This technology is particularly applicable in situations where high Btu associated natural gas is being flared due to lack of gas capture infrastructure. The NGLs can be stripped from the gas stream in the field and stored in tanks at the well site. Trucks would transport the stored NGLs to a gas processing plant for sale. The remaining lower Btu gas would continue to be flared, but typically with a higher combustion efficiency than mixed gas. Conservation of the NGLs from a gas stream would reduce waste, add energy to the domestic supply, and increase royalty payments to the Federal Government and tribal governments.

[214] *See* Carbon Limits (providing detailed evaluation of new and emerging gas utilization technologies).

Facilities to condense natural gas into LNG are more cost-effective at locations with large amounts of flaring, as relatively larger quantities of gas are needed to offset the cost of the LNG equipment. The surface area of well sites may need to be expanded to accommodate truck traffic and product storage needs. Also, because associated gas production drops off quickly at hydraulically fractured oil wells, LNG recovery is more likely to be cost-effective if it is implemented when production starts.

Micro-turbines that generate electricity typically require preprocessing of the associated gas to minimize equipment maintenance issues. Generating electricity can work well if it is paired with NGL recovery, as the NGL residue gas stream is well suited as fuel for the generators. However, scaling the generators to the electricity demand that could be used locally on the well pad complicates their use. The generators may produce more electricity than is needed on site, but it may be too costly to connect to the electric grid from a remote location, as would be necessary to put the excess electricity to productive use. The cost of connecting to the electric grid depends, among other things, on the distance of the operation from the nearest electrical distribution lines. Moreover, the electricity produced for use on site would be viewed as beneficial use, and therefore the gas used to generate the electricity would be royalty free. If the electricity produced by a micro-turbine is sold to the grid, however, it would not be beneficial use and the gas used to generate the electricity would not be royalty free.

The CNG alternative technologies show considerable promise in effectively transporting associated gas to a centrally located processing plant while removing the higher value NGLs for other productive uses. Well sites may need to be expanded to accommodate truck traffic and storage needs, but not to the extent needed under the LNG option. The on-site equipment for CNG is smaller than for LNG, and the size of the CNG operation can also be more easily adjusted to meet the associated gas decline over the life of the well. However, limitations on the amount and rate of natural gas capture/compression on-site can limit applicability of this technology. Breakthroughs in compression technology are increasing the range of viable sites where CNG would be the preferred alternative technology. This technology could become sufficiently attractive to reduce flaring to near zero rates, according to companies offering these services. While these newer on-site technologies may not be suitable in all situations, in many cases they could provide a profitable alternative to using traditional pipelines for capture and sale as a way to reduce waste, and operators should consider these approaches in assessing the opportunities to reduce waste from venting and flaring.

In addition, there are a number of technologies that can improve the efficiency of flares and ensure that a flare combusts as large a proportion of the gas as possible. In particular, automatic igniters can be used to ensure that the flare is relit if the gas flow stops intermittently.

(c) Factors Driving Flaring

In considering how to reduce flaring, it is important to recognize that gas is flared under a variety of circumstances, some of which are unplanned or unavoidable in the course of normal oil and gas production. Emergencies can occur through an unforeseen event, such as a weather-related incident or an accident that damages equipment resulting in the loss of gas.

In other cases, operators flare gas because they, and the midstream processing companies that commonly build and operate gas gathering and processing infrastructure, do not yet know whether there will be a sufficient quantity of gas available to capture. Thus, companies have not yet invested in building gathering lines and processing plants to capture and sell gas for commercial use. For example, the well may be an exploration or wildcat well in a new field, far from existing capture infrastructure, and it is not yet known whether the field will produce much gas. Similarly, in some fields, the overall quantity of gas produced across multiple wells is sufficiently small that, even cumulatively, the wells do not produce enough natural gas to offset the costs of building pipeline infrastructure. While flaring in these situations has generally been considered unavoidable, the BLM believes this assumption is challenged by the development of the alternative capture technologies described above, which calls into question whether it remains reasonable to assume that there are no alternatives to flaring when a field produces only a small quantity of natural gas. The BLM requests comment on this point. In many instances, however, the decision to flare large quantities of associated gas is driven by an operator's economic calculation that the value of immediately producing the oil outweighs the value of the natural gas that could be captured. In addition, inadequate maintenance or oversight can result in avoidable waste of gas.

Two circumstances that result in substantial ongoing or intermittent flaring of associated gas on BLM-administered leases are: (1) Flaring in areas with existing capture infrastructure, but where the rate of new-well construction is outpacing the infrastructure capacity; and (2) Flaring in areas where capture and processing infrastructure has not yet been built out. While the majority of associated gas flaring on BLM-administered leases occurs in the first situation, our proposed approach to reducing flaring addresses both circumstances.

The first situation occurs in areas that have extensive natural-gas gathering lines, which are connected to pipelines leading to processing plants. However, in many areas in recent years the rate of oil development and the rapid rise in quantities of associated gas have overwhelmed the capacity of the gathering lines and/or processing plants. New wells (especially in shale formations) often start out producing a relatively large amount of oil and/or gas at relatively high pressures, which then declines rapidly over time. Thus, each time a new oil well with associated gas connected to the gathering system starts production, it may increase the pressures on the system above the pressures generated by existing producing wells, pushing those wells off the gathering system. Operators of these existing wells then must choose between shutting in or throttling the well, employing other technologies to use the gas, reinjecting the gas, or flaring. This is the situation in the Permian basin in New Mexico, where almost all of the producing wells are connected to gas-gathering infrastructure, but substantial flaring still occurs due to inadequate capacity or pressure restrictions in the pipelines and/or processing plants. Much of the flaring in the Bakken basin is also driven by capacity constraints. In reviewing applications to vent or flare in North Dakota, the BLM found that out of 1,292 applications to vent or flare received between September 2012 and August 2014, 887, or about 70 percent, were from wells that were already connected to a gas pipeline, but had pipeline capacity or pressure restrictions.[215]

Flaring also occurs in the second situation identified above, when gas capture infrastructure has not yet been built out to a particular field or well, even though the well is expected to produce substantial quantities of gas. In many instances, operators or midstream processing companies plan to construct gathering lines, but the rate of oil well development outpaces the rate of development of capture infrastructure.

In both situations, lack of adequate planning and communication can result in flaring. North Dakota's recognition of this cause of flaring led the State to require an operator to provide an affidavit at the well permitting stage stating that the operator met with gathering companies and informed them of the operator's expected well development timing and production levels.[216]

The BLM recognizes that in the aggregate, operators do not want to waste gas. It is a valuable commodity that operators can sell for a profit. But when the economic return on oil production is substantially higher than the economic return on gas production, as it has been in recent years, there is an economic incentive for individual operators to focus on oil development at the expense of gas-capture infrastructure. Thus, operators may not adequately plan and coordinate with midstream companies, schedule oil well development with gas capture capacity in mind, build infrastructure, or otherwise ensure adequate capacity. As the GAO noted, even though it would be profitable in many instances for a company to make investments to reduce venting and flaring, the operator may choose to invest instead in a new well that would be even more profitable.[217] The GAO also identified a lack of operator awareness of the available cost savings, limited capital availability for small companies, and institutional inertia as reasons that companies fail to capture the economic benefits of investing in waste reduction measures.[218] In addition, operators typically consider only the costs and revenues of gas capture with respect to their individual operation. But in many instances, when costs and revenues are evaluated across a larger area, such as a group of wells that would share access to a gas transmission line and processing plant, gas capture that may appear less economically attractive to an individual operator may be more economical if all of the wells in that area were capturing and selling their gas. This concept is recognized in the existing requirements under NTL–4A, which directs the Supervisor to consider "the economics of a field wide plan" in evaluating the feasibility of requiring capture.[219]

(d) Proposals To Reduce Waste From Venting and Flaring

A focus on oil development rather than gas capture may be a rational decision for an individual operator, but it does not account for the broader impacts of venting and flaring, including the costs to the public of losing gas that would otherwise be available for productive use, the loss of royalties that would otherwise be paid to States, tribes, and the Federal Government on the lost gas, and the air pollution and other impacts of gas wasted through venting or flaring. A single operator's focus on its own operations can also produce a skewed assessment of the returns on investment in capture infrastructure across an entire area, where shared infrastructure may lower costs relative to the returns from the sale of gas.

Thus, a decision to vent or flare that may make sense to the individual operator may constitute an avoidable loss of gas and unreasonable waste when considered from a broader perspective and across an entire field. Further, as capture technologies improve, the economics of capture are improving for individual operators.

The BLM's proposed approach would reduce venting and flaring through a combination of measures: Prohibiting venting except in a narrow range of circumstances; reducing flaring by limiting the per-lease per-month rate of flaring; requiring operators to submit gas capture plans with their Applications for Permits to Drill new wells; requiring royalties on flared gas where appropriate; and simplifying both compliance with and administration of the venting and flaring requirements. The proposed rule would streamline the current regulatory regime by establishing thresholds and presumptions that initially apply across the board, but would maintain the BLM's ability to address individual situations through case-by-case determinations and exemptions where warranted.

(i) Phasing Out Routine Venting

With respect to venting, the proposal specifies that an operator must flare rather than vent gas, except in four specified circumstances: (1) When flaring the gas is technically infeasible (for example, because there is insufficient volume of gas); (2) When

[215] Phone conversation with BLM, Planning and Environmental Coordinator, Miles City, MT, September 2014.

[216] Letter from North Dakota Oil and Gas Division to Operators, Re: Gas Capture Plans Required on All APD's (May 8, 2014).

[217] GAO–11–34 (Oct. 2010) at 24.

[218] Ibid.

[219] 44 FR 76600 (Dec. 27, 1979).

the loss of gas is uncontrollable or venting is necessary for the safety of workers and others on the site; (3) When the gas is leaking from a storage vessel under circumstances that do not trigger the flaring requirements of proposed § 3179.203; or (4) When the gas is vented through operation of a natural gas-activated pneumatic controller or pneumatic pump that complies with the equipment requirements of proposed § 3179.201. As a practical matter, the BLM believes that the great majority of associated gas routinely lost from oil production wells is flared, rather than vented, and the proposed prohibition on venting would further reduce losses through venting. Thus, the discussion that follows generally references flaring, which is the main focus of these provisions.

The BLM is aware that venting may occur at gas gathering lines due to maintenance activities. We request comment on whether the proposed venting prohibition will sufficiently address these maintenance emissions.

(ii) Limits on Rates of Flaring

The proposed requirements to reduce flaring focus on the routine flaring of associated gas from development oil wells. Associated gas represents the bulk of the current flared gas, and is easier to capture than other flared gas. To address this waste of gas, the BLM proposes to establish a limit on the average rate at which gas may be flared of 1,800 Mcf per month per producing well on a lease.

The BLM is proposing to retain the current exemptions from royalties and gas capture requirements for gas flared in other specified situations, as long as the operator has complied with the proposed requirements to minimize these losses. These exemptions include gas lost in the normal course of well drilling and well completion; well tests; emergencies, as defined in the regulations; and gas flared from exploration or wildcat wells, or from delineation wells (wells drilled to define the boundaries of a mineral deposit). As described in more detail below, these exemptions represent situations in which: (1) A well is least likely to be connected to a pipeline, and on-site capture technologies are least likely to be economical; or (2) Flaring is likely to be unavoidable or necessary for safety.

(a) Proposed Per-Well Flaring Limit

As noted, the primary means by which the BLM proposes to reduce flaring is by limiting the average rate at which gas may be flared to 1,800 Mcf/month, per producing well on a lease.

In essence, the BLM is proposing that, subject to limited exceptions, very high rates of flaring from a lease—that is, rates above the proposed 1,800 Mcf/month threshold—constitute unreasonable waste under the MLA. As discussed above, operators have multiple avenues to reduce high levels of flaring. One is to speed up connection to pipelines, and another is to boost compression to access existing pipelines with capacity issues. BLM believes there are also other options available to avoid this waste. The economics of alternative on-site capture technologies improve as quantities of gas increase. Imposing a limit on the overall rate of flaring on a lease would provide operators an incentive to implement these technologies, where net costs are not prohibitive, to allow the wells to produce oil at the maximum rate. Alternatively, an operator could slow production sufficiently to stay below a flaring limit. Slowing the rate of flaring is likely to conserve gas overall because less gas is lost before capture infrastructure comes on line (or is upgraded, in the case of a field with insufficient capacity).

To select an appropriate numeric limit for flaring, the BLM analyzed data indicating the average flaring rates across wells. The BLM used venting and flaring data reported to ONRR by operators of oil and gas leases on Federal and Indian lands. For the analysis, the BLM used the most recent full fiscal year of available data—records covering the time period from October 1, 2013, through September 30, 2014. The BLM extracted from the ONRR data 15,530 records that document more than 76 Bcf of natural gas flared from oil wells during the time period. These records represent monthly flared volumes on a lease or unit basis from over 2,000 unique leases or units that flared natural gas from Federal or Indian mineral estates. As the number of wells on a lease or unit that might contribute to the monthly flaring volume can affect the cost to capture, the BLM further reviewed the BLM Automated Fluid Minerals Support System database for the number of total active wells associated with the lease or unit. With the number of active wells linked to the lease or unit, the records were sorted in order of increasing average flare volume per month per well.

These data indicate that in 2014:

- A 1,200 Mcf/month/well threshold would have impacted about 20 percent of the oil wells flaring associated gas, which accounted for 91 percent of the gas flared;
- A 1,800 Mcf/month/well threshold would have impacted about 16 percent of the oil wells flaring associated gas, which accounted for 87 percent of the gas flared;
- An 2,400 Mcf/month/well threshold would have impacted about 13 percent of the oil wells flaring associated gas, which accounted for 84 percent of the gas flared;
- A 3,000 Mcf/month/well threshold would have impacted about 11 percent of the oil wells flaring associated gas, which accounted for 81 percent of the gas flared.[220]

While these are average flaring volumes spread across all active wells, they represent an approximation of how oil well flaring is distributed across the spectrum of activity.[221] Operators have full discretion in how they choose to meet a rate-based flaring limit, with the result that compliance strategies may vary. For example, operators with wells that are only slightly over the flaring limit may choose to comply by slowing the rate of production until either: (1) The well is connected to pipeline infrastructure; or (2) Well decline brings the rate of gas production under the flaring limit. In the first instance, the over-the-limit quantity of gas would ultimately be conserved—in fact, even more gas might be conserved because the operator is likely to capture *all* of the gas that would otherwise have been flared. In contrast, in the second instance, the over-the-limit quantity of gas would still be flared, just later in time. Thus, there is substantial uncertainty in analyzing the impact of a flaring limit.

The BLM has analyzed the impacts of alternative flaring limits by adopting two simplifying assumptions. First, the BLM assumed that all over-the-limit quantities of gas would be captured instead of flared (an assumption that tends to overstate reductions in flaring); second, the BLM assumed that operators would comply only down to the level of the flaring limit and not below (an assumption that tends to *understate* reductions in flaring). With these competing assumptions in place, the projected reductions in flaring that might be achieved under different numeric limits are:

- A 1,200 Mcf/month/producing well threshold could conserve 80 percent of the gas flared;
- An 1,800 Mcf/month/producing well threshold could conserve 74 percent of the gas flared;

[220] RIA at 33–35.

[221] Data supplied by ONNR.

- A 2,400 Mcf/month/producing well threshold could conserve 69 percent of the gas flared; and
- A 3,000 Mcf/month/producing well threshold could conserve 65 percent of the gas flared.

These estimates were generated for the purpose of comparing alternative options for the flaring limit; the estimated overall impacts of the proposed flaring limit, combined with the effects on flaring of other elements of the rule, are presented in Section VI.B.4. of this preamble and Section 8.4.1. of the RIA. The BLM proposes in § 3179.6(b) to set a flaring limit of 1,800 Mcf per month per well, averaged over all producing wells on a lease. We believe this limit would effectively maximize flaring reductions while minimizing the number of affected leases. This proposed limit is consistent with Wyoming's and Utah's approaches: Wyoming and Utah limit flaring from a well to 60 Mcf/day and 1,800 Mcf/month, respectively, unless the operator obtains State approval of a higher limit.[222] As applied, the numeric limit proposed by the BLM would be somewhat less stringent than the State limits, because operators would be able to average flaring across all of the wells on a lease, rather than being required to meet the limit at each individual well. This approach incorporates some of the flexibility allowed by North Dakota, where operators can show compliance with the State's flaring limits on a field, county, or state-wide basis. In addition to reducing waste of gas through flaring, we believe this proposed approach would give operators more clarity about when they may flare, and reduce administrative burdens for the BLM, compared to the current approach to obtaining approval for flaring under NTL–4A. Operators would no longer have to submit applications to obtain approval for flaring from each individual well, and the BLM would no longer need to review and decide on each of those requests. Currently, some field offices receive hundreds of flaring applications each year, and processing these applications on a case-by-case basis uses BLM resources that could be used to process applications for permit to drill, process right-of-way applications, and conduct inspections, among other activities.

(b) Phase-In of the Proposed Limit

The BLM recognizes that in the first few years of the rule, it may be difficult for operators to meet the newly proposed flaring limit across all of their existing operations, because operators of oil wells drilled prior to the effective date of this rule may not have planned for gas capture. To assist these operators in transitioning to the proposed flaring limits, we propose to phase in those limits over the first few years after the effective date of the rule. Specifically, we propose flaring limits of: 7,200 Mcf per month per well on average across a lease in the first 12 months in which the regulations are in effect; 3,600 Mcf per month per well on average across a lease in the second 12 months in which the regulations are in effect; and 1,800 Mcf per month per well on average across a lease thereafter. This approach of phasing in the flaring limits is intended to allow operators initially to focus their resources on addressing wells with the highest rates of flaring.

(c) Alternative Flaring Limits or Renewable, 2-Year Exemption

Lessees that entered into Federal and Indian leases prior to the imposition of the proposed flaring limits (depending on the location of their wells) may have limited options for substantially minimizing waste. As a result, the BLM believes it is appropriate and necessary to provide an exemption to ensure that no lessee is entirely deprived of its ability to develop an existing Federal or Indian lease.

Thus, the BLM proposes in § 3179.7 to provide existing lease holders with the possibility of obtaining an exemption to the applicable flaring limit. Specifically, we propose to provide that an existing lease holder may apply for an alternative flaring limit or, under specific circumstances, may qualify for a renewable, 2-year exemption from the flaring limit. These provisions are intended to help existing operators transition to the proposed regulatory regime; operators on new leases would have more flexibility to plan for gas capture ahead of drilling, and thus would not be eligible for either form of exemption.

(i) Alternative Flaring Limits

The alternative flaring limit provision would apply to any operator (operating on an existing lease) that demonstrates, to the BLM's satisfaction, that the flaring limit specified in the regulations would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

In making the determination of whether a lease qualifies for an alternative flaring limit, the BLM would consider the costs of capture and the costs and revenues of all oil and gas production on the lease. For any operator that made a sufficient showing, the BLM would set an alternative flaring limit. The BLM would aim to set this alternative limit at the lowest level that would not cause the operator to cease production and abandon significant recoverable oil reserves.

The proposed standard for approving an alternative flaring limit is similar to the existing standard in NTL–4A for approving venting or flaring of oil well gas. NTL–4A allows the BLM to approve flaring if it is justified by data showing that ''the expenditures necessary to market or beneficially use such gas are not economically justified and that conservation of the gas, if required, would lead to the premature abandonment of recoverable oil reserves and ultimately to a greater loss of equivalent energy than would be recovered if the venting or flaring were permitted to continue.''[223] Given the substantial variation in how the BLM has interpreted and applied this standard, the BLM is proposing to establish a refined formulation of this test, to allow for a more uniform interpretation going forward. In particular, in some instances in the past, even small net costs have been viewed as meeting the test under NTL–4A, as any net cost might theoretically cause an operator to abandon a well earlier than it otherwise would have. In light of the BLM's statutory obligation to reduce waste of natural gas from venting, flaring, and leaks, however, the BLM believes that an operator must demonstrate more than a negligible economic impact in order to qualify for an exemption from the flaring limit. Thus, we propose to allow an exemption only on a showing that the net costs of compliance with the flaring limit would be sufficient to cause the operator to cease production and abandon ''significant'' recoverable oil reserves. The BLM requests comment on this approach.

To make the proposed showing, an operator would have to provide information about the quantity of flaring from the lease, projected costs of capture (including an evaluation of on-site approaches), and projected prices and returns on oil and gas production from the lease. Where operators need to project future costs and returns, the projections would be required to cover either the life of each lease or the next

[222] Wyoming Operational Rules, Drilling Rules Section Ch. 3, Section 39(b), *available at http://soswy.state.wy.us/Rules/RULES/9584.pdf* (60 Mcf/day); Utah R649–3–20, Gas Flaring or Venting Section 1.1, *available at* (*http://www.rules.utah.gov/publicat/code/r649/r649-003.htm#T20* (1,800 Mcf/mo.).

[223] NTL–4A, IV.B.

15 years, whichever is less. This is similar to the information that NTL–4A currently requires operators to provide in a request for approval of flaring, although the proposed regulations are more specific. NTL–4A currently requires an applicant for royalty-free flaring to submit ''all appropriate engineering, geologic, and economic data in support of the applicant's determination that conservation of the gas is not viable from an economic standpoint and if approval is not granted to continue the venting or flaring of the gas, that it will result in the premature abandonment of oil production and/or the curtailment of lease development.'' [224] Pursuant to this language in NTL–4A and guidance from individual BLM State offices, operators generally give the BLM information on projected oil and gas production, revenue projections, costs, and returns on investment under scenarios in which the gas is and is not captured, although the specific information submitted varies between applicants and across BLM field offices and States.

The BLM believes that requiring the information specified in this proposal to support a request for an alternative flaring limit would not impose substantial new paperwork burdens on operators, given the information currently required to be submitted under NTL–4A. In addition, given the rigor of the qualifying requirements, we do not expect many lease holders to apply for an alternative flaring limit, further limiting the potential burden. We request comment, however, on this point.

(ii) Renewable, 2-Year Exemption

Unlike the alternative flaring limit, the renewable exemption would provide certain operators with a complete exemption from the flaring limit, for a period of 2 years. The BLM generally prefers to assess the need for alternative flaring limits on a case-by-case basis, but we recognize that it may be more efficient to grant a short-lived, across-the-board exemption to a small class of operators that are: (1) Operating at significant distances from gas processing facilities, and (2) Generating high volumes of associated gas, such that capture and sale of the gas is plainly infeasible with current technologies.Thus, the proposed rule identifies three criteria that an operator must meet to qualify for an exemption from the flaring limit. Specifically, the BLM proposes that operations on an existing lease would qualify for an exemption from the flaring limit if: (1) The lease is not connected to a gas pipeline; (2) The closest point on the lease is located more than 50 straight-line miles from the nearest gas processing plant; and (3) The rate of flaring or venting from the lease exceeds the applicable flaring limit by at least 50 percent.

There are two reasons why the BLM believes that meeting all three of these criteria would be sufficient to demonstrate that an operator on an existing lease would be unlikely to be able to meet the flaring limit with today's technologies. First, a 2015 study by the entity Carbon Limits AS, titled *Improving Utilization of Associated Gas in US Tight Oil Fields,*[225] suggests that on-site capture is most cost-effective within a 20–25 mile radius of gas processing facilities.[226] Existing leases located more than 50 miles from such facilities are thus unlikely to be able to avail themselves of this technology. (While leases located more than 25 but less than 50 miles from gas processing facilities might similarly find on-site capture less cost-effective, that might not always be the case. Those leases could make a case-by-case showing under the proposed provision for alternative flaring limits.)

Second, while operators could respond to the flaring limit by deferring production, that is unlikely to be an option for operators on existing leases that are flaring more than 50 percent above the applicable limit. For these operators, reducing flaring below the limit would require reducing production by one-third or more. Thus, the BLM believes that leases meeting these distance and flaring rate criteria should qualify for an automatic exemption from the flaring limit.

To obtain the exemption, the BLM proposes to require that an operator submit a Sundry Notice with an affidavit certifying that the lease meets the specified criteria. The authorizing officer would then have the opportunity to verify the accuracy of the submission.

Because the circumstances supporting an exemption may change over time, the BLM proposes that the exemption would extend for 2 years, and could be renewed by the operator with submission and BLM approval of a new Sundry Notice.

(d) Request for Comments

To assist the BLM in finalizing the proposed flaring limit, we request comment on:

- The proposed 1,800 Mcf/month/well limit on the quantity of flared gas;
- Whether the flaring limit should be 1,200 Mcf/month/well, which would likely further reduce flaring, or 2,400 Mcf/month/well, which would likely reduce compliance costs for operators, but increase flaring above the amount anticipated by the proposed rule;
- Operators' likely response(s) to the proposed 1,800 Mcf/month/well limit (that is, the degree to which operators would respond by deploying on-site capture technologies, increasing capture capacity, speeding connections to pipelines, or slowing production, or with some combination of those responses);
- The proposal to phase-in the flaring limits and the specific limits proposed for year-one and year-two;
- The proposed provisions for operators to obtain an alternative flaring limit; and
- The proposed criteria for operators to qualify for the renewable, 2-year exemption, as well as the proposed 2-year duration of the exemption and the opportunity for renewal.

(iii) Waste Minimization Plans for Applications for Permit To Drill

The BLM is also proposing that prior to drilling a new development oil well, an operator would have to evaluate the opportunities and prepare a plan to minimize waste of associated gas from that well, and the operator would need to submit this plan along with the APD.

The BLM proposes to amend § 3162.3–1 to require an operator to submit along with its APD a plan to minimize waste of gas from the well to the degree reasonably possible. Failure to submit a complete and adequate waste minimization plan would be grounds for denying or disapproving an APD.

The plan must set forth a strategy for how the operator will comply with the proposed requirements to control waste from venting, flaring, and leaks, and it must explain how the operator plans to capture associated gas upon the start of oil production, or as soon thereafter as reasonably possible. The waste minimization plan must include specified information, including: Anticipated well completion timing; anticipated gas production rates, durations, and declines; a map and information on the locations and operators of nearby gas pipelines and processing plants; proposed routes and tie-in points; pipeline capacities, throughputs, and expansion plans, if known; an evaluation of opportunities for alternative on-site capture approaches, if pipeline transport is

[224] 44 FR at 76600 (Dec. 27, 1979).

[225] Hereinafter ''Carbon Limits.'' The study is available at *http://www.catf.us/resources/publications/files/Flaring_Report.pdf.*

[226] Ibid. at 34.

unavailable; and the volume and percentage of produced gas that the operator is currently flaring from wells in the same field. In addition, the operator must certify that it has provided one or more midstream processing companies with information about its production plans, including the anticipated completion dates and gas production rates of the proposed well or wells. We request comment on whether the waste minimization plan provisions should also require an operator to identify the projected gas production volumes that would be moved by pipeline or by truck.

While the BLM is proposing to require submission of a waste minimization plan together with the APD, we are not proposing to include the submitted plan as an element of the APD or otherwise to enforce the terms of the plan.

The BLM believes that requiring submission of a waste minimization plan would ensure that as an operator plans a new well, the operator has the information necessary to evaluate and plan for gas capture. This requirement would also ensure that the operator provides this information to the companies most likely to install and operate the necessary gas capture infrastructure—namely, midstream processing companies operating in the area. Both procedural steps are vitally important to development of a robust gas capture system for a new well.

As with development of an environmental analysis under the National Environmental Policy Act, the BLM believe that significant progress can be made by requiring that operators take these procedural steps prior to drilling. Further, the BLM believes that making the elements of the plan enforceable (for example, by incorporating it in the APD) might create an unintended incentive for operators to understate the degree of capture they anticipate achieving, or to write a very general plan, with few specifics. As a result, the BLM believes more can be achieved by requiring operators to develop a thorough and practical plan prior to submitting their Applications for Permits to Drill. The plan requirement is intended to assist operators in better preparing to comply with the proposed flaring limits.

The information required by this proposed provision is comparable to the information North Dakota requires to be included in the gas capture plan that each operator must provide. North Dakota requires that the gas capture plan include: A detailed gas gathering pipeline system location map identifying the location of connections to the gathering system and processing plants, as well as the names of gas gatherers and locations of lines for each gas gatherer in the vicinity; information on the existing line to which the operator proposes to connect, including the maximum current capacity, current throughput, and gas gatherer issues or expansion plans for the area (if known); a flowback strategy including the anticipated date of first production, and anticipated oil and gas rates and duration; the amount of gas the applicant is currently flaring; and alternatives to flaring, including specific alternate systems available for consideration and the expected flaring reductions if such plans are implemented.[227] North Dakota regulators have identified the requirement for gas capture plans as a highly effective element of their requirements to reduce flaring.[228]

(iv) Estimating or Measuring Quantities of Flared or Vented Gas

Under proposed § 3179.8, the BLM would require operators to report the quantities of all flared and vented gas. In determining the quantity of gas flared or vented, operators either estimate the volumes using engineering protocols or measure the volumes with gas meters. Meters generally produce more accurate results, but are also more costly. Thus, the BLM proposes to specify when operators may estimate the volumes of flared or vented gas, and when operators must measure the quantities for reporting purposes. Specifically, the BLM proposes that when the combined total of an operator's flaring and venting reaches least 50 Mcf of gas per day from a flare stack or manifold, the operator must measure rather than estimate the volume lost (*i.e.,* flared and/or vented) from that flare stack or manifold.

The BLM believes that in calculating small volumes of lost gas, any additional accuracy provided by meters may not justify their additional cost. Accordingly, the proposed rule would allow operators to estimate rather than measure volumes of lost gas below 50 Mcf. The BLM proposes to require measurement when gas losses are at least 50 Mcf per day because as the volume of gas flared nears 60 Mcf/day it is effectively nearing the 1,800 Mcf/month limit, and at that point accurate measurement of that volume becomes increasingly important for compliance and enforcement purposes. Moreover, as the volumes of gas flared increase, the economics of gas capture become more favorable, and the importance of using more refined data increases. We request comment on this proposed approach.

(v) Costs and Benefits of These Proposals

The requirement to meter flares is estimated to pose compliance costs of $7,500 per meter and operating costs of about $500 per meter per year. Assuming an equipment life of 10 years, the cost per meter is about $1,570 per year when costs are annualized using a 7 percent interest rate, or $1,380 per year using a 3 percent interest rate. In total, we estimate that the proposed flare metering requirement would impact 635 operations in 2017, with that number increasing on an annual basis to an estimated 1,175 operations in 2026. We estimate compliance costs ranging from $1.0–1.8 million per year when the capital costs of equipment are annualized with a 7 percent discount rate or $0.9–1.6 million per year when the capital costs of equipment are annualized with a 3 percent discount rate. Since these sources are not addressed by the EPA's proposed 40 CFR part 60 subpart OOOOa, the estimated impacts of the requirements are not influenced by that proposal.[229]

The requirement to limit gas flaring to 1,800 Mcf/month per average well on a lease may result in a range of potential benefits and costs depending on operator response, commodity prices, and the levels of flaring in future years. Operators could choose to comply by immediately using the excess gas on-site or deploying on-site capture technologies; they could briefly slow oil production while they expand capture capacity, where such expansion is cost-effective; or they could defer some portion of their production. We request comment on the likely balance among these response approaches, and the likely volume and duration of any partial deferment in oil production.

We considered this range of responses in estimating the costs and benefits of the flaring provisions, although we recognize that these estimates are subject to significant uncertainty, given the uncertainty about operator response. In designing the analysis, we looked at data for leases in North Dakota and New Mexico with respect to characteristics that might influence an operator's choice of how to comply with the flaring limits. Specifically, we identified whether wells on the lease were

[227] Letter from North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division to all Hearing Applicants, re Gas Capture Plan Required Hearing Exhibit (Sept. 16, 2014).

[228] Telephone Communication from North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division to BLM Staff, (May 13, 2015).

[229] RIA at 69.

connected to pipeline infrastructure, the rate of flaring (specifically, whether the rate was at least 50 percent above the flaring limit, or whether the rate was within 40 Mcf/day of the flaring limit), and the distance from the nearest gas processing plant (specifically whether the well was more than 50 miles, less than 20 miles, or between 20 and 50 miles from the nearest gas processing plant) for each lease where these data were available. We then constructed eight possible operator response scenarios based on combinations of these characteristics. We evaluated how operators in each scenario might respond to the flaring limit (*e.g.,* by deferring production, conducting on-site capture, or obtaining an exemption), assigned costs for each type of response, calculated the number of leases that would fall into each response category, and derived an estimate of overall costs. The RIA provides additional detail on our analysis.

We estimate that the proposed flaring limits, including the 3-year phase-in period, would affect an estimated 435–885 leases in any given year. These requirements could pose total costs of about $32–68 million per year (7 percent discount rate) or $26–43 million per year (3 percent discount rate). Because these requirements would drive additional capture of gas, the flaring limits are also projected to pose total cost savings (from the value of the captured gas) of about $40–58 million per year (7 percent discount rate) or $40–64 million per year (3 percent discount rate). We also estimate that they would increase natural gas production by 2.5–5.0 Bcf per year, and increase NGL production by 36–51 million gallons per year. The net benefits of these requirements are estimated to range from negative $10 to positive $8 million per year (7 percent discount rate) or $13–30 million per year (3 percent discount rate). Also, we expect there would be additional environmental benefits associated with the productive use of the gas downstream.[230]

(e) When Flared Gas Is Subject to Royalties

Along with the other aspects of NTL–4A, it is necessary to update the NTL–4A provisions regarding the applicability of royalties. As noted above, this proposal would clarify the determination of whether routine flaring from a production well is considered an avoidable waste of gas subject to royalties. Requiring royalty payments on wasted quantities of gas does not compensate for all the harm to the public from that waste, but it at least ensures that the public does not lose the royalty revenue they would have received had the gas been put to productive use.

The BLM is proposing in § 3179.4 to maintain the general approach of NTL–4A for distinguishing between avoidable and unavoidable losses of gas. The proposed rule would reduce regulatory burden and confusion, however, by providing additional and more specific requirements, and it would modify the NTL–4A approach with respect to flaring from wells that are already connected to gas capture infrastructure.

