April 22, 2016

via e-filing at www.regulations.gov

US Department of the Interior
Bureau of Land Management
Mail Stop 2134 LM
1849 C St., NW
Washington, DC 20240

Re: RIN 1004-AE14: Waste Prevention, Production Subject to Royalties, and Resource Conservation, proposed rule published in the Federal Register on February 8, 2016 (81 Fed. Reg. 6616)

To Whom It May Concern:

I. INTRODUCTION

The Independent Petroleum Association of America ("IPAA"), the Western Energy Alliance ("Alliance"), the American Exploration and Production Council ("AXPC"), and the US Oil and Gas Association ("USOGA") (collectively "the Associations") submit the following comments on the Bureau of Land Management's (BLM) proposed Waste Prevention, Production Subject to Royalties, and Resource Conservation Rule ("Proposed Rule").

<u>The Associations</u>

The Independent Petroleum Association of America represents the thousands of independent oil and natural gas exploration and production companies, as well as the service and supply industries that support their efforts.. Independent producers drill about 95 percent of American oil and natural gas wells, produce about 54 percent of American oil, and more than 85 percent of American natural gas.

Western Energy Alliance represents over 450 members involved in all aspects of environmentally responsible exploration and production of oil and natural gas in the West. The Alliance represents independent oil and gas producers, the majority of which are small businesses with an average of fifteen employees.

The American Exploration & Production Council is a national trade association representing 28 of America's largest and most active independent natural gas and crude oil exploration and production companies. AXPC's members are "independent" in that their operations are limited to the exploration for and production of natural gas and crude oil. Moreover, its members operate autonomously, unlike their fully integrated counterparts, which operate in additional segments of the energy business, such as downstream refining and marketing. AXPC's members are leaders in developing and applying the innovative and advanced technologies necessary to explore for and produce crude oil and natural gas, and that allow our nation to add reasonably priced domestic energy reserves in environmentally responsible ways.

The US Oil & Gas Association was founded almost one hundred years ago and is the oldest national trade association for oil and natural gas producers. The Association's Division in Washington, D.C., is the umbrella for its Divisions in Texas, Louisiana, Oklahoma and Mississippi/Alabama. With nearly 5,000 Members, USOGA represents the full spectrum of the domestic petroleum industry; it provides a forum for the discussion and advocacy of mutually beneficial domestic exploration and production policies for all members regardless of size.

The member companies of the Associations have valid existing and producing oil and gas leases on federal and Indian lands, and plans that include future leasing, exploration and production activities on federal and Indian lands. Consequently, the companies will be directly affected by the many requirements that the Proposed Rule seeks to impose.

The Associations have made significant progress in addressing the issues of venting, flaring, and methane emissions from their oil and gas operations, and will continue to do so. However, after careful examination, we have concluded that the Proposed Rule, which addresses those issues, is arbitrary and in excess of BLM's legal authority and should not be promulgated. Among other things, the Proposed Rule is in direct conflict with the written approvals that BLM has given to hundreds of operators to vent and flare. It is also focused in many respects on reducing methane emissions, which BLM lacks authority to do, rather than on preventing the "waste" of gas.

At a minimum, we urge BLM to suspend its rulemaking efforts until the Environmental Protection Agency (EPA) has finished the work it has recently begun on regulations governing the emissions of air pollutants from existing oil and gas sources. In accordance with BLM's own policy, that would insure that the regulated community is not subjected to conflicting or redundant federal mandates. Instead, BLM should redirect its resources towards processing applications for the pipeline rights-of-way across federal and Indian lands that are essential for the building of gas capture technology. Timely processing of such applications would have a much greater and more immediate impact on reducing flaring levels than BLM's proposed one-size-fits-all, command-and-control regulation.

Should BLM choose to proceed with the Proposed Rule despite its lack of authority, the Associations urge BLM to make numerous revisions to the Proposed Rule which, in its current form, is unworkable for the oil and natural gas industry as well as BLM. We have provided numerous detailed suggestions on how to make the Proposed Rule workable in this letter. We look forward to working with BLM to reduce any "waste" of gas that may be occurring due to venting and flaring from the operations of our member companies on federal and Indian lands.

II. GENERAL LEGAL AND POLICY CONCERNS

A. Work on the Proposed Rule should be suspended pending the completion of EPA's "existing sources" rule

A primary focus of BLM's Proposed Rule is to reduce venting and flaring from existing oil and gas operations.[1] However, on March 10, 2016, the White House announced that EPA, as part of the President's climate change agenda, will immediately begin developing regulations that will regulate methane emissions from existing oil and gas operations. In view of this announcement, BLM should suspend further development of the Proposed Rule until it can insure that the requirements of the Proposed Rule, when considered together with the regulations for existing oil and gas operations that EPA is now developing, will not subject operators to "conflicting or duplicative Federal mandates." [2] It would be a significant waste of the time and resources of both BLM and the regulated community to continue to work on the development of the Proposed Rule without knowing what EPA will soon propose in its regulations for existing oil and gas operations. Moreover, as explained below, BLM lacks the authority to directly regulate the emission of methane and should not be engaged in any such effort under any circumstances.

B. The Proposed Rule is arbitrary and should not be promulgated

Under the Administrative Procedure Act, a court may set aside agency actions that are "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law."[3] The Supreme Court has stated that an agency rule is arbitrary if "the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem," or failed to "articulate a satisfactory explanation for its action, 'including a rational connection between the facts found and the choice made.'" [4] It has also stated that a rule that is intended to replace an existing policy is arbitrary if the agency "disregards [the] facts and

[1] Waste Prevention, Production Subject to Royalties, and Resource Conservation, 81 Fed. Reg. 6616, 6627 (Feb. 8, 2016).
[2] *Id*.
[3] 5 U.S.C. § 706(2)(A).
[4] Motor Vehicle Mfrs. Ass'n v. State Farm Ins., 463 U.S. 29, 43 (1983).

circumstances that … were engendered by [its] prior policy."[5] As explained below, BLM has violated these well-established standards in developing the Proposed Rule. The Proposed Rule is therefore arbitrary and should not be promulgated.[6]

1. BLM may not justify its waste prevention measures by reference to the reductions in methane emissions that they might achieve

One of the primary goals of the Proposed Rule is to reduce the amount of methane emissions from oil and gas operations. In fact, the way the Proposed Rule is promoted, this appears to be <u>the</u> primary goal of the Proposed Rule. The Proposed Rule is cited as one of the principal methane reduction actions under the President's *Climate Action Plan: Strategy to Reduce Methane Emissions*.[7] In addition, BLM has repeatedly emphasized the methane reductions the Proposed Rule would achieve as a justification for its provisions. Most recently, in announcing the extension of the comment period on the Proposed Rule, BLM referred to the Proposed Rule as the "Proposed Rule to Reduce Methane Emissions, Wasted Gas on Public Lands," and as the "Methane and Waste Prevention Rule," and touted the fact that the "proposal is consistent with the Obama Administration's goal to cut methane emissions from the oil and gas sector by 40-45 percent from 2012 levels by 2025." As explained below, BLM lacks authority to require the oil and gas industry to reduce such emissions, except as those reductions may occur as an incident of an otherwise lawful measure to prevent the "waste" of gas adopted pursuant to BLM's authority under the Mineral Leasing Act ("MLA").

BLM is proposing to adopt the waste prevention measures in the Proposed Rule based on the authority granted to it by section 225 of the MLA.[8] That section provides that federal oil and gas lessees, as a condition of their leases, must "use all reasonable precautions to prevent waste

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[5] FCC v. Fox TV Stations, Inc., 556 U.S. 502, 516 (2009).

[6] The Proposed Rule is unclear in its applicability with respect to instances of mixed ownership. We seek clarification from BLM on whether operators drilling from a location on state or fee surface ownership that enter or pass through federal minerals will be subject to the Proposed Rule. We contend that these locations should be exempt from compliance with the Proposed Rule. Should BLM apply the Proposed Rule to these locations, it would need to revise its cost-benefit analysis to reflect that decision, as that would add significant costs for operators.

[7] WHITE HOUSE, CLIMATE ACTION PLAN: STRATEGY TO REDUCE METHANE EMISSIONS (2014), https://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf

[10] The attached economic analysis demonstrates that BLM's cost-benefit analysis is badly flawed and may not be taken at face value.

of oil and gas developed in the land."[9] The Proposed Rule purports to be an attempt to clarify what constitutes a "reasonable precaution" against "waste."

For purposes of the MLA, it is well established that gas is "wasted" only if it could have been economically captured and marketed or put to beneficial use on the lease, but is not. Thus, to establish that a proposed waste prevention measure is a "reasonable precaution" against "waste," and authorized under the MLA, BLM must demonstrate that the gas that is subject to the measure can be economically captured by the operator. If the gas cannot be economically captured, then it is not being "wasted," and BLM has no authority to otherwise regulate what is being done with it, no matter how much methane it may contain.

Even taking BLM's cost-benefit analysis of the Proposed Rule at face value,[10] it is clear that BLM cannot make the required demonstration with respect to several of its proposed waste prevention measures. For example, BLM estimates that its requirement to replace certain pneumatic pumps with zero-emission pumps would impose costs of $2.7 million per year, but would result in only $2.2 million in savings. Thus, the requirement has a negative cost-benefit ratio, or, in other words, BLM cannot demonstrate that the gas that is currently be vented from the pumps subject to the Proposed Rule can be economically captured by replacing the pumps with zero-emission pumps. Even assuming the validity of BLM's analysis, the only way BLM can justify the measure on a cost-benefit basis is by adding in the $18 million in "monetized benefits" that it believes can be achieved in terms of climate change by the reduction in methane emissions that would occur if zero-emission pumps were used.

However, BLM lacks authority under the MLA to justify its waste prevention measures by adding in the supposed climate change benefits that might be realized by society generally from the incidental reduction in methane emissions that would occur if the measures are implemented. Neither the MLA, nor any of the other statutes that BLM cites in the Proposed Rule's preamble, gives BLM the authority to regulate the emission of gas from oil and gas

[10] The attached economic analysis demonstrates that BLM's cost-benefit analysis is badly flawed and may not be taken at face value.
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operations out of a concern about the effect those emissions may have on climate change. That authority, to the extent it exists, has been given by Congress exclusively to EPA under the Clean Air Act. By relying on the benefits of methane reduction to justify its waste prevention measures, BLM is clearly "rel[ying] on factors which Congress [did] not intend it to consider" when developing such measures under the MLA, and is therefore acting arbitrarily and in violation of law.

To demonstrate that a particular measure is a "reasonable precaution" against "waste," BLM must demonstrate that the gas subject to the measure can be economically captured by the operator. Whatever benefits calculated using the social cost of methane might be realized as a result of the measure have no place in that demonstration. The benefits that may flow to society generally are irrelevant to the question of whether the gas can be economically captured by the operator. Put simply, because those benefits do not flow to the operator, they are not benefits that can be spent to capture the gas. Thus, while an otherwise "reasonable" measure to prevent the "waste" of gas may have the incidental effect of reducing the amount of methane that is emitted from oil and gas operations, such a measure may not be made "reasonable" for purposes of the MLA by virtue of that incidental effect.

Federal oil and gas lessees have a right to develop the oil and gas resources on their leases, subject to the requirement that they take "reasonable precautions" to prevent the "waste" of those resources, and that they comply with other applicable federal laws and regulations, like the ones adopted by EPA to regulate air emissions. If they are not "wasting" those resources—i.e., if those resources cannot be economically captured—BLM is not free to impose so-called waste prevention measures on them pursuant to its MLA authority just because society as a whole may benefit from the incidental methane reductions that would occur if the measures were implemented. The oil and natural gas industry has and will continue to work voluntarily to address methane emissions, but federal oil and gas lessees may not be made to bear the costs of reducing those emissions under the guise of BLM's authority to impose "reasonable precautions" to prevent the "waste" of gas.

BLM seems to suggest (without explanation) that its obligation under the Federal Land Policy and Management Act ("FLPMA") to manage public lands under the principle of multiple use, which is defined as "management in a 'harmonious and coordinated' manner 'without permanent impairment to the quality of the environment,'" may provide it with the authority to regulate methane emissions.[11] But that general reference to the "permanent impairment of the environment," which is found only in the definition section of FLPMA, cannot be read as a substantive grant of authority to BLM to set its own methane emission standards, or to limit methane emissions out of a concern for the effect they may have on climate change. There is nothing in the substantive provisions of FLPMA that would support such a reading, or that would give BLM any parameters to observe in exercising such an authority. Especially in light of the detailed and complex provisions for that Congress has established for the regulation of air quality in the Clean Air Act, it is unreasonable to suppose that Congress would give BLM the authority to regulate air quality completely untethered to any substantive guidance from it as to how to exercise that authority. At most, the provision in FLPMA can be read as requiring BLM to insure that activities conducted on federal lands comply with all applicable environmental standards, as established by the agencies with express and substantive authority from Congress to do so.

BLM further confirms the air quality focus of the Proposed Rule when it notes that:

> 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. Volatile Organic Compounds (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 Nitrogen Oxides (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

[11] 81 Fed. Reg. 6629.

> known or suspected to cause cancer or reproductive effects. Flaring of gas produces NO_X and particulate matter, both of which can cause respiratory and heart problems.[12]

However, as explained above, BLM lacks the authority to regulate such emissions for the sake of air quality.

Moreover, even if BLM somehow had authority to require federal oil and gas lessees to reduce methane emissions out of a concern for the effect they might have on climate change, BLM would still have to provide a reasonable justification for doing so, which it has not. Indeed, it is extremely unlikely that the Proposed Rule will have any meaningful impact on global greenhouse gas (GHG) emissions. Global methane emissions are estimated at 6,875 million metric tons CO_2-eq per year, whereas U.S. methane emissions are about 708 million metric tons per year, or about 10.2% of global emissions. BLM estimates that the Proposed Rule will reduce between 4.1 and 4.2 million metric tons of CO_2-eq per year.[13] Taking BLM's 4.2 MMT CO_2-eq per year, the Proposed Rule provides a reduction of 0.061% of global methane emissions. More importantly, methane emissions make up only a small portion of total global GHG emissions. EPA estimates put annual global greenhouse gas emissions at approximately 45,863 million metric tons of CO_2-equivalent (CO_2-eq) in 2010.[14] By BLM's most ambitious estimates, which are likely overstated, its Proposed Rule will reduce greenhouse gas emissions by 4.2 million metric tons of CO_2-eq. That's approximately 0.0092% of global greenhouse gas emissions.

While BLM asserts that "[v]enting and leaks of natural gas in the oil and gas production process also contribute to climate change,"[15] the empirical evidence on this record contradicts BLM's assertion. BLM's proposal is devoid of any discussion or evidence demonstrating how significantly less than a 1% reduction in domestic methane emissions will have any impact on climate change. The APA demands far more than regulation via the precautionary principle. See e.g., Washington Environmental Council v. Bellon, 732 F.3d 1131, 1145 (9th Cir. 2013) (striking

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[12] 81 Fed. Reg. 6627

[13] *Fact Sheet on Methane and Waste Reduction Rule.* Bureau of Land Management. January 2016.

[14] U.S. EPA, Climate Change Indicators in the United States, https://www3.epa.gov/climatechange/science/indicators/ghg/global-ghg-emissions.html (last visited Apr. 6, 2016)

[15] *Id.* at 6627.

down Plaintiff's arguments that "any and all contribution of greenhouse gases must be curbed," and noting the common-sense notion that, as articulated in Massachusetts v. EPA, regulatory action should focus on reducing "meaningful contributions" of GHGs).

