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April 22, 2016

U.S. Department of the Interior
Director (630)
Bureau of Land Management
Mail Stop 2134 LM
1849 C Street, NW
Washington, D.C. 20240

Attention: Docket ID Number 1004-AE14
Submitted to the Federal eRulemaking Portal (www.regulations.gov)

Re: Bureau of Land Management's "Waste Prevention, Production Subject to Royalties, and Resource Conservation" Proposed Rule at 81 FR 6616 (February 8, 2016)

Dear Sir/Madam:

BP America Inc. (BP, or the Company) appreciates this opportunity to submit comments on issues raised by the Bureau of Land Management's (BLM, or the Bureau) proposed "Waste Prevention, Production Subject to Royalties, and Resource Conservation" rule (Venting and Flaring Rule).

Over the past decade, BP has been America's largest energy investor. BP employs about 16,000 people across the country and supports some 170,000 other US jobs across the supply chain. BP is also a U.S. producer of fuels, lubricants, and petrochemicals, and buys, sells, and markets energy products throughout the United States. BP is the largest marketer of natural gas in the United States.

BP's Lower 48 onshore oil and gas business (L48) is one of the nation's largest producers of natural gas. Seventy percent of BP's global well count is comprised of gas wells in L48. Operating across a vast U.S. geography, from the onshore U.S. Gulf Coast north through the Rocky Mountains, BP's L48 onshore business has a presence in six of the country's top basins. Headquartered in Houston, Texas, L48 employs 1,200 people across five states. It operates about 9,800 producing wells, and has approximately 70,000 royalty owners. About 40% of the L48's gas wells are federal or tribal wells that will be subject to this proposed rule.

BP recognizes the importance of methane emissions management and of reducing waste in the production of oil and natural gas, including on federal and Indian lands. We believe our interests in these areas and those of the BLM are aligned. Moreover, we understand the Bureau's interest in updating its requirements to minimize waste of natural gas and particularly commend the BLM for its stakeholder outreach during and after the issuance of its Notice of Proposed Rulemaking (NOPR). Provided it is achieved in the most cost-effective manner, BP shares the BLM's stated principal objective – to reduce the waste of natural gas resources on federal and Indian land. We appreciate that cost-effective waste reduction can benefit not only the U.S. taxpayer but the developers of those resources as well. We also recognize that a co-benefit of, if not the principal stated reason for, this

regulation is reduction of emissions of methane, a potent greenhouse gas. This co-benefit has been a primary emphasis of this Administration, bolstered by the President's January 2015 announcement of a goal to cut U.S. methane emissions from the oil and gas sector 40%-45% below 2012 levels by 2025.

The increased production and use of natural gas, and associated fuel switching to natural gas, have accounted for and will continue to produce many of the significant reductions in greenhouse gas emissions achieved by the United States. As a major producer and the largest marketer of natural gas in North America, BP recognizes the importance of methane emissions. As stated by BP in the 2015 Sustainability Report: "Methane emissions are important to understand, and even more important to control, in order to reduce their impact on climate change and to maximize the life cycle greenhouse gas advantages of natural gas."[1]

BP has years of experience studying and improving the emissions performance of its onshore L48 assets, and has also completed baseline surveys of its other operated facilities, all of which help identify potential reduction opportunities. As an early leader in the Environmental Protection Agency's (EPA) voluntary Natural Gas STAR methane emissions reduction program, the Company has done much to lower its methane emissions including by replacing high bleed pneumatic controllers, installing solar pumps, and by pioneering "green completions." In addition:

- In 2015, BP joined the Climate and Clean Air Coalition (CCAC) methane initiative, which aims to reduce methane emissions in the oil and gas sector. BP and other participating companies are analyzing sources of methane in the global industry to evaluate cost-effective technologies for methane emissions reduction;

- Through its participation in the Oil and Gas Climate Initiative (OGCI), BP and nine other members comprising over one-fifth of the world's oil and gas production are working to improve the understanding and reliability of methane data. One of OGCI's key focus areas is understanding methane emissions and ways to reduce those emissions;

- BP is a founding member of the World Bank's Global Gas Flaring Reduction Partnership, a public-private partnership supporting development of infrastructure and regulatory mechanisms to help use gas that would otherwise be vented or flared during oil and gas operations; and.

- In 2015, BP joined the World Bank Zero Routine Flaring by 2030 initiative, which aims to eliminate routine flaring from oil assets by 2030.

We also want to highlight that BP has worked with the Environmental Defense Fund (EDF) to develop a petition process and a number of criteria that could be inserted into EPA's NSPS OOOOa rule, to provide for rapid approval by that Agency of new, more efficient and cost-effective methane leak detection and control technologies. These technologies are currently under development by both EDF and Advanced Research Projects Agency - Energy (ARPA-E) at the Department of Energy (DOE) together and their private sector partners, and could be commercially available in as little as one to two years. While we recognize that BLM has anticipated this and has included in the proposed rule a placeholder for Bureau approval of such technologies as and when they arise, we would welcome the opportunity to work with the Bureau to develop greater detail around a petition process and set of criteria for approval. It is critical that the criteria for approval are straightforward and unambiguous, and the process is as efficient and expeditious as possible, to provide a realistic

[1] Sustainability Report 2015, p. 43, available at: http://www.bp.com/content/dam/bp/pdf/sustainability/group-reports/bp-sustainability-report-2015.pdf.

on-ramp for these promising new technologies. Experience teaches us that regardless of good intentions, if these elements are not spelled out clearly at the rulemaking stage, subsequent petitions can become bogged down in extended review processes that could ultimately frustrate the shared goal of facilitating introduction of new and better technologies. Assistant Secretary Schneider expressed interest in discussing this further when we met with her on April 20, and we look forward to that discussion.

The American Petroleum Institute (API), a trade association of which BP is a member, has likewise submitted comprehensive comments on all aspects of the proposed rule pertinent to our industry as a collective whole. BP has taken the opportunity with these comments to highlight particular sections of the proposed rule that are of greatest concern to our Company and to emphasize what we believe to be alternatives and solutions that the Bureau could reasonably adopt to mitigate these concerns. We have endeavored to offer constructive solutions to each of the issues we have raised in the hope that this input would be most helpful to the Agency in its deliberation process.

BP welcomes the opportunity to continue to work with the Department of the Interior (DOI) and the BLM to improve waste reduction at lower cost to the industry, and achieve the co-benefits of methane reduction during this difficult economic time for our industry. Even after the written comment period has closed, and well before the rule is finalized, we hope to have further discussions with the Bureau focused on the points raised in the attached comments. If there are any questions regarding these comments, please do not hesitate to contact me.

Sincerely,

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Attached: BP America Inc.'s Comments on BLM's Waste Prevention, Production Subject to Royalties, and Resource Conservation Proposed Rule

Comments on BLM's
Waste Prevention, Production Subject to Royalties, and Resource Conservation Proposed Rule

Docket ID Number 1004-AE14

April 22, 2016

Submitted by:
BP America Inc.

Table of Contents

Executive Summary

BP recognizes the importance of reducing waste of natural gas produced from oil and gas operations on federal and Indian lands as well as the importance of addressing methane emissions to respond to climate change. BP wants natural gas to continue to be recognized for what it is: a cleaner fuel, the increased use of which has been and will continue to be one of the most effective ways of reducing U.S. greenhouse gas emissions.

As our detailed comments outline, we have a genuine high-level policy concern that many of the same methane emission sources will now be regulated under two different federal regimes as well as under state, local and tribal programs. Compliance with these overlapping and likely nonaligned regulations will be challenging, especially in our operations located in "checkerboard" areas where federal and non-federal sections are located side-by-side. We urge the Bureau to consider the overlapping nature of these regulations and the challenges they raise regarding cost, efficiency, effectiveness and governance, and to focus on reducing the duplication that will arise from other state, local, tribal and federal regulatory requirements. Considering (a) the existing overlap and duplication in methane control regulation, which will be further exacerbated by future EPA regulation of existing as well as new and modified sources, and (b) the benefit of allowing time for more effective and efficient LDAR technologies to be developed and deployed in the near term, we respectfully suggest that the best policy course overall would be for the Bureau to hold off promulgating additional methane regulation at this stage

Nevertheless, acknowledging the Bureau's stated determination to press ahead with the rule, we have chosen to focus our comments on:

- Instances where a different technical approach could be adopted in a final rule that would be more efficient and effective but would not materially affect BLM's efforts to reduce waste of natural gas and methane emissions in accordance with the Administration's international greenhouse gas emission goals; and
- Instances where the proposed regulatory approach is either infeasible, highly cost-ineffective without providing significant benefits, or where we believe there currently exists an incomplete understanding of the technical challenges surrounding what is proposed and believe we can provide explanations that could strengthen the rule.

Leak Detection and Repair (LDAR)

Issue: We are concerned that BLM has greatly underestimated the cost of the proposed LDAR requirements by not including: (a) the upfront cost of an optical gas imaging (OGI) camera; (b) the extensive training of new employees that would be required; (c) the extensive and complex recordkeeping system required for compliance; and (d) the cost of a manned transportation fleet to engage in frequent inspections and repairs. We have found that the cost of each survey is underestimated based on actual industry experience. In addition, we are concerned that BLM has overstated the benefits of subsequent LDAR surveys since leaks decrease after the initial survey (fewer leaks and lower leak rates).