(i) Unavoidable Losses of Gas

The BLM proposes to determine that a loss of gas is unavoidable if all of the following four conditions are met. (1) The operator has not been negligent; (2) The operator has complied with all applicable requirements; (3) The operator has taken prudent and reasonable steps to avoid waste; and (4) The gas is lost from any of the following specified operations or sources, subject to the applicable limits or conditions specified in the proposed regulations: Emergencies; well drilling; well completion and related operations; initial production tests and subsequent well tests; exploratory coalbed methane well dewatering; leaks; venting from conforming pneumatic devices in the normal course of operation; evaporation from storage vessels; and downhole well maintenance and liquids unloading. Where these losses result from flaring, the BLM is proposing to establish quantity and/or timing limits on gas that may be flared royalty-free, such as the definition of what is considered an emergency and the limits on royalty-free flaring for well testing. Beyond these limits, continued losses would generally be considered avoidable and subject to royalties, except that, with respect to testing, the BLM may approve an operator's request for royalty-free flaring beyond the specified limits.

In addition, the BLM is proposing to find a loss of gas unavoidable where produced gas is flared from a well not connected to gas capture infrastructure, as long as the BLM has not otherwise determined that the loss of gas is avoidable, subject to the 1,800 Mcf/month limit in § 3179.6. In some cases, the effectiveness and affordability of on-site capture technology may mean that an operator could avoid flaring gas from a well not connected to capture infrastructure. At this time, however, on-site capture technology is not always effective and affordable; thus, the BLM is not proposing to find all flaring of associated gas from development wells to be avoidable.

The specifics of the proposal with respect to unavoidable losses depend on the category of loss. With respect to emergencies, NTL–4A currently authorizes royalty-free flaring of gas without approval from the BLM, but the proposed rule would clarify and narrow the scope of this exemption. As proposed under § 3179.105, emergencies result in infrequent and unavoidable flaring (or venting), and they may include failures of equipment located on the lease, relief of abnormal system pressures, or other unanticipated conditions. Operators may flare under this exemption for up to 24 hours per incident, and for no more than three emergencies per lease within a 30-day period. The BLM proposes to clarify that emergencies do not include: More than three failures of the same equipment within 365 days; failure to install adequate equipment to capture the gas; failure to limit production when the production rate exceeds the capacity of the related equipment; scheduled maintenance (whether by the operator or downstream facilities); or operator negligence. The BLM believes that repeated failure of the same piece of equipment within a given span of time indicates that the equipment is not properly sized or may need to be replaced, and that the operator should have taken action to address the problem. The BLM requests comment on the specific failure frequencies over a given time-period that would tend to indicate avoidable incidents.

With respect to flaring during well drilling and completion, the BLM proposes under § 3179.101 that gas produced during normal well drilling operations and then flared would be deemed unavoidably lost. Similarly, under proposed § 3179.102, gas produced during well completion and post-completion drilling fluid recovery or fracturing fluid recovery operations would be deemed unavoidably lost when flared, subject to a volume limit. Under proposed § 3179.103, gas from initial production testing may be flared and deemed unavoidably lost until the first of the following occurs: (1) The operator has adequate reservoir information for the well; (2) 30 days (90 for coal-bed methane dewatering) have passed; (3) The operator has flared 20 MMcf of gas, including any gas flared that was produced during well completion and post-completion fluid recovery; or (4) Production begins.

The 20 MMcf limit is lower than the maximum volume of royalty-free flaring authorized under NTL–4A (50 MMcf). The BLM's experience in the field

[230] RIA at 60.

indicates that adequate testing to determine a well's production capacity can almost always be conducted within the 20 MMcf volume threshold. The current 50 MMcf threshold is seldom, if ever, exceeded in actual well testing operations. The BLM specifically seeks comments on the amount of gas that should be allowed to be flared royalty-free during initial production testing.

Under proposed § 3179.104, during well tests subsequent to the initial production test, the operator may only flare gas for 24 hours royalty free, unless the BLM approves otherwise.

Operators would no longer need to apply for approval of flaring under the preceding conditions. Any gas flared in excess of these limits, however, would be deemed avoidably lost and subject to royalties, except where the BLM approved a request to extend the limits. In addition, regardless of whether the gas is subject to royalties, BLM also proposes under § 3179.8 that the operator must measure or estimate all quantities of gas flared and vented, including those that are deemed unavoidably lost, and report these quantities to ONRR.

(ii) Avoidable Losses of Gas

Under proposed § 3179.4(b), all losses of gas not specifically found to be unavoidable would be considered avoidable. Proposed § 3179.5(a) would subject all avoidably lost gas to royalties. One key consequence of this proposal is that royalties would apply to associated gas flared from a development well that is already connected to capture infrastructure.

The BLM believes that where operators are connected to capture infrastructure, but are nevertheless flaring, they have made an economic choice to flare, and flaring in those instances should not be considered an unavoidable consequence of oil production. Most flaring at wells already connected to pipelines occurs when wells are bumped off the pipeline due to pressure or capacity constraints, or when downstream equipment is brought down for maintenance. Where wells are already connected to gas capture infrastructure, midstream companies and operators have presumably already found that gas capture pays for itself. Nonetheless, operators may choose to expand production beyond the capacity of existing capture infrastructure, or to do so faster than capture infrastructure can be expanded (where capacity issues can be addressed with installation of additional compression, the rate of expansion is often in the operator's control). This may be a rational business decision for an operator, but with better planning or more deliberate development, both the oil and gas resources could be developed without waste.

Further, operators may be able to use alternative on-site gas capture equipment to put the gas to productive use during any period in which gas production exceeds transport capacity. Similarly, when downstream equipment is temporarily brought down for maintenance, operators could curtail production for a short period or use on-site capture equipment to avoid wasting gas in the interim.

(f) Alternative and Additional Approaches

The BLM considered, but did not include in the proposed rule text, a range of supplemental or alternative approaches to the flaring limit and royalty provisions described above. For example, one alternative approach that BLM considered for increasing capture of associated gas was to rely solely on royalties on flared gas to discourage flaring. Under this approach, all flaring of associated gas would be presumptively subject to royalties. Similar to the current standard under NTL–4A, operators could then obtain an exemption to the requirement to pay royalties by showing that a requirement to conserve the gas would cause the operator to cease production and abandon significant recoverable oil reserves. To support such a claim, the operator could be required to provide: The projected costs of each technically viable method of capturing and/or using the gas (including, if applicable, pipelines, removal of NGLs, CNG, LNG, and electricity generation); the current return on investment for the oil and gas operation on the lease; the projected return on investment for the oil and gas operation if some or all of the gas were captured; projected oil and gas prices and production volumes; the location and capacity of the closest pipelines; and other relevant information. In making the determination, the BLM would consider the costs of capture, and the costs and revenues of all oil and gas production on the lease.

While market-based mechanisms, such as royalty imposition, can be highly effective policy instruments, and we do propose to charge royalties on gas flared above the 1,800 Mcf/month limit because we believe flaring above that level is avoidable, we do not believe that royalties on flared gas alone would curtail flaring. At current gas prices, oil prices, and royalty rates, applying royalties to flared gas does not provide a sufficient incentive for operators to invest in gas capture to any appreciable degree. This is evident in areas such as Carlsbad, New Mexico, where most operators are currently paying royalties on associated gas that is flared, and in spite of those payments, rates of flaring have not changed appreciably since 2013. The BLM would not expect the imposition of royalties at the current royalty rate to lead to a significant increase in gas capture as long as the economic return on the oil production is substantially higher than the economic loss from the flared gas. The BLM requests comments on this conclusion.

A more significant royalty-based approach to flaring would be to apply a higher royalty rate to all production from a lease on which the operator is routinely flaring gas from development wells. This concept is discussed in more detail in Section V.C. of this preamble.

Another alternative to the proposed approach to flaring would be to distinguish between new and existing wells. The current proposal applies the same flaring requirements to both. The BLM is, however, considering including a complete prohibition on routine flaring of associated gas from new development wells. This approach would shift the burden of flaring from the public, which currently absorbs the costs of flaring, to operators, which have greater capacity to anticipate and plan for capture infrastructure to be ready at the time they shift from exploration to development in a given field. The BLM requests comment on this approach.

Finally, the BLM is requesting comment on other innovative approaches to reduce wasteful flaring and determine when flaring should be subject to royalties. In evaluating alternative approaches suggested in comments, we would consider a variety of factors, including the approach's effectiveness in: Increasing gas capture; reducing waste and compensating the public through royalties; enhancing regulatory clarity and transparency; reducing uncertainty for operators; minimizing inconsistency across BLM offices; minimizing cost, paperwork, and any other burdens on operators; minimizing administrative burden on the BLM; increasing overall practical workability; and satisfying existing legal authorities.

2. Leaks

(a) Estimates of Quantities of Gas Leaked

As discussed in detail in the RIA, using data from the EPA GHG Inventory, we estimate that about 4.35 Bcf of natural gas was lost in 2013 as a result of leaks or other fugitive emissions from various components, including valves, fittings, pumps, storage vessels and compressors on well site operations on BLM-administered leases.[231] This quantity of gas would supply nearly 60,000 homes each year.[232]

(b) Technologies and Practices To Reduce Leaks

Multiple studies have found that once leaks are detected, the vast majority of them can be repaired at low enough cost that the captured gas provides a positive return to the operator. For example, the Carbon Limits study found that 97 percent of the total leak rate could be repaired with a positive return, even at low producer gas prices of $3 per Mcf.[233] Further, over 90 percent of gas leak emissions are from leaks that could be repaired with less than a 1-year payback period.[234] Given that leak *repair* is generally economical, the key question is how the cost of leak *detection* compares with the value of the gas that could potentially be saved by repairing leaks.

The term ''Leak Detection and Repair'' (LDAR) refers to both the practices and programs that operators put in place to inspect for and repair leaks, and the specific technologies and methods the operators use to detect leaks during inspections. Recent technological developments have reduced the cost of leak detection while simultaneously improving operators' ability to detect less obvious leaks. Traditional methods coupled with new technology can also be effective.

States are beginning to take advantage of these new technologies. Colorado, for example, requires instrument-based emission monitoring as part of an LDAR program that applies to well production facilities and compressor stations.[235] Also, Wyoming has regulations that require operators in the Upper Green River Basin nonattainment area to develop LDAR programs if their facilities emit more than an estimated 4 tons of VOCs each year.[236]

(i) Auditory, Visual, and Olfactory (AVO) Method

The AVO method consists of physically inspecting the facilities—looking, listening, and smelling for leaks. AVO inspections have traditionally been the backbone of an inspection program, and BLM inspectors typically use this method when inspecting well and facility sites. The use of AVO inspections is most effective in detecting obvious and significant emissions-release events, resulting in the cost-effective reduction of high-volume leaks. The BLM believes AVO is affordable for the many small operators that only operate a few well sites each. Costs associated with the AVO method are largely for labor, paying for qualified technicians and their mileage to and from the well or facility sites.[237] AVO inspections are not, however, very effective at catching smaller or less obvious leaks, which can be a source of significant wasted gas.

(ii) Portable Analyzers

Portable monitoring instruments or portable analyzers detect hydrocarbon leaks from individual pieces of equipment. These analyzers may use any of a variety of methods of detection, including catalytic ionization, flame ionization, photoionization, infrared absorption, and combustion, and they are generally used only to detect and measure the quantity of a single component of the vapor, such as methane. These analyzers are sensitive and can detect emissions at extremely low concentration levels. Typical portable analyzers range in cost from $3,000–$12,000.[238]

One standard approach for using portable analyzers is ''Method 21,'' the EPA's method for detecting VOC emissions from leaking equipment.[239] Method 21 provides the specifications and performance criteria that must be used under EPA's regulations to detect leaks using portable analyzers.

(iii) Optical Gas Imaging (Infrared Camera)

A newer technology that operators and inspectors are increasingly using for leak detection is optical gas imaging (OGI). OGI uses infrared detectors (commonly called ''infrared cameras'') to provide visual images of gas emissions in real time. The OGI instrument can be used to monitor a wide range of oilfield equipment and its effectiveness as a means for detecting leaks is widely recognized.

OGI costs more than AVO approaches, but it also detects more leaks, which can result in additional gas savings. The GAO noted that infrared cameras allow users to rapidly scan and detect vented gas or leaks across wide production areas. The GAO specifically recommended that the BLM consider the expanded use of infrared cameras, where economical, to improve reporting of emission sources and to identify opportunities to minimize lost gas.[240] In its recent proposed rule, EPA also notes the advantages of OGI compared to a portable analyzer.[241] Several studies discussed in EPA's white paper on leak detection estimated that OGI can monitor 1,875–2,100 components per hour.[242] In comparison, the average screening rate using a portable analyzer is roughly 700 components per day.[243] Although EPA noted that these studies may underestimate the amount of time necessary to thoroughly monitor for fugitive emissions using OGI instruments, EPA stated that it still believes that the use of OGI can reduce the amount of time (and therefore the cost) necessary to conduct fugitive emissions monitoring, because multiple fugitive emissions components can be surveyed simultaneously.[244]

Infrared cameras have high capital costs, and they also require calibration, maintenance, and training. As a result, while some operators purchase and operate this equipment themselves, others contract with specialized firms for leak detection surveys using this equipment. For example, the equipment may cost from $85,000 to $100,000 or more, with packages that include many peripherals costing upwards of $125,000. Batteries, chargers, and other required peripherals can add $5,000 to $10,000. Service provider rates may be in the range of $500 per day to $2,000 per week, while annual service contracts may range from $5,000 to $10,000.[245] Calculated on an individual facility basis, another study found that the average cost of hiring an external service provider to conduct a leak survey and provide a report is: $400 per individual well site (with a single well); $600 per single well battery, which includes additional equipment on site; $1,200 per multi-well battery; and $2,300 per compressor station.[246] The BLM has also received information from external service providers indicating that costs can be substantially lower than these, and we request comment on this point.

[231] RIA at 19.

[232] Based on an estimate of 74 Mcf of gas used per household per year. See footnote 2.

[233] Carbon Limits, 16.

[234] Carbon Limits, 16.

[235] Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9, Section XVII.F.

[236] Wyoming Operational Rules, Drilling Rules Section Ch. 8, Section 6(g), *available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.*

[237] API, 2014.

[238] API, 2014.

[239] 40 CFR part 60, App. A–7.

[240] GAO–11–34 (Oct. 2010) at 34.

[241] 80 FR 56593, 56634.

[242] Ibid.

[243] Ibid.

[244] Ibid.

[245] API, 2014.

[246] Carbon Limits, 14, 32.

Studies and some operators' experiences indicate that LDAR programs based on the use of infrared cameras actually save operators money overall, while substantially reducing waste. For example, the Carbon Limits study found that because leaks are not evenly distributed across all facilities, not every leak survey finds leaks and saves money for the particular operator. But when considered across a broader set of facilities (such as those located on BLM-administered leases or a set of facilities owned by a single operator), the study found that these programs have either cost-neutral or positive returns on average, depending on the type of facility surveyed.

Specifically, the Carbon Limits study found that for well sites and groups of wells, about one-third of the facilities had no detectable leaks, 7 percent had leaks above 500 Mcf per year, and the remainder had leaks of less than 500 Mcf per year. (To put this number into perspective, a typical home uses 74 Mcf of gas a year.[247]) For compressor stations, roughly 10 percent had no leaks, while almost 25 percent leaked at 500 Mcf per year or more.

When aggregated across a larger group of facilities, rather than being evaluated on a facility-by-facility basis, the Carbon Limits study found that these infrared camera leak surveys produce net cost savings.[248] Broken down by facility type, it found that surveys at well sites are cost-neutral measured on a ton of avoided CO_2-e basis, and that surveys at compression stations produce net savings. Specifically, on average, the net present value (NPV) of applying LDAR to an individual well site or well battery was a loss of $35, assuming recovered gas at $4 per Mcf. The average cost saving across all compressor stations surveyed was $3,376. Moreover, the authors note that most of the facilities in the study were Canadian facilities that are already inspected for leaks every 1 to 2 years, and thus the current leak rates—and, consequently, proceeds from repairs—at U.S. facilities without leak inspection programs would be expected to be higher.[249]

(iv) Continuous Emissions Monitoring Systems and Other New Technologies

Another possibility for leak detection is continuous emissions monitoring. Continuous Emissions Monitoring Systems (CEMS) are commonly used as a means of monitoring various components of a large industrial source's emissions stream, including oxygen, carbon monoxide and carbon dioxide, for compliance with EPA or State air emissions standards. More recently, researchers have been evaluating the possibility of adapting the technology for use in identifying leaks in and around oil and gas operations.[250] Due to the dispersed nature of potential leaks within the area of concern (compared to the concentrated gases in a flue gas stream), challenges remain in developing a CEMS (standalone or mobile) that has the requisite sensitivity to detect leaks under a variety of atmospheric and field conditions. One possibility is to use a CEMS as an area monitor for fugitive emissions, which would then alert the operator for the need to use a more focused leak detection device to pinpoint the leak needing repair. Research is continuing to determine if CEMS could supplement or be a viable alternative to current leak detection instruments.

There is also extensive ongoing work to develop other, more effective and less costly advanced leak detection technologies. For example, DOE initiated an effort to advance methane-sensing technologies through the Advanced Research Projects Agency—Energy (ARPA–E) MONITOR (Methane Observation Networks with Innovative Technology to Obtain Reductions) program.[251] In December 2014, this $30-million, 3-year program announced support for 11 new projects that are developing low-cost, highly sensitive systems that detect and measure methane associated with the production and transportation of oil and natural gas.[252]

(iv) LDAR Programs

An effective LDAR program depends not just on the technology used to detect leaks, but also on the overall approach an operator uses to inspect for leaks, conduct preventative maintenance, and repair leaks that are found. Two of the largest operators in one of BLM's field offices conduct routine operations checks, which typically use AVO inspection methods. In addition to well site inspections, a preventative maintenance program is often used. Adherence to a properly designed preventive maintenance program proactively minimizes equipment failures and gas losses from leaks. In general, a maintenance program may consist of a variety of activities that are applicable to operating location, type of operations, and equipment used. An operator will design the preventive maintenance program that is most suitable for the site. These efforts include periodic inspection (AVO inspection and general equipment inspection on at least a monthly basis) and service of components that are not leaking, material selection appropriate to service (*i.e.,* alloys, gaskets, filters, etc. that are wear and/or leak resistant), active corrosion monitoring, the application of corrosion and scale inhibitors, use of maintenance records to identify components at risk of failure, and pre-emptive replacement of at-risk equipment.[253]

For example, one major operator in northwest New Mexico, which oversees 10,000 wells in the San Juan Basin, has its lease operators visit each well site each week.[254] The visits are tracked using GPS, which is installed in each truck.[255] According to the operator, any leaks are fixed within days, new facilities are leak-tested prior to production, and most wells have Remote Terminal Units installed, which monitor gas flow rate and volume, static pressure, differential pressure, temperature, controller settings, plunger arrivals/rod pump status/compressor status and both oil and water tank levels.[256] The data flow via solar-powered telemetry at 1-minute intervals. Alarms are triggered if there are sudden pressure changes or tank level drops, and a lease operator can be dispatched to the well site to investigate.[257]

(c) Proposals To Reduce Waste From Leaks—Leak Detection and Repair Programs

The BLM believes that LDAR programs are a cost-effective means of reducing waste of gas in the oil and gas production process, based on the State programs, studies, and findings discussed above. Thus, the BLM is

[247] See footnote 2.

[248] Carbon Limits. The study increased the cost estimates by 50 percent to account for the internal costs to a firm of arranging for this work, and it assumed a 7 percent discount rate and $4 per Mcf value of gas.

[249] Ibid.

[250] Briefing from Dr. Bryan Wilson, Program Director, Advanced Research Projects Agency—Energy on O&G emission projects the agency is funding, August 3, 2015.

[251] ARPA–E, *http://arpa-e.energy.gov/?q=arpa-e-programs/monitor.*

[252] Briefing from Dr. Bryan Wilson, Program Director, Advanced Research Projects Agency—Energy on O&G emission projects the agency is funding, August 3, 2015.

[253] API, June 13, 2014. Re: EPA VOC/Methane White Paper on Oil and Natural Gas Sector Leaks. Pages 7–9.

[254] Phone conversation with Conoco Phillips on San Juan Basin operation, February 2015.

[255] Phone conversation with Conoco Phillips on San Juan Basin operation, February 2015.

[256] Phone conversations with Conoco Phillips and WPX energy on San Juan Basin operations, February 2015.

[257] Ibid.

proposing under §§ 3179.301 through 3179.305 to require that each operator on a Federal or Indian lease institute an LDAR program that meets specified standards for detection methodology, frequency, and leak repairs, and use this program to inspect each of the operator's well sites and compressor locations.

The BLM's proposed approach, outlined below, is similar to the requirements adopted by Colorado and Wyoming. EPA's proposed regulations to reduce methane emissions from the oil and gas production sector also include fugitive emission requirements, which would apply to certain new and modified oil and gas production facilities. Specifically, the EPA's September 18, 2015 proposal, if finalized, would require that new, reconstructed, and modified well sites and compressor stations conduct regular (semi-annual, annual, or quarterly) fugitive emissions surveys using optical gas imaging technologies.[258] As both agencies have worked to develop their proposed rules, we have shared technical information and communicated extensively. We share the goal of aligning the final requirements for LDAR in the two rules to the maximum extent practicable. At minimum, we would seek to ensure that operators could develop a single LDAR program that meets the requirements of both agencies. We will continue to focus on this issue over the course of the rulemaking process, and we request public comment on how best to achieve this goal.

(i) LDAR Options in the Proposed Rule

The BLM proposes under § 3179.302 to require that operators use an instrument-based approach to leak detection. Advances in OGI leak detection technology, in particular, now allow for affordable detection of more, smaller, and less accessible leaks, compared to what would be identified through a pure AVO approach. Both Colorado and Wyoming require operators to use an instrument-based approach.[259] In the EPA 40 CFR part 60 subpart OOOOa rulemaking, OGI is the proposed technology for detecting fugitive emissions.

The BLM believes that optical gas imaging is currently the most effective instrument for leak detection, but infrared cameras may be more expensive than portable analyzers, which are also reasonably effective in certain situations. As infrared cameras are used more commonly, and the capacity to conduct infrared-based surveys increases, the BLM believes that the economics of this method will become increasingly favorable for identifying leaks at a wide variety of operations. At present, however, infrared cameras are most cost-effective when used to inspect large numbers of facilities. Thus, the BLM believes it is appropriate to require an infrared camera-based program for operators with larger numbers of wells, and to allow operators with fewer wells to use portable analyzers instead.

The BLM also seeks to account for advances in continuous emissions monitoring technology, and also for other advances in leak detection technologies, which may result from ongoing technology development efforts such as the DOE ARPA–E MONITOR program. We believe it is important to ensure that operators be allowed to take advantage of any new, more effective, and less expensive technologies, as they become available. Accordingly, the BLM is proposing to require, under § 3179.302(b), that operators that have 500 or more wells within a BLM field office jurisdiction must use one of the following three approaches to LDAR: (1) An optical gas imaging device like an infrared camera; (2) A new, equally advanced and effective monitoring device, not yet developed and therefore not listed in the rule text, which the BLM would review and approve for use by any operator;[260] or (3) A comprehensive LDAR program, approved by the BLM, that includes the use of instrument-based monitoring devices. The standard for approval of options (2) and (3) would be a BLM determination that the alternative device or program meets or exceeds the effectiveness for leak detection of an optical gas imaging device used with the frequency specified in proposed § 3179.303(a).

Operators with fewer than 500 wells located within a single BLM field office's jurisdiction could use any of these three LDAR approaches, but they would also have the option of using a portable analyzer device, such as a catalytic oxidation, flame ionization, infrared absorption or photoionization device, operated according to manufacturer specifications, and assisted by AVO inspection.

The BLM requests comment on the above LDAR proposal. In particular, comments should address the appropriateness of requiring the use of optical gas imaging devices in some or all circumstances. We request data and comment on the appropriateness of using the 500-well threshold to identify those larger operators for whom the economics of these devices may be more favorable, whether optical gas imaging is cost-effective for operators with a smaller number of wells, and should therefore be required for all operators.

Further, the BLM requests comment on whether the above suite of options for LDAR (three options for large operators, four for smaller operators) is reasonable to allow operators flexibility to design and implement leak detection programs that work for them, while still setting sufficiently rigorous minimum standards to ensure that all such programs are comprehensive and effective. In particular, we request comment on whether the standard for BLM approval of an alternative approach (that it meets or exceeds the effectiveness of an optical gas imaging device used at the frequency specified in proposed § 3179.303(a)) provides sufficient guidance to the BLM, and whether the standard would result in adequate consistency across field offices.

The BLM is also proposing under § 3179.302(a)(4) that operators who choose to use portable analyzers would be required to use them according to manufacturers' specifications. The EPA's Method 21, discussed above, is one specific method for ensuring that portable analyzers that are capable of detecting fugitive emissions (or leaks) are used in a manner that produces accurate results. The BLM is not proposing to require the use of Method 21. The BLM requests comments on: (1) Whether this rule should require the use of Method 21 if an operator chooses to use a portable analyzer; (2) The adequacy of manufacturers' use specifications to produce accurate results regarding the presence or absence of a leak; and (3) Whether there are other use protocols for portable analyzers that produce accurate results for leak detection purposes.

The BLM also requests comment on whether the regulations should include a threshold volume of gas that will be deemed a leak with respect to gas losses detected by portable analyzers, and if so, what that threshold volume should be. In contrast to optical gas imaging, portable analyzers are so sensitive that, at the lowest measured levels, it may be difficult to tell whether the analyzer is detecting a leak or simply registering background levels of the measured gas. The BLM requests comment on whether it should provide that a release of gas

[258] 80 FR 56593, 56611–56614.

[259] Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9, Section XVII.F.3; Wyoming Operational Rules, Drilling Rules Section Ch. 8, Section 6(g).

[260] The BLM could provide notice to all operators that it had found that a specified new technology would satisfy these requirements.

would be considered a leak if the detected concentration were 500 ppm or more above the measured background levels. This would be consistent with the EPA's proposed approach, which provides that a leak would be considered repaired if a portable analyzer, used according to Method 21, indicates concentrations less than 500 ppm above background levels.

(ii) Frequency of LDAR Inspections

Another key element of an effective LDAR program is to define the frequency of inspections. Colorado bases its frequency-of-inspection requirement on the level of estimated uncontrolled emissions from storage vessels or the potential to emit VOCs from all facility components.[261] Inspection frequency can vary from monthly to annually depending on the magnitude of the emissions.[262] Wyoming simply requires quarterly inspections.[263]

Multiple studies have found that a relatively small percentage of facilities are responsible for the majority of leaks and for most of the wasted gas (this is known as a ''fat-tail'' problem).[264] If some operators, in fact, experience proportionally fewer leaks than others, this would support allowing the frequency of periodic screening to vary depending on the operator's past history of leak detections. Based on experience in the field, the BLM believes that there are systematic differences among operators' leak rates, but we understand that some recent studies indicate that leak rates are random.[265]

Increasing survey frequency allows more leaks to be found, but also increases costs. Accordingly, the BLM aims to establish an approach to survey frequency that reduces the most waste at the lowest cost. The Carbon Limits study analyzed the impact of survey frequency by analyzing over 400 annual surveys.[266] This study found that annual or semi-annual (twice-yearly) surveys generally resulted in net benefits to the operator—the benefits of leaks avoided exceeded the costs of the surveys—whereas quarterly or more regular surveys imposed net costs on the operator—the costs of the frequent surveys outweighed the benefits of leaks avoided. This study supports starting with a frequency of annual or semi-annual surveys. We request data and comment on the data, methodology, and analysis used in this study.

Thus, the BLM is proposing under § 3179.303 to require all operators to conduct semi-annual surveys of their sites—defined in proposed § 3179.303 to mean a discrete area suitable for inspection in a single visit and containing wellhead equipment, compressors, and facilities[267] (which would include, for example, separators, heater/treaters, and liquids unloading equipment). If an operator finds no more than two leaks at a site for two consecutive inspections, it may change to annual inspections at that site. If the operator is inspecting semi-annually and finds three or more leaks at a site for two consecutive inspections, it must inspect quarterly. The quarterly rate would continue unless and until an operator finds no more than two leaks in two sequential inspections, at which point it could revert back to twice-yearly inspections. On the other hand, if the operator is inspecting semi-annually and finds no more than two leaks for two consecutive inspections, the operator may reduce the frequency of inspections to once per year, unless and until it finds more than two leaks for two consecutive inspections, which would require it to revert back to semi-annual inspections.

The BLM has proposed three or more leaks at a site as the threshold for increasing the frequency of inspections, and two or fewer as the threshold for decreasing the frequency of inspections, as a possible way to distinguish between sites with very little loss from leaks and sites with more significant leak problems. The BLM requests comment on whether these are the appropriate numbers of leaks to use as thresholds, and if not, what the threshold levels should be.

Once a leak is identified, the BLM proposes under § 3179.304 that the operator would be required to repair the leak as soon as practicable, but no later than 15 calendar days after discovery, unless there is a good cause necessitating a longer period. The BLM believes that a ''good cause'' for a longer period would be something that prevents the operator from repairing the leak within the 15 calendar day period and that the operator could not reasonably have prevented. Examples of potential good cause for a longer period include the unavailability of a needed part or severe weather conditions that prevent safe access to the site. Preferred scheduling for maintenance would not be an example of good cause for delay in leak repair. If a delay in repair is attributable to good cause, the operator must notify the BLM of the cause and must complete repairs within 15 calendar days after the cause of delay ceases to exist. The BLM proposes to require operators to verify the effectiveness of a repair within 15 calendar days after completion using the same leak detection method used to find the leak.

The BLM proposes under § 3179.305 that operators be required to keep and make available to inspectors records documenting the dates of leak inspections, the sites where any leaks are found, and a description of each leak. Operators would also need to record when leaks were repaired, and the dates and results of follow-up inspections to verify the effectiveness of the repairs.

The BLM is aware that some well sites and compressor stations could be subject to both the fugitive emission requirements of the proposed EPA rule and the requirements of the proposed BLM rule. In addition to our request for comments discussed above, regarding further alignment of the BLM rule and the EPA rule, we are proposing that an operator may demonstrate to the BLM that it is complying with the EPA LDAR requirements in lieu of the BLM LDAR requirements, for some or all of the operator's sites. We specifically request comment on this element of the proposal, including whether it would help to reduce the compliance burden on operators, whether it could compromise program effectiveness in any way, and whether it may present challenges for BLM and EPA to administer and enforce. The BLM expects that the LDAR requirements ultimately adopted by the EPA for new and modified well sites would be as effective in minimizing the volume of gas lost through leaks as the final BLM requirements, and we should be able to confirm this expectation prior to finalizing this proposed provision.

(iii) Possible Alternatives to the Proposed LDAR Provisions

In addition to the BLM's proposed approach, we are taking comments on other possible approaches to reducing waste through LDAR requirements.

[261] Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9 at Section XVIII.F.3.

[262] Ibid.

[263] Wyoming, Nonattainment Area Regulations Ch. 8 (June 2015), Section 6(g), *available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.*

[264] See Zavala-Araiza, et al., *Reconciling divergent estimates of oil and gas methane emissions,* Proceedings of the National Academy of Sciences, vol. 112, no. 51, at 15600 (Dec. 22, 2015

[265] Ibid.

[266] Carbon Limits.

[267] Note that the BLM has proposed to define ''facility'' in part 3170 as ''(1) A site and associated equipment used to process, treat, store, or measure production from or allocated to a Federal or Indian lease, unit, or CA that is located upstream of or at (and including) the approved point of royalty measurement; and (2) A site and associated equipment used to store, measure, or dispose of produced water that is located on a lease, unit, or CA.'' 80 FR 40767 (July 13, 2015).

These include variations on the proposed approach, an alternative approach suggested by a stakeholder, and an alternative method of establishing the inspection frequency.

One small variation on the proposed LDAR approach would be to require that LDAR inspections be conducted by third parties. Requiring third parties to conduct inspections could provide additional assurance that surveys are conducted effectively and produce accurate results. While some operators conduct their own inspections, many already contract with third parties that provide the equipment, trained operators, and detailed reports. The BLM acknowledges, however, that third-party contracting might in some instances be more costly and might prove unnecessary for operators that have their own equipment and substantial in-house expertise. A variation on this option would require periodic third party inspections as a means of confirming the efficacy of an operator's internal leak detection program, while still allowing most inspections to be conducted in-house, if an operator so chooses. For example, the BLM could require that operators contract with a third-party to perform at least one annual or biannual inspection. The BLM requests comments on these options.

A second possible variation would be to constrain approval of alternative leak detection approaches. For example, the BLM could limit authorization of alternatives to new technologies and devices, rather than new detection programs. (That is, the final rule could eliminate proposed § 3179.302(a)(3).) Another approach would be to limit authorization for an alternative leak detection program under proposed § 3179.302(a)(3) to operators that already have an effective program in place as of the effective date of this rule. That approach would reward operators that proactively invest in leak detection, but would require operators that do not make that proactive investment to comply with the standards established in the regulation. The BLM requests comment on these variations.

A third possible variation would be to focus operators' LDAR efforts on higher production wells. For example, a stakeholder suggested that the BLM could require the development of an LDAR program at those wells in the top 75 percent of an operator's inventory, in terms of production volume, and address storage vessels separately. Under this suggested approach, the operator would be required to conduct an initial survey of its top-producing wells, and would then design an appropriate leak detection program, with a specified frequency based on the results of that survey.

Others have suggested modifying or waiving the LDAR requirements for stripper wells—a specific category of low-yield wells producing 15 bbl of oil-equivalent per day or less. In its 40 CFR part 60 subpart OOOOa rulemaking, for example, EPA proposed that new and modified wells producing 15 bbl of oil-equivalent per day or less be exempted from the LDAR requirements, or allowed to inspect less frequently, such as annually or on a one-time basis. Presumably, modifying the LDAR requirements for stripper wells relies on an assumption that the amount of leaked methane correlates with well production, and therefore frequent LDAR is not a cost-effective means of reducing methane emissions from low-producing wells. In addition, proponents of this approach assert that LDAR requirements for marginal wells would disproportionately impact small businesses.