On a global scale, the purported impact of the Proposed Rule is far from "significant." It is hard to imagine anywhere else where a 0.0092% reduction of anything would be considered significant, particularly given that climate change is a global phenomenon, generally measured on the basis of country-by-country or even continent-by-continent contribution. By justifying the Proposed Rule by reference to climate change benefits and contributions towards mitigating climate change impacts, the Proposed Rule proposal falls far short of the rational basis that the APA requires to support a rulemaking. Simply put, BLM does not make even a slightly credible case that the Proposed Rule will have any impact on climate change.

The Proposed Rule also ignores the reality on the ground in the oil and natural gas production industry. To date, industry has achieved remarkable emission reductions without duplicative and burdensome federal regulations. Methane emissions from oil and natural gas exploration and production (E&P) are 1.07 percent of total U.S. GHG emissions[16] and the natural gas sector alone has reduced methane emissions by 38 percent since 2005. *See EPA, 2014 GHG Reporting Data* (2014). In 2013, "reported methane emissions from petroleum and natural gas systems sector" decreased by 12 percent from 2011, and the largest reduction came from

[16] EPA has announced modification of the petroleum and natural gas systems methane emissions estimates in the GHG Inventory. EPA asserts that this change reflects new data. Two changes affecting the exploration and production component are at issue. The first involves estimating emissions from gathering and boosting activities that have not been reported under the GHG Inventory which EPA is arbitrarily assigning to production. The second involves methane reported under Subpart W suggesting that some exploration and production emissions are higher than previous estimates. Much of EPA's rationale for increasing the GHG Inventory for these emissions hinges on scaling up the Subpart W reported emissions to reflect the entire industry. EPA indicates that only 30 percent of exploration and production facilities report under Subpart W. However, EPA's efforts to scale up emissions appear to rely too heavily on the facility number rather than its nature. Clearly, the non-reporting facilities would overwhelmingly be marginal oil and natural gas wells. Marginal wells would have a very different and lower emissions profile than the larger facilities reporting under Subpart W. Even EPA initially recognized this distinction when it selected the facility size for reporting under Subpart W. It chose the threshold that yields the 30 percent of facilities reporting because EPA concluded that these facilities accounted for 85 percent of emissions. Consequently, EPA's actions to alter the GHG Inventory need to be thoroughly vetted before they are accepted. If they are found to be accurate, these changes increase the "production" segment of the petroleum and natural gas systems share of GHG emissions to 2.45 percent of the total GHG Inventory or 1.83 percent if the historical definition of exploration and production were used. However, these changes would not be an actual increase in emissions but an alteration of the entire baseline for the Inventory.

hydraulically fractured natural gas wells (resulting in a decrease of 73 percent in emissions). *Id.* According to a study by the University of Texas, Austin, methane emitted from all upstream source categories at natural gas production sites represents just 0.42 percent of gross natural gas production volumes.[17] On a national scale, despite significant growth in production in this sector over the past several years, methane and other emissions have continued to decline.

Technological and operational improvements in this sector continue to advance at remarkable rates and the emissions profile for new and modified facilities is declining and will only continue to do so, particularly as operators move towards centralized gathering systems and tankless or pressurized tank facilities. For example, in Colorado, recent emissions inventories for the oil and gas sector demonstrate significant *decreases* (*i.e.*, more than 60 percent through 2017) in VOCs despite a growth in production. *See Overview of 2011 and 2017 VOC and NOx Emission Inventories*, Colorado Regional Air Quality Council, at 7 (November 19, 2015). These decreases are due to advances in technology, facility design, better emissions controls, and the inherent incentive to capture and sell as much methane as possible. New facilities in combination with growing infrastructure and voluntary and state-led emission control efforts are already resulting in decreases in sector emissions. Unlike virtually every other industrial sector, production in upstream E&P sources declines over time bringing with it declining emissions (of both VOCs and methane). The Proposed Rule ignores these fundamental realities. Until these contradictions can be satisfactorily explained, any decision to regulate in the face of such overwhelming data would be arbitrary.

In fact, by making natural gas development more expensive and time consuming, the result will be less American natural gas production than without the Proposed Rule, which is directly at odds with the President's overall climate goals. Specifically, since increased natural gas electricity generation is the primary reason that the United States has reduced GHG emissions, as recognized by the International Energy Agency, the Energy Information Administration, and EPA's data, the Proposed Rule is actually counterproductive to efforts to

[17] David T. Allen et al., *Measurements of Methane Emissions at Natural Gas Production Sites in the United* States, 110 Proc. of the Nat'l Acad. of Sci. of the U.S. 18023 (2013).

address climate change.[18] By focusing on the small picture, BLM is losing sight of the bigger picture.

2. BLM's prohibitions on venting and flaring by operators with NTL-4A approvals are arbitrary

Another primary goal of the Proposed Rule is to reduce the amount of associated gas that is being routinely vented or flared from development oil wells. Under current BLM policy, which is set forth in NTL-4A, such venting and flaring is generally prohibited and may only take place with BLM's written approval. To obtain that approval, an "operator [must] demonstrate to the satisfaction of" BLM, based on "an evaluation report supported by engineering, geologic, and economic data, "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." Hundreds of operators have made the demonstration required by NTL-4A to BLM's satisfaction and are currently venting or flaring with BLM's written approval.

BLM is now proposing, however, to do two things in section 3179.6 of the Proposed Rule that are in direct conflict with those approvals. First, it is proposing to prohibit all routine venting of gas, subject to certain narrow exceptions. In other words, it is proposing to find, as a matter of law, that routine venting, regardless of the circumstances of the operator and any approval that has been given to it by BLM under NTL-4A, is a "waste" of gas. Second, it is proposing to limit all routine flaring of gas, subject to certain narrow exceptions, to 1,800 Mcf/month per well. In other words, it is proposing to find, as a matter of law, that "very high rates of flaring from a lease—that is, rates above the proposed 1,800 Mcf/month limit—constitute unreasonable waste under the MLA," regardless of the circumstances of the operator and any approval that has been given to it by BLM under NTL-4A.[19] BLM is proposing to say, in effect, to all operators who currently have BLM's express approval to vent under NTL-4A

[18] U.S. Int'l Energy Agency, World Energy Outlook, (2011) http://www.iea.org/Textbase/npsum/weo2011sum.pdf.; See Figure 12 at U.S. Energy Information Admin., U.S. Energy-Related Carbon Dioxide Emissions, http://www.eia.gov/environment/emissions/carbon/ (last visited Apr. 6, 2016).

[19] Waste Prevention, Production Subject to Royalties, and Resource Conservation, 81 Fed. Reg. at 6639.

(based on BLM's case-by-case examination of their particular circumstances) that they may no longer vent, and to all operators who have BLM's approval under NTL-4A to flare amounts of gas in excess of 1,800 Mcf/month per well (based on BLM's examination of their particular circumstances) that they may no longer do so. And BLM is proposing these new prohibitions, which may lead to the shutting-in of wells, without any explanation as to why the venting and flaring it approved should now be prohibited.

In making its proposal to replace NTL-4A with the Proposed Rule, BLM is "disregarding [the] facts and circumstances that … were engendered by [its] prior policy"—i.e., the well-specific determinations that it made under NTL-4A that current levels of routine venting and flaring of associated gas from particular oil wells is not a "waste" of gas—and is proposing to simply declare by fiat that what it once considered not "wasteful" it now considers "wasteful." By failing to explain on a case-by-case basis why its existing approvals should be revoked, BLM has "entirely failed to consider an important aspect of the problem" that it claims it is trying to address. Thus, the proposed prohibitions on venting and flaring in section 3179.6 are arbitrary as applied to operators who are currently venting and flaring with BLM's approval. Unless and until BLM can explain, on a case-by-case basis, why its previous approvals, on which operators have reasonably relied, are in error, it may not simply set those determinations aside and impose new prohibitions on the operators. Consistent with its obligation not to act arbitrarily, BLM cannot say one day to an operator that a particular practice, as a matter of fact, is not "waste," and then say to that same operator the next day that that same practice, as a matter of law, is "waste."

The Proposed Rule does give operators subject to the flaring prohibition (but not those subject to the venting prohibition) the option of applying for an alternative flaring limit. But operators should not be put to the time and expense of demonstrating to BLM under the Proposed Rule what they have already demonstrated to BLM under NTL-4A—i.e., that the flaring they are doing is not a "waste" of gas. The demonstrations required by NTL-4A having been made to BLM's satisfaction, BLM now bears the burden of explaining with supporting facts why the NTL-4A approvals that were based on those demonstrations should be set aside. Unless BLM provides such an explanation based on the particular circumstances of each operator, operators with approval to vent and flare under NTL-4A must be exempted from the Proposed Rule’s venting and flaring prohibitions. If BLM were to retroactively reverse course on currently approved venting and flaring, many well would need to be plugged and abandoned, resulting in the loss of otherwise economically recoverable oil and natural gas reserves.

3. The 1,800 Mcf/month flaring limit is arbitrary

As explained above, BLM’s MLA authority is limited to requiring that operators take “reasonable precautions” to prevent “waste” of gas. The Proposed Rule is based on the notion that a “reasonable precaution” would be to limit the amount of gas that can be flared from each well to 1,800 Mcf/month. For three reasons, however, the proposed limit is arbitrary and should not be promulgated.

First, as explained above, the limit is arbitrary as applied to operators who are currently flaring with BLM’s approval. Unless and until BLM can justify, on case-by case basis, the setting aside of those approvals, any imposition of a new limit is arbitrary.

Second, the limit is arbitrary as applied to leases issued after the effective date of the Proposed Rule because it makes no allowance whatsoever for the widely varying circumstances of the leases and the wells drilled on them. Under the Proposed Rule, if a well is drilled on a lease that is issued after the effective date of the Proposed Rule, it is subject to the flaring limit, regardless of the circumstances. NTL-4A, on the other hand, has wisely recognized for over 30 years the undeniable fact that there are a variety of factors that must be taken into account in determining whether gas from a particular well can be economically captured. It therefore provides all operators, regardless of when their lease was issued, the opportunity to seek an exception from NTL-4A’s general prohibition against venting and flaring on a well-by-well basis. In the preamble to the Proposed Rule, BLM justifies its change of course on the backlog of sundry notices awaiting approval. While we are concerned with this backlog of sundry notices, we would argue that BLM’s resources could be better put to use by addressing that backlog, rather than embarking on a time-consuming new regulatory process.

Third, the 1,800 Mcf/month limit is itself arbitrary, regardless of how it is applied to different classes of operators. "To select an appropriate numeric limit for flaring," BLM simply "analyzed data indicating the average flaring rates across wells."[20] Based on that analysis, it then calculated the number of the oil wells that would be impacted by limits of 1,200, 1,800, 2,400 and 3000 Mcf/month. For example, it calculated that a limit of 1,800 Mcf/month would "impact about 16 percent of the oil wells flaring associated gas." It then chose the 1,800 Mcf/month limit, not because of its effect on preventing "waste" of gas, but because, it "would effectively maximize flaring reductions while minimizing the number of affected leases."[21]

Fourth, BLM's own economic analysis recognizes that, at best, the proposed flaring limit benefits are highly uncertain. At worst, those benefits could be negative by as much as $10 million, indicating a net cost to society[22].

What is entirely missing from BLM's analysis is any attempt at all to calculate how much "waste" each of the flaring limits it considered would prevent. Reductions in flaring, which is the only metric BLM used, do not equate to prevention of "waste." There is no linear relationship between the two concepts, as witnessed by the amount of flaring that is taking place pursuant to NTL-4A approvals, and is therefore not a "waste" of gas. Unless and until BLM can demonstrate the effect that the 1,800 Mcf/month limit will have on reducing "waste," it is an entirely arbitrary limit that may, in fact, require significant reductions in flaring that is not "waste." On the current record, it is obvious that BLM, in proposing the 1,800 Mcf/month flaring limit, is interested only in reducing flaring solely for the sake of reducing flaring, and its associated methane emissions, rather than reducing flaring for sake of preventing "waste" of gas.. As explained above, however, BLM does not have authority under the MLA to require operators to take "reasonable precautions" to prevent flaring; it only has authority to require operators to take "reasonable precautions" to prevent "waste." Due to BLM's lack of analysis, it

[20] *Id.*
[21] *Id.* at 6640. This, of course, is not true. A 1,200 Mcf/month limit would "maximize" flaring reductions, while a 3000 Mcf/month limit would "minimize" the number of affected leases.
[22] *Id.* at 6620

is impossible to discern whether the 1,800 Mcf/month limit is a "reasonable precaution" against "waste."

The 1,800 Mcf/month number was derived from the Utah and Wyoming state rules, referenced below, that are totally unfit as models for a nationwide standard. Utah's flaring limit of 1,800 Mcf/month is set forth in 1988 in Section 1.1 of Utah's Administrative Code, R649-3-20 *Gas Flaring or Venting*. Utah's decision to adopt the limit was based on the unique operational and geologic conditions in the Altamont Bluebell field in Utah's Uinta Basin during the 1970s and 1980s. The Altamont Bluebell field is a vertical play; even today, little horizontal drilling exists as compared to other large unconventional plays. Geologically, the reservoir is primarily tight sandstone with extensive natural fractures. The main hydrocarbons are a high paraffin crude oil, known as "waxy crude" that is substantially different in its chemical composition from the light shale oils being developed in today's unconventional plays in the Bakken and Permian basins.

BLM's proposed flaring limit a one-size-fits-all solution rather that fails to recognize that different regions have different challenges. The proposed limit on flaring is so far from reality in certain basins that it would make future development of federal oil wells nearly impossible. The proposed limit is based on a limit that was developed for conventional plays in Utah and Wyoming with adequate infrastructure that have been primarily developed with vertical wells. However, today's unconventional plays allow one well to replace four or even eight conventional vertical wells. Overall, this trend offers tremendous environmental benefit by greatly reducing the surface impact of development. Notably, though, these new horizontal wells are replacing many vertical wells and have commensurately higher production. These unconventional plays are relatively new, which means that the full development cycle of a field is not yet fully understood. Some operators have found that GOR actually increases as unconventional wells decline. This could have potentially complicating implications for long-term development, particularly under extremely tight flaring limits.

According to one New Mexico operator, BLM's proposed 1,800 Mcf/month flaring limit would cause them to reduce the amount of production so significantly that they would only produce 17 barrels of oil a day (BOD). Currently, the average GOR of this particular operator's wells in New Mexico is 3,500 scf producing an average of 68 BOD. Limiting flaring to 60 Mcf per day, given their GOR, would, in turn, cause them to limit oil production to 17.1 BOD. Requiring operators to limit production to 17 BOD significantly impacts their ability to cost-effectively operate these wells. Operators have predetermined fixed costs that cannot be paid if they have to curtail their production. This will further impact their ability to drill additional wells as their cash flow declines. Not only will operators' cash flow plummet, but so will the federal and state governments' stream of income which depends on royalties—again directly contrary to the stated purpose of the proposed regulations. This also greatly impacts private mineral owners with royalty in federal CAs or units. To meet these thresholds in the Bakken, additional equipment must be installed to shut-down wells based on a flare meter. Pigging will also be problematic, as it requires maintaining flow even as pressures go up and will result in increased flaring. A solution involving well shutdowns will lead to cycling across the whole field as various operators turn production streams off/on. Equipment failures will increase in areas constrained to make sales.