Recommendations: To make the LDAR requirements more cost-effective, BP requests that BLM establish the OGI monitoring frequency as annual and limit the LDAR program to those sites with the greatest leak potential (i.e., sites with compressors or controlled storage vessels). Annual OGI inspections could be supplemented with more frequent audio, visual, and olfactory (AVO) inspections.

In addition, BLM should provide companies more time to implement the LDAR program. First, 30 days (rather than 15) are necessary for repairs to be made at these highly dispersed, remote, unmanned, un-electrified locations. Second, BP requests three years (rather than 60 days) to roll-out the program to allow the Company to budget, plan, procure cameras, train personnel, and fully implement the program. Alternatively, BLM should provide for a two-year phase-in period with half of a company's facilities complying in year 1 and the remainder in year 2, with the mix determined by the Company. Either alternative should also allow for the rapid approval and on-ramping of new, more efficient, effective and low-cost LDAR technologies that are currently under development. In addition to providing time that will be needed for the effective implementation of any new LDAR requirements in the Bureau's proposed rule, this would have the additional policy benefit of allowing time for the development and deployment of even more effective methane LDAR technologies. Indeed it is entirely possible that some of these new technologies will be ready for deployment within the next 2 years, thereby overlapping the period for implementing the rule. BP hopes to continue to work with BLM to establish clear criteria to facilitate rapid approval of alternative LDAR technologies.

Liquids Unloading Venting

Issue: BLM has proposed prohibiting all venting during liquids unloading from wells drilled after the effective date of the rule. It is technically infeasible to eliminate all venting from liquids unloading without premature abandonment of the well. Venting can be minimized, but not entirely eliminated. Furthermore, there is no single method or technology that can reduce liquids unloading in every instance because the characteristics of each well and each stage in the life of the well are quite different.

Recommendation: Either require operators to use best management practices to minimize well venting as in Colorado's Regulation 7, or allow companies to submit a plan to BLM for its approval detailing its protocol for minimizing venting during liquids unloading.

Storage Vessels

Issue: BLM has proposed control of emissions from storage vessels emitting over 6 tons per year (TPY) of volatile organic compounds (VOCs). This requirement does not advance the stated purpose of the rule, because the only feasible control option is to combust the gas which requires additional gas to keep the pilot lit on the combustion device. Moreover, by the time the VOCs reach the storage vessel they are mixed with only very small amounts of methane. The only control option that would advance the purpose of the rule is the use of a vapor recovery device that is very costly and requires compression (often multiple stages) to enter the higher pressure natural gas sales pipelines. Most BLM land does not have electricity so natural gas engines must be brought in to power the compressors which use more natural gas.

Recommendation: We propose that BLM remove the storage vessel control requirements from the rule. However, should these requirements remain, the definition of "tank" should be identical to the EPA definition and the control threshold should be raised to 15 TPY of VOCs so as to make the requirements cost-effective for existing facilities. In addition, operators should no longer be subject to the controls once emissions drop below the control threshold. Finally, a source should be allowed to limit potential emissions to below the threshold with a legally and practically enforceable limit.

Insufficient Time to Implement Some Requirements of the Rule

Issue: As EPA and other agencies have typically done when promulgating rules requiring installation of new controls, BLM should allow a reasonable time for implementation of such requirements. Six

months to one year is insufficient to ensure compliance with multiple requirements at many thousands of geographically dispersed sites. Acquisition of the necessary equipment and recruiting and training necessary personnel cannot be fully accomplished in that period.

Recommendation: To allow an orderly roll-out of the rule and prevent the shut-in of facilities, we request that BLM allow three years for (a) the replacement or control of existing equipment, including storage vessels, pneumatic pumps, and pneumatic controllers and (b) the implementation of the LDAR requirements. This period is needed so that companies can:

- Incorporate the costs of equipment and personnel in their budget;
- Plan their work and staffing needs;
- Order equipment;
- Manufacture or procure equipment; and
- Have time for proper and expert installation of the equipment and execution of needed work.

BP AMERICA INC. COMMENTS

1. Overarching Policy Considerations Should be Taken into Account by the BLM

1.1 Compliance burdens must be considered, including concerns that the rule will likely overlap with and be duplicative of EPA and state regulation

BLM recognizes in its proposal that other federal and state regulations already – or will soon – control emissions of methane from oil and gas operations on federal lands.[2] Of greatest importance are the EPA Subpart OOOO standards of performance under section 111(b) of the Clean Air Act (CAA) (NSPS) for new and modified oil and gas wells, first promulgated in 2012[3] and now undergoing extensive revisions through a rulemaking proposed by EPA in September 2015.[4] When finalized later this spring, the expanded Subpart OOOOa regulations will, for the first time, impose controls on methane emissions directly and put in place stringent requirements for reducing methane leaks and emissions from nearly all types of equipment at new and modified oil and gas production sources. In addition, major drilling states that have extensive federal land holdings, like Colorado and Wyoming, already require comprehensive emission controls for methane and other pollutants. In these states, oil and gas operators leasing federal lands will need to comply with both state requirements and the soon-to-be promulgated federal requirements under Subpart OOOOa. Although the BLM recognizes that operators should not be burdened with conflicting or redundant requirements, as currently drafted, this rule poses a very real risk of conflict and redundancy with existing state-level requirements and the regulatory proposals already announced and under development by EPA referred to in the NOPR.

The BLM regulations would add yet another layer of overlapping regulation to these existing and proposed federal and state programs. BLM says it "intends to coordinate its requirements with EPA as much as possible" and recognizes the need to assure that "industry is not burdened by duplicative or conflicting requirements."[5] But it insists that EPA and state requirements "would not be sufficient to meet the goals of BLM's proposed rule for several reasons."[6] To justify the overlap with the EPA regulations, BLM argues that "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." It also asserts that "the EPA regulations would apply only to new and modified sources, whereas this proposal would reach existing sources as well."[7] We do not believe that either of these factors supports the need for the proposed BLM regulation at this time.

The divergent approaches of BLM and EPA to controlling well maintenance and liquids unloading are not a function of differing legal authorities but reflect different technical and policy judgments about the benefits of regulating these sources. While the BLM sees a regulatory "gap" with respect to the

[2] 81 Federal Register 6617-18. (Feb. 8, 2016).
[3] 40 CFR part 60 subpart OOOO; 77 Federal Register 49490 (Aug. 16, 2012).
[4] 40 CFR part 60 subpart OOOOa, 80 Federal Register 46593 (Sept.. 18, 2915).
[5] 81 Federal Register 6635.
[6] Id.
[7] Id. BLM also argues that EPA regulations do not include provisions to prevent flaring during normal operations and that BLM has a unique role to play in this area given its mandate to prevent "waste" of resources on leased federal lands. It is not strictly true that EPA regulations do not impact flaring; by requiring "green completions" in gas production activities and now in oil production as well, the Subpart OOOO regulations will capture methane that would otherwise be vented or flared. Apart from this point, however, BLM's interest in preventing waste by reducing venting and flaring would not justify regulating equipment leaks and releases, an area where EPA has responsibility and statutory authority as well as a regulatory platform that predates BLM's involvement.

issue of waste of gas from BLM-administered leases, we do not. State regulatory systems coupled with the already proposed NSPS OOOOa will provide a system of methane emissions regulation that will correspondingly reduce waste. Most importantly, while perhaps true at the time of BLM's proposal, its assumption that EPA would not regulate existing sources – and therefore BLM should – is no longer correct. On March 10, 2016 EPA announced it was "moving to regulate emissions from existing sources" in the oil and gas industry and would begin a "formal process" for "development of comprehensive regulations to reduce methane emissions" under CAA section 111(d).[8] Thus, the "gap" that BLM seeks to fill – control of emissions from existing emission sources on federal lands – will cease to exist.

EPA plans to issue the first draft of an Information Collection Request (ICR) in the spring of 2016 The ICR would "gather important information on existing sources of methane emissions, technologies to reduce these emissions and the costs of those technologies in the production, gathering, processing, and transmission and storage segments of gas sector"[9] and will require companies operating existing oil and gas sources to provide "information to assist in the development of comprehensive regulations to reduce methane emissions."[10] As EPA explained:

> *There are hundreds of thousands of existing oil and gas sources across the country; some emit small amounts of methane, but others emit very large quantities. Through the ICR, EPA will be seeking a broad range of information that will help us determine how to effectively reduce emissions, including information such as how equipment and emissions controls are, or can be, configured, and what installing these controls entails.*
>
> *EPA will also be seeking information that will help the Agency identify sources with high emissions and the factors that contribute to those emissions. The ICR will likely apply to the same types of sources covered by the current and proposed New Source Performance Standards for the oil and gas sector, as well as additional sources.*

There may be an expectation that the BLM's requirements for existing sources will mirror those later imposed by EPA. However, the type of rule EPA will ultimately issue under CAA section 111(d) is highly uncertain at this stage. It would be premature to make a judgment now about the degree of equivalence between the BLM requirements for existing sources and the treatment of these sources under the future EPA section 111(d) rule. Informed by the extensive data it intends to collect and analyze, EPA may design an existing source rule that looks very different from the proposed NSPS OOOOa rule for new and modified sources and from the proposed BLM regulations. Indeed, recent comments by EPA Administrator McCarthy suggest that the Agency may well undertake revisions to the Subpart OOOOa rule itself after its promulgation to account for new information about methane emissions sources and possible controls.[11]

Even though EPA cites extensive background on the issues,[12] it nevertheless has identified a need for additional analysis on which to base future regulatory proposals. The first ICR surveys are not anticipated until fall 2016.[13] Because EPA must conduct two rounds of public comment on its draft ICR, and because industry will need several weeks to gather the information called for by the ICR, it

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[8] EPA Fact Sheet: Reducing Methane Emissions from the Oil and Gas Industry, March 10, 2016. (https://www3.epa.gov/airquality/oil and gas/pdfs/20160310fs.pdf).(https://www3.epa.gov/airquality/oilandgas/pdfs/20160310fs.pdf).
[9] Id.
[10] *Id. Id.*
[11] INSIDE EPA, *McCarthy Says NSPS May Not Cover Full Range of Oil and Gas Sources*, April 5, 2016.
[12] *See* https://www3.epa.gov/airquality/oilandgas/methane.html.
[13] *See* https://www3.epa.gov/airquality/oilandgas/pdfs/icr-presentation.pdf.

is anticipated that EPA will still be receiving and analyzing ICR responses in the first half of 2017.[14] In that event, no rule regulating existing sources could be proposed until late 2017, at the earliest, and a final rule would not be promulgated until late 2018 or early 2019.