This rulemaking does not propose a modified standard for stripper wells, because 85 percent of oil wells and 73 percent of gas wells on Federal and Indian leases meet the definition of stripper wells.[268]

Thus, while reducing the frequency of leak detection inspections for stripper wells might decrease the costs of the leak detection requirement, we believe that approach would negate most of the expected benefits of the LDAR requirement for existing leases on Federal and Indian lands.

Moreover, the factual record available to the BLM indicates that requiring leak detection at stripper wells would produce significant gas savings. Recent studies do not support the suggestion that leak rate correlates with yield. Rather, these studies suggest that even low-yield wells can leak at significant rates.[269] Based on these studies, DOI does not believe it is appropriate to exclude low-yield wells from any instrument-based inspection requirement, or to allow those wells to be inspected less frequently.

Establishing a separate standard for stripper wells also would not align the proposed BLM requirements with the proposed EPA requirements. The EPA's standard for stripper wells applies only to new or modified wells that come online as stripper wells, not to wells that initially produce at higher rates, but eventually decline to stripper status. Based on our experience in the field, we believe that a very small number of wells would qualify for a relaxed standard under the EPA proposal. In our experience, most new wells produce at rates higher than 15 barrels-of-oil-equivalent per day, because operators are unlikely to invest in completing newly drilled wells that produce at very low rates.

Many of the stripper wells producing from Federal and Indian leases are existing wells that once produced at higher rates, but have declined to stripper status, and they therefore would not qualify for the EPA's LDAR standards for stripper wells. Thus, although the BLM recognizes the importance of harmonizing this rule with EPA's proposed 40 CFR part 60 subpart OOOOa rulemaking, establishing a different LDAR standard for existing stripper wells on Federal or Indian leases would not, in fact, advance that goal.

Another alternative approach to the proposed LDAR requirements would be to retain all of the elements of the proposed approach, except the basis for setting the required frequency of inspections. Specifically, rather than having the frequency vary based on the results of previous surveys, the inspection frequency would be set based on the type of facility being inspected. As noted previously, Colorado uses this method, with frequencies that range from monthly to one-time, depending on the type of facility and the level of uncontrolled VOC emissions.

One simplification of the Colorado approach would be to focus on sites with vibrating equipment or storage vessels. Industry stakeholders have stated that they find most leaks at sites with equipment that vibrates (*e.g.,* compressors), and at sites with storage vessels. Thus, requiring more frequent inspections at sites with those characteristics, and less frequent inspections at other sites, might be a way to increase the cost effectiveness of the LDAR program by targeting inspections to the sites most likely to produce the largest losses through leaks.

A different simplification of Colorado's system would be to distinguish between gas wells and oil wells, requiring more frequent inspections at gas wells and less frequent inspections at oil wells. EPA's emissions factors indicate generally higher volumes of fugitive emissions

[268] U.S. Energy Information Administration. United States Total 2009 Distribution of Wells by Production Rate Bracket, available at *http://www.eia.gov/pub/oil_gas/petrosystem/us_table.html.*

[269] See Zavala-Araiza et al., *Reconciling divergent estimates of oil and gas methane emissions,* Proceedings of the National Academy of Sciences, vol. 112, no. 51, at 15600 (Dec. 22, 2015).

from gas wells, compared to oil wells.[270] Assuming these emissions factors are accurate, this indicates that focusing more inspection resources on gas than oil wells would identify and save a relatively larger volume of gas at roughly the same cost.

(iv) Requests for Comments on LDAR Alternatives

The BLM requests comment on all of the LDAR variations discussed above. In particular, the BLM requests comment on:

- The initial frequency of surveys;
- Requiring more frequent surveys, such as quarterly;
- The concept of changing inspection frequency depending on the operators' record of past leaks;
- The triggers for increasing and decreasing inspection frequency (*e.g.,* whether finding a certain number of leaks is the appropriate trigger for changing inspection frequency); and
- Whether the frequency of inspections should be the same across all of the sites on a lease, and if so, how to operationalize that requirement.

In connection with any comments related to modifying the inspection frequency for stripper wells, the BLM specifically requests submission of data regarding the relationship between well production and levels of leaked methane from a well site. The BLM also requests comment on whether it should require gas wells to be inspected quarterly and oil wells annually. While there is substantial uncertainty in the cost-benefit analysis of these provisions, with certain simplifying assumptions, the analysis indicates that this alternative approach could increase net benefits, compared to the proposed approach. As detailed in the RIA, the projected annual net benefits for a semi-annual inspection requirement for all wells range from $19–48 million, with the range largely depending on the year, compared to annual net benefits of $3–43 million (again largely depending on the year) with quarterly inspections for gas wells and annual inspections for oil wells.[271]

In addition, the BLM requests comment on simply requiring semi-annual or quarterly inspections for all well sites, facilities, and compressor stations subject to the LDAR requirements, with no mechanism to increase or decrease inspection frequency based on how many leaks are found. A quarterly inspection requirement would track the Wyoming approach for the Upper Green River Basin. Requiring semi-annual or quarterly inspections for all sites would reduce the potential confusion of inspection frequencies that vary over time and across an operator's well sites. Tracking the required frequency for each discrete leak inspection site could be burdensome and prone to error and confusion. Requiring quarterly inspections would also maximize the gas savings from avoided leaks, although it would have higher costs than the other approaches discussed here. As with setting different frequencies for gas and oil wells, this approach would not track with the EPA's LDAR requirements, assuming that the EPA finalizes its proposed approach.

The BLM also requests comment on the approach of focusing the LDAR requirement on sites with vibrating equipment or storage tanks, perhaps by requiring a one-time inspection of all sites, but quarterly inspections of sites with such equipment. Would that approach successfully target sites that are most prone to significant leaks? Would it reduce costs for operators? And finally, could it readily be enforced?

Finally, the BLM notes that many of these LDAR approaches deviate from EPA's proposed approach. The BLM requests comment on the importance and implications of aligning BLM and EPA LDAR requirements.

(v) Costs of the LDAR Provisions

Assuming that the EPA finalizes its 40 CFR part 60 subpart OOOOa rulemaking, then the BLM expects that its proposed requirements would affect up to 36,700 existing wellsites, and pose total costs of about $69–70 million per year (using 7 percent and 3 percent discount rates). These requirements are also projected to result in cost savings of about $12–15 million per year (7 percent discount rate) or $15–17 million per year (3 percent discount rate), increase gas production by 3.9 Bcf per year, and reduce VOC emissions by 18,600 tpy. We estimate they would reduce methane emissions by 67,000 tpy, producing monetized benefits of $73 million per year in 2017–2019, $87 million per year in 2020–2024, and $100 million in 2025 and 2026. Thus, we estimate that these provisions would result in net benefits of $19–21 million per year in 2017–2019, $31–35 million per year in 2020–2024, and $43–48 million in 2025 and 2026.[272] We request data and comment on whether this analysis fully captures the benefits of identifying and fixing high-volume leaks.

If, for analytical purposes, we assume a baseline in which EPA does not finalize its proposed LDAR requirements, we estimate the following impacts from our proposed LDAR requirements. We project that the proposed requirements would affect up to about 37,000–38,000 wellsites per year, and pose total costs of about $70–71 million per year (using 7 percent and 3 percent discount rates). These requirements are also projected to result in cost savings of about $12–18 million per year (using 7 percent and 3 percent discount rates), increase gas production by 3.9–4.0 Bcf per year, and reduce VOC emissions by 19,000 tpy. We estimate they would reduce methane emissions by 68,000 tpy, producing monetized benefits of $75 million per year in 2017–2019, $88 million per year in 2020–2024, and $102 million in 2025 and 2026. Thus, we estimate that these provisions would result in net benefits of $19–21 million per year in 2017–2019, $30–35 million per year in 2020–2024, and $43–48 million in 2025 and 2026.[273]

As noted, some operators reportedly already have leak detection programs in place. To the extent that these operators currently have LDAR programs that are approved by the BLM, the actual impacts of this proposal would be lower than these estimates.

3. Pneumatic Controllers and Pneumatic Pumps

Pneumatic controllers are automated instruments that control certain processes or conditions, such as liquid level, pressure, and temperature in oil and gas production, treatment, storage, and handling operations. Pneumatic controllers are operated by gas pressure, and the gas is emitted from the device when the device is active. Some types of controllers ''bleed'' gas continuously as part of their normal operations, while others emit gas intermittently. While these controllers can operate using any pressurized gas, for the purposes of this proposed rule, the term pneumatic controller means an instrument that is operated by natural gas pressure and emits natural gas.

Pneumatic pumps of different varieties are commonly used in oil and gas production and treating operations. For example, gas-assist glycol dehydrator pumps are used to circulate glycol in dehydrators. Chemical injection pumps are used to pump chemicals down a well to facilitate production or into a pipeline to prevent

[270] 80 FR 56593, 56635.

[271] RIA at 113.

[272] RIA at 109.

[273] RIA at 108–109.

freezing. Diaphragm pumps are used to move larger volumes of liquids, such as to circulate heat trace medium at well sites during cold winter conditions, or to pump out sumps. Similar to pneumatic controllers, pneumatic pumps can operate on gas pressure and emit that same gas from the pump. For the purposes of this proposed rule, the term pneumatic pump means a pump that is operated by natural gas pressure and emits natural gas.

(a) Estimates of Gas Released From Pneumatic Controllers and Pneumatic Pumps

As described in the RIA, using data from the EPA GHG Inventory, we estimate that about 5.4 Bcf of natural gas was lost in 2013 from pneumatic controllers on BLM-administered leases.[274] That volume includes releases from high bleed continuous controllers, low bleed continuous controllers, and intermittent controllers. Using prevalence data from the EPA and an analysis of EPA GHGRP data conducted by ICF, we estimate that there are 18,150 high bleed pneumatic controllers on BLM-administered leases, or about 19 percent of the total number of pneumatic controllers on these leases. In addition, using data from the EPA's GHG Inventory, we estimate that about 2.5 Bcf of natural gas was lost in 2013 from pneumatic pumps on BLM-administered leases. That volume includes releases from chemical injection pumps, diaphragm pumps, and gas-assist glycol dehydrator pumps.

(b) Technologies To Reduce Quantities of Gas Released From Pneumatic Controllers and Pneumatic Pumps

Pneumatic controllers and pneumatic pumps are common equipment at well site facilities. For well sites without electrical service, gas pressure is used as a ready energy source to operate this equipment. There are several options for minimizing the amount of natural gas that is used and emitted from existing controllers and pneumatic pumps, which bear a range of associated cost and practicality considerations.

As discussed earlier in § III.I.3, in the existing EPA NSPS rule (40 CFR part 60 subpart OOOO) for the oil and gas sector, the EPA established an emissions rate of 6 scf/hour as the upper limit for new and replacement pneumatic controllers (pneumatic controllers meeting this standard are referred to as ''low-bleed'' pneumatic controllers).[275] The EPA NSPS requires new and replacement natural-gas-operated pneumatic controllers at natural gas well sites and gathering and boosting stations to meet the 6 scf/hour limit, unless a higher bleed rate is necessary for safety or to perform the designed function. The EPA NSPS requirement does not currently apply to intermittent pneumatic controllers nor to pneumatic pumps, but the EPA's proposed 40 CFR part 60 subpart OOOOa rulemaking would extend to new or modified pneumatic pumps.[276]

Existing high-bleed controllers can generally be replaced with models that use and emit less natural gas. For most applications, low-bleed controllers are available and make suitable replacements for high-bleed controllers. At facilities with a gas sales line, the replacement cost of low-bleed controllers is generally rapidly offset by gas savings. ICF identified replacement of high-bleed pneumatic controllers with low-bleed pneumatic controllers as one of the most cost-effective options for reducing methane. Specifically, ICF estimated that the replacement would save industry $2.65 per Mcf of avoided methane emissions.[277]

The State of Colorado has prohibited use of ''high bleed'' pneumatic controllers, with limited exemptions.[278] Colorado adopted the existing EPA NSPS standards for new pneumatic controllers, prohibiting operators from installing new ''high bleed'' controllers, and the State required operators to replace all existing high bleed controllers with low-bleed or no-bleed controllers by May 1, 2015.[279] The operator may request an exception on the grounds that use of a high-bleed controller is needed for safety or process purposes. As of April 2015, however, the State had not received a single request to use or keep high bleed controllers under this provision.[280]

In May of this year, the State of Wyoming adopted regulations that require operators in the Upper Green River Basin to replace high-bleed pneumatic controllers with low-bleed controllers by January 1, 2017.[281]

Another option that is available in some situations is adding electrical service (power line, generator, or solar array) and replacing pneumatic controllers and/or pneumatic pumps with electric or compressed air controllers and pumps, which do not release any natural gas. Where electrical service is available, existing pneumatic controllers and pneumatic pumps could be operated by the addition of a compressed air system. Installing a compressed air system would involve adding a compressor and tubing to connect each controller and pump to the system. Alternatively, pneumatic controllers and pneumatic pumps could be replaced by electric models. At facilities with a gas sales line, the cost of replacing electric controllers and operating the power system would be at least partially offset by sale of the gas that would otherwise have been vented through operation of the pneumatic controllers and pneumatic pumps. Natural gas could be used to generate electricity to operate electronic controllers; based on the typical number of controllers at a well site and the energy requirements of controllers, however, the BLM does not believe this is the most efficient means of completing the operational objective.

One of the more common applications of this approach is to use solar powered electric controllers and pumps to replace individual pneumatic controllers and pneumatic pumps without replacing the power system for the whole facility. Solar pumps are often used to replace pneumatic chemical injection pumps, in particular. Chemical injection pumps are smaller pumps that inject chemicals into a pipeline to, *e.g.,* to inhibit freezing, and they do not require as much power as larger pumps used in other applications. The EPA's Natural Gas STAR program cites the costs to replace a pneumatic pump with a solar-charged electric pump as about $2,000. Operating costs are minimal, and the lifespans of the solar panels and electric motors are up to 15 and 5 years, respectively. The EPA estimates potential annual natural gas savings of 183 Mcf per pneumatic pump replaced—a volume that would have a sales value of $732 (at $4/Mcf).[282]

A third option for reducing gas losses from pneumatic controllers and pneumatic pumps is to add a low-pressure collection system that would capture the natural gas emitted from pneumatic controllers and pneumatic

[274] RIA at 18.

[275] 40 CFR 60.5390.

[276] 80 FR 56593, 56610.

[277] ICF economic analysis, at 4–4 (base case assumed $4/Mcf price for recovered gas and a 10 percent discount rate/cost of capital).

[278] Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9, Section XVIII, *available at https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9_0.pdf.*

[279] Ibid. at Section XVIII.C.2.

[280] Email from Daniel Bon, Air Quality Planner, Planning and Policy, Air Pollution Control Division, Colorado Department of Public Health and Environment, to Alexandra Teitz, BLM (April 27, 2015).

[281] Wyoming, Nonattainment Area Regulations Ch. 8 (June 2015), Section 6(f), *available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.*

[282] U.S. EPA, Office of Air Quality Planning and Standards, Oil and Natural Gas Sector Pneumatic Devices Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel (April 2014) at 53.

pumps and either combust it or re-pressure and route it into the natural gas sales stream.

The State of Wyoming has adopted regulations that require pneumatic pumps used in the Upper Green River Basin to destroy or capture emissions or be replaced by zero-emission solar-, electric-, or air-driven pumps by January 1, 2017.[283]

(c) Proposals To Reduce Waste From Pneumatic Controllers and Pneumatic Pumps

The BLM believes that replacing high-bleed pneumatic controllers with low- or no-bleed controllers is a cost-effective way to reduce waste of natural gas. In most cases, this is projected to increase operators' net profits. We have heard from one company that has already voluntarily replaced all of its high-bleed pneumatic controllers because it found that the new equipment more than paid for itself within 3 to 6 months.[284] Given the EPA requirements for new pneumatic controllers and the fact that, on average, this waste-reduction measure would save companies money, the BLM believes that continued reliance on high-bleed pneumatic controllers leads to avoidable waste of public resources, except in limited situations.

Under proposed § 3179.201, the BLM would require operators to replace all pneumatic controllers that have bleed rates greater than 6 scf/hour with low-bleed or no-bleed pneumatic controllers within 1 year of the effective date of the final rule. This rule would apply only to pneumatic controllers that are not subject to the EPA regulations at 40 CFR 60.5360 through 60.5390. We request comment on whether 1 year is an appropriate amount of time for compliance, and whether we should include interim deadlines for the replacement requirement such that operators must replace certain percentages of their pneumatic controllers within specified timeframes.

In § 3179.201(b), the BLM is proposing several exemptions to the replacement requirement. Like the existing EPA NSPS, this proposed rule would allow an exception to the maximum emission rate for a pneumatic controller when the operator demonstrates, and the BLM concurs, that a higher emission rate is necessary for response time, safety, and positive actuation. The proposed rule would also provide for an exception from the replacement requirement if the requirement would cause the operator to cease production and abandon significant recoverable oil reserves under the lease. In making this determination, the BLM would consider the costs of capture, and the costs and revenues of all oil and gas production on the lease.

In addition, under proposed § 3179.201(c), the BLM would allow an operator to retain a high-bleed pneumatic controller for up to 3 years from the effective date of the final rule, if the well or facility served by the controller has an estimated remaining productive life of no more than 3 years from the effective date of the final rule. The BLM believes the 3-year threshold represents the typical payback period for a replacement controller, given an average-cost replacement device, average reduction in waste gas, and an average value for the recovered gas. We request comment on whether this extension is needed and whether it would meaningfully reduce costs for operators with wells and facilities with remaining productive lives less than 3 years from the effective date of this rule. We also request comment on whether providing this extension would increase waste of gas and make implementation of the replacement requirement more difficult, as the actual remaining productive life of a well or facility may be longer than projected. We note that neither Colorado nor Wyoming provides for such an extension.

We estimate that the proposed pneumatic controller requirements would impact up to about 15,600 existing low-bleed pneumatic devices, and pose total costs of about $6 million per year (using a 7 percent discount rate) or $5 million per year (using a 3 percent discount rate). Because the sale of recovered gas is expected to offset the engineering costs of new controllers, the BLM expects that compliance with the pneumatic controller requirements would increase gas production by 2.9 Bcf per year, result in cost savings to the industry of about $9–11 million per year (using a 7 percent discount rate) or $11–12 million per year (using a 3 percent discount rate). On net, we project that the industry would save $3–5 million per year (using a 7 percent discount rate) or $6–7 million per year (using a 3 percent discount rate) under these requirements. These requirements are also projected to reduce methane emissions by 43,000 tpy, producing monetized benefits of $48 million per year in 2017–2019, $56 million per year in 2020–2024, and $65 million in 2025 and 2026. The resulting net benefits (including the cost savings from the value of the gas) would be $53–68 million per year (using a 7 percent discount rate) or $54–73 million per year (using a 3 percent discount rate), along with a reduction in VOC emissions of about 200,000 tpy.[285]

For pneumatic chemical injection pumps, the BLM believes that in many instances the function performed by such a pump could be performed by a zero-emissions pump (typically solar) instead. The BLM believes that the replacement costs in these situations are relatively modest and would be at least partially offset by the value of the saved gas. Where a zero-emissions pump could not perform the function, but a flare is available on-site, the cost of routing the gas from either a chemical injection pump or a diaphragm pump to a flare is expected to be quite small.

Thus, the BLM is proposing under § 3179.202 to require the operator either: (1) To replace a pneumatic chemical injection or diaphragm pump with a zero-emissions pump; or (2) To route the pneumatic chemical injection or diaphragm pump to a flare. Under proposed § 3179.202(c), an operator would be exempt from this requirement if it demonstrates, and the BLM concurs, that: (1) There is no existing flare device on site, or routing to such a device is technically infeasible; and (2) A zero-emission pump is not a viable alternative because a pneumatic pump is necessary based on functional needs. An operator would also be exempt if the operator demonstrates, and the BLM concurs, that replacing the pneumatic pump(s) would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. This rule would apply only to pneumatic pumps that are not subject to the EPA regulations. As with pneumatic controllers, the BLM proposes that operators must replace pneumatic pumps or route to a flare device, subject to this proposed section, within 1 year of the effective date of the rule, or within 3 years of the effective date of the rule if the pneumatic pump serves a well or facility with an estimated remaining productive life of 3 years or less. We request comment on whether this extended time-period for replacement is needed or whether a shorter time-period would be sufficient. In Wyoming, pneumatic pump replacement is now required by regulation by January 1, 2017.[286]

[283] Wyoming, Nonattainment Area Regulations Ch. 8 (June 2015), Section 6(e), *available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.*

[284] Phone conversation with Conoco Phillips on San Juan Basin operation, February 2015.

[285] RIA at 78.

[286] Wyoming, Nonattainment Area Regulations Ch. 8, Section 6(e) (June 2015), *available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.*

If the EPA finalizes its concurrent 40 CFR part 60 subpart OOOOa rulemaking, the BLM estimates that the proposed requirements would impact up to 8,775 existing pumps, posing total costs of about $2.5 million per year. They would also increase gas production by 0.46 Bcf per year and result in cost savings of about $1.5–1.9 million per year (7 percent discount rate) or $1.75–2.15 million per year (3 percent discount rate). In addition, they are projected to reduce methane emissions by about 16,000 tpy, producing monetized benefits of $18 million per year in 2017–2019, $21 million per year in 2020–2024, and $24 million in 2025 and 2026. This would result in net benefits of $17 million per year in 2017–2019, $20 million per year in 2020–2024, and $23 million in 2025 and 2026, as well as reducing VOC emissions by about 4,000 tpy.[287]

Assuming, for purposes of analysis, that EPA does not finalize the 40 CFR part 60 subpart OOOOa rulemaking, the BLM estimates that the pneumatic pump requirements would affect up to about 8,775 existing pumps and about 75 new pumps per year, posing total costs of about $2.5–2.7 million per year (using 7 percent and 3 percent discount rates). They would also increase gas production by 0.5 Bcf per year and result in cost savings of about $1.5–2.2 million per year (using 7 percent and 3 percent discount rates).

In addition, they are projected to reduce methane emissions by about 16,000–17,000 tpy, producing monetized benefits of $18 million per year in 2017–2019, $22 million per year in 2020–2024, and $26 million in 2025 and 2026. This would result in net benefits of $17 million per year in 2017–2019, $21–22 million per year in 2020–2024, and $25 million in 2025 and 2026, as well as reducing VOC emissions by about 4,000 tpy.[288]

We request comment on the practicality and costs of replacing pneumatic chemical injection and diaphragm pumps with solar pumps or routing the pump exhaust to a flare that is already installed on-site, including whether 1 year is an appropriate amount of time for compliance.

Unlike pneumatic chemical injection and diaphragm pumps, the BLM has not identified a cost-effective means to reduce gas releases from gas-assist glycol dehydrator pumps at sites that are not connected to the electric grid, and thus we are not proposing any requirements to reduce gas losses from gas-assist glycol dehydrator pumps. The BLM requests comment, however, on whether there are additional measures that could further reduce gas lost from pneumatic pumps.

4. Storage Vessels

Storage vessels are ubiquitous in oil and gas production. Crude oil and condensate storage vessels are designed to hold a slight back-pressure. When the pressure in the vessel exceeds the back-pressure—due to fluids being added or an increase in temperature of the vessel contents—vapors are allowed to escape, thereby equalizing the pressure inside the vessel. Released vapors are a lost source of energy and revenue, and they also represent a safety and health concern for on-site workers. In addition, these vapors, which may contain methane, ethane, and a variety of VOCs, contribute to local air pollution problems. The significance of vapor loss, in terms of energy losses, revenue losses, safety risks and environmental impacts, depends upon the volume and composition of the released vapors.

New, modified, and reconstructed storage vessels used in oil and natural gas production, natural gas processing, and natural gas transmission and storage are already subject to emissions limits under the EPA NSPS, which requires that individual storage vessels with potential to emit VOC emissions equal to or greater than 6 tpy achieve at least a 95 percent reduction in VOC emissions.[289] The EPA standards also provide that if a storage tank that initially emitted at least 6 tpy of VOCs now emits less than 4 tpy without considering any emission controls in place for a period of 12 consecutive months, emission controls are not required if the operator monitors regularly to ensure that emissions do not exceed 4 tpy.[290] Unmodified storage vessels that were in place as of August 23, 2011, are currently allowed to vent vapors uncontrolled, unless subject to State controls.[291] EPA requires operators to determine the VOC emission rate within 30 days, and storage vessels must have a cover and closed vent system that meets specifications.[292]

Colorado requires the capture or combustion of vapors from storage vessels with a capacity to emit 6 tpy VOC or more.[293] The control equipment must reduce hydrocarbons by 95 percent, or by 98 percent if the operator uses a combustion device.[294] Storage vessels that require emission control systems are also subject to increased monitoring, and Colorado requires operators to develop STEM plans.[295]

In the Upper Green River Basin, Wyoming requires that when VOC emissions from vessels or glycol dehydrators are at least 4 tpy, the operator must reduce those emissions by 98 percent.[296]

(a) Estimates of Quantities of Gas Lost From Storage Vessels

The quantity of gas released from condensate and storage vessels depends on the throughput volumes of those vessels and how much gas is lost for a given volume of throughput. These loss rates vary depending on whether the vessel is controlled or uncontrolled and on the region of the country in which it is located. We estimate that 2.77 Bcf of natural gas was lost in 2013 from storage vessels venting on Federal and Indian lands.[297] These estimates were calculated using data from the 2015 GHG Inventory and the share of natural gas and crude oil production coming from Federal and Indian lands.

(b) Technologies and Practices To Reduce Gas Losses From Storage Vessels

Storage vessel vapors can be controlled by routing them to a flare or combustor, or by installing a VRU, which collects and compresses the vapors and returns them to the vessel or into a natural gas sales line.

Where a well facility is equipped with a flare pit or flare stack, tank vapors could be routed to that flare device. With a properly designed manifold, these flare devices can meet the 95 percent emission control standard established in the current EPA NSPS.[298]

Combustors are enclosed devices that efficiently combust tank vapors by ensuring an optimal mix of air and flammable vapor entering the combustion chamber. Combustors meet the 95 percent emission control standard established in the existing EPA NSPS. Combustors can be sized for a specific volume of natural gas/vapors, or can be operated in series to accommodate a wide volume range. Combustors are not dependent on other equipment or operating conditions and therefore have wide applicability.

In proposing the existing NSPS rule, EPA estimated that the average operating cost of a flare device (which

[287] RIA at 82.

[288] RIA at 81.

[289] 40 CFR 60.5395.

[290] Ibid.

[291] Ibid.

[292] 40 CFR 60.5395, 60.5415–5416.

[293] Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9, Section XVII.C.

[294] Ibid.

[295] Ibid.

[296] Wyoming Operational Rules, Drilling Rules Section Ch. 8, Section 6(d).

[297] RIA at 18.

[298] 40 CFR part 60 subpart OOOO.

includes both flares and combustors) is $8,900 per year, assuming that a flare device is already in place at the facility.[299]

VRUs meet the 95 percent emission control standard established in the EPA NSPS, and because the vapors are captured, there are no combustion emissions. Applicability of VRUs is limited by a number of conditions. VRUs require a power source, and a gas line must be available into which the controlled vapors can be directed. Due to their relatively high cost of operation (which EPA estimated at $18,900 per year in proposing its 2012 NSPS rule[300]), the economic viability of a VRU as a storage tank emission control device depends on high production throughput. In other words, net VRU costs rise as production volumes decline.

(c) Proposals To Minimize Vapor Losses From Storage Vessels

Under proposed § 3179.203, the BLM would address gas losses from storage vessels that are not covered by the EPA standards for new and modified storage vessels—or, by and large, existing, unmodified storage vessels. The BLM believes that reducing venting from existing storage vessels with higher rates of venting is a reasonably cost-effective means of reducing gas losses. We also believe that rather than establishing new and separate standards for venting from existing vessels, it would be easier for operators to comply if we require existing vessels on Federal and Indian leases to meet the same standards that already apply to new, rebuilt, and modified vessels on those leases.

The aim of this proposed rule is to reduce waste of whole gas. Nevertheless, the BLM believes that it may be appropriate to express the requirements for storage vessels as a VOC standard (as a proxy) rather than a whole gas standard, as EPA and Colorado do. There is no uniform conversion factor to translate a VOC standard like that established by EPA and Colorado into a whole gas standard. The ratio of VOCs leaked to hydrocarbons leaked depends on the makeup of the gas in the particular vessel. We propose to adopt the same standard that EPA applies to new storage vessels. Specifically, the BLM proposes to require, under § 3179.203(c), that VOC emissions from existing vessels with VOC emissions equal to or greater than 6 tpy be routed to a combustion device, continuous flare, or sales line. Under proposed § 3179.203(d), these requirements would no longer apply if the uncontrolled VOC emissions fall below 4 tpy for 12 months. This proposed lower bound addresses the fact that well production, and hence gas losses from vessels, are expected to decline over time, and it is less cost-effective to require control of lower volumes of tank venting. The 6 tpy and 4 tpy thresholds are consistent with EPA regulations.[301]

We request comments on the approach of applying EPA's new source threshold to existing storage vessels, to facilitate efficient compliance for the industry.

The proposed 6 tpy threshold tracks Colorado's standard for new storage vessels.[302] The threshold is somewhat less stringent than Wyoming's requirements, which apply to facilities with VOC emissions of 4 tpy or more and extend to glycol dehydrators, which the BLM does not propose to regulate.[303] The BLM also requests comment on applying a more stringent threshold consistent with Wyoming's requirements.

The BLM estimates that the proposed requirements would affect about 300 existing storage vessels on BLM-administered leases, and pose total costs of about $6 million per year (using 7 percent and 3 percent discount rates).[304] We project that these requirements would increase gas production by 0.04 Bcf per year, resulting in cost savings of about $0.1—0.2 million per year (using 7 percent and 3 percent discount rates). They would also reduce methane emissions by 7,000 tpy, producing monetized benefits of $8 million per year in 2017–2019, $9 million per year in 2020–2024, and $11 million in 2025 and 2026. Overall, we estimate that these provisions would result in net benefits of $2 million per year in 2017–2019, $3–4 million per year in 2020–2024, and $5 million in 2025 and 2026, and reduce VOC emissions by 32,500 tpy.[305]

5. Well Maintenance and Liquids Unloading

Over time, as well pressure in a natural gas well drops, liquids often start accumulating at the bottom of the well, which can then slow or halt gas production. Operators must remove or ''unload'' the liquids to maintain or restore production. Some of the methods used for liquids unloading can release substantial quantities of natural gas into the environment. In particular, operators sometimes allow the bottom hole pressure to increase and then vent or ''blow down'' or ''purge'' the well.

(a) Estimates of Quantities of Gas Lost Through Well Maintenance and Liquids Unloading

The amount of gas lost through liquids unloading varies substantially across regions, and also depends on whether wells are equipped with plunger lifts. We estimate that 3.26 Bcf of natural gas was lost in 2013 during liquids unloading operations on Federal and Indian lands, with 1.1 Bcf lost from wells with plunger lifts and 2.16 Bcf lost from wells without plunger lifts.[306] These estimates were calculated using data from the GHG Inventory, including the regional prevalence of wells with and without plunger lifts, and emissions factors for each. We chose to calculate emissions using a bottom-up approach for this emissions source because the prevalence of liquids unloading with and without plunger lifts and the emissions factors for each vary across regions. We then applied the prevalence and emissions factors to the number of producing gas wells on Federal and Indian lands as of January 1, 2014.

(b) Technologies and Practices To Reduce Gas Losses From Well Maintenance and Liquids Unloading

Technological developments have reduced the need for operators to unload liquids by venting a well to the atmosphere. Many companies use automated systems that rely on well pressure or timers to unload liquids using plunger lifts. More recent technology allows companies to use well data to optimize liquids unloading, a technique sometimes called ''smart'' automation. These ''smart'' systems reduce unnecessary unloading events and can dramatically cut venting from liquids unloading. For example, according to the Natural Gas STAR Report in 2006, BP reported installing plunger lifts with smart automated control systems on approximately 2,200 wells, which resulted in annual savings of 900 Mcf per well.[307] For a $12 million capital investment, BP realized a $6 million total annual savings.[308] Automated systems, whether ''smart'' or more conventional, are particularly useful for wells located in remote areas, typical of BLM lands, as they help

[299] 76 FR 52738 (Aug. 23, 2011).

[300] Ibid.

[301] 40 CFR 60.5395.

[302] Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9, Section XVII.C.

[303] Wyoming Operational Rules, Drilling Rules Section Ch. 8, Section 6(d).

[304] RIA at 95.

[305] Ibid.

[306] RIA at 128–129.

[307] EPA PowerPoint presentation found at *http://www3.epa.gov/gasstar/documents/workshops/fortworth-2006/gremillion.pdf.*

[308] Ibid.

maintain the well even when operators are not present.

Advanced reservoir-energy management and optimized liquids-unloading management can reduce the frequency of well venting and the quantity of resulting emissions. These management practices can reduce venting from wells with or without plunger lifts. There are a wide variety of artificial lift systems to unload gas wells, which may be applied based on the specific mechanical conditions of the well and the conditions of the reservoir. Some of these methods are described below.

One method that can be effective when a well first exhibits signs of liquid loading is to temporarily shut-in the well to allow the pressure to increase. The well is then cycled on at a high rate to unload the well. This method is inexpensive, but as pressures in the well decline, it becomes less effective.

Using surfactants (or soap injection) is another option. With this method, a foaming agent is injected in the casing/tubing annulus by a chemical pump on a timer. The gas bubbling through the soap-water solution creates gas-water foam, which is more easily lifted to the surface for water removal. Capital and startup costs to install soap launchers range from $500–$3,880 per well.[309]

Another option is to change the tubing in a well to smaller diameter ''velocity strings.'' Much like a narrowing in a river, these smaller diameter strings result in a higher fluid velocity at any given volumetric flow rate, and as a result these strings provide higher liquid lift capabilities. As reservoir pressure decreases, however, this method is less effective because of the increased friction in the smaller diameter tubing. Capital and installation costs provided from industry range from $7,000–$64,000 per well.[310] Other operators use compression to reduce flowing operating pressure, thus reducing flowing bottomhole pressure, which increases inflow from the reservoir. This is a means of achieving higher well-bore velocities. Compression can be used in conjunction with other artificial lift methods.