Bakken wells produce more than twice the oil and about 1.5 times more gas in the first month of production than an Altamont Bluebell development well. After the first year of production, the typical Bakken well produces 140 barrels of oil per day (bopd)/150 Mcf per day (Mcfpd). By comparison, production after the first year from Altamont Bluebell wells averages 53 bopd/120 Mcfpd. There is also a vastly different scale of development between the two fields. Since 2000, only 462 wells have been developed in the Green River or Wasatch formations in the Altamont Bluebell field. In the Bakken, 10,629 wells have been developed in the Bakken or Three Forks formations during that same time.

In certain areas of the Bakken, an operator may exceed the proposed 1,800 Mcf/month limit in a period of hours, as GOR can be up to 4 Mcf/bbl. What is lost in BLM's monthly limit is proportionality to the well. A horizontal well equates to several vertical wells, in the range of eight to twenty, depending on the number of frack stages and the length of the lateral. Applying the same flaring limit to a low volume vertical well as to a horizontal well equivalent to multiple vertical wells is simply not logical.

In the Permian Basin, the problem is also severe. One member reports its production from federal wells averages 68 bopd/238 Mcfpd. The Southwest New Mexico portion of the Permian Basin contains over 4 million acres of federal minerals with 2,350 well developed since 2010. As a result, increasing gas capture in the Permian is an entirely different undertaking compared to the relatively modest volumes produced in Utah's Altamont Bluebell filed.

Even after applying the flexible monthly averaging proposed by BLM, there is no way around the basic reality that BLM is two orders of magnitude apart from the on-the-ground reality in unconventional plays. That means that per-well gas production in some unconventional plays may 100 times greater than BLM's proposed flaring limit. The economic impacts on Permian and Bakken wells will be significant on both existing leases and future development. Even after applying the flexible monthly average limit, these volumes are too low for Permian and Bakken operations and will significantly impact well economics on existing leases and future development if/when the infrastructure catches up.

4. BLM fails to consider the most important factors affecting the availability of pipeline infrastructure

BLM states that "the primary alternative to flaring associated gas from oil wells is to capture [it], transport [it] in pipelines, and process [it] for sale."[23] BLM states further that the primary reason that more gas is not being captured and transported in pipelines is that "[i] n some areas, there is capture infrastructure, but the rate of new well construction is outpacing infrastructure capacity," while in other areas, "capture and processing infrastructure has not yet been built out."[24] Thus, in order to justify imposing a flaring limit on operators – which is based on the assumption that operators could capture more gas than they currently are – BLM must demonstrate that its Proposed Rule will solve the problem of pipeline availability. Without solving that problem, operators will have little chance of meeting the flaring limit and its imposition on them will be arbitrary.

[23] *Id.* at 6619.
[24] *Id.*

In BLM's view, the primary reason that capture infrastructure is not available is that "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."[25] It therefore proposes to solve this problem by requiring in section 3162.3-1(j)(4)(v) that operators develop and submit a "waste minimization plan" with each Application for Permit to Drill (APD) that includes a "[c]ertification that the operator has provided one or more midstream processing companies with information about the operator's production plan, including the anticipate completion dates and gas production rates of the proposed well or wells."

In designing its solution to the problem of pipeline availability, however, BLM "entirely failed to consider [two] important aspect[s] of the problem," and its solution is therefore arbitrary and destined to fail.[26] First, BLM assumes that gas capture infrastructure will be developed in advance of proven oil production and increased field development if operators would only share information about their project production rates with midstream processing companies at the time it submits an APD to BLM. However, in reality, operators must first prove production for a new oil play and initiate larger scale development before the midstream processing companies are willing to invest capital in new facilities or in the expansion of existing facilities. Just sharing "projected gas production rates" with midstream processing companies is not enough.

Second, BLM completely overlooks the most significant reason why new production outpaces infrastructure capacity—i.e., the time-consuming process of obtaining the necessary pipeline rights-of-way from BLM. The process of obtaining the necessary rights-of-way can sometimes take years. In these situations, operators are left with no choice but to flare associated gas from production or shut in their wells.

The following provides illustrative details of the time needed to obtain approval to construct a pipeline across federal land, including tribal land, in this case, the Fort Berthold

[25] *Id.*
[26] Motor Vehicle Mfrs. Ass'n v. State Farm Ins., 463 U.S. 29, 43 (1983).

Indian Reservation. It does not even take into account the time needed to obtain the necessary approvals to cross state and private land:

1. Obtain permission to survey (PTS) from landowners and submit to BIA (Bureau of Indian Affairs) New Town office for approval. ***(4 weeks)***

2. "Soft stake" the pipeline centerline after PTS has been granted by BIA (surveying company/ engineers). ***(1 week)***

3. Schedule Environmental Assessment (EA) onsite with representative from the BIA-New Town office. ***(1 week)***

4. Prepare final plans. ***(3 weeks)***

5. Prepare and send scoping letter for approved pipeline (if applicable, for trunk lines only, lateral lines to well locations will not require scoping). ***(4 weeks)***

6. The EA cannot be submitted until the end of the 30-day comment period

7. Schedule Right-of-Way (ROW) onsite with the BIA-New Town office. ***(1 week)***

8. Prepare EA and cultural reports; from initial surveys conducted in step 3. ***(12 weeks)***

9. If habitat for a listed endangered/threatened species is present, an informal consultation with the US Fish and Wildlife Service (USFWS) is required. Project must receive concurrence from USFWS. ***(8 weeks or longer)***

10. Submittal of EA to BIA Aberdeen office and Finding of No Significant Impact (FONSI) is reached. ***(4 weeks)*** There is a 30-day notice period after the FONSI is issued

11. Pipeline Company obtains landowner signatures agreeing to terms and payment. These signatures are then filed in the ROW application that is submitted to the BIA New Town office for approval. ***(4 weeks)***

12. Construction operations can begin only after the BIA issues a Notice to Proceed and ROW grant. ***(5 weeks)***

The above-described times for completion of each stage will increase depending on: BIA onsite schedule, completeness of supplementary information, results of resource surveys, results of onsite surveys, completeness of application packages, public response to projects, weather conditions, and, of course, securing proper consents from all necessary landowners.

If BLM is serious about reducing flaring that occurs, by its own analysis, because “the rate of new well construction is outpacing infrastructure capacity,” then it must it must design a rule that facilitates the timely and predictable processing and approval of pipeline right-of-way applications.

5. BLM fails to establish a rational connection between “the factors driving flaring” and the choices it made in the Proposed Rule

BLM “recognizes that … operators do not want to waste gas,” as it is “a valuable commodity that operators can sell at a profit.”[27] Yet the need for the Proposed Rule is based on the premise that notwithstanding that powerful economic incentive, operators are “wasting” a substantial amount of gas through venting and flaring and must therefore be prevented from doing so. Accordingly, to justify its Proposed Rule, BLM must explain why the operators are acting against their own economic self-interest, and why and how its Proposed Rule is necessary and effective to change that behavior.

In addition to the lack of capture infrastructure, which is discussed above, BLM gives four other explanations for why operators are allegedly “wasting” so much gas in spite of the economic incentive they have to capture it. First, BLM asserts that because the “the economic

[27] *Id.* at 6638.

return on oil production is substantially higher than the economic return on gas production … there is an economic incentive for individual operators to focus on oil development at the expense of gas-capture."[28] But operators' focus on oil development is an entirely rational one, and it is one that presumably benefits the federal government in the form of higher royalties, which is one of the principal goals BLM claims it is seeking to achieve through adoption of the Proposed Rule. This explanation therefore does not provide a rational basis for the Proposed Rule's requirement that operators capture more gas where "the economic return of oil production is substantially higher than the economic return on gas production," as doing so will work to the economic detriment of both the operator, the federal government, the public and Indian tribes.

Second, BLM asserts that some operators simply lack "awareness of the available cost savings" from capturing more gas, and thus "fail to capture the economic benefits of investing in waste reduction measures."[29] But BLM offers no support for its inherently implausible assertion that operators are ignoring significant cost saving opportunities. Accordingly, it is reasonable to conclude that there must be some other reason that would explain their behavior. Indeed, as discussed above, BLM completely overlooks one of the primary reasons why are operators are not capturing more gas, which is that, in spite of the best intentions of operators and pipeline companies, the build out of the pipeline infrastructure that is needed for gas capture is heavily dependent on the pipeline companies receiving in a timely fashion the necessary rights-of-way from BLM, state, tribal and private landowners. Those approval processes can take an inordinate amount of time. Moreover, even if BLM were correct in its assertion about lack of operator awareness, it does not take a complex command and control regulation of the type that BLM is proposing to solve the problem. BLM could simply provide the operators the information of which it claims they are unaware, and then let the strong economic incentive that they already have motivate them to capture the gas.

Third, BLM notes that some companies fail to invest in gas-capture technologies because of "limited capital availability."[30] Where this is the case, the problem will not be solved by the Proposed Rule. Instead, by placing an arbitrary and across-the-board limit on the amount of gas

[28] *Id.*
[29] *Id.*
[30] *Id.*

that can be flared, the Proposed Rule may cause operators to forego development of certain oil reserves entirely. In the example referenced above, a Permian operator reporting a field average of 68 bopd/238 Mcfpd would be forced to choke back its oil production from 68 bopd to 17 bopd in order to meet BLM standards. That translates into a 75% decline in production, and consequently in revenue and royalties. Besides limiting the economic viability of oil development in that particular basin, it represents a waste of resources, which should be considered antithetical to a rule proposing to minimize "waste."

Fourth, BLM underestimates the fact that even when gathering infrastructure is in place, some flaring and venting may be unavoidable due to gas quality, plant processing capacity, maintenance and other factors. Under NTL-4A, flaring due to equipment failures, relief of abnormal system pressures, or other conditions resulting in short-term venting or flaring is authorized without incurring royalty obligations. These situations often occur over a short period of time and may come with little to no notice. Generally, they are outside of operators' control and even close coordination between upstream and midstream companies will not eliminate them entirely. To assume otherwise would be unreasonable.

Finally, BLM asserts that "operators typically consider only the costs and revenues of gas capture with respect to their individual operation," and that "in many instances, when costs and revenues are evaluated across a larger area, … gas capture … may be more economical."[31] However, operators can only "consider … the costs and revenues of gas capture …across a larger area" when they control the assets in that larger area, which is often not the case. They do not know, and cannot consider, the "costs and revenues of gas capture" of their competitors.

As BLM fails to establish a rational connection between the factors it believes are driving flaring and its proposed solution of requiring operators to provide more information to "midstream processing companies" at an earlier date, and complying with one-size-fits-all venting and flaring limits, the solution is arbitrary.

[31] *Id.*

6. BLM has not demonstrated that it will have the resources necessary to administer the Proposed Rule in a timely fashion

The Proposed Rule would place significant new responsibilities on BLM, as set forth in sections 3162.3-1, 3197.7, 4179.10, 3179.11, 3179.201, 3179.202, and 3179.401. BLM's ability to perform those responsibilities in a timely manner is key to the successful working of the Proposed Rule. Yet the preamble contains no estimates of the additional resources that BLM will need to administer the Proposed Rule, nor any assurance that those resources will be available to it, nor does it set any deadlines for BLM's fulfillment of its responsibilities so that operators can reliably plan their operations.

BLM is already failing to timely fulfill its current oil and natural gas program responsibilities, particularly with respect to the approval of APDs and pipeline rights-of-way across federal lands. This latter failure is particularly significant in light of the Proposed Rule's effort to stimulate the timely building of more pipeline infrastructure so that more gas can be captured. Thus, before any final rule is promulgated, it is imperative that BLM assess and disclose to the regulated community whether it will be able to effectively administer the rule with the resources available to it. Just as BLM was required to quantify the time burden and costs that the information collection requirements of the Proposed Rule will impose on the public, so should it be required to quantify the time burdens and costs that the Proposed Rule will impose on itself, and to demonstrate that it will be able to fulfill its new administrative responsibilities in a timely fashion. BLM should not impose significant new requirements on the oil and gas industry without demonstrating that it will not become a bottleneck in the industry's efforts to comply with those requirements.

7. BLM's Regulatory Impact Analysis is deeply flawed and does not support adoption of the Proposed Rule

We have attached a thorough analysis of the Regulatory Impact Analysis ("RIA") on which the Proposed Rule is based. The analysis demonstrates that the Proposed Rule will impose costs of $1.26 billion annually to the economy, and that those costs far outweigh even the highest end BLM benefit estimate of $384 million.[32] This is based on a price for natural gas of $2.00/Mcf.[33]

This year, natural gas prices have dropped to as low as $1.57 per million BTU and $1.40 Mcf according to the EIA and media sources. Discounting the idea that a reduction in potential methane emissions would have any benefit on the environment that could be monetized, a more reasonable calculation of the potential benefit of the Proposed Rule would be $90 million. With a cost of $1.26 billion and a potential benefit of just $90 million, the Proposed Rule does not produce a net social or economic benefit. Additionally, those economic losses create an additional loss of $114,112,000 in federal and state taxes.

The benefits as laid out by BLM are also speculative at best as they rely on passage of EPA Subpart OOOOa and on certain flawed assumptions that methane gas reductions have a social cost benefit.

In addition to not completing the RIA in accordance with published OMB guidelines, BLM included a number of assumptions that were on their face either false, or should not have been used as part of this type of analysis. The most glaring problem, however, is BLM's inflated commodity price estimates which underlie the economic benefit estimate in an economy where commodity prices, significantly for oil and natural gas, are in their biggest bear market in 30 years. Additionally, the central purpose of any regulation is to have an in-depth safety focus, which is not examined in any real depth in this RIA, especially when limits for venting or flaring per well are suggested as a remedy in a very broad context.

BLM's failure to conduct a comprehensive alternative analysis was clearly in violation of the OMB guidelines. An alternatives analysis may have shown that the proposals could actually lead to increased and significant economic costs to the oil and gas industry.

In addition to the flaws in the RIA, the Associations are concerned by the numerous instances where BLM ignores significant economic burdens that would result from its Proposed

32 Op. cit. Regulatory Impact Analysis, pages 6-8.
33 Op. cit. Regulatory Impact Analysis, page 42.

Rule. This is particularly evident in the proposed flaring limits, but runs throughout the Proposed Rule. BLM generally underestimates or ignores entirely the development costs in terms of both time and capital with building out pipeline infrastructure. The proposed flaring standards, when applied broadly, will severely limit producers' ability to develop oil wells and will discourage investment in new plays. BLM's economic analysis understates the complexity of the economics of developing pipelines.

In the immediate term, the effects of the Proposed Rule will be pronounced, but in the longer term it means that the domestic energy renaissance we have recently witnessed would be extremely difficult to sustain. The overwhelming capital costs of developing new fields and expanding current fields into new areas would strongly deter investment and would have lasting economic, geopolitical and environmental consequences in this country. In addition to the potentially severe economic consequences the proposed rule would create, BLM failed to fully contemplate the environmental impacts of its proposal. Since oil and natural gas can be produced in many different countries the regulations may simply transfer activity from the United States to Russia, Mexico, Iraq or Nigeria. This can not only impact the American economy but could also lead to increased methane production.

8. BLM overstates the effectiveness of remote gas capture technology

In the preamble of the Proposed Rule, BLM describes several alternative gas capture technologies that it believes can be used as an alternative to flaring. However, in support of this, BLM relies heavily on the Carbon Limits study that bases its assumptions on gas prices that are more than double today's market value of natural gas. BLM goes on to suggest that due to these remote capture technologies, "[w]hile 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."[34]

[34] *Id.* at 6637.