Under this scenario, a final BLM rule would become effective for existing sources, only to be followed by new EPA requirements applicable to the same sources that, in all likelihood, could differ from those adopted by BLM. To the extent that the BLM and EPA rules conflict, developers would be in an untenable position, and BLM could find itself needing to consider conforming changes in its regulations. Not only would this lead to additional work and protracted uncertainty, but BLM could ultimately conclude that, since existing sources on federal lands will be adequately regulated by EPA, a separate BLM rule is unnecessary.

For operators of existing oil and gas wells on federal lands, compliance with the BLM rule would be required well in advance of when drillers on private lands would need to comply with the forthcoming EPA existing source regulations. This would require producers like BP with a significant presence on federal and Indian lands to incur large costs and other burdens that their competitors are able to avoid, placing them at an economic disadvantage. Operators on federal lands would also be forced to put compliance systems in place to meet the BLM rule that would have to be revisited and modified in light of the likely differing requirements of an EPA rule, further resulting in unnecessary effort and cost. The emission reductions that might occur at existing sources on federal lands during this interim period would be extremely small and would not justify the added burdens for both government and industry.

In sum, with EPA now targeting regulation of existing sources under CAA section 111(d), the proposed BLM rule is no longer necessary to fill a perceived "gap" in coverage. Pushing ahead with a final rule now will likely lead to duplicative and conflicting requirements when EPA's regulations take effect a few years hence. The consequence will be confusion and uncertainty, as well as additional costs for both industry and BLM as it undertakes further rulemaking to conform to the EPA requirements. Thus, the most cost effective and efficient course is for BLM to suspend work on its rule as it relates to existing sources pending the outcome of EPA's separate section 111(d) rulemaking. In the case of new and modified sources, we believe BLM should likewise not finalize its rule since these sources will be adequately controlled by the final Subpart OOOO and OOOOa rules that EPA will promulgate later this spring.[15]

As reflected in the many actions detailed in BP's cover letter, we appreciate the importance of methane emissions management in oil and gas operations, and the Agency's goal of perpetuating good operational practices to address these emissions across the industry. But in this case, given the panoply of state regulations that already require such practices, a decision by BLM to stay its hand for now pending the development of a more consistent and comprehensive federal framework would not leave methane emissions unregulated. On the contrary, regulations in many of the states with tribal and federal leases already apply to existing sources, including Colorado's Regulation 7[16] and Wyoming Department of Environmental Quality's (WYDEQ's) Oil and Gas Permitting Guidance[17]. Furthermore, once EPA finalizes the Control Technique Guidelines (CTGs) for oil and gas in ozone

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[14] INSIDE EPA, *Advocates Eye Interim Existing Source Controls Ahead Of EPA Methane ICR*, April 13, 2016.

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

[17] http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/2013-09_%20AQD_NSR_Oil-and-Gas-Production-Facilities-Chapter-6-Section-2-Permitting-Guidance.pdf,

nonattainment areas, states will have to issue more regulations for ozone nonattainment areas to comply with the CTGs.

1.2 The effects of the proposed rules and their cumulative costs on the economics of oil and gas production must be balanced carefully

As BLM is aware, during the preceding months, exceptionally low oil and gas prices combined with increased costs of production have caused the U.S. oil and gas industry to cut more than 118,000 jobs nationwide.[18] BP L48 has reduced its workforce by over 50% since 2013. BP is particularly concerned that the cost to its L48 business of the complex regulation of a relatively small portion of U.S. oil and gas wells is not warranted in terms of the environmental benefits to be achieved, even if the savings to the government of the waste of natural gas averted are considered.

In today's low-cost environment, the cumulative costs of the proposed rules will likely render some wells non-economic immediately and shorten the economic life of many more. In the case of BP, wells and associated reserves would be abandoned by a company that has shown dedication to methane emission reduction and environmentally sound operations. The result will be reduced natural gas recoveries, reduced royalty payments to the federal government, reduced tax payments to state governments and reduced employment. These outcomes will frustrate the BLM's stated objectives of boosting royalty receipts and enhancing natural gas supplies. They also raise serious questions about the validity of the cost-benefit assumptions underlying the NOPR.

BLM should exempt from the requirements of the rule any well that will become uneconomic immediately upon or within five years of the effective date. This exemption should be based on a current threshold production rate, projected decline, and "net back" value of production so that it is clear, simple, and definitive. The cost portion of this analysis should be determined by adding the current operating costs to the ***combined*** cost of implementing the rule requirements, instead of examining the cost of each individual portion of the rule requirement, and allowing an exemption only for that portion of the rule requirement that ultimately renders the well uneconomic.

Proposed Revisions

Add an exemption to the requirements in §3179 to §3179.2.

§3179.2 (c) If the provisions of the Subpart render a lease, unit, or CA uneconomic immediately upon or within 5 years of the effective date based on current threshold production rate, projected decline, and net back value of the production, the lease, unit, or CA shall be exempt from the requirements of this Subpart.

1.3 The relationship between the costs of the proposed rule and any resulting environmental benefits must be accurately considered

Where EPA already has proposed NSPS for methane and volatile organic compounds emissions from the oil and gas sector, and is planning to propose rules for methane emissions from existing sources, the efficacy of a BLM regulatory program to reduce environmental damage from venting, flaring and leaks must be questioned. The proposed regulations would apply to only approximately 10% of U.S. oil and gas wells. Even recognizing the legitimate goal of addressing methane emissions, we would urge the Bureau to consider more closely the cost and burden of the proposed rules – not only on industry but also on the Agency accountable for administering a complex new regulatory program. In sum, the cost and modest environmental benefits from the proposed BLM rule do not appear to be justified when considering current EPA and state rules as well as the soon-to-be-finalized EPA rules.

[18] Houston Chronicle, *U.S. oil job cuts reach about 118,000*, April 8, 2016

2. Applicability of the Rule is Overly Broad

The scope of the rule is overly broad and difficult for operators to interpret and implement. BLM should provide clarity on the percentage of total royalties under BLM authority to which the requirements would apply. BLM has done this in other guidance such as the Commingling Guidance.[19] BP recommends that the requirements apply only to sites where BLM or the tribes are a majority interest owner with more than a 51% interest prior to royalty measurement and that the cost/benefit analysis done by BLM must consider whether there is a benefit at 51% of the interest.

Proposed Revisions

§3179.2(a) This subpart applies to all of the following with more than 51% interest prior to royalty measurement:

3. Insufficient Time Is Provided to Implement the Rule

As EPA and other agencies have typically done in promulgating their own rules requiring installation of new controls, BLM should allow a reasonable time for implementation of such requirements in its own rule. Specifically, we propose that BLM allow three years as a reasonable period for the replacement and control of existing equipment including storage vessels, pneumatic pumps, and pneumatic controllers so that companies can:

- Incorporate the costs of equipment and personnel in their budget;
- Plan the work and staffing needs;
- Order equipment;
- Manufacture or procure equipment; and
- Have time for proper and expert installation of the equipment and execution of needed work.

Six months to one year is insufficient time to accomplish all the work on so many existing sites, much less even to acquire the necessary equipment for replacement and controls. EPA's existing source rules in 40 CFR 63 Subparts HH and ZZZ, which required replacement and retrofitting of applicable existing sources in the oil and gas sector, provided three years to complete the work and establish compliance. EPA also allowed for seven years for compliance with the interim goals of the Clean Power Plan for existing power plants, and 15 years for full compliance. BLM should similarly allow reasonable time for these substantial new requirements to be implemented by operators of wells on federal and Indian lands.

4. Flaring Does Not Reduce Waste, It Increases Waste

Under the logic of this rule, saleable gas that is not beneficially used or captured and profitably sold is considered as waste. It makes no difference whether the gas is vented or flared. **The operation of a flare or combustion device to burn the gas requires a pilot of natural gas that actually results in increased waste of gas and not a reduction of waste.** Therefore, BLM should remove the requirements to flare emissions from certain sources from the rule. However, if BLM chooses to keep the requirements for flaring over venting, BLM should allow for venting (versus flaring) whenever:

- Volumes and pressures are too low to reach the flare;
- The gas cannot be separated from liquids;
- Gas is not readily combustible and would require the use of additional natural gas or assist gas to burn it, which will cause further waste of natural gas;

[19] Instruction Memorandum – Commingling Guidance

- Adequate space is not available to provide safety buffers for thermal radiation for other hydrocarbon-containing equipment to prevent explosion or damage; and
- Local restrictions on flaring are in effect, for example, due to potential fire hazard or permafrost damage.