A plunger lift is used in conjunction with a lower-flowing tubing pressure (compression) and intermittent flow (shut-in cycle/smart automation) to lift liquids. Plungers have a wide operating range, but require a minimum gas-liquid ratio, so they are not appropriate for all applications. Plungers are most successful in low volume gas wells (*e.g.,* 30 bbl of liquid or less per day). The capital, installation and startup cost of a plunger lift is estimated at $1,900–$7,800,[311] but it can reach as high as $20,000.[312] Adding a smart automation system is estimated to cost $4,700–$18,000.[313]

Another alternative is a gas lift, which is used to raise gas velocity in the production tubing by injecting gas down the space between the tubing and surrounding casing and combining it with gas from the reservoir to assist in lifting liquid accumulations. Gas lift typically requires additional compression and piping at the surface. The additional compression would either be electrical- or natural-gas powered, adding to emissions, complexity, reliability, and operating costs. Also, gas lift is limited to those reservoir/well combinations that are configured in such a way that the gas injected down the well will flow up the well-bore and not simply dissipate into the formation.

Finally, operators may also use artificial lifts (*e.g.,* rod pumps, beam lift pumps, pumpjacks, and downhole separator pumps). Downhole pumps require an external power source to operate in order to remove the liquid buildup from the well tubing. Capital and installation costs (including location preparation, well clean out, artificial lift equipment, and pumping unit) is estimated at $41,000–$62,000 per well.[314]

Besides these measures to reduce gas losses, operators may also minimize the impact of well purging by flaring rather than venting the released gas through use of a mobile flare, but it can be difficult to separate purged gas from purged liquids.

Colorado allows an operator to vent during unloading of liquids from the wellbore only after the operator has unsuccessfully attempted to unload liquids without venting.[315] To minimize venting associated with liquids unloading, Colorado also requires an operator representative to remain on site during the unloading event.[316] The EPA's proposed 40 CFR part 60 subpart OOOOa rulemaking requests comment on ''nationally applicable technologies and techniques that reduce methane and VOC emissions'' during liquids unloading, but the EPA does not believe it has sufficient data to propose a standard for unloading events.[317]

(c) Proposals To Reduce Waste From Well Maintenance and Liquids Unloading

Recent technological developments allow liquids to be unloaded with minimal loss of gas. The BLM believes that it is reasonable to expect operators to use these available technologies to minimize gas losses, and we believe that failure to minimize losses of gas from liquids unloading should be deemed avoidable waste subject to royalties. Under proposed § 3179.204, except in specified circumstances, the BLM would prohibit new wells from unloading liquids by simply purging the well. While the BLM believes that the alternative technologies discussed above now generally make well-purging unnecessary, some of these alternatives are less costly to plan and install at the design stage, and they are therefore more appropriate for new than for existing wells. In addition, some options, such as installing an automated plunger lift, may make less sense at a well that is already nearing the end of its productive life. Thus, the BLM is proposing to limit the prohibition on well purging to new wells drilled after the effective date of this rule. We request comment on whether we should also prohibit well purging at existing wells.

In addition, under proposed § 3179.204(c), the BLM would require specified best management practices to minimize venting from liquids unloading at both new and existing wells. Specifically, the BLM proposes to require that the operator be on-site during well purging events for monitoring and reporting, unless the operator uses an automatic control system. Note that automatic control systems may vent more or less depending on the setting. We request comment on whether BLM should also require that wells with automatic control systems optimize the automatic settings so as to minimize venting.

Also, the BLM proposes under §§ 3179.204(d) and (e) to require that operators maintain certain records to document liquids unloading events.

[309] EPA, Natural Gas STAR Program, 2011, *http://www3.epa.gov/gasstar/documents/ll_options.pdf.*

[310] Ibid.

[311] EPA (2014). Oil and Natural Gas Sector Liquids Unloading Process; Report for Oil and Natural Gas Sector Liquids Unloading Process Review Panel. April 2014. Available at *http://www3.epa.gov/airquality/oilandgas/pdfs/20140415liquids.pdf,* p. 16.

[312] ICF International (2014) Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, March (2014), p.p. 3–17.

[313] EPA, Natural Gas STAR Program (2011). *http://www3.epa.gov/gasstar/documents/ll_options.pdf.*

[314] Ibid.

[315] Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9, Sections XVII.

[316] Ibid.

[317] 80 FR 56593, 56614.

This would allow the BLM to verify compliance, and it would provide additional information on the amounts of gas lost through these activities on Federal and Indian lands. We are seeking comments on the appropriate level and extent of required recordkeeping in the proposed rule, as well as other aspects of this approach to reducing waste from well maintenance and liquids unloading.

We estimate that there are currently about 8,500 operating gas wells where gas is vented during liquids unloading. Of those wells, we estimate that about 6,950 wells (or 82 percent) are equipped with plunger lifts, while 1,550 wells (or 18 percent) are not.[318] The proposed requirements would impact the 1,550 wells that are not equipped with plunger lifts, as well as any of the wells equipped with plunger lifts that lack automation (a number the BLM cannot accurately estimate at this time). In addition to the 8,500 wells currently venting during liquids unloading, there is the potential that a number of additional, producing gas wells will develop liquids accumulation issues in the future. Depending on how the operator removes the liquids from the wellbore, those wells could potentially be impacted by the requirements.

Under the proposed rule, we expect most new wells would use plunger lifts for liquids unloading, except where those lifts are technically infeasible or unduly costly. Plunger lifts are already used widely,[319] suggesting that under many circumstances their benefits—in terms of increased gas recovery, slowed declines in production, and improved well productivity—exceed their costs.

The proposed rule would require monitoring and reporting if the operator does not use an automated system, to minimize the venting and loss of gas during liquids unloading to the minimum amount necessary to bring the well back into production. The operator may choose to install an automated system and avoid the monitoring and reporting requirements altogether. Both approaches are likely to reduce venting or loss of gas, but we are unable to estimate annual incremental production, royalty, or emissions reductions because we cannot accurately predict how many operators will choose to install an automated system.

We do not anticipate that the additional monitoring requirements would substantially increase burdens on operators, because the available data indicate that average vent times are relatively short. In the Rocky Mountain region, for example, one industry survey indicates that wells without plunger lifts vent for an average of 1.76 hours.[320] The BLM does not expect that requiring operators to remain at the well site for such short periods would impose a significant financial burden.

Since the gas wells that encounter liquids accumulation problems generally do so after well production starts to decline, the timing of any future impacts of this rule is also uncertain. The EPA's Natural Gas STAR Program has shown, however, that investing in liquids removal processes at the start of a well's decline is more successful than making similar investments later in the productive life of the well. This suggests that it is reasonable to apply a more stringent requirement for new wells drilled after the effective date of this rule, as we have proposed, but we specifically request comment on this point.

There are a range of costs for various alternatives to uncontrolled liquids unloading. The annualized cost of a plunger lift is estimated to be $1,845–$2,816 using a 7 percent discount rate or $1,788–$2,587 using a 3 percent discount rate. The annualized cost of a ''smart'' (or automated) plunger lift is estimated to be $2,471–$4,520 using a 7 percent discount rate or $2,303–$3,900 using a 3 percent discount rate. All estimates are in 2012 dollars and are based on an equipment life of 10 years.[321]

We note that these cost estimates do not include sales of the recovered gas. The EPA Natural Gas STAR program information indicates that operators that install plunger lifts may experience increases in production from two effects—the capture of gas that would otherwise have been vented, and improvements in well performance due to the operation of the lifts. The gains are well-specific, but the Natural Gas STAR partners found that the additional sales of gas generally offset the costs of the lifts.[322]

Overall, based on the experiences of the Natural Gas STAR Program partners, we would expect that the boost in well productivity and the sale of recovered gas associated with the use of plunger lifts and other well-maintenance equipment would pay for the capital costs of purchasing and installing the equipment. We request comments on this point, both in general, and specifically with respect to the proposed prohibition on the use of well purging to unload liquids from new wells.

We estimate that the proposed liquids unloading requirements would affect up to about 1,550 existing wells and about 25 new wells per year, posing total costs of about $6 million per year (using a 7 percent discount rate) or $5–6 million per year (using a 3 percent discount rate). We project that the requirements would increase gas production by roughly 2 Bcf per year, resulting in cost savings of about $7–8 million per year (using a 7 percent discount rate) or $7–10 million per year (using a 3 percent discount rate). In addition, these requirements are projected to reduce methane emissions by 30,000 to 34,000 tpy, producing monetized benefits of $33–34 million per year in 2017–2019, $41–43 million per year in 2020–2024, and $50–51 million in 2025 and 2026. Overall, we estimate that these provisions would produce net benefits of $35–52 million per year (using a 7 percent discount rate for costs and cost savings) or $35–55 million per year (using a 3 percent discount rate for costs and cost savings), and reduce VOC emissions by about 136,000 to 156,000 tpy.[323]

6. Reduction of Waste From Drilling, Completion, and Related Operations

Substantial quantities of gas can be lost during drilling, completion, and refracturing (often referred to as ''workover'') operations. As explained in the RIA, we estimate that in 2013, up to 2.08 Bcf of natural gas was lost from these operations on BLM-administered leases. Of this, we estimate that completion emissions from hydraulically fractured oil wells accounted for 1.4 Bcf of the loss, while all other completions accounted for about 0.7 Bcf of the loss.[324]

As discussed above, the EPA requires new hydraulically fractured and refractured gas wells to undergo green completions to capture or flare gas that otherwise would be released during drilling and completion operations. On September 18, 2015, the EPA proposed to extend these requirements to new hydraulically fractured and refractured

[318] RIA at 216.

[319] According to the 2015 GHG Inventory, 13 percent of the gas wells nationwide vent to the atmosphere during liquids unloading, and of those, more than 60 percent lack plunger lifts. RIA at 216. In the Rocky Mountain region, however, where over 90 percent of the gas wells on Federal and Indian lands are located, plunger lifts are far more common than elsewhere in the country. RIA at 217.

[320] RIA at 217. Source is Shires & Lev-on analysis of API/ANGA survey data.

[321] RIA at 85.

[322] EPA Natural Gas STAR, *Lessons Learned from Natural Gas STAR Partners, available at http://www3.epa.gov/gasstar/documents/ll_plungerlift.pdf.*

[323] RIA at 87.

[324] RIA at 205.

oil wells.[325] If the EPA finalizes that proposal, it appears likely that all new hydraulically fractured or refractured oil and gas wells, other than wildcat and delineation wells, would be required to capture or flare the gas produced from these drilling operations. Nonetheless, the BLM believes that it is appropriate for the BLM to adopt its own requirements to minimize the waste of gas during well drilling and well completion and post-completion operations at conventional and hydraulically fractured and refractured wells. The BLM has an independent statutory obligation to minimize waste of oil and gas resources on BLM-administered leases. As proposed, we expect that the BLM waste requirements for well drilling, and completions at both conventional and hydraulically fractured wells would apply to a broader set of wells than the EPA proposal would cover. Finally, if the EPA finalizes a rule regulating hydraulically fractured and refractured oil wells, the BLM anticipates that any operator subject to both sets of requirements (*i.e.*, an operator completing a hydraulically fractured oil well) could satisfy both agencies' requirements by either capturing or flaring the gas that would otherwise be released. The BLM is coordinating closely with the EPA on the agencies' proposals, and the BLM expects to ensure that our final requirements would not impose additional burdens on an operator that complied with any EPA requirements on well completions.

Proposed § 3179.101 would generally require operators to capture or flare gas generated during drilling operations. Alternatively, the operator could inject the gas or use it for production purposes. We estimate that the rule would apply to up to about 3,000 wells per year, and would contribute to the BLM's overall effort to comprehensively address associated gas venting and flaring during all phases of oil and gas production. Based on our experience in the field, the BLM believes, however, that most operators are already diverting and flaring much of the gas from drilling operations as a matter of safety and operating practice, under Onshore Oil and Gas Order No. 2. As such, we do not estimate significant costs associated with this requirement.

Proposed § 3179.102 would similarly require operators to capture or flare gas generated during well completions and well fracturing or refracturing operations. Alternatively, the operator may inject the gas or use it for production purposes.

[325] 80 FR 56593.

We believe that the compliance costs associated with a requirement to flare gas would be minimal, especially for hydraulically fractured oil wells, where the equipment needed to flare is commonly already on site. We believe that operators generally direct (or may easily direct) the gas coming off of the separator to a flare pit. If this is infeasible, then the operator would likely bring a combustor to the site for the duration of the completion or direct the gases to a combustor that it would have on site to fulfill other regulatory requirements.

If the EPA finalizes its 40 CFR part 60 subpart OOOOa rulemaking, as we expect, then as a practical matter, this rule's completion requirements will only impact conventional well completions, because the EPA will regulate completions of new and modified hydraulically fractured oil and gas wells. We estimate that the BLM rule would impact between 115–150 completions per year and pose costs to the industry of less than $430,000 per year. There would be only *de minimis* anticipated incremental production, incremental royalty, and emissions reductions.[326]

If, for purposes of analysis, we assume that EPA does not finalize its 40 CFR part 60 subpart OOOOa rulemaking, the BLM estimates that these provisions would affect about 1,250 to 1,575 completions per year and pose total costs of about $8–12 million per year (using a 7 percent discount rate) or $12 million per year (using a 3 percent discount rate). We further estimate that these provisions would increase gas production by 0.5 to 0.6 Bcf per year, resulting in cost savings of about $2 million per year (using a 7 percent discount rate) or $2–3 million per year (using a 3 percent discount rate). This would also reduce methane emissions by 11,500 to 14,500 tpy, producing monetized benefits of $13 million per year in 2017–2019, $16–18 million per year in 2020–2024, and $21–22 million in 2025 and 2026. Overall, under this scenario, these provisions are estimated to produce net benefits of $3–15 million per year (considering the present value of costs and cost savings using a 7 percent discount rate) or $3–13 million per year (considering the present value of costs and cost savings using a 3 percent discount rate), and reduce VOC emissions by 9,600 to 12,200 tpy.[327]

[326] RIA at 74.

[327] Ibid.

7. Additional Opportunities To Reduce Waste From Venting

The BLM requests comment on whether there are additional opportunities to reduce waste from venting through reasonable and cost-effective measures. For example, there are several categories of sources discussed in the EPA white papers and ICF studies on venting that this proposal does not currently address, including gas-assist glycol dehydrator pumps, intermittent bleed pneumatic devices, compressor stations (with respect to specific interventions that could be required), glycol dehydrators, and pipeline venting. The proposal does not currently extend to these sources for one of two reasons: Either we do not believe that the source commonly occurs on BLM-administered leases, or we are still reviewing possible approaches to reduce venting from the source. We solicit additional information on these points, and also request comments on whether any of these sources should be addressed (or addressed differently) in the final rule.

The EPA and various studies have identified operational losses (in addition to leaks) from compressors as significant sources of methane emissions, and the EPA NSPS rule establishes requirements for new and modified centrifugal wet seal compressors and reciprocating compressors.[328] Specifically, that rule requires compressors with wet seals to reduce VOC emissions by 95 percent, which can be met through flaring or gas capture.[329] The EPA rule also requires operators of reciprocating compressors to replace the rod packing systems every 26,000 hours of operation or every 36 months, and requires initial performance testing and reporting.[330] The BLM has not proposed to adopt similar requirements for operational losses from existing compressors on BLM-administered leases, as we believe that these losses from compressors are not a significant source of waste on those leases. We request comment on whether adopting similar requirements for existing compressors would significantly reduce waste of gas from BLM-administered leases in a reasonable and cost-effective manner.

In addition, the BLM requests comment on whether the rule should require operators to use automatic igniters on their flares and other combustion devices, and if so, under what circumstances those should be required. The proposed provisions on

[328] 40 CFR 60.5380–5385.

[329] 40 CFR 60.5380.

[330] 40 CFR 60.5385.

well drilling, § 3179.101, and completions, § 3179.102, include requirements for the associated flare device to be equipped with an automatic igniter, as we believe that these activities involve more sporadic gas releases, such that an automatic igniter could be helpful in avoiding venting. However, we request comment on whether there are other situations under which automatic igniters should be required, and if so, what deadline should be imposed for the retrofit. For example, the State of Colorado requires that all combustion devices used to control emissions of hydrocarbons be equipped with automatic igniters, and the State gave operators 2 years (until May 1, 2016) to retrofit existing combustion devices.[331]

Other approaches to address venting from flare malfunctions include requiring operators to install malfunction alarms with remote notification systems, and/or to use enclosed combustors rather than open flares. We request comment on whether the BLM should include these requirements as well.

In addition, the BLM requests comment on whether we should require flares to achieve a specified level of performance in eliminating venting, and if so, what level. Under the 2012 NSPS rules, EPA requires 95 percent control of VOCs from vessels and other sources, and operators may use flares to meet this standard.[332] To the extent that operators do so, the flares must achieve at least a 95 percent removal efficiency for VOCs. Colorado and Wyoming both require combustion devices used to control hydrocarbons from vessels and other sources to achieve at least a 98 percent ''design destruction efficiency'' or ''destruction removal efficiency'' for VOCs.[333]

B. Royalty-Free Use of Production

As noted above in Section III.F of this preamble, the MLA's reference to applying royalties to production ''removed or sold from the lease'' has long been interpreted to allow for both royalty-free ''unavoidable'' losses of gas (see discussion above in Section IV.A.1.e of this preamble), and royalty-free on-site use of gas production (discussed here). For example, operators commonly combust a portion of the produced oil or gas to run production equipment, such as to power artificial lift equipment and drilling rigs, or to heat, separate, or dehydrate production. Operators also use gas pressure to activate pneumatic controllers and pneumatic pumps. This royalty exemption for on-site use is not unlimited, however, as the requirement to prevent waste limits royalty-free on-site use to reasonable uses that are not wasteful. Today's proposal would clarify the scope of the royalty exemption for on-site use and resolve ambiguities that have arisen under NTL–4A.

Specifically, subpart 3178 of the proposed rule would identify the oil and gas uses that would qualify for royalty-free treatment and explain related requirements. In addition, proposed § 3178.8 would specify how an operator must determine and report royalty-free volumes. Among other issues, the proposed rule addresses the following:

- Use of produced oil or gas at locations beyond the boundary of the producing lease, unit or communitized area (CA);
- Use of produced oil or gas to power equipment that the operator does not own; and
- The practice of ''hot oiling,'' in which oil used in the operation is not consumed.

To prevent unreasonably high royalty-free use, we considered proposing a limit, in the form of a maximum volume or maximum percentage of production. We concluded, however, that it is too difficult to identify specific volume or production percentage thresholds that would appropriately distinguish between reasonable and unreasonable quantities of on-site use. Instead, the proposed rule would directly address the royalty-free treatment of various uses of lease production and identify the situations in which prior written BLM approval would be required for royalty-free treatment of production used.

The proposed rule states that qualifying royalty-free uses must be for operations and production purposes, including placing oil and gas into marketable condition. The lessee ordinarily bears the responsibility for placing oil and gas into marketable condition at no cost to the lessor.[334] When a particular operation involved in placing the oil and gas into marketable condition is performed on the producing lease, unit participating area (PA), or CA, and the operator has met all other requirements, however, it is an appropriate royalty-free use. The production used in that operation is not royalty-bearing because the production is not removed from the lease, unit, or CA.[335]

C. Royalty Rates on New Competitive Leases

In addition to clarifying the scope of the royalty exemption for on-site use and resolving ambiguities that have arisen under NTL–4A, the BLM also proposes to conform its regulatory provisions governing royalty rates for new competitive leases to the corresponding rate provisions in the MLA. The MLA directs the BLM to set the royalty rate for all new competitively-issued leases ''at a rate of *not less than* 12.5 percent in amount or value of the production removed or sold from the lease.'' [336] Despite the inherent flexibility of this statutory language, the BLM's existing royalty regulation sets a flat rate of 12.5 percent for all new competitive leases.[337] The proposed rule would adopt the statutory language, with the result that the ''base'' royalty rate on competitive oil and gas leases issued after the effective date of this rule would be ''not less than'' 12.5 percent.

As noted, this proposed change would align the BLM's royalty authority with that delegated by Congress. In addition, the change would also respond to concerns expressed by the GAO and others about the adequacy of the BLM's onshore oil and gas fiscal system. In 2007 and 2008, the GAO released two reports addressing the United States' oil and gas fiscal system. The first report compared oil and gas revenues received by the Federal Government to the revenues that foreign governments receive from the development of their public oil and gas resources.[338] That report concluded that the United States' oil and gas ''take'' is among the lowest in the world.[339] The second report, which focused on whether the Department of the Interior receives a fair

[331] Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9, Sections XII.C.1.e, XVII.B.2.d.

[332] 40 CFR part 60, subpart OOOO.

[333] Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9, Section XVII.G; Wyoming Operational Rules, Drilling Rules Section Ch. 8, Section 6(c)(1)(A).

[334] *See, e.g.*, 30 CFR 1206.55 (Indian oil); 1206.106 (Federal oil); 1206.152(i) and 1206.153(i) (Federal gas); 1206.172(e)(3)(iii)(B) and 1206.174(h) (Indian gas); *Devon Energy Corp.* v. *Kempthorne*, 551 F.3d 1030 (D.C. Cir. 2008); *Amoco Production Co.* v. *Watson*. 410 F.3d 722 (D.C. Cir. 2005); *Amerada Hess Corp.* v. *Dep't. of the Interior*, 170 F.3d 1032 (10th Cir. 1999); *Mesa Operating Limited Partnership.* v. *Dep't. of the Interior*, 931 F.2d 318 (5th Cir. 1991); *Shoshone and Arapaho Tribes* v. *Hodel*, 903 F.2d 784 (10th Cir. 1990).

[335] *See Plains Exploration & Production Co.,* 178 IBLA 327, 335–336, 341–343 (2010).

[336] 30 U.S.C. 226(b)(1)(A) (emphasis added); *see also* 30 U.S.C. 352 (applying the Section 226 royalty provisions to leases on acquired land).

[337] 43 CFR 3103.3 1(a)(1).

[338] GAO, Oil and Gas Royalties: A Comparison of the Share of Revenue Received from Oil and Gas Production by the Federal Government and Other Resource Owners, GAO 07 676R, May 2007.

[339] GAO–07–676R at 2.

return on the resources it manages, cited the ''lack of price flexibility in royalty rates,'' and the ''inability to change fiscal terms on existing leases,'' in support of a finding that the United States could be foregoing significant revenue from the production of onshore Federal oil and gas resources.[340] Based on that finding, the second GAO report recommended that the U.S. Congress direct the Secretary of the Interior to convene an independent panel to review the Federal oil and gas fiscal system and establish procedures for periodic evaluation of the system going forward.

Congress did not act on the recommendation in the second GAO report, but the Department nevertheless undertook its own review. Specifically, the BLM and the BOEM contracted with the consulting firm Information Handling Services' Cambridge Energy Research Associates (IHS CERA) for a comparative assessment of the fiscal systems applicable to certain Federal, State, private, and foreign oil and gas resources (''IHS CERA Study'').[341] The IHS CERA Study identified four factors amenable to comparison: Government take, internal rate of return, profit-investment ratio, and progressivity.[342] The IHS CERA Study also considered measures of revenue risk and fiscal system stability. Overall, the IHS CERA Study found that, as of the time of the study, the Federal Government's fiscal system and overall take, in aggregate, were in the mainstream both nationally and internationally. Even within specific geographic regions, however, the IHS CERA Study estimated a wide range of government take, and its authors acknowledged that take varies with a variety of factors, including commodity prices, reserve size, reservoir characteristics, resource location, and water depth. As a result, the IHS CERA Study's authors favored a sliding-scale royalty system, because a sliding-scale royalty is more progressive than a fixed-rate royalty, and can also respond to changes in commodity market conditions.

In addition to the IHS CERA Study, the BLM also reviewed a separate study conducted by industry, the ''Van Meurs Study.''[343] The Van Meurs Study looked at a range of jurisdictions and regions across North America and provided a comparison of the oil and gas fiscal systems on Federal, State, and private lands throughout the United States and the provinces in Canada. The Van Meurs Study suggested that as of 2011, Federal Government take on Federal lands was generally lower than the corresponding take on State or private lands. The Van Meurs Study also made several recommendations to State and Federal Governments in the United States and Canada, including that governments apply different fiscal terms to oil leases than to gas leases, based on the differing prices of oil and gas at the time the report was published.

In 2013, the GAO issued another report identifying specific actions for the Department to take to ensure that the Federal Government receives a fair return on the resources it manages for the American public.[344] The GAO acknowledged that actions had been taken in response to its prior recommendations, but remained concerned that the Department had not taken steps to change its onshore royalty rate regulations to provide flexibility with respect to fiscal terms for oil and gas leases.[345]

In April 2015, as an initial response to these various studies and reports, the BLM published an Advance Notice of Proposed Rulemaking (ANPR) to solicit public comments and suggestions that might be used to update the BLM's regulations related to royalty rates, annual rental payments, minimum acceptable bids, and other financial measures.[346] In preparing the ANPR, the BLM gathered information about royalty rates charged by States and private mineral holders for oil and gas activities on State and private lands, and compared those rates to rates charged for Federal oil and gas resources. The data showed that the royalty rates charged on private and State lands range from 12.5 to 25 percent, and that the average rate assessed exceeds 16.67 percent.[347]

The comment period on the ANPR closed on June 19, 2015. BLM received 82,074 comments, many of which were form letters, including thousands of comments from NGOs. In addition to the NGO comments, individual companies and industry trade groups, including the American Petroleum Institute, Independent Petroleum Association of America, and Western Energy Alliance, submitted comments on behalf of their members. Most of the comments focused on lease fiscal terms—royalty rates, rentals, and minimum bids.

With respect to royalty rates, comments ran the gamut from supporting increases to opposing any such changes. Commenters supporting changes to the BLM's royalty rate regulations noted that the regulations are decades old and set a rate that is generally lower then rates for comparable State and private land leases. These commenters expressed concerns about whether, in light of these facts, the BLM is obtaining a fair return for the American taxpayer from Federal oil and gas leases. A number of these commenters suggested that the BLM should, at a minimum, increase the onshore royalty rate to match the rate currently set by BOEM offshore (18.75 percent). Other commenters suggested that royalty rates should be increased in order to account for the social and environmental costs of oil and gas development.

Many commenters took the opposite view, however, opposing any changes in royalty rates and arguing that higher regulatory costs, operating costs, and uncertainty on Federal lands justify royalty rates lower than those on State and private lands. These commenters also asserted that any increase in royalty rates for Federal oil and gas leases would lead to an overall decrease in government revenue by discouraging exploration and development of Federal oil and gas resources.

Finally, some commenters offered input on alternate royalty rate structures, focusing in particular on sliding scale systems. Some commenters encouraged the BLM to consider such a system, especially a sliding scale based on market price or regional location. Other commenters were opposed to a sliding scale approach, due to perceived implementation challenges and uncertainty in reporting. These commenters also questioned the appropriateness of setting up a royalty regime in which the Federal Government shares with investors some of the risk of fluctuating gas and oil prices. Overall, most individual commenters appeared to agree generally with giving BLM the flexibility to change fiscal terms at the lease sale stage, rather than fixing royalty rates by rule.

[340] GAO–08–691 at 6.

[341] Agalliu, I. (2011). Comparative Assessment of the Federal Oil and Gas Fiscal Systems. U.S. Department of the Interior, Bureau of Ocean Energy Management, OCS Study, BOEM 2011–xxx, *available at http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=d174971c-4682-4d96-b194-a85fa2b86774.*

[342] A ''progressive'' royalty rate refers to a rate that increases with the quantity of the resource being sold.

[343] PFC Energy, Van Meurs Corporation, and Rodgers Oil & Gas Consulting (2011). World Rating of Oil and Gas Terms: Volume 1—Rating of North American Terms for Oil and Gas Wells with a Special Report on Shale Plays.

[344] GAO, Oil and Gas Resources—Actions Needed for Interior to Better Ensure a Fair Return, GAO–14–50, (Dec. 2013), 11.

[345] Ibid. At 23.

[346] 80 FR 22148 (April 21, 2015).

[347] 80 FR at 22151–52 (April 21, 2015).

Based on the GAO's repeated recommendations, the IHS CERA Study, the royalty rate data collected by the BLM, and the comments received in response to the ANPR—and in light of the volatile nature of oil and gas markets—the BLM has determined that its regulations should provide for maximum flexibility to adjust royalty rate terms for new competitively issued oil and gas leases. Accordingly, this proposed rule would revise the existing regulations to track statutory authority.

The BLM does not currently anticipate increasing the base royalty rate for new competitively issued leases above 12.5 percent. Before making such a change, the BLM would announce the change prior to the effective date, and would provide for a public comment period. Any proposed change would be based on relevant factors, potentially including an assessment of comparable onshore State and private fiscal systems, and an assessment of the proposed impacts of the change on Federal revenue, on production from Federal lands, and on demand for Federal oil and gas leases relative to State and private leases.

The BLM requests input on this proposed change to the royalty provisions. In particular, commenters should address the merits of the proposed change to conform to statutory language, suggest the proper factors for the BLM to consider if and when it decides to adjust royalty rates for new competitive leases, and evaluate the adequacy of the public process outlined above.

At present this is the only change the BLM proposes to make to its royalty regulations. The BLM is, however, considering a provision that would allow royalty rates on new competitively issued leases to vary after the first year, based on the lease holder's record of routine flaring of associated gas from the lease during the previous year. Implementation of such a royalty ''adder'' provision would involve a ''look back'' at each lease holder's venting and flaring activity over a 12-month period. On October 1st of each year, a lease holder would evaluate its record of routine flaring of associated gas from the lease over the prior 12-month period. If a lease holder flared above a de minimis threshold for at least 6 months of that 12-month period, then its royalty rate for the *subsequent* calendar year would increase by some increment (for example, 4 percent). In all other cases, the royalty rate would remain at, or revert to, the base rate specified in the lease.

To make this idea more concrete, suppose the BLM finalizes the proposed changes to the existing royalty provisions in 43 CFR 3103.3–1(a)(1) and (2), detailed below in the section-by-section analysis (Discussion of the Proposed Rule, V.I.1.) and laid out in the proposed regulation text.[348] In that case, the additional regulatory language implementing a royalty adder could take the following form:

1. *Amend § 3103.3–1(a)(2) to add the following subparagraphs:*

(iii) An additional 4 percent above the base rate on all competitively-issued leases for any calendar year in which the operator reported above-threshold flaring of associated gas during at least six of the 12 months preceding October 1st;

(iv) The threshold flaring rate for purposes of paragraph (iii) is 300 Mcf/month multiplied by the number of wells on the lease that produced for at least 10 days during the month.

(v) For communitized or unitized leases, the threshold flaring rate for purposes of paragraph (iii) is 300 Mcf/month multiplied by the sum of the number of stand-alone wells on the lease and the number of wells on each agreement from which the lease is receiving an allocation. To be counted, each well must have produced for at least 10 days during the relevant month. The flaring volume used to assess exceedance of the threshold will be determined using the same allocation formula that each agreement uses to allocate production to the lease under consideration.

In this illustrative regulatory text, the royalty ''adder'' is 4 percent, and the threshold, *de minimis* flaring rate that would trigger application of the adder is 300 Mcf/producing well/month (or approximately 10 Mcf/producing well/day). Assuming the current base rate of 12.5 percent, a lease holder would continue to pay 12.5 percent for any year in which routine flaring of associated gas from its lease did not exceed the threshold rate during at least six of the 12 months preceding October 1st. On the other hand, any lease holder that reported above-threshold flaring of associated gas during at least 6 months of a calendar year would be obligated to pay a 16.5 percent royalty rate on all oil and gas production removed or sold from the lease during the *subsequent* calendar year. The rate would then revert back to 12.5 percent, for any year in which the lease holder reported at- or below-threshold flaring of associated gas during at least 6 of the 12 months preceding October 1st. Note that the 16.5 percent rate would be less than the average royalty rate that lease holders currently pay on oil and gas production removed or sold from onshore State and private leases (16.67 percent).[349] As noted previously, this provision, if adopted in the final rule, would apply only to new competitively issued leases issued after the effective date of the rule, and would not apply to existing leases.

The purpose of the royalty adder provision would be: (1) To create an incentive for bidders to consider the availability of gas capture infrastructure and the proximity of gas processing facilities as attributes that add significant value to Federal oil development leases; and (2) To create an incentive for Federal lease holders to plan for gas capture prior to or in conjunction with the development of oil wells.

The BLM requests comment on both the concept and the implementation of the royalty adder. Would a royalty adder accomplish the purposes outlined above? If so, is the structure suggested above appropriate? Does a 4 percent adder provide adequate incentive to lease holders to plan for gas capture at the same time they plan for oil development? Is a threshold rate of 10 Mcf/producing well/day (or 300 Mcf/producing well/month) over 6 months of the previous calendar year an appropriately de minimis rate to trigger the adder? Is an annual ''look back'' mechanism that focuses on production over the 12 months prior to October 1 workable given how oil and gas production volumes, and flaring levels, are currently reported to ONRR, or would a different 12-month period be easier to implement? Would there be a simpler and/or more effective way to implement a royalty adder concept?

D. Record Keeping Requirements

The BLM is proposing to require operators to keep records documenting their compliance with several provisions of this rule. Under proposed § 3179.8, for example, operators would need to estimate or measure all volumes of gas vented or flared, and report those volumes under applicable ONRR reporting requirements. This includes flaring of associated gas, and flaring that occurs during well drilling (proposed § 3179.101), well completions (proposed § 3179.102), initial production testing (proposed § 3179.103), and subsequent well testing (proposed § 3179.104). With respect to venting and flaring during emergencies (proposed § 3179.105), the BLM is proposing to require the operator also to estimate and report to the BLM on a Sundry Notice the volumes flared or vented beyond

[348] See footnote 64.

[349] 80 FR at 22151–52 (April 21, 2015).

specified timeframes. We are also soliciting comment on the most efficient and least burdensome means to make appropriate data available to the public.