This selective review of remote capture technology fails to acknowledge the overwhelming evidence from on-the-ground experience with these control strategies. Numerous operators have deployed remote gas capture technology in the field, and their experience has clearly demonstrated that in the vast majority of cases, this technology is not economically viable.

Additionally, the expanded use of remote natural gas capture technology would necessitate expanding the footprint of many wellpads to safely accommodate the additional equipment. The emissions, noise, and dust associated with the additional construction requirements would have environmental consequences that BLM has failed to fully consider. The installation, operation, and maintenance of these remote capture facilities would also require additional truck traffic, resulting in additional vehicle emissions.

According to one North Dakota operator, "based on its extensive evaluations of remote capture technology, [we have] concluded that the technologies are not economically viable given their substantial cost in comparison to the nominal value of gas being flared.... To the extent that they are economically viable at all, remote capture technologies have the greatest likelihood of providing an economically viable alternative to flaring when the technologies are deployed to capture gas flared from stranded wells (i.e., wells incapable of being connected to a pipeline). Unlike wells connected to pipelines, which intermittently and unavoidably flare negligible volumes of gas, stranded wells flare larger volumes of gas..."

Another operator found, "[o]ur efforts to date establish that remote capture technology is uneconomic and will not alleviate flaring or resolve pipeline capacity and constraint issues."

A third operator noted, "[t]he remote capture technologies presently available are uneconomical and they do not entirely resolve gas flaring. The lease cost of the remote capture units (NGLs) are greater than the value of the natural gas liquids they produce at current market prices…. NGL units are notoriously difficult to winterize and have low winter runtimes. NGL units require semi-stable inlet gas rates to run; many connected sites flare intermittently which would make operation difficult and runtimes low. NGL units require a large footprint to safely operate, which is an issue on smaller pads. [Current] vendors are not able to scale down further than 250 [Mcfd], which is greater than the amount of flaring on most connected sites. Additionally... the NGL unit will reduce but not eliminate the flare."

One operator developed an economic model that represents a theoretical application of remote capture technology in which 12 months of gas capture is required to satisfy regulatory requirements for a new location. This model is based on average costs incurred over 15 locations during 2014, and pricing believed to be available in October 2015. A unit with 2,000 Mcfd capacity was selected to match with production forecast in month 4 of production. Prior to month 3, some gas will be flared. After month 3, the equipment will be underutilized. A location gas capture goal of 85% is assumed.

The following assumptions were made:

<u>Gas Capture Unit Capacity:</u> 2,000 Mcfd

<u>Direct Service Costs Including:</u>

Mobilization and installation charges

Costs of moving equipment to location, cranes, pipe, valves, and fittings, roustabout work, electrical installation, hydrostatic testing, and commissioning. Assumed equipment is moving from gulf coast.

Monthly fees to service company

Includes lease, operation, and maintenance of compressors (2), mechanical refrigeration unit (2), stabilizer (2), natural gas generators (2), product storage tanks (2), and waste tank (1).

Project term: 12 months

Demobilization fee at term end

Includes breakdown and removal of piping, electrical, crane, and trucks to lift and remove equipment skids from location

Total payments to gas capture operator: $750,000

Company Costs: $124,430

Site preparation

Company oversite billed to location

Company gas capture supervisor on location 8 hours per week during operation, plus one company consultant on location 8 hours per week during operation. Excludes cost associate with field safety and environmental personnel, and administrative costs.

Tie-ins to gas plan

Includes custody transfer gas supply meter to gas plant and meter for residue gas stream to flare, and piping required to connect treaters to gas plant

Total Costs for Four-Month Operation: $874,430

Production Data

Equipment availability assumed: 90%

Total gas processed: 492,750 Mscf

Assumed that 75% utilization of available capacity is used due to production decline below equipment capacity maximums

Average gallons extracted per Mscf processed: 2

Total NGLs extracted and sold: 985,500 gallons

2015 Economics of Project

Average revenue per gallon after	$0.22

transportation, fractionation, and marketing	
Total project revenue	$216,810
Total project costs	$874,430
Net project profit/(loss)	($657,620)

This economic analysis underscores how critical it is for BLM to recognize current commodity prices in its analysis. Using an outdated study based on inaccurate price data tells a vastly different story than an analysis based on current economics. As the above analysis based on real-world market conditions demonstrates, BLM's belief that these types of remote capture technologies are economical cannot be supported.

III. SECTION-SPECIFIC CONCERNS

Many of the provisions that we discuss below have been addressed by EPA in its proposed rule for new and modified sources of emissions or will be addressed by EPA in the rule that it is now developing to address existing sources of air emissions from oil and gas operations. These include venting and flaring limits, Leak Detection and Repairs (LDAR), replacing high-bleed pneumatic controllers and pneumatic pumps, and limiting emissions from downhole well maintenance and liquids unloading. Consistent with BLM's policy, which is to avoid mandates that would be duplicative of, or conflicting with, those imposed by EPA, BLM should defer to EPA on this issue and not proceed with its proposal. If BLM chooses to promulgate the provisions in spite of their arbitrary nature and BLM's lack of authority to do so, then it must address the following concerns that we describe below.

A. Actions to reduce the "waste" of gas

1. Prohibiting venting of associated gas

Section 3179.6(a) "would require operators to flare all gas that is not captured, except under certain limited circumstances."[35] The Proposed Rule states that the "operator must flare rather than vent any gas that is not captured."[36]

As explained above, this prohibition should not apply to operators with current NTL-4A approvals. However, regardless of to whom it applies, it is not a "reasonable precaution" against the "waste" of gas, and should not be promulgated. As explained below, a total cessation of venting is not feasible in many instances for safety and economic reasons. Moreover, it is grounded in a concern for the reduction of methane emissions, rather than in a concern for the prevention of the "waste" of gas, as is required by the MLA. If BLM chooses to promulgate the prohibition, in spite of its arbitrary nature and lack of authority to do so, then it must address the following concerns.

1. The Proposed Rule's stipulation of a "no venting" standard is highly problematic and fails to acknowledge the operational realities of the oil and natural gas industry. Operators minimize the venting of gas whenever possible for economic and safety considerations. Venting is generally avoided when it is feasible and practical to do so.

However, there are situations when a "no venting" standard is impossible to meet. There are numerous instances where a *de minimis* volume of gas will be vented and any attempt to capture that gas would be technically and economically infeasible. For instance, during drilling operations, there are very small volumes of gas entrained in drilling mud. When mud is processed, small pieces of drilling cuttings are filtered out using devices like mud shakers. During the process of removing these cuttings, some of the gas entrained in the drilling mud will be released into the atmosphere. These volumes are exceedingly low and have virtually zero economic value, and it would be impossible to completely eliminate these emissions in meeting a

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[35] *Id.* at 6666.
[36] *Id.* at 6682.

“no venting” standard. Other instances in which such a standard is infeasible would be when small amounts of gas have to be vented to blow and depressurize equipment to work on it. We ask BLM to clarify that these instances would be clarified in its clause on technical infeasibility.

Other situations may involve low API gravity oil production from certain wells. In instances where the gas-to-oil ratio (GOR) is low or an oil is particularly heavy there may be very low volumes of associated gas that cannot be feasibly separated out at the wellhead. In these instances it is unrealistic and unreasonable for BLM to expect operators to totally eliminate venting.

Permian Basin production offers another example of the infeasibility of a “no venting” standard. A significant amount of associated gas is produced with horizontal drilling in the Permian Basin. Many wells do not have gas in the formation downhole, but rather it is actually dissolved in the oil and water and is only present as the pressure is reduced on the liquids. This pressure drop occurs when the oil and water are sent from the flowback separator at 50-200 psi to the tanks which are at atmospheric pressure. There will always be some gas that comes out of solution during this process and is vented through the tanks.

If BLM adopts a venting prohibition, then it must clearly allow an exception for the venting *de minimis* volumes like the examples describe above; requiring operators to eliminate venting entirely is impossible given today’s technological and economic constraints.

2. It is clear from the preamble that the prohibition is intended to apply only to venting from development oil wells, but the Proposed Rule does not so state. Accordingly, section 3179.6(a) should be revised to state that “the operator of a development oil well must flare rather than vent any gas that is not captured.”

3. While section 3179(a) of the Proposed Rule states that the “operator must flare rather than vent gas that is not captured,” section 3179.6(b) states that an operator “must not flare <u>or</u> vent gas” (emphasis supplied) in excess of the limits that the Proposed Rule establishes, thus appearing to allow an operator to continue to vent gas as long as the total volume of gas that is

flared or vented is not in excess of the limits. If this is what BLM intended, it would be preferable to the total prohibition of venting, and should be clearly stated.

4. It is not clear from the Proposed Rule when an operator must be in compliance with the prohibition. Section 3179.9 says that NTL-4A approvals "to flare or vent at a level above the 7,200 Mcf per month limit …, which are in effect as of the effective date of this rule, will continue in effect until [90 DAYS AFTER THE EFFECTIVE DATE OF THE FINAL RULE]." Does that mean that approvals to flare or vent at a level below the 7,200 Mcf per month limits will remain in effect in accordance with the 3 year phase-in set forth in section 3179.6? That would be preferable to the flat cut-off of all venting as soon as the Proposed Rule becomes effective that is suggested by the language of section 3179.6(a). Obviously, operators cannot be expected to cease all venting from one day to the next.

2. Setting limits on the flaring of associated gas

To address the waste of associated gas from flaring, the Proposed Rule proposes to "establish a limit on the average rate at which gas may be flared of 1,800 Mcf per producing well on a lease" per month. The limit will apply immediately to new wells, and after a two-year phase-in period to existing wells. For the following reasons, the proposed limit is arbitrary and should not be adopted by BLM.

As explained above, the limit is arbitrary as applied to operators with existing NTL-4A approval to flare above the limit, and to operators of new wells.

The limit is also arbitrary because it is based on outdated economic data. BLM apparently took its cue for the establishment of flaring limits from a 2010 GAO Study, which was entitled "Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared natural Gas Which Would Increase Royalty Payments and Reduce Greenhouse Gases" ("GAO Study").[37] As an explanation of the need for its rulemaking, BLM states that "GAO found that 'around 40 percent of natural gas estimated to be vented and flared on onshore Federal leases

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[37] GAO-11-34 (Oct. 2010).

could be economically captured with currently available control technologies.'"[38] Using 2008, the RIA cites a GAO estimate that about 128 billion cubic feet of natural gas was either vented or flared from Federal leases, of which 50 billion cubic feet was economically recoverable.[39] This recoverable volume represents about $23 million in lost Federal royalties and 16.5 million metric tons of carbon monoxide equivalent emissions.

This reasoning, however, does not reflect the current state of the market. First, the average natural gas price for the full year 2008 was $8.85 per MCF, as compared to the spot price of natural gas in March of 2016 which is $1.40 on March 14, 2016.[40] This is an 84 percent drop in the price of natural gas since the 2008 time frame used in the RIA. Based on the 84 percent reduction in the price of natural gas, the $23 million dollar figure presented by the BLM would drop to $3.68 million.

If BLM chooses to proceed with adopting the limit in spite of the arbitrariness of the limit and its own lack of authority, then the following concerns need to be addressed.

1. Under the Proposed Rule, alternative limits may only be granted if the operator can demonstrate that complying with the required limits "would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves." But the flaring limits alone may not be the sole determining factor in a well's economic viability. The Proposed Rule imposes layers of cost through a variety of requirements – e.g., the cost of replacing high-bleed pneumatic controllers, the cost of developing and implementing a leak detection and repair (LDAR) program, the added administrative burden of recordkeeping and reporting for federal wells, etc. Operators don't make decisions about these costs in a vacuum; they are considered in concert. BLM should allow for similar considerations as part of the alternative flaring limit requirements. One factor alone may not be enough to render a well uneconomic, but the myriad and burdensome requirements of the Proposed Rule might when taken together. The total cost of

[38] 81 FR 6617.

[39] Government Accountability Office, *Federal oil and gas leases: Opportunities exist to capture vented and flared natural gas, which would increase royalty payments and reduce greenhouse gases*,. GAO Report 11-34, October 2010, at: www.gao.gov/new-items/d1134.pdf.

[40] Braziel, E. Russell, The Race To Liquids, Oil & Gas Finance Journal, August 1, 2010, on-line at: www.ogfj.com/articles/print/volume-7/issue-8/features/the-race_to_liquids.html; CNBC.com for March 14, 2016 natural gas price.

implementing the Proposed Rule is certainly relevant to an operator's determination about whether it can afford to continue to produce from a well, and the total cost of implementing the Proposed Rule should therefore be relevant to BLM in determining whether to grant relief from the Proposed Rule's requirements. Moreover, the granting of an alternative limit should not depend on a demonstration that without such a limit there will be "significant" abandonment of oil reserves. That would mean that to prevent the "waste" of some gas through flaring, BLM could, in effect, force operators to "waste" substantial amounts of oil and gas by leaving it in the ground.

2. There is no explanation on treatment of waste gas from the remote capture technology—i.e., after the NGLs are removed, the remaining gas goes to flare and should be considered unavoidable and not included in limits or royalty calculation. The North Dakota Energy and Environmental research committee evaluated remote capture technology. Its conclusion is summarized in the following: "New Technology Investigations. The Energy & Environmental Research Center." EERC conducted an assessment of alternative gas uses upstream of traditional gas-processing plants. The study investigated using associated gas for power production, transportation fuel, and chemical production, as well as analyzed small-scale gas processing to recover NGLs. Although intriguing, the economic viability of these alternatives was complicated by the distributed and transient nature of flared gas, requiring innovative approaches to effective implementation."[41] This reinforces the belief that the gas is not wasted but is an uneconomic byproduct of the oil production.

3. The flaring limits cannot be reasonably enforced with Federal and Non-Federal wells on the same gas sales line. Non-Federal well will make sales and block Federal wells, thus competitively ruining production on Federal land.

4. With respect to alternate flaring limits, no valuation of flared gas is provided. Flared gas cannot be valued the same as sales gas because it must properly account for implementation of a redundant gathering system. When these added costs are considered, the netback price of the gas is essentially zero.

[41] https://www.undeerc.org/bakken/Reduced-Gas-Flaring.aspx.

5. BLM proposes that under § 3179.8, “operators would need to estimate or measure all volumes of gas vented or flared” which includes “flaring of associated gas, and flaring that occurs during well drilling (proposed § 3179.101)…”. This is technically infeasible. Gas flow meters require a steady stream of gas to be accurate. Drilling operations do not provide the requisite steady stream of gas required. Furthermore, gas rate meters will not work in the presence of liquids – an element often included in the gas stream from drilling operations. In sum, measuring the gas stream from drilling operations is technically infeasible and estimating the gas stream is a highly subjective process. Instead of relying on inaccurate and costly metering, operators should be allowed to use a GOR to calculate total produced gas or measure total produced gas then use calculation: (Total Produced Gas – Lease Use – Gas Sales). Based on our analysis, BLM’s cost estimate for flare meters is extremely low. On any given day, an operator could temporarily lose access to natural gas sales and lines and be above 50Mcfd. Based on this reality, BLM’s proposed requirements would necessitate a meter on every site production could be greater than 50 Mcfd. Even if sales are not lost, virtually every well will flare > 50 Mcfd at some point due to compressor maintenance, force majeure, and emergencies and would then have to measure. It appears BLM did not consider this factor when estimating the number of impacted sites. In addition, there is no measurement that will accurately measure the very big swings in flow. If flare meters are required for every flare that hits 50 mcfd at any point in time, nearly every flare will require a meter. And the vast majority of those meters will have zero flow most of the time, then spike during temporary periods of flaring. There is no meter on the market that can accurately gauge volumes at a spike period when generally it has no flow. BLM should consider more carefully examining their metering requirements so that meters are only required if 50 Mcfd is estimated for more than 60 days.