5. Overly Burdensome and Costly LDAR Requirements Should Be Modified

From BP's perspective, the LDAR requirements are the most concerning portion of the rule and need to be addressed by BLM to reduce very significant costs that could otherwise drive oil and gas development from federal and Indian land.

5.1 Numerous differences with NSPS OOOOa

The draft rule, as we interpret it, contains differences with EPA's overlapping NSPS OOOOa rule, which will make managing both programs confusing and costly, especially where wells are located side-by-side on a "checkerboard" of federal and non-federal land. These differences include:

- EPA excludes from coverage low-producing "stripper" wells that produce 15 or fewer barrels of oil equivalent (BOE)/day while BLM does not;
- A broader scope in the proposed BLM rule with respect to the equipment covered, including equipment that is designed to vent; and
- A lower threshold for increasing and decreasing the frequency of LDAR (2-3 leaks in BLM's rule versus 1% - 3% of components leaking in EPA's rule).

5.2 Overly burdensome and complicated monitoring frequency

The proposed monitoring frequency is overly burdensome**.** Studies have shown that: annual LDAR monitoring sufficiently reduces emissions; is more cost effective; and, once initial monitoring has been done, that the leak rate continues to decrease over time. For these reasons, LDAR should only be required annually without a variable frequency in monitoring.

The CAPP 2014 study[20] states: "a comparison of the two data sets indicates that, overall, the emissions due to fugitive equipment leaks have decreased by 75 percent since the implementation of DI&M [Directed Inspection and Maintenance] programs" showing emissions from leaks decrease after the initial survey.

Survey data provided to API by companies subject to Colorado Regulation 7 enable a comparison of the percentage of components leaking for different leak survey frequencies [first time, and also quarterly or monthly advanced instrument monitoring mechanism (AIMM) surveys]. The data from annual surveys show decreases of leaks from the initial survey of 0.70-0.88% down to 0.17-0.38% in subsequent surveys. A decrease in the frequency of leaks also supports annual monitoring.

Even though the leaks decrease over time, the cost of each annual survey remains the same, resulting in a decrease in the cost-benefit over time.

[20] Canadian Association of Petroleum Producers (CAPP). 2014. Update of Fugitive Equipment Leak Emission Factors, February 2014. Available at http://www.capp.ca/getdoc.aspx?DocId=238773&DT=NTV.

Increasing the frequency of inspections increases their cost. The Carbon Limits Study (2013)[21] found that increasing the frequency of inspections was not cost-effective for well sites when the cost of the survey and repairs were considered. The study states: "For all three categories [well sites, compressor stations, and gas plants], the majority of facilities have negative NPVs [net present value] with the well sites and batteries having the lowest share of facilities with positive NPVs" (as shown on Figure 8 in the study). In fact, "the mean NPV for the 1,424 well surveys having a negative NPV (81%) was 1,160 USD."

The Carbon Limits Study (2013) also found the emissions reductions per year difference between annual, semi-annual, and quarterly for a well site or well battery were insignificant (<0.5 TPY VOC per site) as shown in Figure 13 from the study.

Based on the information from EPA's Technical Support Document (TSD) for NSPS OOOOa, the cost of the second annual survey would not be cost-effective, as shown in the calculations below using data in the TSD.

From Table 5-18, page 79 of TSD
Annual survey cost = $1329/yr, for 40% reduction, half for CH_4 and half for VOC
Semi-annual Cost = $2330/yr, for 60% reduction, half for CH_4 and half for VOC

Gas Production Site
Assuming 35% new leaks each year.

Year/Emissions CH_4/VOC	Semi-annual reductions CH4/VOC, TPY	Cost/ton, CH4/VOC, $	Annual 40 % reductions CH4/VOC, TPY	Cost/ton, CH4/VOC, $
0 /4.5/1.3	2.7 /0.78	430/1490		
1 /2.4/0.70	1.4 /0.42	**830/2770**	0.96 / 0.28	690/ 2370
2/1.9/0.57			0.76 / 0.23	870/ 2900

Weighted average for gas and oil wells
First semi-annual would be $1100/ton for methane and $3980/ton for VOC.
Second semi-annual would be $2080 for methane and $7430 for VOC.

The cost of the second survey is higher than the weighted average for quarterly monitoring ($1877/ton methane and $6751/ton of VOC) that EPA rejected in proposing the NSPS OOOOa requirements.

5.3 Fixed annual surveys supplemented by periodic AVO inspections

BP urges further consideration by BLM of requiring only fixed (versus variable based on the number of leaks) annual OGI surveys with no performance-based adjustment to the survey frequency. BP believes that is sufficient; however, if BLM will not accept annual leak surveys alone, BP suggests that BLM also require periodic AVO inspections to ensure operators are looking for the larger leaks between OGI inspections. Most large leaks are easily identified using AVO. For example, it is easy to see a thief hatch on a controlled storage vessel that has been left open. The Wyoming Department of Environmental Quality (WYDEQ) allows quarterly monitoring in the Upper Green River

[21] Carbon Limits (CL). 2013. Quantifying cost-effectiveness of systematic Leak Detection and Repair Programs using Infrared cameras. December 24, 2013. Available at http://www.catf.us/resources/publications/files/CATF-Carbon_Limits_Leaks_Interim_Report.pdf.

ozone nonattainment area, allowing for one quarter being OGI and the other quarters to be AVO.[22] One quarter of OGI and three quarters of AVO could be an option for the BLM rules, and even more frequent AVO inspections (such as monthly) could be considered, provided there are reasonable exemptions for those instances when weather-related and other conditions impede the ability to conduct an AVO inspection.

5.4 BLM should focus on higher-risk sites

BLM is proposing monitoring requirements for every location ranging from a single well to a large gas plant. The LDAR requirements, through the BLM's broad definition of a "component," mandate examination of every piece of equipment on the location, whether or not it is designed to vent. To address the high cost of the proposal and to improve reductions in waste of gas, BP recommends that BLM focus on locations that are most likely to have larger leaks. BP recommends further that BLM include only sites with compressors and sites with controlled storage vessels. Compressors and other equipment with rotating, vibrating, and moving parts are more likely to leak. When they do leak, they tend to have larger leaks. The Carbon Limits Study (2013) found that compressor stations leaked more than well sites. The study included 58,421 components that were either leaking or venting gas. The data identified that 44% of gas plant emissions were attributed to leaks, with 36% of compressor station emissions and 17% of well-sites and well batteries also the result of leaks. However, the study incorrectly characterized sources of venting as leaks.

The CAPP 2014 study found that "Components tend to have greater average emissions when subjected to frequent thermal cycling, vibrations or cryogenic service. Different types of components have different leak potentials and repair lives." The CAPP 2014 study also showed that compressors have higher leak rates, as shown on the table below from the study.

Table 6: Summary of leak survey results showing the number of leaking components, the average leak rate and the leak rate standard deviation for reported emissions where the estimated facility component count for the leaking component was zero.

Component Type	Leaking Components[1] (Number)	Leak Rate: Average[2] (kg/h/source)	Leak Rate: STDEV[3] (kg/h/source)	STDEV/ Average (%)	Leaking Components Table 5 (Number)	Leak Rate Table 6/Table 5 (Ratio)
Compressor Seal (GV)	7	0.51142	0.42697	70	82	2.590
Connector (FG)	14	0.21844	0.25549	117	390	1.867
Control Valve (FG)	14	0.10670	0.09843	92	14	1.000
Control Valve (GV)	7	0.08497	0.06722	79	19	1.338
Open-Ended Line (FG)	28	0.36372	0.87591	241	27	1.000
Open-Ended Line (GV)	1	0.00000			25	0.000
Pressure Relief Valve (FG)	1	0.00000			1	0.000
Pump Seal (FG)	9	0.06469	0.07612	118	9	1.000
Regulator (FG)	44	0.19491	0.35115	180	44	1.000
Regulator (GV)	10	0.49748	1.32425	266	15	1.444
Regulator (LL)	1	0.00000			1	0.000
Valve (FG)	2	0.11899	0.02403	20	64	0.287

[1] Leaking components = Total number of leaking components by type included in survey.

[2] Leak Rate: Average = Average of all leak rates by component type.

[3] Leak Rate: STDEV = STDEV of all leak rates by component type.

22 http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/2013-09_%20AQD_NSR_Oil-and-Gas-Production-Facilities-Chapter-6-Section-2-Permitting-Guidance.pdf, page 22

BP is aware of the BLM's concerns that LDAR studies have shown high leak rates from storage vessels due to thief hatches being left open, pressure relief valves lifting, and broken seals on storage vessel thief hatches. However, this would only be a concern on controlled storage vessels where the emissions are required to be routed to a control device through a closed vent system. BLM should exclude sites from LDAR with uncontrolled storage vessels. If a tank is uncontrolled (i.e., <6 TPY VOC uncontrolled), then leaks would be accounted for as part of the allowable emissions for the uncontrolled storage vessel.

5.5 More time needed for repairs

More time is needed than 15 days to make repairs. A 30-day period is a more reasonable amount of time to allow companies to:

- Address safety related concerns, which are of the utmost importance to the Company;
- Acquire replacement parts which are not always readily available;
- Have maintenance personnel address the leak (which can be challenging due to recent staff reductions);
- Account for often hostile weather conditions in the mountainous Western areas in which BP operates; and
- Otherwise deal with a host of issues related to sites that are remote, dispersed, not electrified, and unmanned.