In addition, with respect to venting during well maintenance and liquids unloading under proposed § 3179.204, the BLM is proposing to require operators to keep records on the cause, date, time, and duration of each venting event, as well as estimates of the quantities released. The BLM is also proposing to require operators to keep records on the dates, equipment covered, monitoring methods used, and results of the leak inspections required under proposed § 3179.305, as well as the dates that repairs are attempted, completed, and confirmed. We request comment on whether operators should be required to provide this information in an annual report, consistent with Colorado's requirements.[350]

E. Reporting and Information Availability

Currently, relatively little information on waste from venting and flaring at specific sites is directly provided to the public. The public may request information held by the BLM and ONRR through a request under the Freedom of Information Act (FOIA), but this can be more time-consuming and costly than accessing information publicly posted on Web sites.

Under existing § 3162.3–1(g), upon receiving an Application for a Permit to Drill (APD) on Federal lands, the BLM must post information for public inspection for at least 30 days before taking action. The information includes: (1) The company/operator name; (2) The well name/number; (3) The well location; and (4) Maps of the affected lands. The information must be posted in the local office of the BLM and in the appropriate surface managing agency office, if other than the BLM. Some BLM field offices also make this information available on their Web sites. The BLM has been working to upgrade its systems for accepting and processing APDs and Sundry Notices. The new APD acceptance process will allow the BLM to more easily post general information about those APDs to the Internet for public notice purposes.

With respect to venting and flaring, in some situations, such as emergencies, the operator is not currently required to provide any information to the BLM. In other situations, such as when BLM approval is required, operators typically file a Sundry Notice requesting the approval. When the BLM approves or disapproves the request, the BLM notifies the company. Neither the Sundry Notice nor the BLM disposition is currently posted, although to the extent that the information is not confidential business information, it would be available to the public through a FOIA request. Likewise, although operators are currently required to report gas vented and flared to ONRR on a lease or agreement basis, this information is currently only available to the public through a FOIA request. This information also does not include quantities of gas released through leaks or during routine operation of equipment, such as pneumatic devices.

In recent years, there has been strong and growing public interest in venting and flaring at oil and gas operations. In particular, the public has been calling for more complete, reliable, and available information on the quantities of natural gas vented and flared from BLM-administered leases. The BLM believes it is appropriate for the public to have access to information on venting and flaring from BLM-administered leases. The BLM also wants to be as responsive to reasonable public requests as possible given resource constraints.

Since at least a portion of the data on venting and flaring is already reported to and available from ONRR, the BLM believes that the least burdensome approach to increasing data access would be to expand the information that must be reported to ONRR. The goal would be to ensure that all quantities of gas vented and flared that ONRR requires to be reported are reported on ONRR's Oil and Gas Operations Report (OGOR), form ONRR–4054. Thus, the BLM proposes in §§ 3179.8 and 3179.204 to clarify the reporting requirements to ensure that operators report to ONRR measurements or estimates of all volumes of gas vented or flared. The BLM requests comment on this proposal and whether operators should report any additional information on losses of gas, such as from storage vessels or pneumatic controllers and pneumatic pumps. Several other categories of information may also generate public interest. For example, the proposed rule would require operators to provide significant new information related to plans for disposition of associated gas at the APD phase. In addition, there is already public interest in industry requests for approvals to flare and BLM responses. If this proposal is finalized, the BLM expects that there would be far fewer applications for alternative flaring limits compared to the current level of requests for approval to flare, but that there still might be substantial public interest in the applications for alternative flaring limits that BLM would receive.

To ensure transparency about the use of public resources, the BLM is considering ways to make these kinds of information publicly available online, where appropriate, without requiring interested members of the public to submit FOIA requests. The BLM requests comment on the types of data that are most useful to the public, the types of data that operators believe should remain private, and the most efficient and least burdensome approaches to making appropriate data available to the public. The BLM recognizes, however, that it must balance this interest in open government with the need to protect operators' confidential business information, and with the substantial administrative burden and costs of posting large amounts of information online.

F. Planning Process

During public outreach for the venting and flaring rule, multiple stakeholders asked the BLM to address the waste issue not only through requirements under the MLA, but also through the BLM's land-use planning and environmental review processes. Pointing to the BLM's authorities under FLPMA, procedural statutes such as the National Environmental Policy Act (NEPA), and DOI policies such as the Secretarial Orders that address climate change,[351] these commenters asked the BLM to use landscape-scale planning tools to complement the MLA waste prevention provisions.

These stakeholders recommended that the BLM integrate the waste prevention provisions of the MLA with the planning and management framework informed by FLPMA and NEPA. Commenters specifically suggested that the BLM develop a new rule requiring field offices to integrate waste prevention into planning and management. More broadly, the stakeholders asked the BLM to ''craft its rule to make full use of its 'front end' planning and management tools'' to prevent oil and natural gas waste.[352] They highlighted tools that allow the BLM to plan, manage for, and review the impacts of proposed actions before

[350] Colorado Air Quality Control Commission Regulations, Regulation 7, 5 CCR 1001–9 at Section XVII.H.1.c. and XVII.F.8 for proposed §§ 3179.204 and 3179.305 respectively.

[351] *See, e.g.*, Secretarial Order Nos. 3289 (Sept. 14, 2009) (updated by Amendment No. 1, Feb. 22, 2010) and 3226 (Jan. 19, 2001).

[352] Letter from the Western Environmental Law Center (WELC) *et al.* to Secretary Sally Jewell, DOI, Jan. 27, 2014, p. ii and Attached Core Principles, pp. 23–24 (hereinafter WELC Jan. 27 Letter).

issuing leases or approving oil and gas development projects, in contrast to the ''back end'' application of specific technologies or practices to such projects.[353] For example, these commenters suggested that by providing information to inform oil and gas development decisions, BLM inventories of the resource and other values of specific lands prepared under FLPMA Section 201(a) [354] could facilitate implementation and enforcement of the venting and flaring rule. They further suggested that by providing for public involvement, ''front end'' tools would facilitate public transparency and accountability and help to identify unexpected opportunities to prevent methane waste (such as in NEPA alternatives analyses).[355]

Among other tools, these stakeholders suggested that resource management plans (RMP) offer an opportunity to ensure ''orderly and efficient'' oil and gas development by governing the scale, pace, and nature of exploration, development, and production, and by facilitating the construction of necessary infrastructure for routing captured gas to processing and storage facilities.[356] They also encouraged the BLM to use master leasing plans (MLP) ''to establish front-end waste prevention goals'' when planning for oil and gas development in a defined area and to identify specific best management practices or mitigation measures to prevent waste.[357] These stakeholders argued that these and other tools would enable the BLM to ''prevent methane waste at a broad basin- or field-level scale.'' [358]

In addition, these stakeholders asked the BLM to use NEPA reviews to prevent methane waste. For example, they encouraged the BLM to consider methane waste from all sources in its NEPA analyses, including when considering alternatives and mitigation measures and when analyzing cumulative impacts.[359] These stakeholders also asked that the BLM ''expressly coordinate its planning and management efforts with Federal, State, and local agencies that regulate downstream activities, as well as with industry segments responsible for downstream activities'' to ensure that methane waste prevention actions are effective.[360]

Similarly, in evaluating opportunities for the BLM to reduce venting and flaring of gas, the GAO found that the agency does not as a general matter assess options for reducing venting and flaring in advance of oil and gas production. The GAO pointed out that there are two phases in advance of production where the BLM could assess venting and flaring reduction options—during the environmental review phase and when the operator applies to drill a new well. The GAO found, however, that the BLM largely fails to take advantage of these opportunities to reduce methane waste, instead using its pre-production authority solely to ensure that air quality standards are not violated. The GAO recommended that the BLM assess the potential use of venting and flaring reduction technologies to minimize the waste of natural gas in advance of production wherever applicable.[361]

The BLM is considering the integrated approach suggested by the commenters. The BLM agrees that the land use planning and NEPA processes are important to sound oil and gas development on Federal land. Flaring sometimes results from development of oil wells in advance of gas capture infrastructure. In other cases, flaring occurs when existing gas capture and processing infrastructure is inadequate, or when operators find flaring easier or less costly than connecting to existing gas capture infrastructure. Part of the solution to flaring, therefore, is to align the timing of well development with that of capture and processing infrastructure development, and to create incentives for operators to capture rather than flare.

The land use planning and NEPA review processes could be used to achieve these improvements, but the BLM does not intend to make any changes to BLM land use planning regulations (43 CFR subparts 1601 and 1610) or to any BLM planning or NEPA guidance as part of this rulemaking. This proposed rule focuses on the requirements that apply to operators as they develop wells and produce oil and gas from lands under Federal leases (43 CFR chapter II, subparts 3178 and 3179). The regulatory changes under consideration in this rulemaking are limited to these provisions.

G. Facilities in Rights-of-Way

In response to the BLM's solicitation of stakeholder views, various stakeholders also submitted comments urging the BLM to address not only losses of natural gas from BLM-administered leases, but also losses of natural gas from facilities located in rights-of-way granted by the BLM on Federal and Indian land. As of FY 2014, the BLM had over 33,700 approved rights-of-way in place under the MLA.[362] Facilities located in rights-of-way include gas gathering and transmission pipelines and compressors, which are used to maintain pressure in the pipelines. Of these, it appears that compressors are likely to be the largest source of natural gas losses. Further, it appears that losses from sources located on rights-of-way could be addressed through available technologies and practices, such as LDAR programs.

In evaluating the merits of the stakeholders' suggestion, the BLM believes that relevant considerations include, among others: The quantity of gas lost from these sources, the costs and feasibility of technologies to reduce waste of gas from these sources, and the administrative burden of doing so.

Based on the currently available information, the BLM believes that there are only a small number of sources of lost gas on BLM-managed rights-of-way, and that these sources do not contribute significantly to the problem of waste. The BLM analyzed potential losses from compressors, as the likely largest sources of loss located on BLM-managed rights-of-way. There are an estimated 386 compressors located on BLM-managed rights-of-way, and most of these are believed to be small compressors used for gathering systems (as opposed to the larger compressors used for transmission pipelines). Using EPA GHG Inventory data on emissions from small compressors, the compressors located in BLM-administered rights-of-way are estimated to release approximately 47 MMcf of natural gas per year. This quantity of gas is several orders of magnitude smaller than the on-lease sources of losses on which this proposal focuses—not surprising given that the number of compressors located on BLM-administered rights-of-way is only about 4 percent of the total number of small compressors in the Rocky Mountain region (9,260), and emissions from these

[353] Letter from WELC *et al.* to Secretary Sally Jewell, DOI, May 30, 2014, Attached Comments, p. 11, n. 6 (hereinafter WELC May 30 Letter).

[354] 43 U.S.C. 1711(a).

[355] WELC Jan. 27 Letter, p. 23.

[356] WELC Jan. 27 Letter, pp. 23–24; see also Letter from WELC and Clean Air Task Force to Director Neil Kornze, BLM, Dec. 5, 2014, pp. 2 and 4 (hereinafter WELC Dec. 5 Letter).

[357] WELC Jan. 27 Letter, p. 24.

[358] WELC May 30 Letter, pp. 11–12.

[359] WELC Jan. 27 Letter, pp. 20–21; WELC May 30 Letter, pp. 21–22; WELC Dec. 5 Letter, p. 4 (urging the BLM to consider and require technologies and practices to prevent waste that are deemed reasonable in the context of basin- or field-specific conditions).

[360] WELC Jan. 27 Letter, p. 20.

[361] GAO–11–34, 34.

[362] BLM Public Land Statistics, 2014 Table 3–4, column (c), Mineral Leasing Act.

compressors only total about 1 percent of small compressor emissions in the U.S. according to the latest GHG Inventory.[363] Given the limited impact of these rights-of-way facilities, and the fact that the BLM can already reach the facilities' emissions via conditions on rights-of-way, we are not proposing to address these facilities in this rulemaking. We request comment on this approach.

H. State or Tribal Variances

Several States and tribes have worked to address concerns about venting and flaring from oil and gas production, and others are considering action on this front. The BLM believes that it is important to include in this rule a provision for recognizing highly effective State or tribal requirements that reduce flaring and/or venting as much as, or more than, the proposed rule. Under proposed § 3179.401, such State or tribal provisions could, upon BLM approval, apply in place of a provision or provisions of subpart 3179. To apply for a variance, a State or tribe would have to: Identify the specific provisions of the BLM requirements for which the variance is requested; identify the specific State or tribal regulation that would serve as a substitute; explain why the variance is needed; and demonstrate how that regulation would serve the purposes of the supplanted BLM requirements.

The relevant BLM State Director would review a State or tribal variance request and assess whether the State or tribal regulation meets or exceeds the requirements of the BLM provisions for which the State or tribe sought a variance. The proposed rule would retain the BLM's authority to rescind a variance or modify any condition of approval in a variance.

I. Section-by-Section Discussion

1. § 3103.3–1 Royalty on Production

The proposed revisions to § 3103.3–1(a)(1) and (2) do four things: (1) Remove two provisions of the existing regulations that are no longer necessary (§ 3103.3–1(a)(1)(i) and (ii)); (2) Specify that the rate on all leases existing at the time the rule becomes effective would remain at the rate ''prescribed in the lease or in applicable regulations at the time of lease issuance''; (3) Specify the statutory rate of 12.5 percent for all noncompetitive leases issued after the effective date of the final rule; and (4) Conform the regulatory regime for competitive leases issued after the effective date of the rule to the regime envisioned by the MLA, which specifies that the royalty rate for all new competitively issued leases be set ''at a rate of not less than 12.5 percent.'' [364]

2. § 3160.0–5 Definitions

This proposed amendment to § 3160.0–5 would delete a definition of ''avoidably lost'' that by its terms applies to part 3160. A definition of ''avoidably lost'' is no longer needed for part 3160, and this definition would be superseded by the provisions in proposed subparts 3178 and 3179 governing when the loss of oil or gas is avoidable. In particular, proposed § 3179.4 delineates when the loss of oil or gas is avoidable or unavoidable.

3. § 3162.3–1 Drilling Applications and Plans

This proposed section describes the requirements for drilling applications and plans, including specifying the information that an operator must provide with an APD. We propose to amend this section to require that when submitting an APD for a development oil well, an operator must also submit a waste minimization plan, which would not be part of the APD, and the execution of which would not be enforceable. The waste minimization plan would have to include information regarding: The pipeline infrastructure location and capacity in the area of the well or wells; the anticipated timing, quantity, and production decline curve of oil and gas production from the well or wells; a gas pipeline system location map showing the operator's wells, gas pipelines, gas processing plant(s), and proposed routes for connection to the pipeline; certification that the operator has provided one or more midstream processing companies with information about the operator's production plans, including the anticipated completion dates and gas production rates of the proposed well or wells; the volume and percentage of produced gas the operator is currently flaring or venting from wells in the same field and any wells within a 20-mile radius of that field; and an evaluation of opportunities for alternative on-site capture approaches, if pipeline transport is unavailable.

4. Subpart 3178—Royalty-Free Use of Lease Production

(a) § 3178.1 Purpose

This proposed section states that the purpose of the subpart is to address circumstances in which oil and gas produced from Federal and Indian leases may be used royalty-free. This subpart would supersede those parts of NTL–4A pertaining to oil or gas used for ''beneficial purposes.''

(b) § 3178.2 Scope of This Subpart

This proposed section specifies which leases, agreements, tracts, facilities, and gas lines are covered by this subpart. The proposed section also states that the term ''lease'' in this subpart includes IMDA agreements as consistent with those agreements and with principles of Federal Indian law—an edit intended to enhance the clarity and brevity of these provisions.

(c) § 3178.3 Production on Which Royalty Is Not Due

This proposed section would set forth the general rule that royalty is not due on oil or gas that is produced from a lease or CA and used for operations and production purposes (including placing oil or gas in marketable condition) on the same lease or CA without being removed from the lease or CA.

This section also addresses a similar issue with respect to unit PAs—that is, the productive areas on a unit. Units often include different PAs composed of multiple leases with varied ownership. This section would therefore limit the royalty-free use of gas from a particular PA to uses that are made on the same unit, to support production from the same unit PA. The reason for this limitation is to prevent excessive use of royalty-free gas by prohibiting a unit operator from using royalty-free production from one PA to power operations on, or treat production from, another PA on the same unit, to the benefit of different owners and to the detriment of the public interest.

Proposed § 3178.5 would qualify the general provisions of proposed § 3178.3 by listing specific operations for which prior written BLM approval would be required for royalty-free use.

(d) § 3178.4 Uses of Oil or Gas on a Lease, Unit, or CA That Do Not Require Prior Written BLM Approval for Royalty-Free Treatment of Volumes Used

This proposed section identifies uses of produced oil or gas that would not require prior written BLM approval for royalty-free treatment. The uses listed in this section involve standard and routine production and related operations. In addition, proposed paragraph (b) clarifies that the authorization to use production without payment of royalties is limited to the amount of fuel reasonably necessary to perform the operation on the lease using appropriately sized equipment. This

[363] BLM analysis of EPA GHG Inventory data applied against the estimated number of compressors located on BLM-managed ROW authorizations.

[364] See footnote 64.

ensures that royalty-free on-site use remains subject to the requirement to avoid waste of the resource.

While the royalty-free uses proposed here are generally similar to the uses identified in the definition of ''beneficial purposes'' in NTL–4A, this rulemaking would clarify which uses warrant royalty-free treatment. This proposed rule would not address some uses that are defined as royalty-free under ONRR provisions, such as the royalty-free use of residue gas to fuel gas plant operations as provided in 30 CFR 1202.151(b). In addition, this proposed section would clarify that hot oil treatment is an accepted on-lease use of produced crude oil that does not require prior approval to be royalty-free. In this treatment, oil is not consumed as fuel. Rather, after the oil is pumped back into the well to stimulate production, it is produced again. Although the use of produced crude oil for hot oil treatments on the producing lease, unit, or CA has historically been understood by the BLM and by operators as a royalty-free use, it is not specifically addressed in NTL–4A.

(e) § 3178.5 Uses of Oil or Gas on a Lease, Unit, or CA That Require Prior Written BLM Approval for Royalty-Free Treatment of Volumes Used

This proposed section identifies uses of oil or gas that would require prior written BLM approval to be deemed royalty-free. The aim of this section is three-fold: (1) To ensure that the BLM retains discretion to grant royalty-free use where the BLM deems the use to be consistent with the MLA's royalty requirement for oil or gas that is produced and then removed from the lease and sold; (2) To increase uniformity in the administration of the royalty-provisions by specifying circumstances that warrant particular BLM attention; and (3) To ensure the BLM's awareness of unusual uses that risk the loss or waste of oil and gas.

For two of the identified uses, existing regulations already require BLM approval before the operator may conduct the operation. For all of the identified uses, operators would be required to submit a Sundry Notice requesting BLM approval to conduct royalty-free activities.

The potentially royalty-free uses identified in this section are as follows:

- *Using oil as a circulating medium in drilling operations.* This use is expressly described as royalty-free under NTL–4A. Because using produced oil as a circulating medium is rare and creates a possibility of loss, the proposal would require that the BLM evaluate each request and approve the request in writing only when appropriate.
- *Injecting gas produced from a lease, unit PA, or CA into the same lease, unit PA, or CA to increase the recovery of oil or gas.* An operator must also obtain BLM approval for this use under existing regulations at 43 CFR 3162.3–2. The substance of this provision would not change from NTL–4A.
- *Using oil or gas that was removed from the pipeline at a location downstream of the approved facility measurement point (FMP), provided that both removal and use occur on the lease, unit, or CA.* The BLM anticipates that these situations would be quite rare because the tap that operators use to extract and measure gas is generally upstream of the FMP.
- *Using produced gas for operations on the lease, unit PA, or CA, after it is returned from off-site treatment or processing to address a particular physical characteristic of the gas.* Physical characteristics that might preclude initial use of gas in lease operations and necessitate off-lease treatment or processing include an unusually high concentration of hydrogen sulfide, or the presence of inert gases or liquid fractions that limit the gas's utility as a fuel. The operator would bear the burden of establishing the necessity of off-lease treatment; the BLM typically would not approve, as a royalty-free use, return of production to the lease for use in operations necessary to put production into marketable condition.
- *Any other type of use that is consistent with proposed § 3178.3, but is not specifically identified in proposed § 3178.4.* This provision would clarify that the BLM retains discretion to consider approving royalty-free use under circumstances that are not now anticipated.

(f) § 3178.6 Uses of Oil or Gas Moved Off the Lease, Unit, or CA That Do Not Require Prior Written Approval for Royalty-Free Treatment of Volumes Used

This proposed section identifies two circumstances in which royalty-free use of oil or gas that has been moved off the lease, unit, or CA would be permitted without prior BLM approval.

The first situation is where an individual lease, unit, or CA includes non-contiguous areas, and oil or gas is piped directly from one area of the lease, unit, or CA to another area where it is used, without oil or gas being added to or removed from the pipeline, even though the oil or gas crosses lands that are not part of the lease, unit, or CA. Under this proposed section, the BLM would consider such production as not having been ''removed from the lease.'' This would provide the lessee or operator the same opportunity for royalty-free use as if the lease, unit, or CA were one contiguous parcel. The second situation is where a well is directionally drilled, and the wellhead is not located on the producing lease, unit, or CA, but produced oil or gas is used on the same well pad for operations and production purposes for that well. In such situations, the proposed rule would allow for royalty-free use at the well pad because, as the IBLA noted in *Plains Exploration & Production Co.*, ''(t)he gas (is) not produced (extracted from the ground) until after it (has) crossed the lease line. Production and removal from the lease are both requisite to triggering the royalty obligation. . . . Thus, gas used in wellhead production operations would be regarded as used for the benefit of the lease.'' [365]

(g) § 3178.7 Uses of Oil or Gas Moved Off the Lease, Unit, or CA That Require Prior Written Approval for Royalty-Free Treatment of Volumes Used

This proposed section would address the royalty treatment of oil or gas used in operations conducted *off* the lease, unit, or CA. When production is removed from the lease, unit, or CA, it becomes royalty-bearing unless otherwise provided. This principle is reflected in paragraph (a) of this proposed section, which would provide that with only limited exceptions, royalty is owed on all oil or gas used in operations conducted off the lease, unit, or CA (referred to here as ''off-lease royalty-free use'').

Paragraph (b) of this proposed section identifies circumstances in which, despite the principle articulated in paragraph (a), the BLM would consider approving off-lease royalty-free use. These include situations in which the operation is conducted using equipment or at a facility that is located off the lease, unit, or CA (under an approved permit or plan of operations, or at the agency's request) because of engineering, economic, resource protection, or physical accessibility considerations. For example, a compressor that otherwise would have been located on a lease may be sited off the lease because the topography of the lease is not conducive to equipment siting. To be approved for off-lease royalty-free use, the operation would also have to be conducted upstream of the approved FMP. This proposed

[365] *Plains Exploration & Production Co.*, 178 IBLA 327, 341 n.16 (2010).

paragraph reflects the BLM's policy to encourage operators to reduce the amount of surface disturbance associated with oil and gas exploration and development projects. In some cases, centralizing production facilities at a location off the lease may serve that objective.

Paragraph (c) would require the operator to obtain BLM approval for off-lease royalty-free use via a Sundry Notice containing the information required under proposed section 3178.9 of this subpart. The BLM anticipates that generally such approval would be appropriate only in some of the situations in which the BLM also approves measurement at a location off the lease, unit, or CA, or when the BLM has granted approval to commingle production off the lease, unit, or CA, and to allocate production back to the producing properties.

Paragraph (d) of this proposed section would clarify that approval of off-lease measurement or commingling under other regulatory provisions does not constitute approval of off-lease royalty-free use. An operator or lessee must expressly request, and submit its justification for, approval of off-lease royalty-free use.

Paragraph (e) of this proposed section addresses circumstances in which equipment located on a lease, unit, or CA also treats production from other properties that are not unitized or communitized with the property on which the equipment is located. Unless the BLM approves off-lease royalty-free use in such situations, an operator could report as royalty-free only that portion of the oil or gas used that is properly allocable to the share of production contributed by the lease, unit or CA on which the equipment is located.

NTL–4A does not include a provision that specifically addresses approving off-lease royalty-free use. Such approval is required, however, under ONRR regulations, which provide, ''All gas (except gas unavoidably lost or used on, or for the benefit of, the lease, including that gas used off-lease for the benefit of the lease when such off-lease use is permitted by the BOEMRE or BLM, as appropriate) produced from a Federal lease to which this subpart applies is subject to royalty.'' [366] The proposed section would add clarity and consistency in implementation.

(h) § 3178.8 Measurement or Estimation of Royalty-Free Volumes

This proposed section specifies that an operator must measure or estimate the volume of royalty-free gas used in operations upstream of the FMP. In general, the operator would be free to choose whether to measure or estimate, with the exception that the operator must in all cases measure under the applicable oil or gas measurement regulations: (1) The volume of royalty-free oil used in operations on the lease, unit, or CA; and (2) The volume of royalty-free gas removed from the product downstream of the FMP and used in operations on the lease, unit, or CA. If oil is used on the lease, unit or CA, it is most likely to be removed from a storage tank on the lease, unit or CA. Thus, this proposed section would also require the operator to document the removal of the oil from the tank.[367]

For both oil and gas, the operator would have to report the volumes measured or estimated, as applicable, under ONRR requirements.

(i) § 3178.9 Requesting Approval of Royalty-Free Treatment When Approval Is Required

This proposed section describes how to request BLM approval of royalty-free use when prior-approval is required under proposed § 3178.5 or proposed § 3178.7. NTL–4A is silent with respect to application procedures. This proposed section would require the operator to submit a Sundry Notice containing specified information, which is necessary for the BLM to determine if approval is appropriate. The information would include a description of the operation to be conducted, the measurement or estimation method, the volume expected to be used, the basis for an estimate (if applicable), and the proposed disposition of the oil or gas used.

(j) § 3178.10 Facility and Equipment Ownership

This proposed section clarifies that although the operator would not be required to own the equipment in which production is used royalty-free, the operator is responsible for all authorizations, production measurements, production reporting, and other applicable requirements.

5. Subpart 3179—Waste Prevention and Resource Conservation

(a) § 3179.1 Purpose

This proposed section states that the purpose of subpart 3179 would be to implement the statutes relating to prevention of waste from Federal and Indian (other than Osage Tribe) leases, conservation of surface resources, and management of the public lands for multiple use and sustained yield. The proposed section also provides that subpart 3179 would supersede those parts of NTL–4A that pertain to flaring and venting of produced gas, unavoidably and avoidably lost gas, and waste prevention.

(b) § 3179.2 Scope of This Subpart

This proposed section specifies which leases, agreements, tracts, facilities, and gas lines are covered by this subpart. The proposed section also states that the term ''lease'' in this subpart includes IMDA agreements as consistent with those agreements and with principles of Federal Indian law—an edit intended to enhance the clarity and brevity of these provisions.

(c) § 3179.3 Definitions and Acronyms

This proposed section contains definitions for 13 terms that are used in subpart 3179: ''Accessible component''; ''capture'' and ''capture infrastructure''; ''component''; ''development oil well'' and ''development gas well''; ''gas-to-oil ratio''; ''gas well''; ''liquid hydrocarbon''; ''liquids unloading''; ''lost oil or lost gas''; ''storage vessel''; and ''volatile organic compounds.'' Some defined terms have a particular meaning in this proposed rule. Other defined terms may be familiar to many readers, but we include their definitions in the proposed regulatory text to enhance the clarity of the rule.

(d) § 3179.4 Determining When the Loss of Oil or Gas Is Avoidable or Unavoidable

This proposed section describes the circumstances under which lost oil or gas would be classified as ''unavoidably lost.'' ''Avoidably lost'' oil or gas would then be defined as oil or gas that is not unavoidably lost.

NTL–4A defined the terms ''avoidably lost'' and ''unavoidably lost,'' but the definitions are general and could be applied inconsistently. The descriptions in the proposed rule are intended to enhance clarity and consistency by listing specific operations and sources that produce gas that the BLM would deem ''unavoidably lost,'' as long as an operator has not been negligent, has not violated laws, regulations, lease terms or orders, and has taken prudent and reasonable steps to avoid waste.

The rule would also define as ''unavoidably lost'' any produced gas that is vented or flared from a well that is not connected to gas capture infrastructure, if the BLM has not determined that the loss of gas through such venting or flaring is otherwise avoidable. To be deemed ''unavoidably lost,'' this produced gas would have to

[366] 30 CFR 1202.150(b) (emphasis added).

[367] 80 FR 40767 (July 13, 2015).

comply with the limits of proposed § 3179.6.

Finally, this proposed section would define ''avoidably lost'' oil or gas as lost oil or gas that does not meet this section's definition of ''unavoidably lost.''

(e) § 3179.5 When Lost Production Is Subject to Royalty

This proposed section would reemphasize the distinction that is the foundation of NTL–4A: Royalties are due on all avoidably lost oil or gas, but not on unavoidably lost oil or gas. This section further provides that if oil becomes waste oil through operator negligence, the operator would owe royalties on the waste oil, but absent negligence, waste oil would be royalty-free.

(f) § 3179.6 When Flaring or Venting Is Prohibited

This proposed section would require operators to flare all gas that is not captured, except under certain limited circumstances. Operators would be allowed to vent gas if flaring is technically infeasible—for example if the volumes of gas are too small to operate a flare, or if the gas is not readily combustible. Operators would also be allowed to vent gas in an emergency, when the loss of gas is uncontrollable or venting is necessary for safety. In addition, this proposed section would authorize venting of gas from pneumatic devices, and from storage vessels, as long as flaring of that gas is not required under other provisions of this proposed subpart.

This proposed section would impose an overall limit of 1,800 Mcf per month per well, averaged over all of the producing wells on a lease, on all venting or flaring from development oil wells, unless the BLM approves an alternative volume limit under proposed § 3179.7. This limit would phase in over the first 3 years that the rule is in effect, such that the flaring limit in year 1 would be 7,200 Mcf/well/month, averaged over all of the producing wells on a lease, the limit in year 2 would be 3,600 Mcf/well/month on average, and the limit in year 3 and thereafter would be 1,800 Mcf/well/month, again on average.

(g) § 3179.7 Alternative Limits on Venting and Flaring

This proposed section would apply only to leases issued before the effective date of this regulation. It would allow the BLM to approve a higher limit on venting and flaring for a well, in place of the applicable limit specified in proposed § 3179.6, if the operator demonstrates, and the BLM agrees, that the limit would impose such costs as to cause the operator to cease production on the lease and abandon significant recoverable oil reserves. In making this determination, the BLM would consider the costs of capture, and the costs and revenues of all oil and gas production on the lease. To demonstrate the need for an alternative limit, the operator would have to submit through a Sundry Notice: (1) Information regarding the operator's wells under the lease that produce Federal or Indian gas, including identifying information, and levels of gas production, venting and flaring for each well; (2) Maps showing the lease area, well and pipeline locations, capture, flaring and venting status of wells, and distances to pipelines; (3) Information on pipeline capacity and the operator's cost projections for gas capture infrastructure and alternative methods of transportation that do not require pipelines; and (4) The operator's projections of oil and gas prices, oil and gas production volumes, costs, revenues and royalty payments from the operator's oil and gas operations on the lease over the lesser of 15 years or the remaining period in which the operator will produce from the Federal or Indian lease, unit, or CA. As provided in paragraph (c) of this proposed section, the BLM would aim to set the lowest alternative flaring limit that would not cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

In addition, this proposed section would exempt wells on a lease from the applicable flaring limit for a renewable 2-year period if the operator certifies that the following conditions apply: (1) The lease, unit, or CA is not connected to a gas pipeline; (2) The lease is more than 50 straight-line miles from the nearest gas processing plant; and (3) The rate gas flaring from the lease is 50 percent or more greater than the applicable flaring limit in proposed § 3179.6. An operator would have to submit a Sundry Notice to the BLM, certifying in an affidavit that it meets the conditions for the exemption.

(h) § 3179.8 Measuring and Reporting Volumes of Gas Vented and Flared From Wells

This proposed section would require operators to estimate (using estimation protocols) or measure (using a metering device) all flared and vented gas, whether royalty-bearing or royalty-free.[368]

This proposed section further provides that operators must measure rather than estimate the flared and vented volumes when the operator is flaring 50 Mcf or more of gas per day from a flare stack or manifold, based on estimated volumes.

This proposed section would not specify how to measure gas when measurement is required. Onshore Oil and Gas Orders Nos. 4 and 5, which are currently undergoing revision, contain standards for measuring royalty-bearing oil and gas, respectively.[369]

This proposed section would also require operators to report all volumes vented or flared under applicable ONRR reporting requirements.

(i) § 3179.9 Determinations Regarding Royalty-Free Venting or Flaring

This proposed section would provide for a transition for operators that are operating under existing approvals for royalty-free flaring or venting, as of the effective date of the rule. Those operators could continue to flare or vent royalty-free, and/or to flare or vent above the applicable flaring limit, for 90 days after the effective date of the rule. After 90 days, those operators would become subject to all the provisions of the final rule, including both the royalty provisions and the flaring limit.

Further, this proposed section would clarify that nothing in this subpart alters the royalty-bearing status of flaring that occurred prior to [EFFECTIVE DATE OF FINAL RULE], nor the BLM's authority to determine that status and collect appropriate back-royalties.

(j) § 3179.10 Other Waste Prevention Measures

This proposed section would clarify that nothing in this subpart alters the BLM's existing authority under the MLA to limit the volume of production from a lease, or to delay action on an APD to minimize the loss of associated gas.[370] Specifically, if production from a new well would force an existing producing well already connected to the pipeline to go offline, then notwithstanding the

[368] Estimation in this instance involves the use of known well or reservoir information such as periodic well tests or a well's gas to oil ratio to estimate a well's gas production rate. For example, if a production flow test is conducted monthly on a well, one might presume the well continued producing gas at the tested rate for the entire month. Similarly, if a well has a gas to oil ratio that is uniform over time, the operator could estimate the rate of gas production based on the measured rate of oil production and the gas to oil ratio. Gas volume estimation using these protocols is suitable for reporting flared gas volumes in many cases.

[369] For oil: Onshore Oil and Gas Order No. 4, III(C), III(D), and III(E); for gas: Onshore Oil and Gas Order No. 5, III(C) and III(D). More information can be found at *http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/onshore_oil_and_gas.html.*

[370] 30 U.S.C. 187; 30 U.S.C. 225.

requirements in 3179.6 and 3179.7, the BLM could limit the volume of production from the new well for a period of time, while gas pressures from the new well stabilize. In addition, the BLM could delay action on an APD or approve it with conditions related to gas capture and production levels. The BLM could suspend the lease under 43 CFR 3103.4–4 if the lease associated with the APD is not in producing status.