6. In many instances, oil and natural gas production and natural gas gathering systems are operated by separate companies. BLM’s discussion of third party natural gas gathering systems in the Proposed Rule underestimates the complexity of the agency approval process even with a robus dialog between oil and natural gas producers and midstream system operators. Although companies can and do work together in good faith to ensure resources are developed efficiently and responsibly, market dynamics play an equally important role. A producer cannot

necessarily influence how a midstream operator builds out its gathering system, allocates available capacity, and plans its maintenance schedules, among other decisions. It is unrealistic to place the burden of complying with a standard on an operator that cannot control third party infrastructure. In order to accommodate the many situations that can arise when, despite good faith efforts, operators are unable to utilize gathering systems, BLM should provide adequate exemptions for lack of gathering capacity, maintenance schedules, and other force majeure situations.

This problem is particularly acute in areas like North Dakota. Gas gathering and processing infrastructure exists, but lacks capacity or where new development has occurred without pre-existing infrastructure. Where it is practical, producers will nearly always develop in areas near gas gathering systems. This allows maximum economic and environmental benefits. But it is not always practical to develop near this infrastructure—especially in very remote areas (such as certain parts of North Dakota). Producers do not always have control over how gas gathering infrastructure is used. For example, in some cases, midstream companies may curtail the capacity made available for an operator's associated gas or other constraints. In others, lease terms and other constraints require the resource to be developed on a certain timeline despite dedicated infrastructure. The Proposed Rule appears to assume that availability of gas gathering infrastructure alone will largely solve these problems. In our experience, this is far from accurate. Capacity constraints on existing infrastructure can be both temporary and long-term problems that are very complex to address. Producers and midstream companies work together to minimize capacity constraints but in a dynamic industry like oil and natural gas production, the goal of maximizing gas capture is a constantly moving target. The Proposed Rule risks shutting down significant portions of this industry, which is already strained by low commodity prices. Such consequences are likely to be borne disproportionately by smaller producers.

Further complicating matters, some wells may come online with a high initial production (IP) rate. In these instances, the large volumes of associated gas produced may overwhelm limited gas supply capacity. Operators are left with little choice but to flare that associated gas or risk damage to the reservoir of a highly productive oil well by choking it back. That could have significant economic consequences for operators as well as mineral owners, including the federal government.

If BLM fails to allow adequate provisions, operators would be forced to consider building out redundant gathering systems which is cost-prohibitive and creates added environmental impact through construction, or curtail production which would decrease royalty payments to the federal government and could potentially permanently damage otherwise productive reservoirs.

7. The proposed natural gas measurement requirements are potentially infeasible in certain situations. Low pressure vapors coming from production sites are difficult to measure, but are more easily calculated. BLM should allow operators to determine flaring volumes through calculation, which has proven to be accurate. Metering simply adds cost and logistical difficulties without providing environmental benefit or reducing waste.

8. By requiring that no flaring take place above a certain limit, the Proposed Rule gives pipeline companies unfair leverage to raise their pipeline usage rates. This has been demonstrated in Utah, which imposes a flaring limit similar to the one in the Proposed Rule.

9. We encourage BLM to defer to state flaring rules where such rules exist, like North Dakota, New Mexico and Texas. By doing so, BLM will create a clearer path for development while still utilizing standards that are protective of the environment.

3. Detecting and repairing leaks

The Proposed Rule would require operators to develop LDAR programs for 'all wells that produce natural gas, … including oil wells."[42] Operators would be responsible for inspecting for gas leaks on: 1) all equipment and equipment components at the wellhead; 2) all facilities that the operator operates[43]; and 3) all compressors located on the lease, unit, or CA that the operator owns, lease, or operates. BLM estimates that the requirement would affect up to

[42] *Id.* at 6685.
[43] What is meant by "facilities" is not clear. The term needs to be explicitly defined.

37,000-38,000 well sites per year. The requirement is objectionable for several reasons and should not be adopted.

1. The issue of leak detection and repair for existing equipment is an issue that will be addressed by EPA in the rule that it is now developing to address existing sources of air emissions from oil and gas operations, just as it has been addressed by EPA in its rule for new and modified sources of emissions. BLM has already stated that it "expects that the LDAR requirements ultimately adopted [by 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" that BLM is proposing in the Rule, and that therefore compliance with the EPA requirements would satisfy BLM's requirements.[44] BLM has no reason to expect that "the LDAR requirements ultimately adopted [by EPA for existing well sites] would be [any less] effective in minimizing the volume of gas lost through leaks" than the requirements that BLM is proposing in the Rule for existing well sites. BLM's own cost-benefit analysis, even if it were accurate,[45] demonstrates that its LDAR requirement cannot be justified solely as a "waste" prevention measure. Therefore, instead of going to the trouble and expense of finalizing those requirements, only to have them supplanted by EPA's requirements, BLM should cease its efforts to develop an LDAR requirement.

2. Although BLM heavily touts the environmental benefits of the Proposed Rule, its proposal would create many negative environmental consequences. For example, in its Environmental Assessment, BLM claims the proposed LDAR program would require one to four truck trips per year to each of the roughly 38,000 wellsites impacted by the rule. This is likely understated given that many repairs could require multiple trips, and possibly multiple vehicles per trip, depending on the nature of the repair. This could add up to 150,000 truck trips or more, with many of these trips would be over many miles to remote locations and could have an impact on the local environment such as crop impacts for wellsites in agricultural areas and impacts to wildlife. Additionally, adverse weather could render many of these trips difficult or impossible at certain times of year.

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[44] *Id.* at 6648.

[45] See the attached economic analysis for an explanation as to why BLM's analysis is incorrect.

3. BLM acknowledges that its proposed approach "is similar to the requirements adopted by Colorado and Wyoming."[46] That being true, it should allow operators in those states to satisfy BLM requirements by applying their state-compliant programs on their federal leases. That would avoid duplicative efforts and unnecessary expense, while achieving substantially the same results in terms of preventing the "waste" of gas.

4. The Proposed Rule would impose sweeping, one-size-fits-all requirements in spite of BLM's acknowledgment of the following facts: 1) the Carbon Limits Study found that "about one-third of the facilities had no detectable leaks;"[47] 2) EPA found "higher volumes of fugitive emissions from gas wells compared to oil wells;"[48] 3) "[m]ultiple studies have found that a relatively small percentage of facilities are responsible for the majority of leaks and for most of the wasted gas;"[49] 4) "BLM believes [based on experience in the field] that there are systematic differences among operators' leak rates;"[50] and 5) most leaks are found in equipment that vibrates.[51] Given these facts, it is obvious that BLM's sweeping requirements do not achieve BLM's own goal of "reduc[ing] the most waste at the lowest cost."[52]

To achieve its goal, BLM should revise its requirements to focus on gross emitting components. The Proposed Rule should focus on: (1) the most common sources of leaks, such as valves, open-ended lines, and pumps, or "high motivated operation equipment;" and (2) only those components with the potential to operate at or above sales line pressure. This would allow operators to maximize the cost effectiveness of their LDAR programs by focusing the most resources on quickly identifying and addressing the largest leaks.

Providing operators flexibility in developing LDAR programs similar to directed inspection and maintenance (DI&M) programs tailored to their specific facilities or groups of facilities would provide significantly greater fugitive emissions benefits at a much lower cost than the type of rigid and inflexible program in the Proposed Rule. See Management of Fugitive

[46] *Id.* at 6647.
[47] *Id.* at 6646.
[48] *Id.* at 6649.
[49] *Id.* at 6648.
[50] *Id.*
[51] *Id.* at 6650.
[52] *Id.* at 6648.

Emissions at Upstream Oil and Gas Facilities, Canadian Association of Petroleum Producers (In the upstream oil and gas sector "[o]nly a small percentage of the equipment components have any measurable leakage, and of those only a small percentage contributes to most of the emissions. Thus, the control of fugitive emissions is a matter of minimizing the potential for big leaks and providing early detection and repair.") Accordingly, we strongly support a flexible approach. Allowing operators to focus monitoring efforts on the components that are most likely to leak, and those that are most likely to have the highest leak rates, maximizes both the emissions reductions and cost-efficiencies of an LDAR program.

5. <u>Section 3179.302 Approved Instruments and Methods</u> – For all practical purposes, the Proposed Rule would require the use of optical gas imaging devices ("OGI") for inspections conducted by operators that operate "500 or more wells within the jurisdiction of a single BLM field office."[53] However, OGIs may not function well in all situations. For example, an OGI is not a quantitative tool and, depending on the camera, it may also detect water vapor and heat signatures. An OGI camera survey may not always be able to tell an operator whether a repair is necessary, since it is not quantitative. During periods of overcast skies, high winds, or inclement weather, OGI technology is unable to effectively detect hydrocarbon vapors. In certain parts of the West, such overcast and windy conditions can persist for long periods during the winter, and as a result operators could likely spend considerable time and money repairing leaks of just water vapor. Lastly, OGI cameras are generally not intrinsically safe and would require a hot work permit in many instances. Due to these numerous technical and practical limitations, it would be inappropriate for BLM to adopt a leak threshold definition. We support BLM's decision to not include such a definition in its proposed rule.

Rather, the Proposed Rule should give operators the flexibility to select the ideal monitoring technology for their particular conditions. Instead of having to obtain BLM's approval before using something other than OGI, operators should simply be required to file with BLM a statement identifying the technology and certifying that it meets or exceeds the effectiveness of OGI in detecting leaks.

[53] *Id.* at 6685.

The Proposed Rule also would stifle innovation of more effective monitoring and measuring equipment. Instead of prescribing two methodologies, the Rule should permit flexibility, in accordance with other successful LDAR programs. For example, in Colorado, 5 C.C.R. 1001-9 (Regulation 7) gives operators some flexibility in choosing a leak detection technology. EPA's vendor testing program for flares and combustors may also be another viable option. Under this program, EPA allows vendors to test according to protocols set by EPA and determine standard operating procedures for control devices. New and innovative technologies are constantly involving in this space and the rule should encourage, not stifle, such progress. We encourage BLM to make very clear in the rule that new technologies are encouraged and will be approved and allowed through a straightforward and expedited review process (i.e., avoiding an onerous, years-long application process that would otherwise be applied to actual emissions control devices or continuous emissions monitoring systems). We would welcome the opportunity to work with BLM to determine what methods should be approved for LDAR monitoring and verification.

6. Section 3179.303 Leak detection inspection requirements - We strongly oppose an inspection schedule that varies in frequency. While we appreciate BLM's intent to create a performance-based program, in practice this approach will create a disproportionately large administrative burden while offering minimal environmental benefit. Instead, we urge BLM to implement a fixed annual inspection schedule.

BLM acknowledges the Carbon Limits Study that demonstrated that annual surveys "generally resulted in net benefits to the operator," and that quarterly surveys imposed net costs on the operator. Second, as BLM is well aware, EPA also concluded that "the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions…"[54]. Further, BLM admits that its proposed inspection requirements with "inspection frequencies that vary over time and across an operator's well sites" can be confusing.[55] Accordingly, instead of burdening operators with a set of confusing inspection requirements that will have small to negative net benefits, the rule should simply

[54] 80 Fed. Reg. 56636.
[55] 81 Fed. Reg. at 6648, 6650.

require annual inspections at all sites. Based on the results of those inspections, BLM should then evaluate its inspection requirements at the end of five years.

The Proposed Rule's LDAR inspection requirements take a one-size-fits-all approach that is impractical for many facilities. To treat a well that produces six barrels of oil per day like a centralized well pad with eight horizontal wells is unrealistic. Stripper wells producing less than 15 barrels of oil equivalent per day (boe/d) do not have the potential to emit at the same rate as larger producing facilities, and should therefore be exempted from the proposed LDAR requirements. Although BLM claims that LDAR at stripper wells will offer significant emissions benefit, industry experience indicates otherwise.

In the preamble of the Proposed Rule, BLM itself recognizes that a one-size-fits-all approach will likely not yield equitable costs and benefits. "EPA's emissions factors indicate generally higher volumes of fugitive emissions from gas wells, compared to oil wells. 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." Yet BLM goes on to impose blanket requirements that treat all facilities as equals.

We agree with BLM's assessment that the requirement for OGI only applied to large operators with 500 or more wells per BLM field office. For small operators, the cost of an OGI or Method 21-based LDAR program would be particularly burdensome, and we urge BLM to retain this exemption in the final rule. In some instances, these small operators have only a few wells or wells with low production volumes; and therefore the cost of the equipment or implementing the program may vastly exceed the emissions being saved. As an alternative to expensive instrumental surveys, we recommend that BLM allow for soap bubbles as a potential screening method (only where appropriate, considering the caveats in EPA Method 21, Section 8.3.3.1). EPA already recognizes the effectiveness of soap bubbles in its Method 21, Section 8.3.3 procedure.

We also urge BLM to clarify the phase-in period for its proposed LDAR program. In order to allow companies sufficient time to develop LDAR programs, train staff, and procure equipment, we suggest a 12-month phase-in. BLM should also provide a variance for state LDAR programs as being sufficient to satisfy BLM's requirements.

BLM also solicits comment on the use of third-party LDAR inspections (81 FR 6649) which we strongly oppose. Under no circumstance should BLM impose this needless burden that is devoid of any environmental benefit. BLM does not have unfettered authority to promulgate regulations that could force the entire industry to change the way in which it designs and operates its facilities or reports information—particularly where the rule has neither demonstrated the need to do so, nor discussed the environmental benefits to be obtained or the costs to be incurred. BLM's LDAR program must be reasonable with respect to its requirements and its consequences. On balance, we do not believe requiring third party certification of LDAR is reasonable.

7. Section 3179.304 Repairing leaks – The Proposed Rule would require operators to "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."[56] Given the fact that repairs often cannot be made within 15 days due to weather conditions or the availability of parts, BLM should adopt a more realistic repair window of 30 days, with the possibility to extend for an additional 30 days, in the event that parts are unavailable. This would significantly reduce the paperwork required, and that benefit would clearly outweigh the detriment that might be caused by whatever small amount of gas might leak from a particular component during the extra 15 days. We also ask that BLM clarify that decisions regarding feasibility due to weather or "good cause" allow for operator discretion, as they best understand when weather or other conditions can render repair work infeasible or hazardous.

Further, as most companies do not allow hot work without shutting in production, the Proposed Rule should state that where shut-in is required before a repair can be made, the operator shall make the repair immediately after the next scheduled shutdown, but in no event

[56] *Id.* at 6686.

later than six months after the leak is detected. EPA made a similar allowance in its New Source Performance Standards (NSPS) Subpart OOOO regulations, which provide that "[d]elay of repair for equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown."

8. Section 3179.305 Leak detection inspection recordkeeping – The requirement that the report include a "description of the leak" is ambiguous and superfluous. Requiring operators to document the first attempt at repair is also redundant. All that really needs to be recorded is the component on which the leak was found and the fact that it was repaired.