Fifteen days is simply not enough time.

Also, EPA's Method 21 soap bubble repair confirmation, which has long been shown to be effective in confirming repair operations, should be allowed for all operators.

5.6 There should be clear requirements for approval of new technologies

While periodic surveys of oil and gas well pads using OGI (supplemented by AVO as necessary) may represent the best choice for methane leak detection today, rapid development of new technologies with different and better detection capability may soon make possible less costly, more efficient LDAR programs that achieve equal or greater methane emission reductions. Recognizing the downsides of OGI-based LDAR systems, the BLM notes the possible benefits of continuous emissions monitoring systems (CEMS) and explains that "researchers have been evaluating the possibility of adapting the technology for use in identifying leaks in and around oil and gas operations."[23] More broadly, the NOPR also acknowledges the "extensive ongoing work to develop other, more effective and less costly advanced leak detection technologies."[24]

As BLM is aware, two major initiatives are spurring innovation and development of new detection systems and monitoring protocols. DOE's ARPA-E MONITOR program has committed $35 million to fund 11 separate projects at universities and in industry to develop improved detection technology. Working with five companies, EDF has also launched the Methane Detectors Challenge, an initiative to catalyze commercial low-cost technology that can continuously detect methane leaks over a wide range of conditions.

These programs are progressing rapidly. ARPA-E anticipates that substantial laboratory testing and technology development will occur in 2016, followed by extensive field testing and validation in 2017 and 2018 at a neutral test site. The EDF program commenced with laboratory tests of five different technologies in 2014. Four technologies were selected for further testing in controlled laboratory and outdoor testing, which was completed in the fall of 2015. The final step, now underway, is for members of industry to purchase and conduct trial deployments of the best-performing technologies.

[23] 81 Federal Register 6646.
[24] Id.

It is quite possible that one or more of these technologies, or others from the broader market, will be commercially available within two years. The best way to encourage rapid development and deployment of robust OGI alternatives is to establish in the rule a streamlined, fast-track process for approving new detection technology and monitoring methods.

To its credit, BLM has already anticipated the need for such a process. Underscoring that "operators [should] be allowed to take advantage of any new, more effective and less expensive technologies as they become available,"[25] §3179.302 of the proposed rule allows drillers to seek BLM approval of "an alternative leak detection device, program or method." BLM may approve such a request if it "finds that the alternative would meet or exceed the effectiveness for leak detection" of the required OGI-based system.

However, BLM has provided few details in the NOPR on how this approval process would work, and has requested comments on whether the standard for approval and related procedures "provide sufficient guidance to BLM and would result in adequate consistency across field offices."[26]

BP believes a more fully developed framework, with clear guidance on the information petitioners should provide, the criteria they must meet and timelines for Bureau action on petitions, would be valuable in providing clear targets and expectations to technology developers, avoiding delays in approval and promoting transparent, well-documented approval decisions.

Our principal recommendations are as follows:

- A wide range of parties should be allowed to file petitions, including technology developers, oil and gas producers, NGOs and industry consortia.
- The petition should demonstrate that the alternative leak detection technology and monitoring protocol:
    - Has been shown by appropriate, representative data to achieve equal or greater reduction of methane emissions as compared to the prescribed OGI LDAR requirements,
    - Will produce repeatable, accurate and consistent results across a range of relevant meteorological conditions,
    - Will have a demonstrated limit of detection sufficient to provide assurance of emission reductions equivalent to or greater than those achieved using OGI-based LDAR,
    - Includes the factors that will trigger follow-up inspection of individual components to identify significant leaks and how these leaks will be repaired, and
    - Specifies how monitoring and other key tasks will be conducted in sufficient detail to assure consistent application of the protocol at affected facilities and verification of results.

- The petition should include records from laboratory and field testing plus other key information, such as limitations on types of sites or other conditions on where the technology and protocol can be deployed.
- The Bureau should provide public notice of petitions and the opportunity to submit comments.
- Where a petition is complete, the Bureau should grant or deny it within 180 days.

[25] 81 Federal Register 6647.
[26] Id.

- There should be an expedited process by which the Bureau can allow approved devices and protocols to be used at facilities other than those of the petitioner.
- The Bureau should create a technical committee, with experts from inside and outside the government, to monitor and evaluate development of new measurement technologies and protocols and advise on their progress.

As the two agencies move forward with their respective rules, EPA and BLM must be fully aligned in their approaches to approving LDAR alternatives. Moreover, it is important for BLM and EPA to pool scarce technical resources rather than conducting duplicative reviews of LDAR alternatives.

We recommend that the BLM and EPA rules incorporate identical processes for approval of alternative technologies and that the agencies create joint review teams for evaluating and taking action on proposed LDAR alternatives. A memorandum of understanding between the two agencies would be one vehicle to operationalize such a collaborative relationship. In addition, the expert technical committee described above should be organized jointly by BLM and EPA and report to both agencies.

5.7 BLM should allow compliance with the proposed rule upon compliance with state, tribal, local, and other federal LDAR programs

Operators should be able to request approval of LDAR provisions under another legally and practically enforceable program at the state, local, tribal, and federal levels. BLM should treat compliance with the existing LDAR programs under Colorado's Regulation 7 and Wyoming Department of Environmental Quality's permitting requirements as constituting compliance with this rule. BP recommends for BLM's consideration, that under §3179.301 of the proposed rule, the Bureau exempt sites with a legally and practically enforceable leak detection and repair program in an operating permit or other enforceable requirement established under a federal, state, local or tribal authority.

Many of the states and local air districts already have detailed leak detection and repair requirements either in regulations or permits for facilities. BLM has only provided an exemption for NSPS OOOOa, but should consider other exemptions as well in §3179.301(e). There are other EPA regulations including those under 40 CFR Subparts KKK and OOOO (NSPS KKK or OOOO), that contain LDAR requirements for which exemptions are not provided under §3179.301(e). Also, BLM has only proposed allowing for the state or tribe to apply for a variance from provisions of the rule under §3179.401 if the requirements meet or exceed those in the proposed rule and the BLM State Director approves. It is uncertain whether states will expend the resources to request variances, particularly in the case of leak detection and repair programs in permits for individual facilities. Additionally, §3179.401 does not allow for local air authorities, such as the various California air boards or the City of Albuquerque, to request a variance for their regulations. This leaves companies with the cost and burden of contending with two, and sometimes three, LDAR programs with varying requirements that cover the same facility.

5.8 More time needed to implement LDAR

BP requests that BLM allow three years for the implementation of the LDAR requirements in § 3179.301-305. LDAR cannot be implemented upon the effective date of the rule. Companies (either producers or their contractors) will need time to budget for the OGI equipment, personnel and a data management system, order and acquire optical gas imaging cameras, acquire and train personnel necessary to conduct the monitoring, develop a data management system, train personnel on the data management system, and then actually perform the monitoring on all the facilities.

EPA's National Emission Standards for Hazardous Air Pollutants (NESHAP) HH and ZZZ rules, which require replacement and retrofitting of applicable existing sources in the oil and gas sector, provided three years to complete the work and establish compliance. Under EPA's Clean Air Act authority to control existing equipment under Section 111(d), controls are not required immediately. In fact, under EPA's Clean Power Plan that regulates carbon dioxide emissions from existing power plants, EPA provided seven years to meet interim goals of the rule and 15 years for full compliance.

However, if BLM does not provide a longer implementation period, BP proposes phasing-in the regulation over a two-year period and allowing companies to determine which half of the facilities to address in each of the first and second years. This measure of flexibility would provide enormous relief to an industry that will face a range of compliance issues raised by the rapid implementation schedule of the proposed rule. Company budgets currently do not have the ability to absorb the great up-front cost of LDAR.

6. Issues Surrounding Storage Vessel Requirements

Natural gas is required for the pilot of the control device (combustor or flare) that is needed to control storage vessel emissions. Under the logic of this proposed rule, these requirements result in the increased waste of product – not a reduction of waste. Therefore, we question why storage vessel control requirements are included in the rule. The pilots on combustors and flares burn from 12 - 180 standard cubic feet per hour (scf/hr) of natural gas continuously, which is higher than the threshold for replacement of pneumatic controllers. Furthermore the composition of the flash gas is primarily ethane plus (C2+) with very little methane (1% - 30% on a mole basis depending on the composition of the condensate and operating pressure of the separator). Most of the methane is separated out of the condensate in the separator prior to entering the storage vessel.

The only other option for controlling storage vessel emissions is vapor recovery; however, typically, vapor recovery is technically infeasible, and thus cannot be required. Where it is feasible, it is usually cost-prohibitive to get the recovered gas into a natural gas collection system. Most collection systems pressures are too high and require a large amount of compression to enter the system. Furthermore, most sites on federal lands do not have access to electricity that would power compressors and therefore, natural gas engines are required to power the compression. Powering compression of natural gas wastes more natural gas, and the natural gas engines are very rarely cost-effective.

The cost of controlling existing tanks by combustion is higher than on new tanks, running on average between $100,000 and $175,000 per tank to cover the cost of:

- A control device;
- The thermo-couple (temperature monitor) to continuously monitor the pilot to ensure that it stays lit;
- The equipment to capture and transmit the thermal couple readings to the field office;
- Replacement of the thief hatches and pressure relief valves with ones having lower design leak rates;
- Running piping;
- Installation of a knockout drum so liquids do not reach the control device;
- Land on which to place the control device so it is far enough away from other hydrocarbon containing equipment to provide a safe distance from radiant heat;
- Replacement, in some cases, of the entire tank or addition of a uncontrolled blowdown tank; and
- The ongoing cost of pilot fuel, maintenance, and operation of the control device.