(k) § 3179.11 Coordination With State Regulatory Authority

This proposed section addresses certain ''mixed ownership'' situations, in which a single well may produce oil and gas from Federal and/or Indian mineral interests, and non-Federal, non-Indian mineral interests. This proposed section would provide that to the extent that any BLM action to enforce a prohibition, limitation, or order under this subpart adversely affects production of oil or gas from non-Federal and non-Indian mineral interests, the BLM would coordinate on a case-by-case basis with the State regulatory authority with jurisdiction over that non-Federal and non-Indian production. This is consistent with current practice, in which the BLM and State regulators coordinate closely in regulating and enforcing requirements that apply to operators producing from Federal or Indian and non-Federal non-Indian mineral interests.

6. Flaring and Venting Gas During Drilling and Production Operations

(a) § 3179.101 Well Drilling

This proposed section would require gas that reaches the surface as a normal part of drilling operations to be used or disposed of in one of four specified ways: (1) Captured and sold; (2) Flared at a flare pit or stack with an automatic igniter; (3) Used in the lease operations; or (4) Injected. Under the proposal, gas may not be vented except under the narrow circumstances specified in proposed § 3179.6(a).

The proposed section also addresses gas that is lost as a result of loss of well control. If there is a loss of well control, the BLM would determine whether it was due to operator negligence, and if so, the BLM will notify the operator in writing. Gas lost as a result of a loss of well control would be classified as unavoidably lost and royalty-free, unless the loss of well control was due to operator negligence, in which case it would be avoidably lost and subject to royalties.

(b) § 3179.102 Well Completion and Related Operations

This proposed section would address gas that reaches the surface during well completion and post-completion recovery of drilling, fracturing, or re-fracturing. It would apply the same requirements and exceptions for use, sale, or disposal as proposed for well drilling operations under proposed § 3179.101. In lieu of compliance with the requirements of this proposed section, an operator may demonstrate to the BLM that it is in compliance with the requirements for control of gas from well completions established under 40 CFR part 60 subpart OOOOa.

Volumes flared under this proposed section would be reported to ONRR as directed in proposed § 3179.106 of this subpart.

(c) § 3179.103 Initial Production Testing

This proposed section would clarify when gas may be flared, royalty-free or otherwise, during a well's initial production test. It provides that gas may be flared royalty-free during initial production testing for up to 30 days or 20 MMcf of flared gas, whichever occurs first. Volumes flared under proposed § 3179.102(a)(2) during well completion would count towards the 20 MMcf limit. Under this section, royalty-free flaring would end when production begins.

Paragraph (b) of this proposed section would allow the BLM to approve royalty-free flaring during a longer testing period of up to 60 days, if there are well or equipment problems or a need for additional testing to develop adequate reservoir information. Paragraph (c) would allow a 90- rather than 30-day period for royalty-free flaring, during the variable and time-intensive dewatering and initial evaluation of exploratory coalbed methane well. In addition, the BLM could approve up to two extensions of 90 days each to allow for more time to dewater a coalbed methane well. The operator would have to transmit a request for a longer test period under paragraph (b) or (c) of this proposed section through a Sundry Notice. Under any of these circumstances, notwithstanding an extension of the test period, the well would be still subject to the 20 MMcf limit on flared gas.

Volumes vented or flared under this proposed section would be reported to ONRR as directed in proposed § 3179.8 of this subpart.

(d) § 3179.104 Subsequent Well Tests

The proposed requirement in this section is essentially the same as NTL–4A's requirement regarding subsequent well tests. It would limit royalty-free flaring during production tests after the initial production test to 24 hours, unless the BLM approves or requires a longer test period. The operator must transmit its request for a longer test period through a Sundry Notice.

Volumes vented or flared under this proposed section would be reported to ONRR as directed in proposed § 3179.8 of this subpart.

(e) § 3179.105 Emergencies

This proposed section would provide that an operator may flare or vent royalty-free during a temporary, short-term, infrequent, and unavoidable emergency.

Paragraph (b) would limit royalty-free emergency flaring or venting to a maximum of 24 hours per incident, for a maximum of three incidents per lease, unit, or CA per 30-day period. Together, these limits restrict monthly flaring or venting to a maximum of 72 hours.

The proposed rule would further clarify that more than three failures of the same equipment within any 365-day period, and failures that result from improperly sized, installed, or maintained equipment, would not constitute an emergency. Similarly, the proposed rule would also exclude from the definition of ''emergency'' any equipment failure caused by operator negligence.

In addition, this proposed section would clarify that scheduled maintenance does not constitute an emergency, even when it is outside of the operator's control. For example, the fact that a downstream gas processing plant goes down for maintenance would not constitute an emergency that allows an operator to flare royalty-free.

Volumes vented or flared under this proposed section would be reported to ONRR as directed in proposed § 3179.8 of this subpart.

7. Gas Flared or Vented From Equipment or During Well Maintenance Operations

(a) § 3179.201 Equipment Requirements for Pneumatic Controllers

This proposed section would address gas losses from pneumatic controllers. Paragraph (a) identifies the pneumatic controllers that would be subject to the requirements of this section: Pneumatic controllers that use natural gas produced from a Federal or Indian lease, or from a unit or CA that includes a Federal or Indian lease, if the controllers have a continuous bleed rate greater than 6 scf/hour (''high-bleed'' controllers) and are not covered by EPA regulations that prohibit the new use of high-bleed pneumatic controllers (40 CFR 60.5360 through 60.5390).

Paragraph (b) of the proposed section would require pneumatic controllers subject to the requirement to be replaced with controllers having a bleed rate of no more than 6 scf/hour. Under paragraph (c), operators would be required to replace the controllers within 1 year from the effective date of the final rule, or within 3 years from the effective date of the rule, if the well or facility served by the controller has an estimated remaining productive life of 3 years or less. Under paragraph (d), operators would also be required to ensure that pneumatic controllers are functioning within the manufacturers' specifications.

This proposed section also provides several exceptions to the replacement requirement. An operator would not be required to replace a controller if a high-bleed controller is necessary to perform the needed function. For example, replacement might not be required if a low-bleed controller would not provide a timely response, which would lead to greater waste or create a safety hazard. Likewise, replacement would not be required if the controller is routed to a flare, or if the operator demonstrates, and the BLM concurs, that replacing the pneumatic controllers on the lease would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

(b) § 3179.202 Requirements for Pneumatic Chemical Injection Pumps or Pneumatic Diaphragm Pumps

This proposed section would establish requirements for operators with pneumatic chemical injection pumps or pneumatic diaphragm pumps that use natural gas produced from a Federal or Indian lease, or from a unit or CA that includes a Federal or Indian lease, except those pneumatic pumps covered under EPA regulations at 40 CFR part 60, subpart OOOO. The proposed section would require operators to replace pneumatic pumps covered by this proposed section with a zero-emissions pump or route the pneumatic pump to a flare, no later than 1 year after these rules are effective.

The proposed section also provides for exceptions to the replacement requirement. An operator would not be required to replace a pneumatic pump if a zero-emissions pump would be insufficient to perform the pneumatic pump's function, and an operator would not be required to route a pneumatic pump to a flare if no flare device were available on site. Replacement or routing to a flare is also not required if the operator demonstrates, and the BLM concurs, that the cost of replacing the pneumatic pumps on the lease or routing them to a flare would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

In addition, as proposed for pneumatic controllers and based on the same rationale, this proposed section would provide that if the estimated remaining productive life of the well or facility is 3 years or less, the operator would be allowed to replace the pneumatic controller no later than 3 years from the effective date of the regulation, rather than within 1 year.

The proposed section would also require that pneumatic pumps function within manufacturers' specifications.

(c) § 3179.203 Crude Oil and Condensate Storage Vessels

This proposed section addresses gas vented from an oil or condensate storage vessel (or a battery of storage vessels) that contains production from a Federal or Indian lease, or from a unit or CA that includes a Federal or Indian lease. The proposed section would require operators to route all gas vapor from covered storage vessels or batteries to a combustion device or continuous flare, or to a sales line. Operators would be required to meet this requirement no later than 6 months after the rule becomes effective.

A storage vessel would be subject to this proposed section if the vessel is not covered under EPA regulations at 40 CFR part 60 subpart OOOO, and if it has a rate of total VOC emissions equal to or greater than 6 tpy. Operators would be required to determine the rate of emissions from the storage vessel within 60 days after this rule is effective, and within 30 days after adding a new source of production to a storage vessel.

This proposed section would not apply if the total VOC emissions rate from the storage vessel declines to 4 tpy in the absence of controls for 12 consecutive months, or if the operator demonstrates, and the BLM concurs, that the cost of replacing the pneumatic pumps on the lease or routing them to a flare would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

(d) § 3179.204 Downhole Well Maintenance and Liquids Unloading

This proposed section would establish requirements for venting and flaring during downhole well maintenance and liquids unloading. It would require the operator to use practices for such operations that maximize the recovery of gas for sale, and to flare gas that is not recoverable, unless the practices or flaring are technically infeasible or unduly costly. The proposed rule would also prohibit liquids unloading by well purging (as defined in the section) for wells drilled after the effective date of this rule, except when the operator is returning the well to production following a well workover or following a shut-in of more than 30 days.

For existing wells, before the operator purges a well for the first time after the effective date of this section, the BLM is proposing that the operator must document that purging is the only technically or economically feasible method of unloading liquids from the well. In addition, during any liquids unloading by well purging, an operator would be required to be present on site to ensure that any venting to the atmosphere is limited to what is necessary, unless the operator uses an automated control system that limits the venting event to the minimum necessary. This proposed section would require the operator to maintain records of the date and duration of each venting event and to make those records available to the BLM upon request.

Under this proposal, the operator would be required to notify the BLM by Sundry Notice within 10 days after the first liquids unloading by well purging after the effective date of the rule. Operators would also be required to notify the BLM by Sundry Notice if the cumulative duration of well purging events for a well exceeds 24 hours during any production month, or if the estimated volume of gas vented in the process exceeds 75 Mcf during any production month.

Paragraph (g) would require operators to report volumes vented during downhole maintenance and liquids unloading to ONRR.

8. Leak Detection and Repair

(a) § 3179.301 Operator Responsibility

This proposed section would apply to all oil or gas wells that produce gas from a Federal or Indian lease, or from a unit or CA that includes a Federal or Indian lease. The section would obligate operators to inspect all equipment, equipment components, facilities (such as separators, heater/treaters, and liquids unloading equipment), and compressors located on the lease, unit, or CA for leaks. Operators would be required to conduct the inspections during production operations, and to fix any leaks found.

The proposed requirement would not apply to centralized compressors, owned by a pipeline company, which the operator of the Federal or Indian lease, unit, or CA does not lease or operate, and for which the operator has no direct control over maintenance and operation. In addition, operators would have the option to demonstrate to the BLM in a Sundry Notice that, in lieu of complying with these requirements for LDAR for some or all of their equipment and facilities, the operator is complying with LDAR requirements established by the EPA under 40 CFR part 60 subpart OOOOa for the same equipment and facilities. Under the proposed rule, the BLM's LDAR requirements would apply to operators that are covered by 40 CFR part 60, but do not meet that rule's production thresholds, and are therefore exempt from performing LDAR under that rule. The BLM seeks comment on whether such operators should also be exempt from this rule's LDAR requirements.

(b) § 3179.302 Approved Instruments and Methods

This proposed section would prescribe the types of instruments and monitoring methods that an operator must use to inspect for leaks. Specifically, operators could use: (1) An optical gas imaging device such as an infrared camera; (2) An alternative, equally advanced monitoring device, not listed in the proposed rule, which is approved by the BLM for use by any operator; or (3) A comprehensive program, approved by the BLM, that includes the use of instrument-based monitoring devices or continuous emissions monitoring. Large operators that have 500 or more wells within the jurisdiction of a single BLM field office would have only these three choices for detecting leaks. Smaller operators, however, would have a fourth choice: To use a portable analyzer device, operated according to manufacturer specifications, and assisted by AVO inspection.

(c) § 3179.303 Leak Detection Inspection Requirements for Natural Gas Wellhead Equipment, Facilities, and Compressors

This proposed section would require operators to conduct initial site inspections within specified timeframes after the effective date of the rule. The proposed section would define ''site'' as a discrete area containing wellhead equipment, facilities, and compressors, which is suitable for inspection in a single visit.

The proposed section would require the operator initially to conduct site inspections twice a year. The inspection frequency would be subject to change based on whether leaks are detected in two consecutive inspections, according to the following provisions:

- Case one: If the operator detects no more than two leaks at the site inspected, in each of two consecutive semi-annual inspections, the operator could shift to conducting less frequent, annual inspections.
- Case two: If the operator detects three or more leaks at the site inspected, in each of two consecutive semi-annual inspections, the operator would have to shift to more frequent, quarterly inspections.

The proposed section also specifies that the inspection frequency would revert back to semi-annually if: (1) In case one, the operator detects three or more leaks in two subsequent, consecutive annual inspections; or (2) In case two, the operator detects no more than two leaks in two subsequent, consecutive, quarterly inspections.

Paragraph (b) of this proposed section would authorize the BLM to approve an alternative leak detection device, program, or method, if the BLM finds that the alternative would meet or exceed the effectiveness of the required approach. The operator would have to transmit a request for an alternative leak detection device, program, or method through a Sundry Notice.

Under paragraph (c), an operator would not be required to inspect components that are not accessible.

(d) § 3179.304 Repairing Leaks

This proposed section would require operators to repair leaks within 15 calendar days of discovery of the leak, unless there is good cause for repair to take longer. The proposed rule would require the operator to notify the BLM if this occurs and to complete the repair within 15 calendar days after the cause of the delay ceases to exist. The rule would also require the operator to conduct a follow-up inspection to verify the effectiveness of the repair, using the same method used to detect the leak, within 15 calendar days after the repair and to make additional repairs within 15 calendar days if the previous repair was not effective. The repair and follow-up process would have to be followed until the repair is effective. The BLM would not consider an inspection to verify the effectiveness of a repair to be a periodic inspection under proposed § 3179.303.

(e) § 3179.305 Leak Detection Inspection Recordkeeping

This proposed section would require operators to maintain records of LDAR inspections and repairs, including dates, locations, methods, where leaks were found, dates of repairs, and dates of follow-up inspections. These records would have to be made available to the BLM upon request.

9. State or Tribal Variances

(a) § 3179.401 State or Tribal Requests for Variances From the Requirements of This Subpart

This proposed section would create a variance procedure, under which the BLM could grant a State or tribe's request to have a State or tribal regulation apply in place of a provision or provisions of this subpart. The variance request would have to: (1) Identify the specific provisions of the BLM requirements for which the variance is requested; (2) Identify the specific State or tribal regulation that would substitute for the BLM requirements; (3) Explain why the variance is needed; and (4) Demonstrate how the State or tribal regulation would satisfy the purposes of the relevant BLM provisions. The BLM State Director would review a State or tribal variance request. To approve a request, the BLM State Director would have to determine that the State or tribal regulation meets or exceeds the requirements of the provision(s) for which the State or tribe sought the variance, and that the State or tribal regulation is consistent with the terms of the affected Federal or Indian leases and applicable statutes.

Paragraph (b) would specify that the decision on a variance request is not subject to administrative appeal under 43 CFR part 4. Paragraph (c) would clarify that a variance granted under this proposed section would not constitute a variance from provisions of regulations, laws, or orders other than proposed subpart 3179. Paragraph (d) would reserve the BLM's authority to rescind a variance or modify any condition of approval in a variance.

VI. Analysis of Impacts

A. Description of the Regulated Entities

1. Potentially Affected Entities

Entities that would be directly affected by the proposed rule would include most, if not all, entities involved in the exploration and development of oil and natural gas on Federal and Indian lands. According to AFMSS data (as of March 27, 2015), there are up to 1,828 entities that currently operate Federal and Indian leases.[371] We believe that these 1,828

[371] The actual number is expected to be slightly lower due to duplicate entries.

entities would be most affected by the proposed rule, in addition to entities currently involved with drilling and support activities, and any entities that become involved in the future.

The potentially affected entities are likely to fall within one of the following industries, identified by the North American Industry Classification System (NAICS) codes:

- NAICS Code 21111 ''Oil and Gas Extraction''
- NAICS Code 213111 ''Drilling Oil and Gas Wells''
- NAICS Code 213112 ''Support Activities''

Table 35 of the RIA displays 2011 data from the U.S. Census Bureau, which reveal a number of characteristics about the entities that operate within these industries.[372] First, the table identifies the total number of entities within each industry and the number of entities with less than 500 employees and the number of entities with 500 or more employees. Next, the table identifies the total employment within each industry and the combined employment for entities with less than 500 employees and the combined employment for entities with 500 or more employees. Third, the table shows the total annual payroll for each industry and the combined annual payroll for entities with less than 500 employees and the combined annual payroll for entities with 500 or more employees.

Based on these data, in 2011, there were 6,628 entities directly involved in extraction of oil and gas in the United States, 2,041 entities involved in the drilling of wells, and 8,119 entities providing other support functions. Therefore, the approximately 17,000 entities associated with developing, and producing of domestic oil and gas [373] represent an upper bound estimate of the operators that could potentially be affected by this rulemaking.

2. Affected Small Entities

The Small Business Administration (SBA) has developed size standards to carry out the purposes of the Small Business Act and those size standards can be found in 13 CFR 121.201. For mining, including the extraction of crude oil and natural gas, the SBA defines a small entity as an individual, limited partnership, or small company, at ''arm's length'' from the control of any parent companies, with fewer than 500 employees. For entities drilling oil and gas wells, the threshold is also 500 employees. For entities involved in support activities, the standard is annual receipts of less than $38.5 million. Of the 6,628 domestic firms involved in oil and gas extraction, 99 percent (or 6,530) had fewer than 500 employees. There are another 2,041 firms involved in drilling. Of those firms, 98 percent of those firms had fewer than 500 employees.

To estimate a percentage for firms involved in oil and gas support activities we reference Table 36 of the RIA, which provides the NAICS information for firms involved in oil and gas support activities based on the size of receipts. The most recent data available from the U.S. Census Bureau for establishment/firm size based on receipts is for 2007. Of the 5,880 firms in oil and gas support activities in 2007, 97 percent had annual receipts of less than $35 million.[374]

Based on this national data, the preponderance of entities involved in developing oil and gas resources are small entities as defined by the SBA. As such, a substantial number of small entities may potentially be affected by the proposed rule.

B. Impacts of the Proposed Requirements

1. Overall Costs of the Rule [375]

We analyzed the overall costs of the rule if the EPA finalizes the 40 CFR part 60 subpart OOOOa rulemaking, and also if the EPA does not finalize that rulemaking. As explained above, we expect more significant costs and benefits of the rule for the first few years, during which some operators would have to add or improve gas-capture capability, and some would also have to replace existing equipment. The BLM expects this transitional period to last for the first few years, after which the compliance requirements of the rule would be significantly reduced, as would any benefits associated with increased capture and sale of gas that would otherwise have been vented or flared.

Overall, assuming that the EPA finalizes its concurrent 40 CFR part 60 subpart OOOOa rulemaking, the BLM estimates that this rule will pose costs ranging from $125–161 million per year (using a 7 percent discount rate) or $117–1 34 million per year (using a 3 percent discount rate) over the next 10 years.[376] These costs include engineering compliance costs and the social cost of minor additions of carbon dioxide to the atmosphere.[377] The engineering compliance costs presented do not include potential cost savings from the recovery and sale of natural gas (those savings are shown in the summary of benefits).

If, for analytical purposes, we assume that EPA does not finalizes its concurrent 40 CFR part 60 subpart OOOOa rulemaking, these requirements would affect more sources and the costs would be somewhat higher. Under that scenario, the BLM estimates that this rule will pose costs ranging from $139—174 million per year (using a 7 percent discount rate) or $131–147 million per year (using a 3 percent discount rate) over the next 10 years.[378]

In some areas, operators have already undertaken, or plan to undertake, voluntary actions to address gas losses. To the extent that operators are already in compliance with the requirements of this proposed rule, the above estimates overstate the likely impacts of the rule.

2. Overall Benefits of the Rule [379]

The potential benefits of the rule include the additional production of resources from Federal and Indian leases; reductions in venting, flaring, and GHG emissions; and increased opportunities for royalties.

We measure the benefits of the rule as the cost savings that the industry would receive from the recovery and sale of natural gas and the projected environmental benefits of reducing the amount of GHG and other air pollutants released into the atmosphere. As with the estimated costs, we expect benefits on an annual basis.

The estimated benefits of the rule also depend on whether the EPA finalizes its 40 CFR part 60 subpart OOOOa rulemaking. Assuming that rule is in effect, the BLM estimates that this rule would result in monetized benefits of $255–329 million per year (using a 7 percent discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3 percent discount rate) or $255–357 million per year (using a 3 percent discount rate to

[372] Calendar year 2011 is the most recent data available from the U.S. Census Bureau that includes detailed employment data. Entities primarily involved in the support of mining activities on a contract basis were not included in this count.

[373] U.S. Census Bureau data does not readily differentiate between the number of firms involved in oil development and production activities versus gas development and production.

[374] U.S. Census Bureau does not provide receipt data that allow a break at the $38.5 million threshold as defined by SBA. As such, the 97 percent figure is a slight underestimate.

[375] RIA at 81–90.

[376] RIA at 127.

[377] Some gas that would have otherwise been vented would now be combusted on-site or presumably downstream to generate electricity. The estimated value of the carbon additions do not exceed $21,000 in any given year.

[378] RIA at 127.

[379] RIA at 85–90.

calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3 percent discount rate).[380] We estimate that the proposed rule would reduce methane emissions by 164,000–169,000 tpy, which we estimate to be worth $180–253 million per year (this social benefit is included in the monetized benefit above). We estimate that the proposed rule would reduce VOC emissions by 391,000–411,000 (this benefit is not monetized in our calculations).[381]

If, for purposes of analysis, we assume that EPA does not finalize its 40 CFR part 60 subpart OOOOa rulemaking, we estimate that this proposed rule would result in monetized benefits of $270–354 million per year (using a 7 percent discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3 percent discount rate) or $270–384 million per year (using a 3 percent discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3 percent discount rate).[382] We estimate that the proposed rule would reduce methane emissions by 176,000–185,000 tpy, which we estimate to be $193–277 million per year (this social benefit is included in the monetized benefit above). We estimate that the proposed rule would reduce VOC emissions by 400,000–423,000 (this benefit is not monetized in our calculations).[383]

The proposed rule will also have numerous ancillary benefits. These include improved quality of life for nearby residents, who note that flares are noisy and unsightly at night; reduced release of VOCs, including benzene and other hazardous air pollutants; and reduced production of NOx and particulate matter, which can cause respiratory and heart problems.

3. Net Benefits of the Proposed Rule

Overall, the BLM estimates that the benefits of this rulemaking outweigh its costs by a significant margin. The BLM expects net benefits ranging from $115–188 million per year (using a 7 percent discount rate) or $138–232 million per year (using a 3 percent discount rate). Specifically, assuming a 7 percent discount rate, we estimate the following annual net benefits:

- $115–130 million per year from 2017–2019;
- $155–156 million per year from 2020–2024; and
- $187–188 million per year from 2025–2026.

Assuming a 3 percent discount rate, we estimate the annual net benefits would be:

- $138–151 million per year from 2017–2019;
- $192–196 million per year from 2020–2024; and
- $231–232 million per year from 2025–2026.[384]

If, for purposes of analysis, we assume that the EPA does not finalize the 40 CFR part 60 subpart OOOOa rulemaking, we estimate the net benefits of this proposed rule would be somewhat higher, ranging from $119 million to $203 million per year (costs and costs savings calculated using a 7 percent discount rate) or $139 million to $245 million per year (costs and costs savings calculated using a 3 percent discount rate).

4. Distributional Impacts

(a) Energy Systems[385]

The proposed rule has a number of requirements that are expected to influence the production of natural gas, NGLs, and crude oil from onshore Federal and Indian oil and gas leases.

If subpart OOOOa were not finalized, we estimate the following incremental changes in production, noting the representative share of the total U.S. production in 2014 for context. We estimate additional natural gas production ranging from 12–15 Bcf per year (representing 0.04–0.06 percent of the total U.S. production), the productive use of an additional 29–41 Bcf of natural gas, which we estimate would be used to generate 36–51 million gallons of NGL per year (representing 0.08–0.11 percent of the total U.S. production), and a reduction in crude oil production ranging from 0.6–3.2 million bbl per year (representing 0.02–0.10 percent of the total U.S. production). Separate from the volumes listed above, we also expect 1 Bcf of gas to be combusted on-site that would have otherwise been vented. Combined, the capture or combustion of gas represents 49–52 percent of the volume vented in 2013 and the capture and/or productive use of gas represents 41–60 percent of the volume flared in 2013.[386]

If the EPA finalizes subpart OOOOa, we estimate slightly less additional natural gas production, ranging from 11.7–14.5 Bcf per year (representing 0.04–0.05 percent of the total U.S. production in 2014), and the same amount of additional NGL production and reduced crude oil production as presented above. We also expect 0.5 Bcf of gas to be combusted on-site that would have otherwise been vented. Combined, the capture or combustion of gas represents 44–46 percent of the volume vented in 2013 and the capture and/or productive use of the gas 41–60 percent of the volume flared in 2013.[387]

Since the relative changes in production are expected to be small, we do not expect that the proposed rule would significantly impact the price, supply, or distribution of energy.

(b) Royalties[388]

The rule is expected to increase natural gas production from Federal and Indian leases, and likewise, is expected to increase annual royalties to the Federal Government, tribal governments, States, and private landowners. For requirements that would result in incremental gas production, we calculate the additional royalties based on that production. When considering the deferment of production that could result from the rule's flaring limit, we calculate the incremental royalty as the difference in the net present value of the royalty received 1 year later (using 7 percent and 3 percent discount rates) and the value of the royalty received now.

If subpart OOOOa is not finalized, we estimate that the rule would result in additional royalties of $9–11 million per year (discounted at 7 percent) or $11–17 million per year (discounted at 3 percent). If the EPA finalizes subpart OOOOa, we estimate additional royalties of $9–11 million per year (discounted at 7 percent) or $10–16 million per year (discounted at 3 percent).

Royalty payments are recurring income to Federal or tribal governments and costs to the operator or lessee. As such, they are private transfer payments that do not affect the total resources available to society. An important but sometimes difficult problem in cost estimation is to distinguish between real costs and transfer payments. While transfers should not be included in the economic analysis of the benefits and costs of a regulation, they may be important for describing distributional effects.

(c) Small Businesses[389]

[380] RIA at 130.

[381] RIA at 133–135.

[382] RIA at 130.

[383] RIA at 133–135.

[384] RIA at 67.

[385] RIA at 92–93.

[386] RIA at 140.

[387] RIA at 140.

[388] RIA at 94–95.

[389] The BLM conducted an Initial Regulatory Flexibility Analysis, RIA at 154–166.

The BLM identified up to 1,828 entities that currently operate Federal and Indian leases. The vast majority of these entities are small business, as defined by the SBA. We estimated a range of potential per-entity costs, based on different discount rates and scenarios. Those per-entity compliance costs are presented in RIA.

Recognizing that the SBA defines a small business for oil and gas producers as one with fewer than 500 employees, a definition that encompasses many oil and gas producers, the BLM looked at company data for 26 different small-sized entities that currently hold BLM-managed oil and gas leases. The BLM ascertained the following information from the companies' annual reports to the U.S. Securities and Exchange Commission (SEC) for 2012 to 2014.

From data in the companies' 10–K filings to the SEC, the BLM was able to calculate the companies' profit margins [390] for the years 2012, 2013 and 2014. We then calculated a profit margin figure for each company when subject to the average annual cost increase associated with this rule. For simplicity, we used the average per-entity cost increase figures of $31,400 and $37,600 which roughly represent the middle of the range of potential per-entity costs assuming the EPA finalizes and does not finalize subpart OOOOa, respectively. Both figures include compliance costs and cost savings, calculated using a 7 percent discount rate.

For these 26 small companies, a per-entity compliance cost increase of $31,400 would result in an average reduction in profit margin of 0.087 percentage points (based on the 2014 company data) and a per entity cost increase of $37,600 would result in an average reduction in profit margin of 0.105 percentage points (also based on the 2014 company data). The full detail of this calculation is available in the RIA.

(d) Employment [391]

Executive Order 13563 states, ''Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation.'' [392] An analysis of employment impacts is a standalone analysis and the impacts should not be included in the estimation of benefits and costs.

The proposed rule is not expected to materially impact the employment within the oil and gas extraction, drilling, and support industries. As noted previously, the anticipated additional gas production volumes represent only a small fraction of the U.S. natural gas production volumes. Additionally, the annualized compliance costs represent only a small fraction of the annual net incomes of companies likely to be impacted. Therefore, we believe that the proposed rule would not alter the investment or employment decisions of firms or significantly adversely impact employment.

The proposed requirements would require the one-time installation or replacement of equipment and the ongoing implementation of an LDAR program, both of which would require labor to comply.

(e) Impacts on Tribal Lands [393]

This section presents the costs, benefits, net benefits, and incremental production associated with operations on Indian leases, as well as royalty implications for tribal governments.

If, as we expect, the EPA finalizes 40 CFR part 60 subpart OOOOa, we estimate that the proposed rule would pose costs ranging from $17–$23 million per year (using a 7 percent discount rate) or $16–18 million per year (using a 3 percent discount rate).[394]

Projected benefits from the proposed rule's operation on Indian lands range from $31–39 million per year (using a 7 percent discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3 percent discount rate) or $31–43 million per year (using a 3 percent discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3 percent discount rate).[395]

Net benefits from operation of the rule on leases on Indian lands range from $11–20 million per year (using a 7 percent discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3 percent discount rate) or range from $15–27 million per year (using a 3 percent discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3 percent discount rate).[396]

For impacts on production from leases on Indian lands, the rule is projected to result in additional natural gas production ranging from 1.1–1.5 Bcf per year; the productive use of an additional 4.5–6.4 Bcf of natural gas, which we estimate would be used to generate 5.6–8.0 million gallons of NGL per year; and a reduction in crude oil production ranging from 0.1–0.5 million bbl per year.[397] We further estimate that the proposed rule would reduce methane emissions from leases on Indian lands by 20,000 tpy, and would reduce VOC emissions by 48,000–51,000 tpy.[398]

We estimate additional royalties from leases on Indian lands of $1.1–1.6 million per year (discounted at 7 percent) or $1.1–1.8 million per year (discounted at 3 percent). See previous explanation about how the royalty estimates were derived.

If we assume for analytical purposes that the EPA does not finalize 40 CFR part 60 subpart OOOOa, we estimate that the proposed rule would pose costs ranging from $20–25 million per year (using a 7 percent discount rate) or from $18–21 million per year (using a 3 percent discount rate).

Projected benefits from the proposed rule's operation on Indian lands range from $35–46 million per year (using a 7 percent discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3 percent discount rate) or $35–50 million per year (using a 3 percent discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3 percent discount rate).

Net benefits from operation of the rule on leases on Indian lands range from $13–24 million per year (using a 7 percent discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3 percent discount rate) or range from $17–31 million per year (using a 3 percent discount rate to calculate the present value of future annual cost savings and using model averages of the social cost of methane with a 3 percent discount rate).

With respect to production from leases on Indian lands, the rule is projected to result in additional natural gas production ranging from 1.6–2.1 Bcf per year; the productive use of an

[390] The profit margin was calculated by dividing the net income by the total revenue as reported in the companies' 10–K filings.

[391] RIA at 148.

[392] Executive Order 13563, *Improving Regulation and Regulatory Review* (Jan. 18, 2011).

[393] RIA at 148–150.

[394] RIA at 148.

[395] Ibid.

[396] Ibid.

[397] RIA at 150.

[398] RIA at 149.

additional 4.5–6.4 Bcf of natural gas, which we estimate would be used to generate 5.6–8.0 million gallons of NGL per year; and a reduction in crude oil production ranging from 0.1–0.5 million bbl per year. We further estimate that the proposed rule would reduce methane emissions from leases on Indian lands by 22,000–23,000 tpy, and would reduce VOC emissions by 50,000–53,000 tpy.

We estimate additional royalties from leases on Indian lands of $1.4–1.9 million per year (discounted at 7 percent) or $1.4–2.1 million per year (discounted at 3 percent). See previous explanation about how the royalty estimates were derived.

VII. Procedural Matters

A. Executive Order 12866, Regulatory Planning and Review [399]

Executive Order 12866 requires agencies to assess the benefits and costs of regulatory actions, and, for significant regulatory actions, submit a detailed report of their assessment to the OMB for review. A rule is deemed significant under Executive Order 12866 if it may:

(a) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(b) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(c) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(d) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

The Office of Management and Budget has determined that this proposed rule is a significant regulatory action because it may have an annual effect on the economy of $100 million or more and because it may raise novel legal or policy issues arising out of legal mandates and the President's priorities. This proposed rule would limit flaring of associated gas from oil wells, and it would require operators to take actions to reduce gas losses through venting and leaks.

B. Regulatory Flexibility Act and Small Business Regulatory Enforcement Fairness Act of 1996 [400]

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) 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, unless the head of the agency certifies that the rule would not have a significant economic impact on a substantial number of small entities.[401] Congress enacted the RFA to ensure that government regulations do not unnecessarily or disproportionately burden small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

The BLM reviewed the Small Business Administration (SBA) size standards for small businesses and the number of entities fitting those size standards as reported by the U.S. Census Bureau in the Economic Census. The BLM concludes that the vast majority of entities operating in the relevant sectors are small businesses as defined by the SBA. As such, the rule would likely affect a substantial number of small entities. The BLM believes, however, that the proposed rule would not have a significant economic impact on a substantial number of small entities. The screening analysis conducted by BLM estimates the average reduction in profit margin for small companies will be just a fraction of one percentage point, which is not a large enough impact to be considered significant.