4. Replacing high-bleed pneumatic controllers

The Proposed Rule would require operators to replace approximately 15,600 existing high-bleed pneumatic controllers—i.e., existing pneumatic controllers with a continuous bleed rate greater than 6 standard cubic feet per hour--with low-bleed pneumatic controllers within one year of the effective date of the rule. The requirement is objectionable for several reasons and should not be adopted. If BLM decides to adopt a replacement requirement in spite of the objections noted above, the requirement should be revised as set forth below.

1. The preamble states that the Proposed Rule would require the replacement of pneumatic high-bleed controllers with low-bleed controllers. The Proposed Rule should make clear that high-bleed controllers may also be replaced with intermittent controllers because they are not a significant source of emissions. A 2014 study conducted by Oklahoma Independent Producers Association (OIPA) examined 205 producing wells and 680 pneumatic controllers.[57] The study determined that on average, intermittent vent controllers emitted 0.40 standard cubic feet of gas, a miniscule amount. OIPA's analysis found that prior estimates underestimated the number of vent controllers at visited sites, but overestimated emissions, and overestimated both the number of continuous bleed controllers and their emissions. OIPA's analysis provides further support for allowing intermittent controllers.

[57] Pneumatic Controller Emissions from a Sample of 172 Production Facilities, Oklahoma Independent Petroleum Association, November 20145.

2. Operators should be given at least two years to replace their high-bleed pneumatic controllers. It will take that long for companies to plan accordingly, budget funds to support implementation costs, order and purchase equipment, and complete installation of the replacement equipment. Indeed, given the sudden and significant demand for new controllers that will be created by BLM's replacement requirement, it is highly likely that current supplies will not be adequate to meet the demand and that operators may face significant delays in obtaining the new equipment.

3. The Proposed Rule states that an operator may be exempted from the replacement requirement for a particular controller if it notifies BLM and BLM agrees that compliance with the replacement requirement "would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease."[58] This is the standard that was developed to justify an exemption from the flaring limits for all oil wells on a lease and is not appropriate for use here. Instead, it should be based on the cost of replacing a single pneumatic controller.

4. BLM substantially underestimates the cost of replacing pneumatic controllers in its proposed rule by keeping the focus of its analysis too narrow. The cost of this requirement is not limited to the cost of installing a new controller. There are significant labor costs as well as the costs of downtime and lost production during installation to consider. The Proposed Rule would also lead to a dramatic increase in demand for controllers, particularly given the short implementation window. This could potentially lead to difficulties for manufacturers' ability to meet the new demand, which would in turn drive prices of the device up. There are further downstream effects to consider too, as the increased requirements to capture and route gas will lead to additional demand for pneumatic controllers to manage those systems. This in turn will further drive demand (and therefore costs) higher.

[58] *Id.*

5. BLM should allow for use of high-bleed pneumatic controllers where they remain necessary for safety reasons. EPA makes such an allowance in its proposed NSPS OOOOa and we recommend that BLM do the same.

5. Replacing certain pneumatic pumps

The Proposed Rule would require operators to: 1) replace existing pneumatic chemical injection pumps and pneumatic diaphragm pumps with zero-emissions pumps, or 2) route the emissions from those pumps to a flare device on-site. BLM estimates that 8,775 pumps would be subject to the requirement. The requirement must be met within one year of the effective date of the rule. The requirement is objectionable for several reasons and should not be adopted.

If BLM chooses to adopt a replacement requirement in spite of the general objections noted above, then the requirement needs to be amended as set forth below.

1. The Proposed Rule requires replacement of all chemical injection or diaphragm pumps regardless of the amount of their actual emissions. If there is to be a replacement requirement, BLM should exempt pumps with *de minimis* emissions. Such pumps would include pumps that are: 1) not in constant service—i.e., operate less than 2,160 hours/yr; 2) portable; 3) routed to a process; or 4) whose emissions are less than 6 scfh.

2. The Proposed Rule states that a pump may be exempt from the replacement requirement if the gas that would normally be vented is routed to a flare device. However, flaring gas from pneumatic pump exhaust may not technically feasible in certain situations. Thus, many pumps subject to the rule will need to be replaced. BLM needs to reflect that fact in its cost-benefit analysis. BLM relies heavily on WDEQ's Upper Green River Basin (UGRB) Existing Source Rule pneumatic pump requirements to justify the proposed requirements in § 3179.202. BLM fails to acknowledge that such requirements were promulgated by WDEQ to regulate emissions in an ozone nonattainment area. It is unacceptable to apply a standard for a specific nonattainment area nationwide. It is also important to note that the UGRB is a unique basin that supports a multi-well pad approach to development. Because of this supported

development, it is easier for operators to route pneumatic pumps to combustion devices than it will be in other basins, nationwide.

Both in the UGRB and nationwide, not all pneumatic pumps can be effectively routed to an existing control device. Accordingly, operators will have to install a control device specific to pneumatic pump emissions. Take, for example, natural-gas fired piston pumps (i.e. pneumatic methanol injection pumps) located at the wellhead. Pneumatic methanol pumps at the wellhead are far from where existing combustors are typically located at a site (e.g. at the production equipment and /or storage vessels). As a result, there will be insufficient pressure from the exhaust of the pneumatic pumps to be routed back to the combustor. Operators will not be able to control emissions from these pumps with existing controls.

3. Operators should be given three years to comply with the replacement requirement. It will take that long for companies to plan accordingly, budget funds to support implementation costs, order and purchase equipment, and complete installation of the replacement equipment. Indeed, given the sudden and significant demand for new zero-emission pumps that will be created by BLM's replacement requirement, it is highly likely that current supplies will not be adequate to meet the demand and that operators may face significant delays in obtaining the new equipment. Operators may have hundreds of natural gas driven pneumatic pumps in each basin. One year is an insufficient amount of time to evaluate each pump, order and install replacement pumps or control devices and confirm proper operation. BLM relies on Wyoming's UGRB Existing Source Rule to justify the proposed requirements of § 3179.202 in the preamble. The UGRB Existing Source Rule was effective on June 30, 2015 and provided operators until January 1, 2017 to replace all pneumatic pumps with zero-emissions pumps, route such equipment to a line or closed loop system or route emissions to a control device. The UGRB Existing Source Rule covers a more sensitive area (i.e. an ozone nonattainment area) than BLM's nationwide rule and still provided a year and a half for compliance. A three year deadline to comply with § 3179.201 will give operators a more reasonable amount of time to ensure compliance. Increased compliance will decrease the "waste of natural gas" and conserve BLM inspection and enforcement resources upon final rule implementation.

4. The Proposed Rule states that an operator may be exempted from the replacement requirement for a particular well if it "provides an economic analysis that demonstrates, and BLM agrees, … 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." As stated above, this standard is inappropriate. Instead, it should be based on the cost of replacing a single pneumatic pump.

6. Limiting venting from storage vessels

The Proposed Rule requires operators within six months to "route all tank vapor gas" that is vented from existing storage vessels that have "a rate of total VOC emissions equal to or greater than 6 tons per year" "to a combustion device or continuous flare, or to a sales line."[59] BLM estimates that the requirement "would affect about 300 existing storage vessels on BLM-administered land." The requirement is objectionable for several reasons and should not be adopted.

BLM's decision to use VOCs as a proxy for methane emissions is unreasonable. Generally, when crude oil has reached storage tanks it has undergone separation, where natural gas is removed from the product stream and diverted to sales. Although there will be some residual gas entrained in the crude oil, the vast majority of associated methane has been removed. Therefore BLM's calculations about the benefits of storage tank controls, which rely heavily on the social cost of methane (SCM), are inaccurate. BLM also underestimates the number of affected storage vessels in its analysis of the provisions. One single operator estimates that it will have approximately 100 storage vessels impacted by the proposed

If BLM chooses to adopt the requirements in spite of the general objections noted above, then the requirements needs to be amended as set forth below

1. The cost of controlling the vapors from existing storage vessels is much higher than for new storage vessels, and the life of an existing storage vessel is shorter. Therefore, the emissions

[59] *Id.* at 6685.

threshold for controlling the gas vapors from existing storage vessels should be higher than the 6 tons per year standard established by EPA for new storage vessels.

2. BLM has failed to consider the potential negative effects on climate change that may result from the control of tank vapors. The installation of combustion controls to reduce methane emissions from storage tanks may in fact increase the overall GHG emissions impact as a result of dramatically increased CO2 emissions. The example provided for a typical storage tank battery producing oil from the Bakken formation in North Dakota demonstrates that the installation of combustion controls increases the overall GHG impact by 228 percent. Considering that the Proposed Rule is a component of the President's White House strategy for climate change, it should clearly result in a net benefit in GHG emissions which BLM has failed to demonstrate.

3. Given all of the other requirements that would be placed on operators by the Proposed Rule, operators should be given at least one year to meet the routing requirement for storage tanks, and should be given six months to determine the rate of emissions from their storage vessels. Wyoming's UGRB Existing Source Rule was effective on June 30, 2015 and provided operators until January 1, 2017 to control or route to a sales line all applicable storage vessels. The UGRB Existing Source Rule covers a more sensitive area (i.e. an ozone nonattainment area) than BLM's nationwide rule and still provided a year and a half for compliance. In addition, BLM should clarify what is meant by a "new source of production." Is the rule intended to require an operator to determine the rate of emissions from a storage vessel whenever it receives production from a new well on the same lease as the well[s] from which it has previously received production?

4. The Propose Rule appears to blur the line between a storage vessel and a battery of storage vessels. EPA created some similar confusion in its 2012 NSPS OOOO rulemaking, which it later clarified in its "OOOO 1.75" amendments. NSPS OOOO provides that a "storage vessel affected facility" is an individual storage tank. BLM's Proposed Rule, however, defines a storage vessel as "a crude oil or condensate storage tank or <u>battery of tanks</u> that vents, or is designed to vent, to the atmosphere during normal operations." (emphasis added). The emission

control applicability threshold in BLM's Proposed Rule is defined by the PTE of a crude oil or condensate tank or a "battery of tanks," indicating that operators must determine applicability based on each tank's PTE and, where more than one tank is present, the sum of the PTE associated with multiple tanks in a battery. In light of BLM's definition of "storage vessel," BLM's proposed regulations for existing storage vessels is more stringent that EPA's control requirement for new and modified storage vessels. We strongly encourage BLM to maintain consistency with EPA and apply its storage vessel requirements to individual vessels, not storage vessel batteries.

Applying BLM's requirements to storage vessel batteries would dramatically increase the cost, complexity of requirements, and the number of vessels affected. Such a significant shift would likely necessitate BLM revisiting its cost benefit analysis here. One member reports having at least one basin with over one hundred applicable storage vessel facilities. With an estimated cost of $30,000 - $40,000 to purchase and install emission control equipment, the cost to comply with § 3179.203(c) appears overwhelming. Given this, it would appear BLM's estimate of 300 affected facilities is significantly understated.

A regulatory scheme, like the one BLM has proposed, that imposes more stringent requirements on existing tanks, which are a less significant source of emissions, than EPA imposes on new tanks makes no sense. We therefore urge BLM to forego the regulation of existing storage vessels. In the event BLM moves forward with its regulations, we recommend BLM revise the definition of storage vessel in § 3179.3 to read:

> a crude oil or condensate storage tank that vents, or is designed to vent, to the atmosphere during normal operations.

7. Limiting emissions from downhole well maintenance and liquids unloading

The Proposed Rule "would prohibit new wells from unloading liquids by simply purging the wells."[60] For both new and old wells, operators would be required to use "practices that maximize the recovery of gas for sale and must flare gas not recovered." BLM estimates that the requirements will impact 1,550 existing wells, as well as an undetermined number of other wells that are currently equipped with plunger lifts but not "smart" automation. The requirements are unreasonable and should not be adopted.

BLM bases its requirements on its belief that "[r]ecent technological developments allow liquids to be unloaded with minimal loss of gas," and that it is therefore "reasonable to expect operators to use these available technologies to minimize gas losses."[61] However, BLM's belief is at odds with the conclusion recently reached by EPA in its consideration of new source performance standards for VOC emissions from liquids unloading activities. After an exhaustive examination of the issue of emissions from liquids unloading, EPA concluded as follows:

> Data reviewed also show that liquids unloading events are highly variable and often well-specific. Furthermore, questions remain concerning the difficulty of effective control for those high-emitting events in many cases and concerning the applicability and limitations of specific control technologies such as plunger lift systems for supporting a new source performance standard.[62]

As a result of its analysis, EPA declined to regulate liquids unloading in its proposed NSPS OOOOa, as did the state of Colorado upon adoption of Regulation 7. The Colorado Department of Public Health and Environment (CDPHE) recognized that operators need flexibility to employ best management practices on a well-by-well basis.[63] CDPHE went on to recognize that automated plunger lifts are not pollution control devices and are not used in the field unless the

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[60] *Id. at* 6655.
[61] *Id.*
[62] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56593, 56645 (Sept. 18, 2015) (proposed rule).
[63] *Well Liquid Unloading Frequently Asked Questions*. CDPHE. August 17, 2015.

well design, geologic conditions, and gas content are appropriate for it. Given the significant difference of opinion between BLM and EPA on the feasibility of controlling emissions from liquids unloading, BLM should postpone adopting any liquids unloading requirements until that difference is resolved. The federal government should speak with one voice on this important issue.

We have serious concerns with the proposed liquids unloading requirements, particularly with the prohibition of well purging. The proposed Best Management Practices (BMPs) may not be adequate as a well declines, and later in its productive life, even a well classified as "new" under the Proposed Rule may need to be purged. Plunger lift systems are effective only to a point and do not serve as a panacea for well purging. Plunger lift systems will not be installed on all new gas wells at initial production. A plunger lift generally will not be used until the well has been on production for some time. At that point in time, if a plunger lift were installed at initial production, it would have to be replaced due to age. Differentiating between new and existing sources in this category is not logical as wells generally do not unload until later in life. We ask BLM to consider the following example:

Pipeline companies put back pressure valves on their pipelines. These are typically set at very low pressures in areas with low pressure gathering systems. The purpose of these valves is to protect the pipeline from surges in volume or pressure that in the opinion of the pipeline company might damage their line or metering equipment.

In these same areas, plunger lifts and intermitters are also often used. Intermitters are systems using pressure, or timer, controls that allow well pressure to build up in a well and then they open a control valve on the flow line based on a set time or pressure to allow the well to surge and flow at higher rate than the well could maintain on a continuous basis thereby carrying fluid to surface that would not be carried out if the well were flowing at the rate it can support on a continuous basis. Plunger lifts also use intermitters with the addition of a small plunger made of metal or a synthetic material that travels from a resting point on a stop in the tubing near the top of the wellbore perforations to the surface up the tubing. During each of these cycles, fluid and gas is pushed the hole and is pushed to the top of the tubing by well pressure. The plunger is retained in the wellhead for a short period by pressure and flow. After a certain set period of time, or at a set pressure, the control valve on the flow line closes. After the valve closes, the pressure build-up cycle begins again. In the case of a plunger lift, the plunger drops back down the tubing to a spring loaded stop set in the tubing near the top of the perforations and it sits on the stop until the control valve on the flow line opens for the next cycle. In both cases, pressure builds and fluid that will be carried out of the hole enters the well during the shut-in period. Both of these are automatic unloading devices commonly used, and sometimes used in association with soap sticks and surfactants.

These pipeline backpressure valves cause problems with automatic unloading systems. When the well surges when an intermitter opens there is a higher initial pressure and gas rate with a duration of a few seconds to a few minutes. The volumes actually produced in the first minute would be small. The rate starts high but drops very quickly so the amount of gas flowing at the end of a minute may one quarter of the initial rate at the beginning of the plunger lift cycle or less. Very little gas is produced in the first minute or so of flow. Some of these systems cycle as few as one to three times per day. A more typical number of cycles might be eight to twelve times per day.