This is based on the cost of recent site retrofits to tie in new wells to comply with NSPS OOOO.

At a minimum, if these requirements for storage vessels remain, due to their very high cost and the marginal environmental benefits achieved, the emissions threshold should be raised from 6 TPY to 15 TPY.

Furthermore, while the proposed regulatory language and the preamble repeatedly states an intention to align the storage vessel controls with those in EPA's OOOO/OOOOa, the definition of storage vessel found in § 3179.3 does not align with the definition of a storage vessel in EPA's OOOO/OOOOa. The definition proposed by BLM places the single tank limit on a tank battery, making this existing source rule significantly more stringent than EPA's new source rule. Portable tanks that are at a well site only temporarily should be excluded from rule coverage. We suggest changing the definition to align with EPA's definition of a storage vessel in 40 CFR 60.5430, or removing the reference to a tank battery and exempting temporary tanks and completion flowback vessels.

Also, as EPA has done in NSPS OOOO (40 CFR 63.5365(e)(3)) and OOOOa (40 CFR 60.5365a(e)(3)), BLM should also exclude all tanks under a legally and practically enforceable limit and which are covered in an existing operating permit or other requirement established under a federal, state, local or tribal authority.

BP believes that at least three years (as opposed to only six months as currently proposed) is reasonably required to install all of these controls. If less time is provided, we cannot adequately plan and budget for what we need, order the necessary equipment which often takes many months to be delivered through the supply chain, and then safely install the equipment.

Also, BP requests that BLM make it clear that once emissions drop below 15 TPY of VOCs that the control device can be removed. In EPA's NSPS OOOO and OOOOa, that Agency has allowed for removal of the control device, recognizing that as a well's production declines over time, the emissions from storage vessels decline, and there is no reason to continue to control emissions once they are below the control threshold.

Proposed Revisions

We recommend that BLM remove the storage vessel requirements from the proposed rule or, alternatively, make the following revisions.

§ 3179.3

~~*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.*~~

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback is not a storage vessel. A tank or other vessel shall not be considered a storage vessel if it has been removed from service. The following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

§3179.203
(a) A crude oil or condensate storage vessel ~~located on a BLM lease~~ 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; and
(2) Is not subject to 40 CFR part 60, subpart OOOO, 40 CFR part 60, subpart OOOOa, or under a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or tribal authority; and
(3) Has a rate of total VOC emissions equal to or greater than ~~6~~15 tons per year (TPY) based on a 12 month production average.
(b) The operator must determine the rate of emissions from the storage vessels within ~~60 days~~ three years 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~~ 3 years 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 accounting for other cost associated with this rule in the base cost of the lease.
(d) Controls can be removed from the storage vessels once emissions drop below 15 TPY.

7. Clarification Needed on Exemptions for Pneumatic Pumps

The pneumatic pump requirements as proposed are unclear, especially when it comes to use of "or" and "and". The only exemption from required use of zero-emission pumps is "functional need" or for routing to a control device if there is not one on site. A sundry notice must be submitted that "*Provides an economic analysis that demonstrates, and the BLM agrees, based on information identified in §3179.7(b), that installation of zero emission pump(s) would impose such costs as to cause the operator to cease production and abandon signification recoverable oil reserves under the lease; and demonstrates to the BLM there is no existing flare device on site or routing to such a device is technically infeasible.*" This is an onerous information requirement under 3179.7(b) that will require operators to submit great amounts of data related to associated gas from oil wells being flared instead of sold, which does not appear to be relevant to pneumatic pumps.

BLM did not propose exemptions from the use of a zero-emission pump due to lack of electricity or where the combined volume and pressure needs of the pump exceed the reasonable capabilities of a solar pump. Most of the federal and tribal lands on which BP currently operates do not have electricity available to power pumps, which is why pneumatic pumps have been used. Commercially available solar pumps have a limited volume/pressure capability. They tend to work to replace small chemical injection pumps with low volume/pressure rate requirements or moderate volume/low pressure requirements. Solar pumps cannot reasonably be used to replace higher rate glycol heat trace pumps or sump pumps. Commercially available solar powered pumps with sufficient capabilities to operate the heat trace systems are not reasonably available. Also, since these pumps are essential to prevent freezing of equipment in the winter, operators cannot risk that they will not have sufficient solar power to operate due to snow cover, lack of sunlight, battery theft, or battery failure. As discussed earlier, sending the waste gas from the pneumatic pump to a flare does not reduce waste, but rather increases waste because the flare would need a continuously burning natural gas pilot. Furthermore, routing to an existing control device is not always feasible due to heat input limitations (the device not having the capacity to handle the waste gas), insufficient pressure and/or volume to reach the control device, too much back pressure on the flare or combustion device from the pump, and surface disturbance limitations to piping to the control device. Also, BLM did not include any *de minimis* volumes or operating time exclusions for control of pneumatic pumps.

The cost of replacing pneumatic pumps with solar pumps, where technically feasible, or of routing to a control device, is significantly more than estimated by BLM. In our experience, solar pump replacement can run at least $25,000 per pump. Also, the cost to route to an existing control device includes not just the piping cost but also engineering analysis and design cost as well as construction cost which can run at a minimum around $5,000 per pump. Due to the high cost of replacing pumps with solar pumps or routing to a control device, BLM should exempt pumps that vent less than 53,000 standard cubic feet per year (scf/yr) (equivalent to the 6 scf/hour limit for a pneumatic controller) and pumps that operate less than 98 days per year.

Companies will be unable to replace or control all existing pneumatic pumps in only one year. As discussed above, at least three years is needed for compliance with the proposed rules. Also, up to five years should be given for replacement if the remaining life of the equipment is five years or less. This would provide companies additional time if the equipment is going to be replaced in any event, and allow time for companies to possibly electrify locations if BLM approves (versus installing solar or routing to a control device).

Proposed Revisions

§3179.202

(a) A ~~pneumatic chemical injection or~~ pneumatic diaphragm pump is subject to this section if it:

(1) ~~Uses natural gas produced from~~ Is located on 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 60 Subpart OOOOa~~; a legally and practically enforceable requirement in an operating permit or other enforceable requirement established under a Federal, State, local or tribal authority,

(3) Operates more than 98 days/year or 2360 hours/year; and

(4) Has an exhaust rate greater than 53,000 scf/yr.

(b) The operator must replace a pneumatic diaphragm pump subject to this paragraph with a zero-emissions pump or alternatively route the pump to a ~~flare~~ control device if one is located on site 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 keeps a record that documents ~~notifies the BLM through a Sundry Notice that~~:

(~~i~~1) Use of a pneumatic pump is required based on functional needs, ~~described in the Sundry Notice; and~~

(~~ii~~2) There is no existing ~~flare~~ control device on site or routing to such a device is technically infeasible; ~~or~~

(3) It is technically infeasible to replace the pneumatic pump with zero-emission pump; or

(4) Provides an economic analysis through a Sundry Notice that 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 accounting for other cost associated with this rule in the base cost.

(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~~ 3 years 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~~ 5 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~~5 years from the effective date of this section.

~~*(e) The operator must ensure pneumatic pumps are functioning within manufacturers' specifications.*~~

8. Concerns Regarding Downhole Well Maintenance and Liquids Unloading

Several issues arise with respect to the requirements BLM has placed in § 3179.204 for downhole maintenance and liquids unloading. This section of the rule and discussions in the preamble as well as the Regulatory Impact Analysis (RIA) reflect a basic misunderstanding of the difference between liquids unloading and venting from liquids unloading that must be addressed first. BP has worked on addressing liquids unloading venting for over 18 years and was a pioneer in reductions of liquids unloading venting. For more information, please see the 2014 comments by Gordon Reid Smith to EPA's Liquid Unloading White Paper.[27] Mr. Smith was one of the BP employees involved in the BP San Juan Liquids Unloading Venting Project.

8.1 Liquids unloading venting fundamentals

Managing wellbore liquid build-up in gas wells is fundamental to maintaining production, avoiding early abandonment of wells and maximizing resource recovery. Wells and reservoirs follow a continuum of flow regimes in their economic life as the reservoir depletes, production goes down, wellbore (tubing) velocity goes down, and liquid loading begins to occur in the wellbore. Liquid loading begins when the velocity up the production string is not sufficient to drag liquids up the wellbore. While pressure is a factor, it is generally velocity, not pressure, which causes liquids to accumulate in the wellbore (i.e., "to load")." Gas well unloading is a complex field of engineering where a large number of different technologies, tools and practices are matched to an individual well's characteristics at each stage of its lifecycle to most efficiently manage liquids and maintain economic production. No single technique will be adequate or appropriate across the full lifecycle of a well.