Although it is not required, the BLM nevertheless has chosen to prepare an initial regulatory flexibility analysis for this proposed rule.[402] There are several factors driving this decision. First, although the projected costs are expected to be quite small, as a percentage of a typical firm's annual profits, there is significant uncertainty associated with these costs. There is a combination of factors contributing to the uncertainty associated with the costs of this rule. These factors include limited data, a wide range of possible variation in commodity prices over time, and a variety of possible compliance options, particularly with respect to the flaring requirements. In addition, the BLM is taking comment on a wide range of alternatives to some of the proposed requirements, and some of these alternatives could affect the costs of the rule if the BLM were to adopt them in the final rule. This further enhances the uncertainty regarding the cost projections for the rule. Second, there is no question that if the costs of the rule for affected entities were economically significant, the BLM would be required to prepare an IRFA for the rule, given that the rule will affect a substantial number of small entities.

Thus, given the unique circumstances present in this rulemaking, the BLM believes it is prudent, and potentially helpful to small entities, to prepare an IRFA at this stage in the rulemaking. We do not believe this decision should be viewed as a precedent for preparing an IRFA in other rulemakings, and we may choose not to prepare a final regulatory flexibility analysis for the final rule, if our best estimate at that time is that the final rule would not have a significant economic effect on a substantial number of small entities.

C. Unfunded Mandates Reform Act of 1995

Under the Unfunded Mandates Reform Act (UMRA), agencies must prepare a written statement about benefits and costs prior to issuing a proposed rule that includes any Federal mandate that is likely to result in aggregate expenditure by State, local, and tribal governments, or by the private sector, of $100 million or more in any 1 year, and prior to issuing any final rule for which a proposed rule was published.

This proposed rule does not contain a Federal mandate that may result in expenditures of $100 million or more by State, local, and tribal governments, in the aggregate, or by the private sector in any 1 year. Thus, the proposed rule is also not subject to the requirements of Section 205 of UMRA.

This proposed rule is also not subject to the requirements of Section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. It contains no requirements that apply to such governments, nor does it impose obligations upon them.

D. Executive Order 12630, Governmental Actions and Interference With Constitutionally Protected Property Rights (Takings)

Under Executive Order 12630, the proposed rule would not have significant takings implications. A takings implication assessment is not required. The proposed rule would establish a limited set of standards

[399] RIA at 167.

[400] RIA at 167–168.

[401] 5 U.S.C. 601–612. The exception is found in 5 U.S.C. 605(b).

[402] See RIA, section 9.

under which gas can be flared or vented, and under which an operator can use oil and gas on a lease, unit, or communitized area for operations and production purposes, without paying royalty.

Oil and gas operators on BLM-administered leases are subject to lease terms that expressly require that subsequent lease activities be conducted in compliance with applicable Federal laws and regulations. The proposed rule is consistent with the terms of those Federal leases and is authorized by applicable statutes. Thus, the proposed rule is not a governmental action capable of interfering with constitutionally protected property rights, it would not cause a taking of private property, and it does not require further discussion of takings implications under this Executive Order.

E. Executive Order 13132, Federalism

The proposed rule would not have a substantial direct effect on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the levels of government. It would not apply to States or local governments or State or local government entities. Therefore, in accordance with Executive Order 13132, the BLM has determined that this proposed rule does not have sufficient Federalism implications to warrant preparation of a Federalism Assessment.

F. Executive Order 12988, Civil Justice Reform

This proposed rule would comply with the requirements of Executive Order 12988. Specifically, this rulemaking: (a) Meets the criteria of section 3(a) requiring that all regulations be reviewed to eliminate errors and ambiguity and be written to minimize litigation; and (b) Meets the criteria of section 3(b)(2) requiring that all regulations be written in clear language and contain clear legal standards.

G. Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

In accordance with Executive Order 13175, the BLM has evaluated this rulemaking and determined that it would not have substantial direct effects on federally recognized Indian tribes. Nevertheless, on a government-to-government basis we initiated consultation with tribal governments that the proposed rule may affect.

In 2014, the BLM conducted a series of forums to consult with tribal governments to inform the development of this proposal. We held tribal outreach sessions in Denver, Colorado (March 19, 2014), Albuquerque, New Mexico (May 7, 2014), Dickinson, North Dakota (May 9, 2014), and Washington, DC (May 14, 2014).[403] At the Denver and Washington, DC sessions, the tribal meetings were live-streamed to allow for the greatest possible participation by tribes and others. The tribal outreach sessions served as initial consultation with Indian tribes to comply with Executive Order 13175. We look forward to continuing close interaction with tribal regulators as we proceed through this rulemaking process.

H. Paperwork Reduction Act

1. Overview

The Paperwork Reduction Act (PRA)[404] provides that an agency may not conduct or sponsor, and a person is not required to respond to, a ''collection of information,'' unless it displays a currently valid control number. Collections of information include any request or requirement that persons obtain, maintain, retain, or report information to an agency, or disclose information to a third party or to the public.[405]

This proposed rule contains information collection requirements that are subject to review by OMB under the PRA. In accordance with the PRA, the BLM is inviting public comment on proposed new information collection requirements for which the BLM is requesting a new OMB control number.

As discussed below, some provisions of the proposed rule would involve some of the information collection activities that OMB has approved under Control Number 1004–0137, Onshore Oil and Gas Operations (43 CFR part 3160) (expiration date January 31, 2018).

The information collection activities in this proposed rule are described below along with estimates of the annual burdens. Included in the burden estimates are the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing each component of the proposed information collection requirements.

The information collection request for this proposed rule has been submitted to OMB for review in accordance with the PRA. A copy of the request may be obtained from the BLM by electronic mail request to Tim Spisak at *tspisak@blm.gov* or by telephone request to 202–912–7311. You may also review the information collection request online at: *http://www.reginfo.gov/public/do/PRAMain.*

The BLM requests comments on the following subjects:

- Whether the collection of information is necessary for the proper functioning of the BLM, including whether the information will have practical utility;
- The accuracy of the BLM's estimate of the burden of collecting the information, including the validity of the methodology and assumptions used;
- The quality, utility, and clarity of the information to be collected; and
- How to minimize the information collection burden on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other forms of information technology.

If you want to comment on the information collection requirements of this proposed rule, please send your comments directly to OMB, with a copy to the BLM, as directed in the **ADDRESSES** section of this preamble. Please identify your comments with ''OMB Control Number 1004–XXXX.'' OMB is required to make a decision concerning the collection of information contained in this proposed rule between 30 to 60 days after publication of this document in the **Federal Register**. Therefore, a comment to OMB is best assured of having its full effect if OMB receives it by March 9, 2016.

2. Summary of Proposed Information Collection Requirements

- Title: Waste Prevention, Production Subject to Royalties, and Resource Conservation (43 CFR parts 3160 and 3170).
- Forms: Form 3160–5, Sundry Notices and Reports on Wells.
- OMB Control Number: This is a new collection of information.
- Description of Respondents: Holders of Federal and Indian (except Osage Tribe) oil and gas leases, those who belong to federally approved units and CAs, and are parties to IMDA oil and gas agreements.
- Respondents' Obligation: Required to obtain or retain a benefit.
- Frequency of Collection: On occasion and monthly.
- Abstract: This proposed rule would update standards to reduce wasteful venting, flaring, and leaks of natural gas from onshore wells located on Federal and Indian oil and gas leases, units and CAs.
- Estimated Total Annual Burden Hours: 42,350 hours.

[403] More info can be found at: *http://www.blm.gov/wo/st/en/prog/energy/public_events_on_oil.html*

[404] 44 U.S.C. 3501–3521.

[405] 44 U.S.C. 3502(3); 5 CFR 1320.3(c).

• Estimated Total Non-Hour Cost: None.

3. Proposals Involving APDs and Sundry Notices

(a) Plan to Minimize Waste of Natural Gas (Form 3160–3) (43 CFR 3162.3–1(j))

This proposed rule would add a new paragraph (j) to 43 CFR 3162.3–1 that would require a plan to minimize waste of natural gas when submitting an APD for a development oil well. This information would be in addition to the APD information that the BLM already collects under OMB Control Number 1004–0137. The required elements of the waste minimization plan are listed at paragraphs (j)(1) through (j)(7).

(b) Request for Prior Approval for Royalty-Free Uses On-Lease or Off-Lease (43 CFR 3178.5, 3178.7, and 3178.9)

Under proposed § 3178.5, submission of a Sundry Notice (Form 3160–5) would be required to request prior written BLM approval for royalty-free treatment of volumes used for the following uses:

• Using oil as a circulating medium in drilling operations;
• Injecting gas that an operator produces from a lease, unit participating area (PA), or communitized area (CA) into the same lease, unit PA, or CA for the purpose of increasing the recovery of oil or gas (including gas that is cycled in a contained gas-lift production system), subject to an approval under 43 CFR 3162.3–2 to conduct the gas injection;
• Using oil or gas that an operator removes from the pipeline at a location downstream of the facility measurement point (FMP), if removal and use both occur on the lease, unit, or CA;
• Using gas initially removed from a lease, unit PA, or CA for treatment or processing because of particular physical characteristics of the gas, where the gas is returned to the lease, unit, or CA for lease operations; and
• Any other type of use of produced oil or gas for operations and production purposes pursuant to proposed § 3178.3 that is not identified in proposed § 3178.4.

Under proposed § 3178.7, submission of a Sundry Notice (Form 3160–5) would be required to request prior written BLM approval for off-lease royalty-free uses in the following circumstances:

• The equipment or facility in which the operation is conducted is located off the lease, unit, or CA for engineering, economic, resource-protection, or physical-accessibility reasons; and
• The operations are conducted upstream of the FMP.

Under proposed § 3178.9, the following information would be required in a request for prior approval of royalty-free use under § 3178.5, or for prior approval of off-lease royalty-free use under § 3178.7:

• A complete description of the operation to be conducted, including the location of all facilities and equipment involved in the operation and the location of the FMP;
• The method of measuring the volume of oil, or measuring or estimating the volume of gas, that the operator expects will be used in the operation, and the volume expected to be used;
• If the volume expected to be used will be estimated, the basis for the estimate (*e.g.,* equipment manufacturer's published consumption or usage rates); and
• The proposed disposition of the oil or gas used (*e.g.,* whether gas used would be consumed as fuel, vented through use of a gas-activated pneumatic controller, returned to the reservoir, or some other disposition).

(c) Request for Approval of Alternative Volume Limits (43 CFR 3179.7)

Proposed § 3179.7 would apply only to leases issued before the effective date of the final rule. It would provide that an operator may seek BLM approval of venting and flaring in excess of the applicable limit under proposed § 3179.6. Using a Sundry Notice, the operator would be required to show that the applicable limit would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. To support this showing, the operator would be required to submit the following information:

• Information regarding the operator's wells under the lease that produce Federal or Indian gas, including:
  ○ The name, number, and location of each well, and the number of the lease, unit, or CA with which it is associated;
  ○ The depths and names of producing formations;
  ○ The gas production level of each of the operator's wells for the most recent production month for which information is available; and
  ○ The volumes of gas being vented and flared from each of the operator's wells;
• Map(s) showing:
  ○ The entire lease, unit, or CA and the surrounding lands to a distance and on a scale that shows the field in which the well is or will be located (if applicable), and all pipelines that could transport the gas from the well;
  ○ All of the operator's producing oil and gas wells, which are producing from Federal or Indian leases, (both on Federal or Indian leases and on other properties) within the map area;
  ○ Identification of all of the operator's wells within the lease from which gas is flared or vented, and the location and distance of the nearest gas pipeline(s) to each such well, with an identification of those pipelines that are or could be available for connection and use; and
  ○ Identification of all of the operator's wells within the lease from which gas is captured;
• Data that show pipeline capacity and the operator's projections of the cost associated with installation and operation of gas capture infrastructure and alternative methods of transportation that do not require pipelines;
• The operator's projections of gas prices, gas production volumes, gas quality (*i.e.,* heating value and H_2S content), revenues derived from gas production, and royalty payments on gas production over the next 15 years or the life of each of the operator's leases, units, or CAs, whichever is less; and
• The operator's projections of oil prices, oil production volumes, costs, revenues, and royalty payments from the operator's oil and gas operations within the lease over the lesser of the next 15 years or the anticipated remaining period in which the operator will produce from the Federal or Indian lease, unit, or CA.

(d) Certification in Support of Exemption From Volume Limits (43 CFR 3179.7(d))

Proposed § 3179.7(d) would apply only to leases issued before the effective date of the final rule. It would authorize an operator to provide a certification in support of a renewable, 2-year exemption from volume limits (instead of an alternative limit requested under proposed § 3179.7(b)). The certification would consist of a Sundry Notice with an affidavit verifying that all of the following terms and conditions are met:

• The lease, unit, or CA is not connected to a gas pipeline;
• The closest point on the lease, unit, or CA is located more than 50 straight-line miles from the nearest gas processing plant; and
• In the most recent production month, the lease, unit or CA flared or vented at an average rate that exceeds by at least 50 percent the applicable flaring limit specified in § 3179.6.

(e) Well Completion and Related Operations (43 CFR 3179.102(b))

- Proposed § 3179.102(a) would require gas that reaches the surface during well completion and related operations to be:
  - Captured and sold;
  - Directed to a flare pit or flare stack equipped with an automatic igniter to combust any flammable gasses, subject to the volumetric limitations in proposed § 3179.103(a)(3);
  - Used in operations on the lease, unit, or CA; or
  - Injected.
- Paragraph (b) would authorize an operator to demonstrate to the BLM on a Sundry Notice that it is in compliance with requirements for control of gas from well completions established under 40 CFR part 60, in lieu of compliance with the requirements of paragraph (a).

(f) Initial Production Testing Request for Extension (43 CFR 3179.103)

- Proposed § 3179.103 would allow gas to be flared royalty-free during a well's initial production testing until:
  - The operator determines that it has obtained adequate reservoir information for the well;
  - 30 days have passed since the beginning of the production test;
  - The operator has flared 20 million MMcf of gas; or
  - Production begins.

The BLM may extend the period for royalty-free testing, but only if the operator requests such an extension by submitting a Sundry Notice.

(g) Subsequent Well Tests Request for Extension (43 CFR 3179.104)

Proposed § 3179.104 would limit royalty-free flaring during production tests after the initial production test to 24 hours, unless the BLM approves or requires a longer test period. The operator would be allowed to request for longer test period by submitting a Sundry Notice.

Reporting of Emergency Venting and Flaring Beyond Specified Timeframes (43 CFR 3179.105)

(h) Reporting of Emergency Venting or Flaring Beyond Specified Timeframes (43 CFR 3179.105)

Proposed § 3179.105 would allow an operator to flare or vent gas royalty-free during a temporary, short-term, infrequent, and unavoidable emergency for up to 24 hours per incident, and for no more than 3 emergencies within any 30-day period. The operator would be required to report on a Sundry Notice any volumes of gas flared or vented beyond those specified timeframes.

(i) Pneumatic Controller Report (43 CFR 3179.201(b) and (c))

Proposed § 3179.201 addresses gas losses from pneumatic controllers that are not covered by EPA regulations at 40 CFR 60.5360 through 60.5390. The proposed section would require operators to replace pneumatic controllers that have continuous bleed rates that are greater than 6 scf/hour with lower-bleed models within 1 year after the effective date of the final rule. Paragraph (b) would provide an exception to this requirement if the operator submits a Sundry Notice to the BLM showing that:

- A pneumatic controller with a bleed rate greater than 6 scf/hour is required based on functional needs;
- The pneumatic controller exhaust is routed to a flare device; or
- The replacement of a pneumatic controller would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

Paragraph (c) would provide an exception to the replacement requirement if the operator submits a Sundry Notice showing that a pneumatic controller with a bleed rate greater than 6 scf/hour serves a well or facility has an estimated remaining productive life of 3 years or less. The operator would also be required to replace the device no later than 3 years from the effective date of the rule, absent a showing that replacement would impose costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

(j) Pneumatic Pump Report (43 CFR 3179.202)

Proposed § 3179.202 would require operators to replace pneumatic pumps not covered under EPA regulations with zero-emissions pumps or route the pump exhaust to a flare device within 1 year after the effective date of the final rule. Paragraph (c) would provide an exception to this requirement if the operator makes a showing on a Sundry Notice, and the BLM agrees, that:

- A pneumatic pump is required based on functional needs, described in the Sundry Notice, and there is no existing flare device on site or routing to such a device is technically infeasible; or
- The installation of a zero-emissions pump would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease and there is no existing flare device on site or routing to such a device is technically infeasible.

Paragraph (d) would provide an exception to the replacement requirement if the operator submits a Sundry Notice showing that a pneumatic pump serves a well or facility that has an estimated remaining productive life of 3 years or less. The operator would also be required to replace the device no later than 3 years from the effective date of the rule, absent a showing that replacement would impose costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

(k) Crude Oil and Condensate Storage Vessels (43 CFR 3179.203(c))

Proposed § 3179.203 would require operators to route all tank vapor gas from storage vessels and batteries to a combustion device or continuous flare, or to a sales line, unless the operator submits an economic analysis in a Sundry Notice and the BLM agrees with that economic analysis. Paragraph (c) would require that the operator demonstrate in the Sundry Notice that compliance would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves. Operators would be required to submit this information no later than 6 months after the rule becomes effective.

(l) Downhole Well Maintenance and Liquids Unloading—Documentation and Reporting (43 CFR 3179.204(a) and (d))

Proposed § 3179.204 would pertain to downhole well maintenance and liquids unloading operations. Paragraph (a) would require operators to use practices that maximize the recovery of gas for sale and to flare gas that is not recovered. It would also require operators to document, before purging a well for the first time, a discovery that compliance with these requirements would be technically infeasible or unduly costly. Paragraph (d) would require that documentation to be included as part of a Sundry Notice submitted to the BLM within 10 calendar days after the first liquids unloading event by well purging conducted after the effective date of proposed § 3179.204.

4. Other Proposed Information Collection Activities

(a) Downhole Well Maintenance and Liquids Unloading—Notice of Excessive Duration or Volume (43 CFR 3179.204(e)

Proposed § 3179.204 would pertain to downhole well maintenance and liquids unloading operations. Paragraph (e) would require an operator to notify the

BLM in a Sundry Notice within 14 days if the cumulative duration of well purging events for a well exceeds 24 hours during any production month, or if the estimated gas volume vented in liquids unloading by well purging operations for a well exceed 75 Mcf during any production month.

(b) Leak Detection Inspection and Repair

Proposed §§ 3179.301 through 3179.305 would include information collection activities pertaining to the detection and repair of gas leaks during production operations. The following activities would require operators to submit a Sundry Notice:

- Proposed § 3179.301(e) would allow an operator to satisfy the requirements of proposed §§ 3179.301 through 3179.305 for some or all of the equipment or facilities on a given lease by demonstrating to the BLM on a Sundry Notice that the operator is complying with EPA requirements established pursuant to 40 CFR part 60 with respect to such equipment or facilities.
- Proposed § 3179.303(b) would allow an operator to submit a Sundry Notice requesting authorization to detect gas leaks using an alternative device, program, or method.
- Proposed § 3179.304(a) would require an operator to repair any leak not associated with normal equipment operation no later than 15 calendar days after discovery. In the event of a delay beyond 15 calendar days, paragraph (b) of this section would require the operator to submit a Sundry Notice showing good cause.

5. Burden Estimates

The following table details the estimated annual burdens of activities that would involve APDs and Sundry Notices, the use of which has been authorized under Control Number 1004–0137.

PROPOSALS INVOLVING APDS AND SUNDRY NOTICES ESTIMATED HOUR BURDENS

Type of response A.	Number of responses B.	Hours per response C.	Total Hours (column B × column C) D.
Plan to Minimize Waste of Natural Gas, 43 CFR 3162.3–1, Form 3160–3	2,000	2	4,000
Request for Prior Approval for Royalty-Free Uses On-Lease or Off-Lease, 43 CFR 3178.5, 3178.7, and 3178.9, Form 3160–5	50	8	400
Request for Approval of Alternative Volume Limits, 43 CFR 3179.7(b), Form 3160–5	185	16	2,960
Certification in Support of Exemption from Volume Limits, 43 CFR 3179.7(d), Form 3160–5	15	16	240
Well Completion and Related Operations, 43 CFR 3179.102(b), Form 3160–5	5	2	10
Initial Production Testing Request for Extension, 43 CFR 3179.103, Form 3160–5	5	2	10
Subsequent Well Tests Request for Extension, 43 CFR 3179.104, Form 3160–5	5	2	10
Reporting of Emergency Venting and Flaring Beyond Specified Timeframes, 43 CFR 3179.105, Form 3160–5	25	2	50
Pneumatic Controller Report, 43 CFR 3179.201(b) and (c), Form 3160–5	200	2	400
Pneumatic Pump Report, 43 CFR 3179.202, Form 3160–5	250	8	2,000
Crude Oil and Condensate Storage Vessels, 43 CFR 3179.203(c), Form 3160–5	100	8	800
Downhole Well Maintenance and Liquids Unloading—Documentation and Reporting, 43 CFR 3179.204(a) and (d), Form 3160–5	5,000	1	5,000
Downhole Well Maintenance and Liquids Unloading—Notification of Excessive Duration or Volume, 43 CFR 3179.204(e)			
Form 3160–5	120	1	120
Leak Detection—Compliance with EPA Regulations, 43 CFR 3179.301(e), Form 3160–5	500	8	4,000
Leak Detection—Request to Use and Alternative Device, Program, or Method, 43 CFR 3179.303(b), Form 3160–5	200	40	8,000
Leak Detection—Notification of Delay in Repairing Leaks, 43 CFR 3179.304(a), Form 3160–5	100	1	100
Totals	8,760		28,100

The following table details the annual estimated hour burdens for the rest of the proposed information collection activities in this rule.

ESTIMATED ANNUAL HOUR BURDENS FOR OTHER IC ACTIVITIES

Type of response A.	Number of responses B.	Hours per response C.	Total Hours (column B × column C) D.
Downhole Well Maintenance and Liquids Unloading—Recordkeeping, 43 CFR 3179.204(c)	5,000	0.25	1,250
Leak Detection—Inspection Recordkeeping, 43 CFR 3179.305	52,000	.25	13,000
Totals	57,000		14,250

I. National Environmental Policy Act

The BLM has prepared a draft environmental assessment (EA) to determine whether issuance of this proposed regulation pertaining to oil and gas waste prevention and royalty clarification would constitute a ''major Federal action significantly affecting the quality of the human environment'' under section 102(2)(C) of the National Environmental Policy Act (NEPA).[406] The BLM believes that, for the most part, the proposed rule would benefit the environment by reducing emissions of methane (a potent GHG), VOCs (which contribute to smog), and hazardous air pollutants such as benzene (a known carcinogen). In addition, the proposed rule would reduce light pollution and other impacts from flaring. The rule may also have indirect and minor to negligible adverse environmental impacts, primarily due to land disturbance from increased or accelerated construction of gas pipelines and compressors and/or increased truck traffic on existing disturbed surfaces from the increased use of mobile capture technology. In the aggregate, the beneficial impacts of the proposed rule are expected to dwarf its adverse impacts. Further, the BLM anticipates that any new gathering lines would be subject to additional environmental review based on submission of a Sundry Notice or a FLPMA Title V right-of-way application prior to construction.

During the public comment period for the proposed rule, we will consider any new information we receive that may inform our analysis of the potential environmental impacts of the rule. A copy of the draft EA can be viewed at *www.regulations.gov* (use the search term 1004–AE14, open the Docket Folder, and look under Supporting Documents) and at the address specified in the **ADDRESSES** section.

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

Under Executive Order 13211, agencies are required to prepare and submit to OMB a Statement of Energy Effects for significant energy actions. This statement is to include a detailed statement of ''any adverse effects on energy supply, distribution, or use (including a shortfall in supply, price increases, and increase use of foreign supplies)'' for the action and reasonable alternatives and their effects.

Section 4(b) of Executive Order 13211 defines a ''significant energy action'' as ''any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of (OIRA) as a significant energy action.''

[406] 42 U.S.C. 4332(2)(C).

Since the compliance costs for this rule would represent such a small fraction of company net incomes, we believe that the rule is unlikely to impact the investment decisions of firms. Also, any incremental production of gas estimated to result from the rule's enactment would constitute a small fraction of total U.S. production, and any potential and temporary deferred production of oil would likewise constitute a small fraction of total U.S. production. For these reasons, we do not expect that the proposed rule would significantly impact the supply, distribution, or use of energy. As such, the rulemaking is not a ''significant energy action'' as defined in Executive Order 13211.

K. Clarity of the Regulations

Executive Order 12866 requires each agency to write regulations that are simple and easy to understand. We invite your comments on how to make these proposed regulations easier to understand, including answers to questions such as the following:

- Are the requirements in the proposed regulations clearly stated?
- Do the proposed regulations contain technical language or jargon that interferes with their clarity?
- Does the format of the proposed regulations (grouping and order of sections, use of headings, paragraphing, etc.) aid or reduce their clarity?
- Would the regulations be easier to understand if they were divided into more (but shorter) sections?
- Is the description of the proposed regulations in the **SUPPLEMENTARY INFORMATION** section of this preamble helpful in understanding the proposed regulations? How could this description be more helpful in making the proposed regulations easier to understand?

Please send any comments you have on the clarity of the regulations to the address specified in the **ADDRESSES** section.

L. Executive Order 13563, Improving Regulation and Regulatory Review

Executive Order 13563 reaffirms the principles of E.O. 12866 while calling for improvements in the nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. The executive order directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. E.O. 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. We have developed this proposed rule in a manner consistent with these requirements.

VIII. Authors

The principal authors of this rule are: Timothy Spisak and James Tichenor of the BLM Washington Office; Eric Jones of the BLM Moab, Utah Field Office; and David Mankiewicz of the BLM Farmington, New Mexico Field Office; assisted by Faith Bremner of the staff of the BLM's Regulatory Affairs Division.

List of Subjects

43 CFR Part 3100

Government contracts, Mineral royalties, Oil and gas reserves, Public lands-mineral resources, Reporting and recordkeeping requirements, Surety bonds.

43 CFR Part 3160

Administrative practice and procedure, Government contracts, Indians-lands, Mineral royalties, Oil and gas exploration, Penalties, Public lands—mineral resources, Reporting and recordkeeping requirements.

43 CFR Part 3170

Administrative practice and procedure, Flaring, Government contracts, Incorporation by reference, Indians-lands, Mineral royalties, Immediate assessments, Oil and gas exploration, Oil and gas measurement, Public lands—mineral resources, Reporting and recordkeeping requirements, Royalty-free use, Venting.

Dated: January 21, 2016.

Janice M. Schneider,

Assistant Secretary, Land and Minerals Management.

For the reasons set out in the preamble, the Bureau of Land Management proposes to amend 43 CFR parts 3100 and 3160 and add new subparts 3178 and 3179 to new 43 CFR part 3170 as follows:

PART 3100—ONSHORE OIL AND GAS LEASING

■ 1. Revise the authority citation for part 3100 to read as follows:

Authority: 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359 and 1751; 43 U.S.C.

1732(b), 1733, and 1740; and the Energy Policy Act of 2005 (Pub. L. 109–58).

■ 2. Revise § 3103.3–1 to read as follows:

§ 3103.3–1 Royalty on production.

(a) Royalty on production will be payable only on the mineral interest owned by the United States. Royalty must be paid in amount or value of the production removed or sold as follows:

(1) For leases issued on or before [EFFECTIVE DATE OF THE FINAL RULE], the rate prescribed in the lease or in applicable regulations at the time of lease issuance;

(2) For leases issued after [EFFECTIVE DATE OF THE FINAL RULE]:

(i) 12½ percent on all noncompetitive leases; and

(ii) A base rate of not less than 12½ percent on all competitive leases, exchange and renewal leases, and leases issued in lieu of unpatented oil placer mining claims under § 3108.2–4;

(3) 16 ⅔ percent on noncompetitive leases reinstated under § 3108.2–3 plus an additional 2 percentage-point increase added for each succeeding reinstatement; and

(4) The rate used for royalty determination that appears in a lease that is reinstated or that is in force for competitive leases at the time of issuance of the lease that is reinstated, plus 4 percentage points, plus an additional 2 percentage points for each succeeding reinstatement.

(b) Leases that qualify under specific provisions of the Act of August 8, 1946 (30 U.S.C. 226(c) may apply for a limitation of a 12½ percent royalty rate.

(c) The average production per well per day for oil and gas will be determined pursuant to 43 CFR 3162.7–4.

(d) Payment of a royalty on the helium component of gas will not convey the right to extract the helium. Applications for the right to extract helium shall be made under 43 CFR part 16.

PART 3160—ONSHORE OIL AND GAS OPERATIONS

■ 3. The authority citation for part 3160 continues to read as follows:

Authority: 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359, and 1751; and 43 U.S.C. 1732(b), 1733, and 1740.

§ 3160.0–5 [Amended]

■ 4. Amend § 3160.0–5 by removing the definition of ''Avoidably lost.''

■ 5. Amend § 3162.3–1 by adding paragraph (j) to read as follows:

§ 3162.3–1 Drilling applications and plans.

* * * * *

(j) When submitting an Application for Permit to Drill an oil well, the operator must also submit a plan to minimize waste of natural gas from that well. The waste minimization plan must accompany, but would not be part of, the Application for Permit to Drill. The waste minimization plan must set forth a strategy for how the operator will comply with the requirements of 43 CFR subpart 3179 regarding control of waste from venting, flaring and leaks, and must explain how the operator plans to capture associated gas upon the start of oil production, or as soon thereafter as reasonably possible. Failure to submit a complete and adequate waste minimization plan is grounds for denying or disapproving an Application for Permit to Drill. The waste minimization plan must include the following information:

(1) The anticipated completion date of the proposed well(s);

(2) The anticipated gas production rates of the proposed well(s);

(3) A gas pipeline system location map of sufficient detail, size, and scale as to show the field in which the proposed well will be located, and all existing gas pipelines within 20 miles of the well. The map should also contain:

(i) The name and location of the gas processing plant(s) closest to the proposed well(s), and of the intended destination processing plant, if different;

(ii) The location and name of the operator of each gas pipeline within 20 miles of the proposed well;

(iii) The proposed route and tie-in point that connects or could connect the subject well to an existing gas pipeline;

(4) Information on the gas pipeline to which the operator plans to connect, including:

(i) Maximum current daily capacity of the pipeline;

(ii) Current throughput of the pipeline;

(iii) Anticipated daily capacity of the pipeline at the anticipated date of first gas sales from the proposed well;

(iv) Anticipated throughput of the pipeline at the anticipated date of first gas sales from the proposed well;

(v) Certification that the operator has provided one or more midstream processing companies with information about the operator's production plans, including the anticipated completion dates and gas production rates of the proposed well or wells; and

(vi) Any plans known to the operator for expansion of pipeline capacity for the area that includes the proposed well.

(5) A description of anticipated production, including:

(i) The anticipated date of first production;

(ii) The expected oil and gas production rates and duration from the proposed well. If the proposed well is on a multi-well pad, the plan should include the total expected production for all wells being completed;

(iii) The expected production decline curve of both oil and gas from the proposed well; and

(iv) The expected Btu value for gas production from the proposed well.

(6) The volume and percentage of produced gas the operator is currently flaring or venting from wells in the same field and any wells within a 20-mile radius of that field; and

(7) An evaluation of opportunities for alternative on-site capture approaches, if pipeline transport is unavailable.

PART 3170—ONSHORE OIL AND GAS PRODUCTION

■ 6. The authority citation for part 3170, which was proposed to be added on July 13, 2015 (80 FR 40768), continues to read as follows:

Authority: 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359, and 1751; and 43 U.S.C. 1732(b), 1733, and 1740.

■ 7. Add subparts 3178 and 3179 to part 3170, which was proposed to be added on July 13, 2015 (80 FR 40768), to read as follows:

Subpart 3178—Royalty-Free Use of Lease Production

Subpart 3179—Waste Prevention and Resource Conservation

§ 3178.1 Purpose.

The purpose of this subpart is to address the circumstances under which oil or gas produced from Federal and Indian leases may be used royalty-free in operations on the lease, unit, or communitized area (CA). This subpart supersedes those portions of Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases (NTL–4A), 44 FR 76600 (December 27, 1979), pertaining to oil or gas used for beneficial purposes.

§ 3178.2 Scope.

(a) This subpart applies to:

(1) All onshore Federal and Indian (other than Osage Tribe) oil and gas leases, units, and CAs, except as otherwise provided in this subpart;

(2) Indian Mineral Development Act (IMDA) oil and gas agreements, unless specifically excluded in the agreement or unless the relevant provisions of this subpart are inconsistent with the agreement;

(3) Leases and other business agreements and contracts for the development of tribal energy resources under a Tribal Energy Resource Agreement entered into with the Secretary, unless specifically excluded in the lease, other business agreement, or Tribal Energy Resource Agreement;

(4) Committed State or private tracts in a federally approved unit or communitization agreement defined by or established under 43 CFR subpart 3105 or 43 CFR part 3180;

(5) All onshore wells, tanks, compressors, and other facilities located on a Federal or Indian lease or a federally approved unit or CA; and

(6) All gas lines located on a Federal or Indian lease or federally approved unit or CA that are owned or operated by the operator of the lease, unit, or communitization agreement.

(b) For purposes of this subpart, the term ''lease'' also includes IMDA agreements.

§ 3178.3 Production on which royalty is not due.

(a) To the extent specified in §§ 3178.4 and 3178.5, royalty is not due on:

(1) Oil or gas that is produced from a lease or CA and used for operations and production purposes (including placing oil or gas in marketable condition) on the same lease or CA without being removed from the lease or CA; or

(2) Oil or gas that is produced from a unit PA and used for operations and production purposes (including placing oil or gas in marketable condition) on the unit, for the same unit PA, without being removed from the unit.

(a) For the uses described in § 3178.5, the operator must obtain prior written BLM approval for the volumes used for operational and production purposes to be royalty free.

§ 3178.4 Uses of oil or gas on a lease, unit, or CA that do not require prior written BLM approval for royalty-free treatment of volumes used.