The increased gas rate and pressure at the start of a cycle would typically be inadequate in gas volume to make the sales line pressure up sufficiently to damage the line, even with poly line systems. However, the surge pressure causes the pipeline backpressure valve to shut in many cases because the valve just sees the pressure, it cannot detect the surge volume and associated pressure is inadequate to damage the line. Many of these valves have to be manually reopened. If one shuts it likely means a loss of production for 24 hours and sometimes more plus a fee to reopen them in some cases. Therefore operators in some areas use what is commonly known as a divert valve or “B Valve”.

These diversion valves open at the beginning of a intermitter cycle and divert all or a portion of the gas flow depending on how they are designed into a tank, typically for a few seconds to less than a minute, although some may run longer. They bleed the surplus pressure and gas to a storage tank until the pressure drops enough to allow the gas to enter the pipeline without tripping the pipelines backpressure protection valve. They can be controlled on a set time or pressure. After a certain time period or at a certain pressure the divert valve closes directing all the gas into the gathering line through the sales meter.

These systems are fairly common throughout low pressure gas and oil producing areas with low pressure gathering systems and they allow substantial natural gas, oil and condensate volumes to be economically produced when taken in aggregate over hundreds to thousands of wells in an area. They allow these reserves to be produced from formations where no other system would allow the economic production of these reserves. Their gas losses are minimal on a day-to-day basis and the operators are highly motivated to keep the diversion valves open only long enough to get the pressure low enough to get it into the line without causing the pipeline backpressure valve to shut, as they are losing revenue on every bit of gas going into the tank. The variety of these situations makes it difficult to suggest a simple requirement, which further underscores the inappropriateness of attempting to regulate liquids unloading.

These kind of systems result in minimal gas losses. We suggest an outright venting exemption from the regulations for plunger lift and intermitter systems using a divert valve unless the divert valve is found by BLM to not be closing at all, or in a reasonable period of time, and the operator fails to correct the problem within 5 days or notice being received from the BLM. Shutting the well in until repairs or adjustments could be made would be considered compliance with the 5 day rule.

The Proposed Rule also fails to describe the information collection expectations for subsequent unloading events by well purging at such wells. We would object to subsequent purging events leading to additional information collection requirements that aren't expressly state in the Proposed Rule. Requiring operators to document and notify BLM of all subsequent purging events will be unreasonable for operators and is unnecessary for the proper functioning of BLM. Well purging by liquids unloading is standard industry practice, with individual operators commonly reporting hundreds of liquids unloading events per year. Having to document and notify BLM of all purging events would be extremely burdensome for operators and would be unnecessary for the proper functioning of the BLM because operators are already required to report unloading events under certain state programs (e.g., Wyoming) and pursuant to EPA's Greenhouse Gas Reporting Program. Furthermore, the deluge of notices BLM will receive if all purging events must be reported will overwhelm agency resources and prevent BLM staff from focusing on more important duties.

The Proposed Rule states that "[b]efore [an] operator purges a well for the first time after effective date of this section, the operator must document that other methods [of liquids unloading] are technically infeasible or unduly costly." This is an unreasonable requirement. As BLM notes, "operators must remove or 'unload' the liquids to maintain or restore production."[64] The rule should not require operators to immediately halt their maintenance or restoration efforts for an indefinite period of time while the feasibility and cost of other methods of liquids unloading besides purging are evaluate. Instead, operators should be given at least one year following the effective date of the rule before the documentation requirement must be met for any particular well. That will give operators adequate time to plan for the implementation of the requirement without bringing a halt to their ongoing maintenance or restoration efforts.

The Proposed Rule prohibits all "liquids unloading by well purging" for wells "drilled after the effective date" of the rule. Given the variety of factors from well to well and from field to field that may affect the technical feasibility and cost of using methods other than purging for liquids unloading, operators should be given the flexibility to employ best management practices in a fit-for-purpose manner based on the specific design, casing configuration, geology, and other factors. The state of Colorado acknowledged that need and BLM should as well. BLM's conclusion that "the alternative technologies discussed above [in 81 FR 6654-6655] now generally make well-purging unnecessary" is incorrect. Therefore, the prohibition on purging of new wells is infeasible.

The prohibition on purging will also require well swabbing or other maintenance operations. Swabbing is time-consuming, expensive, results in lost production due to well downtime, and still requires venting in the form of well blowdowns. Well blowdowns must occur before swabbing operations in order to depressurize the system and allow for safe working

[64] 81 Fed. Reg. at 6654.

conditions. The result is that BLM's prohibition on purging will not eliminate emissions from liquids unloading; it simply displaces them to another process while simultaneously adding cost that detrimentally impacts operators and royalty owners. This problem is further compounded because swabbing operations or similar maintenance may need to be done more frequently, again adding emissions and unnecessary costs.

8. Limiting emissions from well drilling and completions

The Proposed Rule would effectively prohibit the venting of any gas that reaches the surface during drilling and certain well completion operations. The gas must instead be captured and sold, flared, used in operations on the lease, or injected. These prohibitions are objectionable for several reasons.

1. Both sections 3127.101 and 102 require that gas that cannot be captured and sold or used in operations on the lease must either be flared or injected. As explained above, this preference for flaring (and injecting) over venting is not a "waste" prevention measure, as it does not prevent any "waste" of gas; instead, it is solely intended to reduce methane emissions out of a concern for the effect such emissions may have on climate change. The requirement that gas that is not captured and sold or used on the lease be flared or injected must therefore be deleted from the Proposed Rule. Moreover, as not all gas will be capable of being economically captured and sold or used on the lease, the Proposed Rule must state that gas that cannot be economically captured and sold or used on the lease may be vented.

2. Section 3179.101 effectively prohibits any venting of gas that reaches the surface during drilling. But achieving a no venting standard is not technically feasible in all circumstances, particularly when the gas reaches the surface through gas in solution, entrained gas or unplanned gas kicks. Gas in solution or entrained gas may be of insufficient volumes to burn continuously even after processing the drilling mud through a gas buster and sending the gas to flare. The gas will go to the flare but may not burn resulting in venting to the atmosphere. Gas from kicks in deeper formations goes to flare after separation in the gas buster but gas constituents such as high CO2 may prevent the gas from burning. Drillers must circulate

the gas out of the well to maintain control and venting is the only solution when gas quality is incombustible. Shallow gas kicks create unique circumstances. Shallow kicks occur when drilling surface hole without conventional BOP equipment. In areas of known shallow gas, a diverter with extended blooie lines is installed to prevent gas from accumulating under the rig in the event shallow gas is encountered. In general, it is not possible to shut in the well due to weak formations and controlling the influx requires diversion away from the rig as quickly as possible. The control method for shallow gas is to pump at the highest rate possible to raise the equivalent circulating density and control the influx. The high velocity mixture of gas, fluid and cuttings is not conducive to separation in a vessel to separate gas from the liquids and solids. The only safe solution is to vent to maintain control of the well.

3. Section 3179.102 effectively prohibits any venting of gas that reaches the surface during well completion and post-completion, drilling fluid recovery, or fracturing or refracturing fluid recovery. BLM should clarify, for fracturing and refracturing, that "gas reaching the surface" refers to the flowback following hydraulic fracturing and refracturing. Meeting a no venting standard is not technically feasible for flowback. Until a two or three phase separator can be operated, the only option for flowback is venting. Moreover, in fields with small volumes of associated gas like the Permian Basin, operators may be unable to run a two or three phase separator, and in fields that produce heavier crudes like Utah's Uinta Basin, operators may also not be able to run two or three phase separators. EPA's regulations allow venting from flowback until a gas/liquid separator can be operated so that sufficient gas can be captured and sent to a flare or put to beneficial use. BLM must allow venting in this circumstance as well.

4. BLM should also exempt wells with less than 300 scf per stock tank barrel of oil produced and wells with artificial lift equipment from the no venting standard, just as is done in EPA's regulations. We also encourage BLM to allow for pilot lights to be used on flares for drilling and completion operations in order to accommodate the variable quality and volume of associated gas that is produced during these processes.

5. BLM should not promulgate requirements for well completion operations following fracturing or refracturing as they duplicate EPA's NSPS Subpart OOOO and proposed OOOOa.

Subpart OOOOa will become applicable to each well completion with hydraulic fracturing or refracturing for all new gas wells and for all new oil wells with a GOR greater than 300 scf of gas per barrel of oil produced if NSPS OOOOa is promulgated as proposed. New wells are already covered by a specific NSPS, including requirements for emission controls, monitoring, recordkeeping and reporting. BLM will not benefit from any additional "waste" recovery by including their own well completion requirement.

6. EPA's OOOOa already includes recordkeeping and reporting requirements for compliance with the control requirements from flowback following hydraulic fracturing or refracturing. States have primacy to enforce NSPS regulations, and there are penalties for non-compliance. No additional compliance assurance will be achieved by requiring operators to submit a Sundry Notice to BLM stating compliance with NSPS OOOOa

9. Requiring the development of waste minimization plans

Section 3162.3-1 would require operators "[w]hen submitting an Application for Permit to Drill an oil well" to "also submit a plan to minimize waste of natural gas from that well."[65] In their plans, operators would be required to "set forth a strategy for how the operator[s] will comply with the requirements … regarding control of waste from venting, flaring, and leaks and must explain how the operator[s] plan to capture associated gas upon the start of oil production, or as soon thereafter as reasonably possible."[66] Although the waste minimization plans would not be enforceable, "[f]ailure to submit a complete and adequate waste minimization plan [would be] grounds for denying or disapproving an Application for Permit to Drill."[67] The proposed requirement is objectionable for several reasons and must not be promulgated.

1. <u>Requiring waste minimization plans is unnecessary</u> – Requiring waste minimization plans is not necessary to achieve BLM's stated goal and is therefore not a "reasonable precaution" against "waste" of gas and is beyond BLM's authority to impose under the MLA.

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[65] Waste Prevention, Production Subject to Royalties, and Resource Conservation,81 Fed. Reg. at 6679.
[66] *Id.*
[67] *Id.*

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."[68] In other words, BLM is assuming that unless operators are required to gather certain information that they will need to comply with the venting and flaring limits, they will not do so. This is an insupportable assumption. Operators routinely conduct extensive planning about the current and future availability of infrastructure in their development plans for the express reason of minimizing flaring and maximizing gas capture.

Moreover, in order to comply with the venting and flaring limits, operators will of necessity have to plan how they will do so, even if there is no requirement to develop a waste minimization plan for submission to BLM. In other words, the existence of the limits themselves will motivate operators to plan; they will not need to be required to plan by BLM.

In addition, operators are fully capable of identifying what information will be needed to prepare their plans. Thus, having to generate and collect the information required by the Proposed Rule and then submit it in a prescribed format to BLM for review will serve no useful purpose. Preparing the plan for BLM will simply be a needless bureaucratic exercise that will waste the time and resources of operators in preparing the plan, as well as the time and resources of BLM in reviewing the plans to determine if they are "adequate and complete."

BLM states that the information required in waste minimization plans is comparable to the information that the North Dakota Industrial Commission ("NDIC") requires in gas capture plans. *See* 81 FR at 6642. However, the NDIC limits the amount of information that operators must provide from midstream companies with which they have no contractual relationship. For gas capture plans in North Dakota, operators simply relay information provided to them from the specific midstream company that is contracted to take that specific operator's gas. An operator must have a pre-existing contract with a gathering company in order for that company to take the operator's gas and to provide the operator the information requested by the NDIC. However, in the Proposed Rule, BLM seeks information operators do not have and may not be able to collect

[68] *Id.* at 6642.

because no contractual relationship exists, or are based on dedications that specific operators cannot use..

2. <u>Requiring waste minimization plans for venting and leaks is unnecessary</u> – The Proposed Rule would prohibit venting, except in specified circumstances, and would require the development and implementation of a Leak Detection and Repair Program. Thus, requiring waste minimization plans to address what will be done to minimize venting and leaks is not necessary since BLM is already prescribing what those actions are to be. BLM should clarify that waste minimization plans need address only how the operator intends to comply with the flaring limits in areas with known capacity issues.

3. <u>Requiring waste minimization plans will further slow an already slow APD approval process</u> – Waste minimization plans will not be enforceable, but a failure to submit an "adequate and complete" plan will be grounds for denying an APD. BLM will therefore have to review each plan before it can approve an APD, thus slowing down the APD approval process, which already often takes more than a year to complete. BLM should not assign itself a new task when it has demonstrated that it is not capable of performing the tasks it already has in a timely manner, nor should it assign itself a new task without establishing a deadline by which it is completed and without demonstrating that it will have the resources to meet that deadline.

Moreover, because it already takes so long to get an APD approved, the information in a waste minimization plan may well be stale by the time the APD is approved, and will thus serve no useful purpose. On average, it takes BLM three to six months to approve an APD on federal lands and 12 to 18 months to approve an APD on Indian lands. The difference with NDIC's gas capture plan is that the NDIC approves APDs within 15-45 days and meets with midstream companies on a regular basis.

By the time BLM approves an APD, most of the information BLM has requested will be out of date. Moreover, some information BLM is requesting in the waste minimization plans is not information an exploration and production company has at the time of submitting an APD. Examples of highly speculative and variable data include the anticipated daily capacity of the pipeline at the anticipated date of first gas sales from the proposed well and the anticipated gas production rates of a proposed well. The waste minimization information collection requirement does not help exploration and production companies better prepare to comply with proposed flaring limits. It will only act to memorialize information that is outdated by the time the APD is approved by BLM or request information the operator cannot know. It is difficult to find any value in outdated and/or obsolete information supplied to BLM at the time of the federal APD submission. The requirement to create and submit waste minimization plan must be removed or drastically modified in the Proposed Rule.

4. Waste minimization plans should not be required to contain confidential and unnecessary information - The information that must be included in a plan pursuant to section 3162.3-1(j)(4)(i-iv and vi), (5)(ii-iv), and (6) is confidential business information and should not be required to be included in a plan. Moreover, the information that must be included in the plan pursuant to section 3162.3-1(j)(4)(i-iv and vi) is in the control of the pipeline companies. Thus, even if it were not confidential, operators would likely not be able to obtain the information. BLM should not demand confidential business information in the form of decline curve projections, price, forecasts, anticipated pressures, etc., particularly from publicly traded companies. Also, operators will not be able to share plans for expansion of pipeline capacity for the area that includes the proposed well, as anticipated in the Proposed Rule, unless the expansion has been publicly announced.[69] BLM has no utility for this information, and if there was any utility, it would not be operators who could provide it.

Some of the information that BLM would require in a waste minimization plan is not necessary to achieve the purpose of the plan, which is to "set forth a strategy for how the operator will comply" with the flaring limits. For example, to achieve that purpose, an operator does not need to identify for BLM "all existing gas pipelines within 20 miles of the well," and "the location and name of the operator of each gas pipeline within 20 miles of the proposed well;" it only needs to identify the pipeline to which it intends to connect. The Associations would argue that information about existing pipelines in an areas is, as a practical matter, irrelevant because BLM cannot force an operator's gas to be delivered to a nearby pipeline

[69] *See* § 3162.3-1(j)(4).

owned by a third party gas gatherer where there is no contractual relationship, except after a full hearing pursuant to 30 U.S.C. 185(r)..