As a well moves through its lifecycle, the appropriate approach to managing liquids changes as shown in Figure 1 below. New wells typically have production rates and flowing velocity high enough that liquids loading is not an issue. As the portion of the reservoir accessed by a well depletes, the production rate and consequent velocity declines and eventually reaches a point where liquid loading begins to be an issue. The time for this to occur is dependent on the reservoir characteristics and varies from well to well. At the onset of liquid unloading, techniques that rely on the reservoir energy are typically used. These include:

- Intermitting: Shutting in a well for a period of time to allow the reservoir to "refill" the pressure and volume "void" in the near-wellbore reservoir. When the well is restarted the production rate and velocity are higher and the well can "unload" liquids through the normal production route to sales;
- Velocity strings: Installing a smaller diameter tubing string in the well that increases the flow velocity at a given production rate sufficiently to drag liquids up the wellbore and prevent liquid loading. Due to the trade-off between higher flowing friction in smaller diameter tubing and increased velocity the practical lower diameter limit is approximately 1 inch;

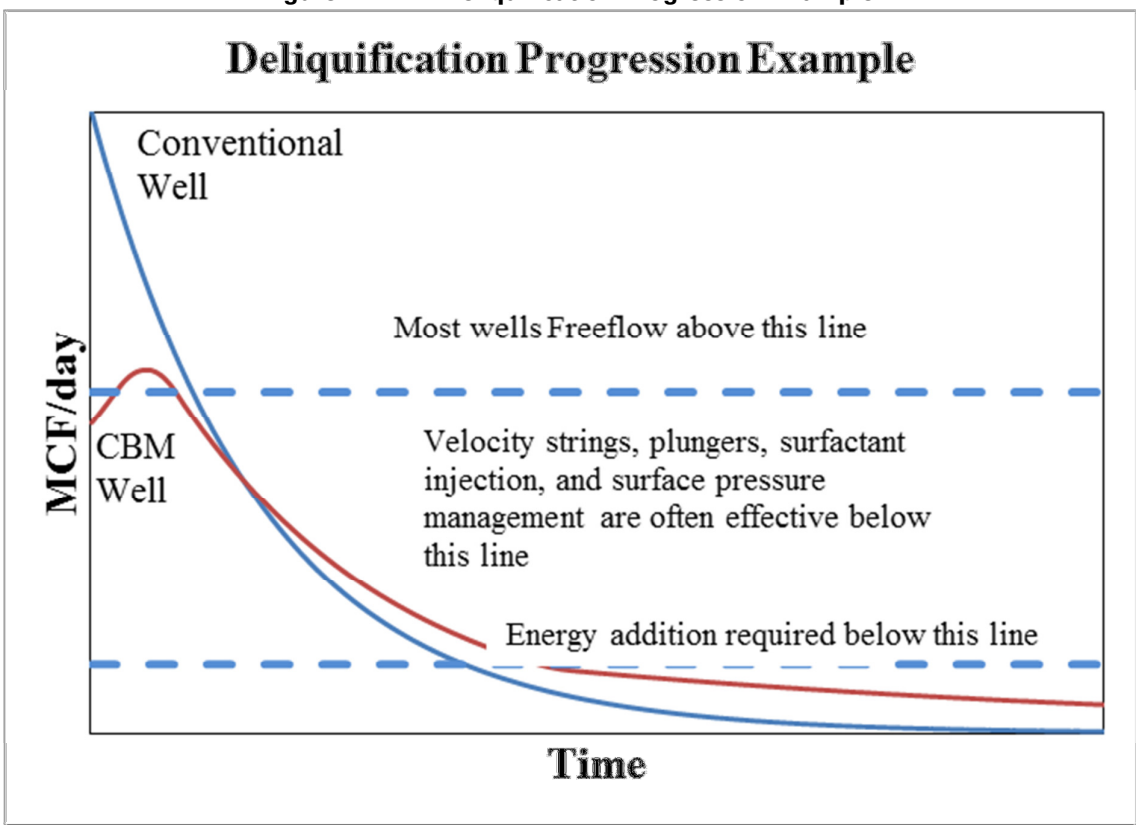
[27] https://www3.epa.gov/airquality/oilandgas/2014papers/attachmentj.pdf

- Surfactants and foaming agents: Introducing surfactants and foaming agents to the bottom of a well (various techniques are used) creates foam with lower specific gravity which enables liquids to be carried up the wellbore at lower velocities;
- Installing a plunger lift system that changes the dynamic for removing liquids from velocity to differential pressure between the bottom-hole and the surface/gas collection line; and
- Installing wellhead compression that lowers the surface back-pressure on a well, increases production rate and flowing velocity, and increases the differential pressure between the reservoir and the collection/sales line.

These techniques can be used individually or in combination to manage wellbore liquids and maintain production.

Eventually a well will reach a point where the reservoir energy is not sufficient to remove the liquids from the well and adding energy to the well is necessary to continue production. Common approaches are to install a pump in the well or install a gas lift system. There are a number of different pump types and gas lift systems, each more effective in some respects than others. Installation of a system to add energy to a well is an economic decision based on whether the continuing production will be sufficient to support the costs of installing and operating a pump or gas lift system. **Well engineers and operators must have the flexibility to employ the appropriate tools at the appropriate times to manage wellbore liquids.**

Figure 1: Deliquification Progression Example



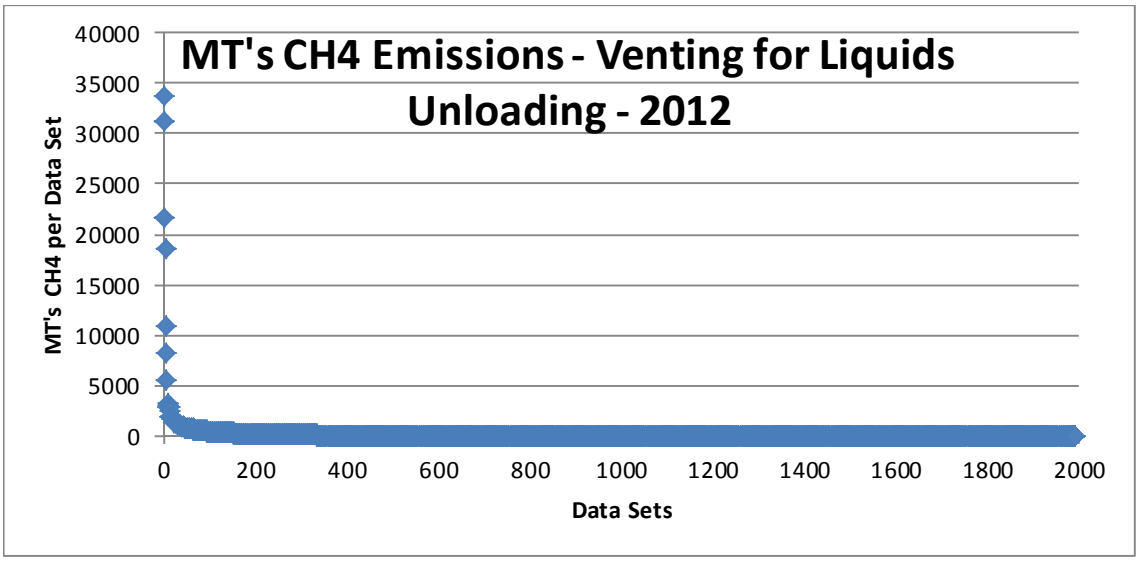
This complexity is why EPA concluded for NSPS OOOOa that regulating venting and emissions associated with managing wellbore liquids is not feasible. We urge the BLM to follow EPA's lead and not attempt regulation associated with wellbore liquid management.

If BLM determines to pursue such regulation, then minimizing venting of gas to assist liquid removal and the resultant emissions should be the focus of BLM's efforts -- and not *which* technology, tool, or approach should be used to manage wellbore liquids. Deliquification/liquid-unloading and venting are not synonymous terms. Liquids can and are routinely removed from gas wells without venting. About 85% of the gas wells in the U.S. have low enough production rates to have liquid loading issues, and only about 13% have liquids unloading venting to assist liquid removal in 2012 (gross up of GHGRP data[28]). In addition, as shown on Figure 2 below:

- The frequency and amount of venting to assist liquid unloading is highly skewed, with 10 of the 1991 non-zero datasets reported at the "sub-basin" level (less than 0.5%) datasets accounting for more than 50% of the emissions reported;
- At the facility (basin) and reporter level (251 non-zero data sets) the top 1 (0.4%) accounted for about 37% of the total reported emissions; and
- The top 3 (1.2%) accounted for over 50% of the total methane reported and the top 11 accounted for over 75% of the reported methane emissions.

It is clear that most operators are managing wellbore liquid removal with no or minimal venting. A regulation is not required for all operators to address the issue. A more focused effort with the highest-venting operators addressing their waste of resources is warranted.

Figure 2: EPA Greenhouse Gas Reporting Rule Venting from Liquids Unloading Data for 2012 in Metric Tons of Methane (MT's C4)[29]



The key to minimizing venting while maintaining liquid removal is understanding and using the reservoir energy dynamics - in particular, build-up of pressure. Venting wells "waste" reservoir energy, which can be used to manage liquids and maintain production.