(a) Uses of produced oil or gas for operations and production purposes that do not require prior written BLM approval for the used volumes to be treated as royalty free under § 3178.3 are:

(1) Use of fuel to power artificial lift equipment;

(2) Use of fuel to power equipment used for enhanced recovery;

(3) Use of fuel to power drilling rigs;

(4) Use of gas to actuate pneumatic controllers or operate pneumatic pumps at production facilities;

(5) Use of fuel to heat, separate, or dehydrate production;

(6) Use of fuel to compress gas to place it in marketable condition; and

(7) Use of oil that an operator produces from a lease, unit, or CA and pumps into a well on the same lease, unit, or CA to clean the well and improve production, *e.g.*, hot oil treatment. The operator must document the removal of the oil from the tank or pipeline under Onshore Oil and Gas Order No. 3 (Site Security), or any successor regulation.

(b) The volume to be treated as royalty free must not exceed the amount of fuel reasonably necessary to perform the operational function, using equipment of appropriate capacity.

§ 3178.5 Uses of oil or gas on a lease, unit, or CA that require prior written BLM approval for royalty-free treatment of volumes used.

(a) Uses that require prior written approval from the BLM before the production used may be treated as royalty free under § 3178.3 include: (1) Using oil as a circulating medium in drilling operations;

(2) Injecting gas that an operator produces from a lease, unit PA, or CA into the same lease, unit PA, or CA for the purpose of increasing the recovery of oil or gas (including gas that is cycled in a contained gas-lift production system), subject to an approval under 3162.3–2 of this title to conduct the gas injection;

(3) Using oil or gas that an operator removes from the pipeline at a location downstream of the Facility Measurement Point (FMP), if removal and use both occur on the lease, unit, or CA;

(4) Using gas initially removed from a lease, unit PA, or CA for treatment or processing because of particular physical characteristics of the gas, where the gas is returned to the lease, unit, or CA for lease operations; and

(5) Any other type of use of produced oil or gas for operations and production purposes pursuant to § 3178.3 that is not identified in § 3178.4.

(b) (1) The operator must obtain BLM approval to conduct activities under paragraph (a) of this section by submitting a Form 3160–5, Sundry Notices and Reports on Wells (Sundry Notice) containing the information required under § 3178.9.

(2) With respect to uses under paragraph (a)(3) of this section, the operator must measure the volume of oil or gas used in accordance with Onshore

Oil and Gas Orders No. 4 (oil) and 5 (gas) as applicable, or other successor regulations.

(3) With respect to uses under paragraph (a)(4) of this section, the operator must measure any gas returned to the lease, unit, or CA under such an approval in accordance with Onshore Oil and Gas Order No. 5 or other successor regulations.

(c) If the BLM disapproves a request for royalty-free treatment for volumes used under this section, the operator must pay royalties for the gas used beginning on the date the operator was required to request approval under paragraph (a) of this section.

§ 3178.6 Uses of oil or gas moved off the lease, unit, or CA that do not require prior written approval for royalty-free treatment of volumes used.

Oil or gas used after being moved off the lease, unit, or CA may be treated as royalty free without prior written BLM approval only if the use meets the criteria under § 3178.4 and when:

(a) Oil or gas is piped along a logical route, based on existing access, topography, land ownership or other similar characteristic, directly from one area of the lease, unit, or CA to another area of the same lease, unit, or CA where it is used without oil or gas being added to or removed from the pipeline while crossing lands that are not part of the lease, unit, or CA; or

(b) A well is directionally drilled and the wellhead is not located on the producing lease, unit, or CA, and oil or gas is used on the same well pad for operations and production purposes for that well.

§ 3178.7 Uses of oil or gas moved off the lease, unit, or CA that require prior written approval for royalty-free treatment of volumes used.

(a) Except as provided in § 3178.6(b) and paragraph (b) of this section, royalty is owed on all oil or gas used in operations conducted off the lease, unit, or CA.

(b) The BLM may grant prior written approval to treat oil or gas used in operations conducted off the lease, unit, or CA as royalty free (referred to as off-lease royalty-free use) if the use meets one or more of the criteria listed in § 3178.5(a) and if:

(1) The equipment or facility in which the operation is conducted is located off the lease, unit, or CA for engineering, economic, resource-protection, or physical-accessibility reasons; and

(2) The operations are conducted upstream of the FMP.

(c) The operator must obtain BLM approval under paragraph (b) of this section by submitting a Sundry Notice containing the information required under § 3178.9.

(d) Approval of measurement or commingling off the lease, unit, or CA under other regulations does not constitute approval of off-lease royalty-free use. The operator or lessee must expressly request, and submit its justification for, approval of off-lease royalty-free use.

(e) If equipment or a facility located on a particular lease, unit, or CA treats oil or gas produced from properties that are not unitized or communitized with the property on which the equipment or facility is located, in addition to treating oil or gas produced from the lease, unit, or CA on which the equipment or facility is located, the operator may report as royalty free only that portion of the oil or gas used as fuel that is properly allocable to the share of production contributed by the lease, unit, or CA on which the equipment is located, unless otherwise authorized by the BLM under this section.

§ 3178.8 Measurement or estimation of royalty-free volumes.

(a) The operator must measure or estimate the volumes of royalty-free gas used in operations upstream of the FMP.

(b) The operator must measure all gas that is removed from the product stream downstream of the FMP and used in operations on the lease, unit, or CA (or off the lease, unit, or CA if the BLM approves such use), using the measurement procedures in Onshore Oil and Gas Order No. 5 or other successor regulation.

(c) The operator must measure the volume of oil used in operations on the lease, unit, or CA (or off the lease, unit, or CA if the BLM approves such use) using the measurement procedures in Onshore Oil and Gas Order No. 4 or other successor regulation. The operator must also document removal of such oil from the tank or pipeline.

(d) Each of the volumes required to be measured or estimated, as applicable, under this subpart, must be reported by the operator following applicable ONRR reporting requirements.

§ 3178.9 Requesting approval of royalty-free treatment when approval is required.

To request written approval of royalty-free use when required under § 3178.5, or of off-lease royalty-free use under § 3178.7, the operator must submit a Sundry Notice that includes the following information:

(a) A complete description of the operation to be conducted, including the location of all facilities and equipment involved in the operation and the location of the FMP;

(b) The volume of oil or gas that the operator expects will be used in the operation, and the method of measuring or estimating that volume;

(c) If the volume of gas expected to be used will be estimated, the basis for the estimate (*e.g.,* equipment manufacturer's published consumption or usage rates); and

(d) The proposed disposition of the oil or gas used (*e.g.,* whether gas used would be consumed as fuel, vented through use of a gas-activated pneumatic controller, returned to the reservoir, or some other disposition).

§ 3178.10 Facility and equipment ownership.

The operator is not required to own or lease the equipment or facility that uses oil or gas royalty free. The operator is responsible for obtaining all authorizations, measuring production, reporting production, and all other applicable requirements.

Subpart 3179—Waste Prevention and Resource Conservation

§ 3179.1 Purpose.

The purpose of this subpart is to implement and carry out the purposes of statutes relating to prevention of waste from Federal and Indian (other than Osage Tribe) leases, conservation of surface resources, and management of the public lands for multiple use and sustained yield. This subpart supersedes those portions of Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases (NTL–4A), 44 FR 76600 (December 27, 1979), pertaining to, among other things, flaring and venting of produced gas, unavoidably and avoidably lost gas, and waste prevention.

§ 3179.2 Scope.

(a) This subpart applies to:

(1) All onshore Federal and Indian (other than Osage Tribe) oil and gas leases, units, and CAs, except as otherwise provided in this subpart;

(2) IMDA oil and gas agreements, unless specifically excluded in the agreement or unless the relevant provisions of this subpart are inconsistent with the agreement;

(3) Leases and other business agreements and contracts for the development of tribal energy resources under a Tribal Energy Resource Agreement entered into with the Secretary, unless specifically excluded in the lease, other business agreement, or Tribal Energy Resource Agreement;

(4) Committed State or private tracts in a federally approved unit or communitization agreement defined by

or established under 43 CFR subpart 3105 or 43 CFR part 3180;

(5) All onshore wells, tanks, compressors, and other facilities located on a Federal or Indian lease or a federally approved unit or CA; and

(6) All gas lines located on a Federal or Indian lease or federally approved unit or CA that are owned or operated by the operator of the lease, unit, or communitization agreement.

(b) For purposes of this subpart, the term ''lease'' also includes IMDA agreements.

§ 3179.3 Definitions and acronyms.

As used in this subpart, the term:

Accessible component means a component that can be reached, if necessary, by safe and proper use of portable ladders or by built-in ladders and walkways. Accessible components also include components that can be reached by the safe use of an extension on a monitoring probe.

Capture means the physical containment of natural gas for transportation to market or productive use of natural gas, and includes reinjection and royalty-free on-site uses pursuant to subpart 3178.

Capture infrastructure means any pipelines, facilities, or other equipment (including temporary or mobile equipment) used to capture, transport, or process gas. Capture infrastructure includes, but is not limited to, equipment that compresses or liquefies natural gas, removes natural gas liquids, or generates electricity from gas.

Component means any piece of equipment that has the potential to leak gas and can be tested in the manner described in §§ 3179.301 through 3179.305 of this subpart.

Development oil well or *development gas well* means a well drilled to produce oil or gas, respectively, from an established field in which hydrocarbons have been discovered and are being produced at a profit or expected profit. For purposes of this subpart, the BLM will determine when a well is a development oil well or development gas well in the event of a disagreement between the BLM and the operator.

Gas-to-oil ratio (GOR) means the ratio of gas to oil in the production stream expressed in standard cubic feet of gas per barrel of oil.

Gas well means a well for which the energy equivalent of the gas produced, including its entrained liquefiable hydrocarbons, exceeds the energy equivalent of the oil produced. Unless more specific British thermal unit (Btu) values are available, a well with a gas-to-oil ratio greater than 6 thousand cubic feet (Mcf) of gas per barrel of oil is a gas well. Except where gas has been re-injected into the reservoir, a mature oil well would not be reclassified as a gas well even after normal production decline has caused the GOR to increase beyond 6 Mcf of gas per barrel of oil.

Liquid hydrocarbon means chemical compounds of hydrogen and carbon atoms that exist as a liquid under the temperature and pressure at which they are measured. The term is used to refer to oil, condensate, liquefied petroleum gas (LPG), liquefied natural gas (LNG), and natural gas liquids (NGL).

Liquids unloading means the removal of an accumulation of liquid hydrocarbons or water in the wellbore of a completed gas well.

Lost oil or lost gas means produced oil or gas that escapes containment, either intentionally or unintentionally, or is flared before being removed from the lease, unit, or CA, and cannot be recovered.

Storage vessel means a crude oil or condensate storage tank or battery of tanks that vents, or is designed to vent, to the atmosphere during normal operations.

Volatile organic compounds (VOC) has the same meaning as defined in 40 CFR 51.100(s).

§ 3179.4 Determining when the loss of oil or gas is avoidable or unavoidable.

For purposes of this subpart:

(a) ''Unavoidably lost'' oil or gas means lost oil or gas where the operator has not been negligent, and has complied fully with applicable laws, lease terms, regulations, provisions of a previously approved operating plan, or other written orders of the BLM, including:

(1) Produced oil or gas that is lost from the following operations or sources and cannot be recovered in the normal course of operations, where the operator has taken prudent and reasonable steps to avoid waste:

(i) Well drilling;

(ii) Well completion and related operations;

(iii) Initial production tests, subject to the limitations in § 3179.103;

(iv) Subsequent well tests, subject to the limitations in § 3179.104;

(v) Exploratory coalbed methane well dewatering;

(vi) Emergencies, subject to the limitations in § 3179.105;

(vii) Evaporation from storage vessels;

(viii) Downhole well maintenance;

(ix) Liquids unloading;

(x) Leaks; and

(xi) Releases from pneumatic controllers and pumps; or

(2) Produced gas that is flared or vented from a well that is not connected to gas capture infrastructure, absent a BLM determination that the loss of gas through such venting or flaring is otherwise avoidable, subject to the limitations in § 3179.6.

(b) ''Avoidably lost'' oil or gas means lost oil or gas that is not unavoidably lost as defined in paragraph (a) of this section.

§ 3179.5 When lost production is subject to royalty.

(a) Royalty is due on:

(1) All avoidably lost oil or gas; and

(2) Waste oil that became waste through operator negligence.

(b) Royalty is not due on:

(1) Unavoidably lost oil or gas; and

(2) Waste oil that did not become waste through operator negligence.

§ 3179.6 When flaring or venting is prohibited.

(a) The operator must flare rather than vent any gas that is not captured except:

(1) When flaring the gas is technically infeasible, such as when the gas is not readily combustible or the volumes are too small to flare;

(2) Under emergency conditions when the loss of gas is uncontrollable or venting is necessary for safety, subject to § 3179.105;

(3) When § 3179.203 does not require the combustion or flaring of gas vapors from storage vessels; or

(4) When the gas is vented through operation of a natural gas-activated pneumatic controller or pump.

(b) Except as provided in § 3179.7, an operator must not flare or vent gas in excess of the following amounts, representing the total volume of gas flared or vented over a production month from all development oil wells on a lease, unit, or CA, divided by the number of development oil wells contributing production for at least 10 days during that month:

(1) 7,200 Mcf, for each month during the period from [EFFECTIVE DATE OF FINAL RULE] until [1 YEAR AFTER EFFECTIVE DATE OF FINAL RULE];

(2) 3,600 Mcf, for each month during the period from [1 YEAR AFTER EFFECTIVE DATE OF FINAL RULE] until [2 YEARS AFTER EFFECTIVE DATE OF FINAL RULE]; and

(3) 1,800 Mcf, for each month thereafter.

§ 3179.7 Alternative limits on venting and flaring.

(a) With respect to leases issued before the effective date of this regulation, the BLM may approve an alternative rate-based limit on venting and flaring from a lease, unit, or CA that is flaring at a rate that exceeds the applicable limit under § 3179.6, if the operator demonstrates, and the BLM agrees, that the applicable limit under § 3179.6 would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

(b) To support such a demonstration, the operator must submit a Sundry Notice that includes the following information:

(1) Information regarding the operator's wells under the lease that produce Federal or Indian gas, including:

(i) The name, number, and location of each well, and the number of the lease, unit, or CA with which it is associated;

(ii) The depths and names of producing formations;

(iii) The gas production level of each of the operator's wells for the most recent production month for which information is available; and

(iv) The volumes of gas being vented and flared from each of the operator's wells;

(2) Map(s) showing:

(i) The entire lease, unit, or CA and the surrounding lands to a distance and on a scale that shows the field in which the well or wells are or will be located (if applicable), and all pipelines that could transport the gas from the well or wells;

(ii) All of the operator's producing oil and gas wells, which are producing from Federal or Indian leases (both on Federal or Indian leases and on other properties) within the map area;

(iii) Identification of all of the operator's wells within the lease from which gas is flared or vented, and the location and distance of the nearest gas pipeline(s) to each such well, with an identification of those pipelines that are or could be available for connection and use; and

(iv) Identification of all of the operator's wells within the lease from which gas is captured;

(3) Data that show pipeline capacity and the operator's projections of the cost associated with installation and operation of gas capture infrastructure and alternative methods of transportation that do not require pipelines;

(4) The operator's projections of gas prices, gas production volumes, gas quality (*i.e.,* heating value and H_2S content), revenues derived from gas production, and royalty payments on gas production over the next 15 years or the life of the operator's lease, unit, or CA, whichever is less; and

(5) The operator's projections of oil prices, oil production volumes, costs, revenues, and royalty payments from the operator's oil and gas operations within the lease over the lesser of:

(i) The next 15 years; or

(ii) The anticipated remaining period in which the operator will produce from the Federal or Indian lease, unit, or CA.

(c) In establishing an alternative volume limit on venting and flaring under this section, the BLM will aim to set the limit at the lowest level that the BLM determines, considering the information identified in paragraph (b) of this section, will not cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

(d) Instead of an alternative limit under paragraph (a) of this section, a lease issued before the effective date of this regulation will receive a renewable, 2-year exemption from the applicable flaring limit specified in § 3179.6 if the authorizing officer verifies that all of the following terms and conditions are met:

(i) The lease, unit, or CA is not connected to a gas pipeline;

(ii) The closest point on the lease, unit, or CA is located more than 50 straight-line miles from the nearest gas processing plant;

(iii) In the most recent production month, the lease, unit or CA flared or vented at an average rate that exceeds by at least 50 percent the applicable flaring limit specified in § 3179.6; and

(iv) The operator submits to the BLM a Sundry Notice with an affidavit certifying that it meets the conditions in paragraphs (d)(i) through (iii) of this section.

§ 3179.8 Measuring and reporting volumes of gas vented and flared from wells.

(a) The operator must estimate or measure all volumes of gas vented or flared from wells, and report those volumes under applicable ONRR reporting requirements, including 30 CFR part 1210.

(b) The operator may choose whether to estimate or measure such volumes, except that measurement is required:

(1) If the operator estimates that the volume of gas vented or flared from a flare stack or manifold equals or exceeds 50 Mcf per day; or

(2) If the BLM determines and informs the operator that the additional accuracy offered by measurement is necessary for effective implementation of this subpart.

§ 3179.9 Determinations regarding royalty-free venting or flaring.

(a) Approvals to flare or vent royalty free, and/or to flare or vent at a level above the 7,200 Mcf per month limit in § 3179.6(b)(1), which are in effect as of the effective date of this rule, will continue in effect until [90 DAYS AFTER EFFECTIVE DATE OF THE FINAL RULE].

(b) The provisions of this subpart do not affect any determination made by the BLM before or after [EFFECTIVE DATE OF FINAL RULE], with respect to the royalty-bearing status of flaring that occurred prior to [EFFECTIVE DATE OF FINAL RULE].

§ 3179.10 Other waste prevention measures.

(a) If production from an oil well newly connected to a gas pipeline results or is expected to result in one or more producing wells already connected to the pipeline being forced off the line, the BLM may exercise existing authority to limit the production level from the new well until the pressure of gas production from the new well stabilizes at levels that allow transportation of gas from all wells connected to the line.

(b) If gas capture capacity is not yet available on a given lease, the BLM may exercise existing authority to delay action on the APD for that lease, or approve the APD with conditions for gas capture or limitations on production. If the lease for which the APD is submitted is not yet producing, the BLM may direct or grant a lease suspension under 43 CFR 3103.4–4.

§ 3179.11 Coordination with State regulatory authority.

To the extent that any BLM action to enforce a prohibition, limitation, or order under this subpart adversely affects production of oil or gas that comes from non-Federal and non-Indian mineral interests, the BLM will coordinate, on a case-by-case basis, with the State regulatory authority having jurisdiction over the oil and gas production from the non-Federal and non-Indian interests.

Flaring and Venting Gas During Drilling and Production Operations

§ 3179.101 Well drilling.

(a) Except as provided in § 3179.6(a) of this subpart, gas that reaches the surface as a normal part of drilling operations must be:

(1) Captured and sold;

(2) Directed to a flare pit or flare stack equipped with an automatic igniter to combust any flammable gasses;

(3) Used in operations on the lease, unit, or CA; or

(4) Injected.

(b) If gas is lost as a result of loss of well control, the BLM will make a determination of whether the loss of well control is due to operator negligence. Such gas is avoidably lost if the BLM determines that the loss of well control is due to operator negligence. The BLM will notify the operator in writing when it makes a determination that gas was lost due to operator negligence.

§ 3179.102 Well completion and related operations.

(a) Except as provided in § 3179.6(a), gas that reaches the surface during well completion and post-completion, drilling fluid recovery, or fracturing or refracturing fluid recovery operations must be:

(1) Captured and sold;

(2) Directed to a flare pit or flare stack equipped with an automatic igniter to combust any flammable gasses, subject to the volumetric limitations in § 3179.103(a)(3);

(3) Used in operations on the lease, unit, or CA; or

(4) Injected.

(b) In lieu of compliance with the requirements of paragraph (a) of this section, an operator may demonstrate to the BLM on a Sundry Notice that it is in compliance with the requirements for control of gas from well completions established under 40 CFR part 60, subpart OOOOa.

§ 3179.103 Initial production testing.

(a) Gas flared during a well's initial production test is royalty-free under §§ 3179.4(a)(1)(iii) and 3179.5(b) of this subpart until one of the following occurs:

(1) The operator determines that it has obtained adequate reservoir information for the well;

(2) 30 days have passed since the beginning of the production test, except as provided in paragraph (b) and paragraph (c) of this section;

(3) The operator has flared 20 million cubic feet (MMcf) of gas, when volumes flared under this section are combined with volumes flared under § 3179.102(b); or

(4) Production begins.

(b) The BLM may extend the period specified in paragraph (a)(2) not to exceed an additional 60 days, based on testing delays caused by well or equipment problems or if there is a need for further testing to develop adequate reservoir information.

(c) During the dewatering and initial evaluation of an exploratory coalbed methane well, the 30-day period specified in paragraph (a)(2) of this section is extended to 90 days. The BLM may approve up to two extensions of this evaluation period, of up to 90 days each.

(d) The operator must submit its request for a longer test period under paragraph (b) or (c) of this section using a Sundry Notice.

§ 3179.104 Subsequent well tests.

During well tests subsequent to the initial production test, the operator may flare gas for no more than 24 hours royalty free under §§ 3179.4(a)(1)(iv) and 3179.5(b) of this subpart, unless the BLM approves or requires a longer period. If the operator requests a longer period, it must submit a Sundry Notice.

§ 3179.105 Emergencies.

(a) An operator may flare or, if flaring is not feasible given the emergency, vent gas royalty-free under § 3179.6(a) of this subpart during a temporary, short-term, infrequent, and unavoidable emergency.

(b) The operator may flare or vent gas royalty free for up to 24 hours per incident (unless the BLM extends the period), and for no more than three emergencies for a lease, unit, or CA within any 30-day period.

(c) The following do not constitute emergencies under this section:

(1) More than 3 failures of the same equipment within any 365-day period;

(2) The operator's failure to install appropriate equipment of a sufficient capacity to accommodate the volume of gas being produced;

(3) Failure to limit production when the production rate exceeds the capacity of the related equipment, pipeline, or gas plant, or exceeds sales contract volumes of oil or gas;

(4) Scheduled maintenance; or

(5) Operator negligence.

(d) The operator must estimate and report to the BLM on a Sundry Notice the volumes flared or vented beyond the timeframes specified in paragraph (b) of this section.

Gas Flared or Vented From Equipment or During Well Maintenance Operations

§ 3179.201 Equipment requirements for pneumatic controllers.

(a) A pneumatic controller that uses natural gas produced from a Federal or Indian lease, or from a unit or CA that includes a Federal or Indian lease, is subject to this section if the pneumatic controller:

(1) Has a continuous bleed rate greater than 6 standard cubic feet (scf) per hour; and

(2) Is not subject to 40 CFR 60.5360 through 60.5390.

(b) The operator must replace a pneumatic controller subject to this section with a pneumatic controller having a bleed rate of 6 scf per hour or less within the timeframes set forth in paragraph (c) of this section, unless:

(1) The operator notifies the BLM through a Sundry Notice that use of a pneumatic controller with a bleed rate greater than 6 scf per hour is required based on functional needs described in the Sundry Notice, that may include, but are not limited to, response time, safety, and positive actuation;

(2) The operator notifies the BLM through a Sundry Notice that the pneumatic controller exhaust is routed to a flare device; or

(3) The operator notifies the BLM through a Sundry Notice and demonstrates, and the BLM agrees, based on the information identified in § 3179.7(b), that replacement of a pneumatic controller subject to paragraph (a)(1)(i) of this section would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

(c) The operator must replace the pneumatic controller(s) no later than 1 year after the effective date of this section as required under paragraph (b) of this section, except that if the well or facility that the pneumatic controller serves has an estimated remaining productive life of 3 years or less from the effective date of this section, the operator must notify the BLM through a Sundry Notice and replace the pneumatic controller no later than 3 years from the effective date of this section.

(d) The operator must ensure pneumatic controllers are functioning within manufacturers' specifications.

§ 3179.202 Requirements for pneumatic chemical injection pumps or pneumatic diaphragm pumps.

(a) A pneumatic chemical injection or pneumatic diaphragm pump is subject to this section if it:

(1) Uses natural gas produced from a Federal or Indian lease, or from a unit or CA that includes a Federal or Indian lease; and

(2) Is not subject to 40 CFR part 60, subpart OOOOa.

(b) The operator must replace a pneumatic pump subject to this paragraph with a zero-emissions pump or route the pump to a flare device within the timeframes set forth in paragraph (d) of this section.

(c) The requirement in paragraph (b) of this section does not apply if:

(1) The operator notifies the BLM through a Sundry Notice that:

(i) Use of a pneumatic pump is required based on functional needs, described in the Sundry Notice; and

(ii) There is no existing flare device on site or routing to such a device is technically infeasible; or

(2) The operator submits a Sundry Notice to the BLM that:

(i) Provides an economic analysis that demonstrates, and the BLM agrees, based on the information identified in § 3179.7(b), that installation of a zero-emissions pump(s) would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease; and

(ii) Demonstrates to the BLM that there is no existing flare device on site or routing to such a device is technically infeasible.

(d) The operator must replace the pneumatic pump(s) or connect to a flare device no later than 1 year after the effective date of this section, except that if the well or facility that the pneumatic pump serves has an estimated remaining productive life of 3 years or less from the effective date of this section, the operator must notify the BLM through a Sundry Notice and replace the pneumatic pump no later than 3 years from the effective date of this section.

(e) The operator must ensure pneumatic pumps are functioning within manufacturers' specifications.

§ 3179.203 Crude oil and condensate storage vessels.

(a) A crude oil or condensate storage vessel is subject to this section if the vessel:

(1) Contains production from a Federal or Indian lease, or from a unit or CA that includes a Federal or Indian lease;

(2) Is not subject to 40 CFR part 60, subpart OOOO; and

(3) Has a rate of total VOC emissions equal to or greater than 6 tons per year (tpy).

(b) The operator must determine the rate of emissions from the storage vessel within 60 days after the effective date of this section, and within 30 days after any new source of production is added to the tank.

(c) No later than 6 months after the effective date of this section, the operator must route all tank vapor gas from a storage vessel that is subject to this section to a combustion device or continuous flare, or to a sales line unless the operator submits an economic analysis to the BLM through a Sundry Notice that demonstrates, and the BLM agrees, based on the information identified in § 3179.7(b), that compliance with this requirement would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

(d) If the rate of total uncontrolled gas release from a storage vessel declines to 4 tpy or less for any continuous 12 month period, the requirements of this section no longer apply.

§ 3179.204 Downhole well maintenance and liquids unloading.

(a) During downhole well maintenance and liquids unloading operations, the operator must use practices that maximize the recovery of gas for sale and must flare gas not recovered except where such practices or flaring are technically infeasible or unduly costly. Before the operator purges a well for the first time after the effective date of this section, the operator must document that other methods are technically infeasible or unduly costly, and provide that information as part of the Sundry Notice required under paragraph (d) of this section.

(b) For wells drilled after the effective date of this section, the operator may not conduct liquids unloading by well purging, except where the operator is returning a well to production following a well workover or following a shut-in for more than 30 days.

(c) For any liquids unloading by well purging, the operator must:

(1) Be present on-site throughout the event to ensure that any venting to the atmosphere is limited to no more than what is practically necessary, unless the operator uses an automatic control system that relies on real-time pressure or flow, timers, or other well data to minimize venting;

(2) Record the cause, date, time, duration, and estimated volume of each venting event; and

(3) Maintain the liquids unloading records for the period required under § 3162.4–1 of this title and make them available to the BLM, upon request.

(d) The operator must notify the BLM by Sundry Notice within 10 calendar days after the first liquids unloading event by well purging conducted after the effective date of this section. This requirement applies to each well the operator operates.

(e) The operator must notify the BLM by Sundry Notice, within 14 calendar days, if:

(1) The cumulative duration of well purging events for a well exceeds 24 hours during any production month; or

(2) The estimated volume of gas vented in liquids unloading by well purging operations for a well exceeds 75 Mcf during any production month.

(f) For purposes of this section, "well purging" means blowing accumulated liquids out of a wellbore by gas pressure where the gas is vented to the atmosphere.

(g) Total estimated volumes vented as a result of downhole well maintenance and liquids unloading during the production month must be included in volumes reported to ONRR as vented.

Leak Detection and Repair (LDAR)

§ 3179.301 Operator responsibility.

(a) The requirements of §§ 3179.301 through 3179.305 of this subpart apply to all wells that produce natural gas from a Federal or Indian lease, or from a unit or CA that includes a Federal or Indian lease, including oil wells that also produce natural gas.

(b) The operator is responsible, as prescribed in §§ 3179.302 and 3179.303 of this subpart, to inspect for gas leaks on the following:

(1) All equipment and equipment components at the wellhead;

(2) All facilities that the operator operates; and

(3) All compressors located on the lease, unit, or CA that the operator owns, leases, or operates.

(c) All leak inspections must occur during production operations.

(d) The operator must fix the leaks as prescribed in §§ 3179.304 and 3179.305 of this subpart. See 43 CFR 3162.5–1 for responsibility to repair oil leaks.

(e) An operator may satisfy the requirements of §§ 3179.301 through 3179.305 for some or all of the equipment or facilities on a given lease by demonstrating to the BLM on a Sundry Notice that the operator is complying with LDAR requirements established under 40 CFR part 60, subpart OOOOa with respect to such equipment or facilities.

§ 3179.302 Approved instruments and methods.

(a) The operator must use one or more of the following instruments or monitoring methods to detect leaks:

(1) An optical gas imaging device;

(2) A monitoring device not listed in this section, which is approved by the BLM for use by any operator, under § 3179.303(b) of this subpart;

(3) A comprehensive program, approved by the BLM under § 3179.303(b) of this subpart, that includes the use of instrument-based monitoring devices; or

(4) A portable analyzer device capable of detecting leaks, such as catalytic oxidation, flame ionization, infrared absorption or photoionization devices, operated according to manufacturer specifications, and assisted by audio, visual, and olfactory inspection.

(b) If an operator operates 500 or more wells within the jurisdiction of a single BLM field office, the operator may only use one or more of the methods identified in paragraph (a)(1), (2), or (3) of this section to detect leaks.

§ 3179.303 Leak detection inspection requirements for natural gas wellhead equipment, facilities, and compressors.

(a) Except as provided below or otherwise authorized in paragraph (b) of this section, the operator must inspect at least semi-annually for leaks the wellhead equipment, facilities, and compressors identified in § 3179.301(b) of this subpart. For purposes of §§ 3179.301 through 3179.305, the term ''site'' means a discrete area containing wellhead equipment, facilities, and compressors, which is suitable for inspection in a single visit.

If the operator inspects	And in two consecutive inspections the operator	The operator
(1) Semi-annually	Detects no more than 2 leaks at the site inspected	Must inspect at least annually.
(2) Annually	Detects 3 or more leaks at the site inspected	Must inspect at least semi-annually.
(3) Semi-annually	Detects 3 or more leaks at the site inspected	Must inspect at least quarterly.
(4) Quarterly	Detects no more than 2 leaks at the site inspected	Must inspect at least semi-annually.

(b) The BLM may approve an alternative leak detection device, program, or method under § 3179.302(a)(2) or 3179.302(a)(3) of this subpart, if the BLM finds that the alternative would meet or exceed the effectiveness for leak detection of the approach specified in §§ 3179.302(a)(1) and 3179.303(a) of this subpart. The operator must submit its request for an alternative leak detection device, program, or method of this section through a Sundry Notice.

(c) The operator is not required to inspect or monitor a component that is not an accessible component.

§ 3179.304 Repairing leaks.

(a) The operator must repair any leak not associated with normal equipment operation as soon as practicable, and in no event later than 15 calendar days after discovery, unless good cause exists for repair requiring a longer period.

(b) If delay in repair beyond 15 calendar days is attributable to good cause, the operator must notify the BLM of the cause by Sundry Notice and must complete repairs within 15 calendar days after the cause of delay ceases to exist.

(c) Not later than 15 calendar days after completion of a repair, the operator must verify the effectiveness of the repair through a follow-up inspection using the same method used to detect the leak.

(d) If the repair is not effective, the operator must complete additional repairs within 15 calendar days, and conduct follow-up inspections and repairs until the leak is repaired.

(e) A follow-up inspection to verify the effectiveness of repairs does not constitute an inspection for purposes of § 3179.303.

§ 3179.305 Leak detection inspection recordkeeping.

The operator must maintain the following records for the period required under § 3162.4–1 of this title and make them available to the BLM upon request:

(a) For each inspection required under § 3179.303 of this subpart, documentation of:

(1) The date of the inspection;

(2) The site where the inspection was conducted; and

(3) The equipment or facility inspected;

(b) The monitoring method(s) used to determine the presence of leaks;

(c) A list of components on which leaks were found and a description of each leak;

(d) The date of first attempt to repair each leak and, if necessary, any additional attempt to repair the leak;

(e) The date each leak was repaired; and

(f) The date and result of the follow-up inspection(s) required under § 3179.304 paragraph (c) or (d) of this subpart.

State or Tribal Variances

§ 3179.401 State or tribal requests for variances from the requirements of this subpart.

(a)(1) At the request of a State (for Federal land) or a tribe (for Indian lands), the BLM State Director may grant a variance from any individual provision of this subpart that would apply to all Federal leases, units, or CAs within a State or to all tribal leases, units, or CAs within that tribe's lands, or to specific fields or basins within the State or that tribe's lands, if the BLM finds that the variance would meet the criteria in paragraph (b) of this section.

(2) A State or tribal variance request must:

(i) Identify the provision(s) of this subpart from which the State or tribe is requesting the variance;

(ii) Identify the State or tribal regulation(s) or rule(s) that would be applied in place of the provision(s) of this subpart;

(iii) Explain why the variance is needed; and

(iv) Demonstrate how the State or tribal requirement would satisfy the requirement of the particular provision from which the State or tribe is requesting the variance.

(b) The BLM State Director, after considering all relevant factors, may approve the request for a variance, or approve it with one or more conditions, only if the BLM determines that the State or tribal regulation or rule meets or exceeds the requirements of the provision(s) from which the State or tribe is requesting the variance, and is consistent with the terms of the affected Federal or Indian leases and applicable statutes. The decision to grant or deny the variance will be in writing and is within the BLM's discretion. The decision on a variance request is not subject to administrative appeal under 43 CFR part 4.

(c) A variance from any particular requirement of this rule does not constitute a variance from provisions of other regulations, laws, or orders.

(d) The BLM reserves the right to rescind a variance or modify any condition of approval.

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