8.2 BP's San Juan Basin Smart Automation Project

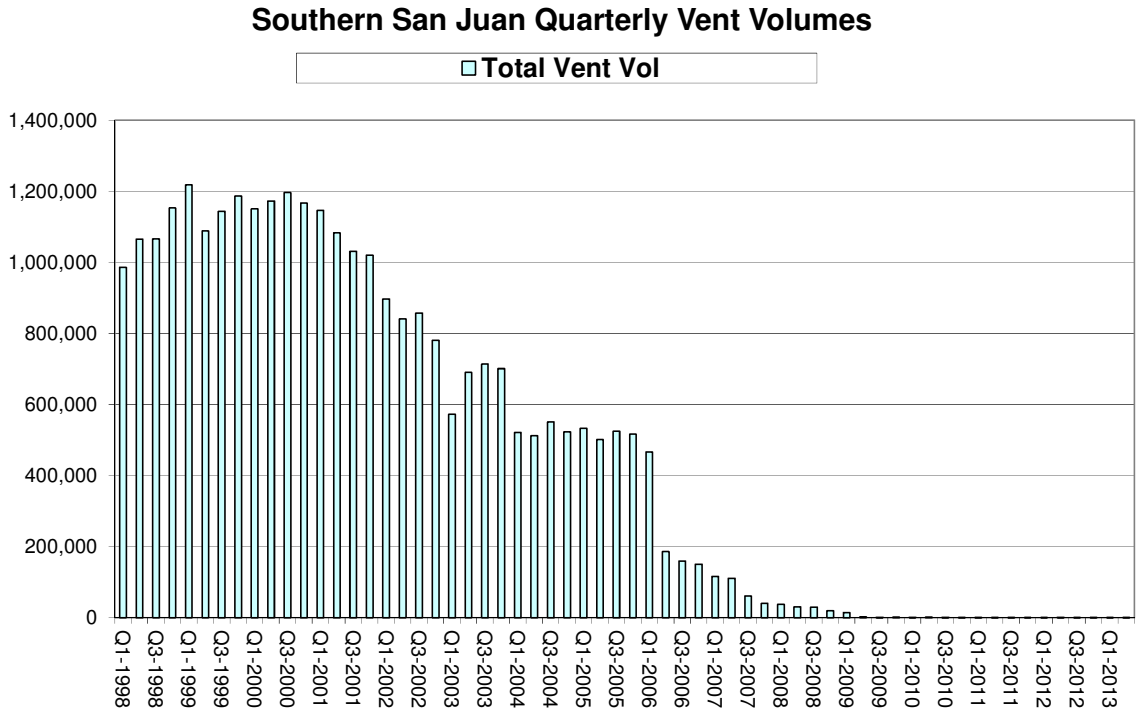
BP's San Juan Basin "smart automation" project is an excellent example of using the understanding and management of the reservoir's energy dynamics to reduce venting of wells during the liquids

[28] US EPA's Greenhouse Gas Reporting Rule Data for 2012 pulled using Facility Level Information on GHGs Tool (FLIGHT) on https://ghgdata.epa.gov/
[29] US EPA's Greenhouse Gas Reporting Rule Data for 2012 pulled using Facility Level Information on GHGs Tool (FLIGHT) on https://ghgdata.epa.gov/

removal process. This system monitors various well parameters and customizes the shut-in and flow times for each well to enable liquid removal with almost zero need for venting. It is used and effective on both plunger equipped wells and wells without plunger lift systems. About one-half of the wells had plungers and about one-half did not. However, a small number of venting instances are still necessary when a well unexpectedly loads up with liquids or the automation system malfunctions. Provision for non-routine venting of wells to assist in unloading liquids must be preserved - both for existing wells and new wells that will likely experience liquid loading at some point in their lifecycle.

In the preamble to the proposed rule, BLM discusses BP's project based on the EPA's Natural Gas STAR presentation. However, we are concerned that BLM has mischaracterized several aspects of the project, including when it states that gas that is not vented is sold. In fact, gas that is not vented is not sold, but rather remains in the reservoir.

Figure 3: BP 1998-2013 Quarterly Venting Volumes from Liquid Unloading Venting in the San Juan Basin



It also appears that BLM incorrectly assumes there is no venting from automated systems. Whether an automated well control system includes routine venting, venting on certain conditions such as a plunger not returning, or shuts in a well and alerts the operator depends upon how the system is configured and the underlying philosophy of deliquification and well operations. Even with a highly sophisticated system, such as the one BP developed in its San Juan operations, which shuts a well in and alerts operations, there is still minimal venting – depending upon on what the operator finds when examining the well.

8.3 Plunger Lift Issue

From BLM's assumption in the RIA that new wells would have plunger lifts installed and venting would be eliminated, it appears that BLM believes plunger lift systems are an emission control technique. This is not correct and clearly not supported by the data as shown on Table 1 below.

Plunger lifts are a valuable, effective and commonly-used methodology/tool to assist in managing wellbore liquid loading. Plunger lifts do increase the efficiency of liquids removal from wells by the reservoir energy and hence help maintain or increase production. However, the efficacy of plunger lifts in reducing venting of wells associated with deliquification and emissions is completely dependent on how they are operated, which is the same for non-plunger lift equipped wells. As the API/ANGA survey report, the GHGRP data, the U.S. Emission Inventory, the ICF/EDF report reanalysis of the GHGRP data, and the UT Phase 2 (2014) study all show, venting wells with plungers have higher emissions per well than venting wells without plunger lifts, and wells with plunger lifts account for the majority of emissions from venting to assist deliquification. Both the API/America's Natural Gas Alliance (ANGA) and Greenhouse Gas Reporting Program (GHGRP) data show more than 70% of emissions are from wells with plunger lifts despite the fact that only 35-40% of U.S. wells are equipped with plunger lifts.

Table 1: Well Venting for Liquids Unloading Venting Emissions Estimates from Multiple Sources

Name	Methane MT's	Total # of Venting Wells	# Venting With Plunger Lift	# Venting Without Plunger Lift	MT's per year per Venting Well	MT's per Venting Well per year with Plunger	MT's per Venting Well per year w/o Plunger
Greenhouse Gas Reporting Program - 2012	276,378	58,663	32,448	26,215	4.711	6.158	2.959
U.S. Inventory of Greenhouse Gas Sources and Sinks - 2013 (2011 Emission Year)	258,667	60,810	23,503	37,307	4.254	4.618	4.024
API/ANGA Report - 2011 data	319,664	65,669	36,806	28,863	4.868	5.207	4.584
ICF/EDF Report	277,307	75,399	44,286	31,113	3.678	4.430	2.607

Note: The different data sources/studies used different methane concentrations to arrive at methane emission estimates. See the individual studies for information on methane content that was used.

It also appears that BLM believes plunger lift systems should be installed on new wells when they are drilled and completed. This is not feasible. Many wells will never be candidates for plunger lift use, and, in those cases, installation of plunger lift systems would not be cost-effective. Most wells that eventually do experience liquids loading and are candidates for plunger lifts will reach that point only after many years of free-flowing production. Installing a plunger lift system at initial well construction would unnecessarily decrease capital efficiency. Practically, during the time that a well is free-flowing, it is likely it will be recompleted or otherwise worked on between three and five times. Each time it is recompleted all of the plunger equipment must be removed to facilitate pulling the tubing. After sitting in a well for many years, it would be rare for components like profile nipples, bumper springs, and lubricators to be in a condition to be re-installed. Therefore, putting this equipment on new wells assures it will be discarded long before it could ever be put in service. Installing plunger lift systems at initial construction would also "lock in" technology choices in a world of dynamically changing and improving technology.

8.4 Issues with the Proposed Rule

A close examination of the rule text raises a number of issues. BLM has placed well maintenance under the liquids unloading section of the rule. However, there is no definition of "well maintenance," and it is unclear what BLM means by that term. Well maintenance should be removed from the rule.

New wells cannot be prohibited from venting, manually or otherwise. There are instances where venting must be done to lift the liquids out of the wellbore. Plunger lifts and automation systems will not prevent a well from venting.

BLM proposes that operators maximize recovery for sale or flaring of the venting from liquids unloading. As discussed above, gas that is not vented during liquids unloading is not sold but remains in the reservoir. Flaring would always be technically infeasible because of the backpressure the flare would put on the well head preventing the lifting of liquids. The cost of providing a temporary flare would make it prohibitive. Portable flares are more expensive as well as a greater safety hazard. Moreover, flaring does not reduce waste. Every well that has liquids unloading venting would have to submit the Sundry Notice required under §3179.204(d) and (e) for venting because it cannot be flared.

Proposed Revisions

BP recommends that BLM remove the liquids unloading venting requirements from the rule. However, if BLM chooses to keep these provisions in the rule, BP recommends that the proposed regulation be modified to address the issues noted in these comments. BLM could either adhere to a management practice standard similar to our proposed Option 1 below or require submission of a venting minimization plan that lays out the ways in which the operator plans to reduce liquids unloading venting in a basin and formation as in Option 2 below.

Option 1:

Replace §3179.204 with the following:

§3179.204

(a) During liquids unloading operations, owners or operators must use best management practices to minimize well venting unless venting is necessary to lift the liquids in the wellbore.

(b) For any liquids unloading venting, the operator must:

(1) Record the cause, date, time, duration, and estimated volume of each venting event; and

(2) 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.

Option 2

Replace §3179.204 with the following:

§3179.204

(a) At an AAPG basin level and only for operators with a venting frequency associated with liquids unloading that is greater than the 90th percentile of the frequency determined from the US EPA's 2015 GHGRP Data for the same AAPG basin, submit a plan to the BLM of how the operator plans to reduce liquids unloading venting in the particular AAPG basin.

(b) Submit a plan to the BLM of how the operator plans to reduce liquids unloading venting in the particular basin and formation combination or if the operator feels they already manage venting associated with liquids unloading to a low level, submit a statement to this effect with supporting information.

(1) The venting frequency is to be determined by dividing the number of venting events/instances in a particular year by the number of operated producing wells in the same year

(2) The basin and/or formation for which the plan applies.

(c) Record the cause, date, time, duration, and estimated volume of each venting event from liquids unloading.

(d) Maintain the liquids unloading records for the period required under §3162.4-1 of this title and make them available to BLM upon request.