5. Waste minimization plans should not be required for every new oil well – BLM should clarify that waste minimization plans only need to be prepared for new oil wells with associated gas on leases that do not already have an easily-accessible pipeline connection. Further, operators should be allowed to develop and submit plans that cover multiple wells, especially for multi-well pads that will utilize a common pipeline tie-in point.

6. Requiring an alternative on-site capture approaches is not necessary – Each waste minimization plan must "explain how the operator plans to capture associated gas upon the start of production."[70] That explanation will necessarily include an explanation of any "on-site capture approach" that the operator intends to use other than connecting to a pipeline. Thus, unless the operator is claiming that capture by pipeline or some on-site method is not economic, there is no need for the requirement in section 3162.3-1(j)(7) that the operator prepare an "evaluation of alternative on-site capture approaches."[71]

BLM has identified the areas where high rates of flaring are taking place, notably, in the Bakken and Permian basins. Given that many other areas with extensive federal minerals, such as Utah's Uinta Basin and California's San Joaquin Valley, do not have high levels of flaring, requiring waste minimization plans in those areas would be a pointless bureaucratic exercise. It is simply common sense that BLM should not require the expenditure of time and resources to prepare plans in area that do not have a problem with high levels of flaring.

10. Section 3179.10 – Other waste prevention measures

Section 3179.10 states that if gas capture is not yet available on a given lease, BLM may "exercise existing authority to delay action on the APD for that lease." The preamble cites 30 USC 187 and 225 as this existing authority. BLM's position is apparently that its authority to prevent "waste" allows BLM to indefinitely suspend action on an APD until gas capture

[70] *Id.* at 6679.
[71] *Id.*

infrastructure is available. Even assuming the statutory provisions for "waste" prevention extend to such an action, the Propose Rule would allow BLM to stifle exploration in frontier areas distant from gas gathering infrastructure. Although the Proposed Rule also allows BLM to suspend a non-producing lease while action on the APD is held in abeyance (authority BLM already has under 30 USC §209), the point is that BLM is creating a chicken and egg situation: gathering infrastructure will not be built in an area until there is a proven supply of gas to transport, and the existence of that gas cannot be shown until wells are drilled. In addition, §3179.10 seems to ignore Sec. 366 of the Energy Policy Act which requires BLM to issue the permit within 30 days after receipt of a complete APD "if the requirements under the National Environmental Policy Act of 1969 and other applicable law have been completed within such timeframe" or defer a decision and provide the applicant a notice that specifies any steps the applicant could take for the permit to be issued AND a list of actions that BLM needs to complete together with timelines and deadlines for completing such actions. In frontier areas, there will be nothing the applicant can do to make "gas capture capacity" available unless it is willing to bear the expense of installing electricity generation or gas liquidation facilities in advance of knowing whether the well will produce sufficient quantities of gas to power those facilities. A regulation that allows BLM to delay indefinitely the approval of an APD in areas where gathering infrastructure is not yet available could seriously diminish the value of leases covering lands in remote areas and work as a disincentive to test new geologic concepts.

B. Criteria for determining when flared gas is "waste"

Section 3179.4 is intended to clarify the definition of what constitutes "unavoidable loss" of gas from flaring by, among other things, "listing specific operations and sources that produce gas that BLM would deem 'unavoidably lost,' as long as the operator has not been negligent, has not violated laws, regulations, lease terms or orders, and has taken prudent and reasonable steps to avoid waste."[72] The list needs to be expanded, as explained below.

1. The definition of "unavoidably lost" should include gas gathering force majeure events, which disrupt gas take-away capacity, and should not be subject to the 24 hour duration limit applicable to emergencies. Venting and flaring during a force majeure event should also

[72] *Id*. at 6665.

not be royalty bearing (3179.5) and should be excluded from flare limit calculations (3179.6) and measurement requirements (3179.8).

Volumes flared as a result of a force majeure event are unavoidably lost under NTL-4A Section II.C.(2) ("'Unavoidably lost' production shall mean…(2) that oil or gas which is lost because of line failures, equipment malfunctions, blowouts, fires, or otherwise…"). During a force majeure event, a well may continue to sell at its full rate or at a reduced rate, depending on whether the gatherer is flaring gas at the pipeline outlet and depending on how much line pack volume (spare capacity) is available before the pipeline reaches maximum allowable operating pressure (MAOP).

Once connected to a gas sales pipeline, all flaring due to "compressor or other equipment failures, relief of abnormal system pressures, or other conditions which result in the unavoidable short-term venting or flaring of gas" is authorized under NTL 4A Section III.A as an "Emergency" without incurring a royalty obligation. Gas is frequently flared in North Dakota when the line capacity or compression capacity is reached because allowing those volumes to flow (such as by increasing the separator pressure), creates the potential to exceed pipeline MAOP and risk line failure.

In addition, the State of North Dakota flaring regulations provide exceptions to the flaring limits for flaring that result from force majeure events.[73] The North Dakota requirements have achieved the goal of reducing flaring in the state while still providing critical flexibility that allows for continued operations without penalties during a force majeure event.

Thus, the Proposed Rule is inconsistent with the existing flaring regulations in North Dakota and the BLM's own existing regulations under NTL-4A, both of which provide essential exceptions for force majeure events. Because a force majeure event is, by its very nature, unforeseen and beyond an operator's control, all flaring during a force majeure event should

[73] *See* North Dakota Industrial Commission, North Dakota Industrial Commission Order 24665 Policy/Guidance, , available at https://www.dmr.nd.gov/oilgas/GuidancePolicyNorthDakotaIndustrialCommissionorder24665.pdf, stating that "[t]he operator is allowed to remove from the total monthly volume calculation gas volumes flared from wells already drilled and completed on the date a force majeure event occurs if the event is properly documented in writing by the gas gathering company."

constitute “unavoidably lost” gas under the proposed rule, should not contribute to any volume limitation, and should not require metering. BLM could simplify the rule by simply considering any gas flared from a well that is connected to a pipeline as being unavoidably lost. Obviously, once an operator has connected a well to a pipeline, it has every incentive to maximize the revenue from that investment. Any disruptions are going to be the result of operational events beyond the operator’s control, such as those related to capacity issues.

2. Consistent with NTL-4A, losses from “low-pressure production vessels” (such as heater treaters, which function as secondary separation), should be considered “unavoidably lost” (3179.4), should not be royalty bearing (3179.5), and should be excluded from flare limit calculations (3179.6) and measurement requirements (3179.8).

Low-pressure production vessels typically include secondary (tertiary, etc.) separation equipment, wherein gas is recovered at pressures below the gathering pipeline operating pressure and wherein the gas volume contribution is too low to reasonably make sales without significant operating and/or capital expense.

For example, traditional facility setups in the Bakken include a first stage two phase separator, which separates the majority of gas from the combined liquid stream. It is followed by a three phase heater treater, which separates water from oil as well as any gas remaining with the liquid stream that is recoverable at the equipment’s specific operating conditions. The standard practice is to operate the inlet separator at or slightly above (to account for line loss pressure drop between the separator and sales meter) the MAOP of the gas sales line. Thus as long as the pipeline has not reached its MAOP, all separator gas will sell.

The treater typically operates at least 15 psig less than the separator to allow liquids to dump via pressure between the two vessels. The treater’s maximum allowable working pressure is typically 75 psig, which is less than typical sales line MAOP in the Bakken. Because this vessel operates at a very low pressure, closer to 30-50 psig, treater gas cannot normally enter the sales line and any treater gas vented or flared from this low-pressure vessel should constitute an “unavoidable loss” consistent with NTL-4A Section II.C.(1) (“‘Unavoidably Lost’ production shall mean (1) those gas vapors which are released from storage tanks or other *low-pressure production vessels*…") (emphasis added). This exception in NTL-4A for low-pressure vessels reflects operational realities and must be included in the Rule. Note that the language of NTL-4A expressly provides a separate exemption for low pressure production vessels in addition to storage tanks. Per ASME Boiler & Pressure Vessel Code VIII, a "pressure vessel" is defined relative to a tank as operating above 15 psi, thus a Treater constitutes a "low-pressure production vessel."

Furthermore, to comply with NDIC Order #25417 (the "Oil Conditioning Order"), companies must operate treaters at or below 50 psig, which will ensure these treater gas volumes must go to flare rather than to sales based on typical gathering line pressures. Consequently, the proposed rule directly conflicts with existing North Dakota requirements, and it would be infeasible (if not impossible) to comply with both rules simultaneously.

Field measurements at a sample of sites across the Bakken where the separators and the treaters are equipped with allocation gas meters show that treater gas makes up approximately 3% or more of total, non-tank vapor gas on average for typical pressure conditions. Due to the relatively low volume of gas from the treater, it is infeasible, uneconomic and unnecessary to install pad compression or a vapor recovery unit to capture this low pressure gas. Again, NTL-4A reflects operational realities that the proposed rule fails to consider.

3. It is not feasible to add a redundant gathering system, especially with a dedicated gas contract in place. BLM has grossly underestimated the time, effort and cost to capture incremental volumes in a constrained system like the Bakken. The Rule must account for the economics specific to the well and region in question.

BLM's premise in the preamble, RIA, and Proposed Rule itself is that additional permanent infrastructure can be built to capture the incremental flare volumes where capacity is constrained or remote capture technology can be deployed to individual well sites where permanent infrastructure is undersized or infeasible. The RIA incorrectly asserts that in times of downturn and reduced activity due to low commodity prices, gathering companies can "catch up." However, the exact opposite is true. When commodity prices are low, it also impacts the gas gatherers, making additional capital investment difficult and less likely.

Under NTL 4A, BLM may approve venting or flaring of oil well gas without incurring a royalty obligation based on engineering, geologic, economic, and recoverable reserves information. A narrower set of standards for existing wells is specified in Section 3179.7(a)-(c) of the new rule. In connection with a recent appeal to the BLM State Director of a BLM North Dakota Field Office Decision Record regarding the Field Office's proposed plan for processing flaring sundry notices, the State Director issued a decision ("State Director Decision") concluding, among other things, that the costs and economics of gas capture must be considered in making an "avoidably lost" or "unavoidably lost" determination.[74] BLM must revise the "unavoidably lost" definition to include gas flared once connected to a gas pipeline. However, if such a definition change is not made, section 3179.7 should be simplified to expedite the approval process and modified to apply to both existing and new pads with gas pipeline connections.

Gas pipelines require long term planning and investment, including lengthy ROW and permitting processes, particularly on tribal land. Often the slowest permits are related to the BIA, USFS, and BLM jurisdictions, and the State Director Decision recognizes these ROW challenges and deems all flaring while a ROW is pending to constitute "unavoidable loss". In addition, the "North Dakota Industrial Commission Order 24665 Policy/Guidance" document issued by the NDIC expressly provides for temporary exemptions for ROW delays. The local BLM authority in the Bakken and the State both recognize that flexibility is required for ROW delays. This concept is absent from the Proposed Rule and needs to be included.

Midstream companies gather gas from many pads from many operators under dedications because production from multiple locations is necessary to invest in the infrastructure, especially with rapid decline rates such as in the Bakken. It would be difficult and uneconomic for any single operator to pay for a dedicated gas pipeline and processing system with a few wells that

[74] *See* SDR No. 922-15-07 issued February 11, 2016 by Aden L. Seidlitz, Acting State Director, at 9, 10, 12.

quickly decline to low volumes. To support infrastructure investment, gas gatherers require commitments from producers to ensure gas will flow through their infrastructure. These commitments vary by agreement and market but almost universally limit alternate gathering options. Furthermore, most dedicated contractual obligations make it difficult to bring a long-term secondary gathering system to the same pad location. If such a secondary agreement were allowed, it would only be allowed on an interruptible basis and would only be used sporadically, thereby making a secondary system even more uneconomic and infeasible.

Gas gatherer economics (a full discussion of which is beyond the scope of these comments) are heavily dependent on capturing volumes because most gas gathering agreements charge per unit of gas transported across the system. Gas gathering systems rely on pad-specific infrastructure that typically consists of a pipeline and measurement equipment that connects the pad to a commingled system of lower pressure trunklines, compressors, and higher pressure discharge lines to efficiently move the gas from the pad to a treating and/or processing facility to make the gas and associated liquids (if any) marketable to the downstream markets. Early production in a well's life is critical for the gas gatherer to recoup the investment for the pad-specific infrastructure. Any operation mode (e.g. automatic shut-ins or waiting until infrastructure "catches up") that risks flattening the decline curve by capping production could be expected to jeopardize gas gatherer economics and further hinder infrastructure investment.

Building a separate gathering system for each operator would not only be economically prohibitive, but it would also be redundant and require multiple ROWs in the same area and across the same landowner property. Repeated ROW requests increase surface use and have led historically to landowners unreasonably or intentionally blocking easements and demanding exorbitant compensation from operators.[75] A redundant plant and the necessary compressor stations further lead to increased surface use.

Any backup gas gathering infrastructure must be completely redundant and would require a cost burden of approximately 10 times the market value of the recovered gas, assuming gas

[75] The North Dakota Industrial Commission recognizes the difficulty in obtaining rights-of-way and specifically allows temporary exemptions for right-of-way delays.

volumes available for redundant sales of approximately 20%, based on current Bakken flare percentages. Lessees cannot afford this undue burden.

4. BLM should consider flaring associated with pigging activities "unavoidably lost."

Due to the high liquid content of the gas in some areas, the gas gatherers must frequently pig their lines, sometimes multiple times in the same day, to manage liquid buildup. Pigging essentially involves launching a malleable or hard plug (called a pig) from an upstream location and allowing pressure to carry the pig to a receiver. The pig sweeps liquid forward and thus reduces liquid in the line. As the pig and liquid front sweep through the system, pressure increases upstream and can thus reduce sales volumes.

Pigging is generally not considered a force majeure event, but it can cause operational outages similar to a force majeure event. Furthermore, during pigging operations, it is undesirable to completely shut-in upstream wells as the drive mechanism for the pig will be lost and the likelihood of a stuck pig scenario will be increased, which would only exacerbate flaring or keep wells shut-in longer.

Flaring during pigging operations should be considered "unavoidable". Given the frequency of pigging, it is infeasible and unduly burdensome for the gatherer to document and provide notice of all pigging events. Therefore, proper gathering line operation and pigging further justify that all flaring from wells connected to pipeline constitutes "unavoidably lost" gas without necessity of BLM approval.

5. It is not a given that associated gas produced from a well will be of sufficient quality to be marketed, and in some instances the cost of processing gas to bring it to pipeline specification may exceed the value of the recovered product. We urge BLM to consider exempting gas based on the presence of CO2, Oxygen, Nitrogen, H2S, and other impurities.

C. Royalty rates for newly-issued competitive leases

1. The process for raising the royalty rate above 12.5%

In accordance with the MLA, the Propose Rule would authorize BLM to set the royalty rate on competitive leases issued after the effective date of the rule at not less than 12.5%. BLM states that it "does not currently anticipate increasing the base royalty rate for new competitively issued leases above 12.5 percent," and that "[b]efore making such a change, the BLM would announce the change prior to the effective date, and would provide for a public comment period."[76] It also lists some of the "relevant factors" that it would "potentially" take into account in any decision to raise the royalty rate. BLM requests comment on "the adequacy of the public process [it] outlined."

As was made clear in the numerous responses that BLM received in response to its Advanced Notice of Proposed Rulemaking on the subject of raising royalty rates,[77] any decision to do so would be highly significant to a wide variety of stakeholders, and should be informed by a wide variety of considerations. The public process for making such a decision should not therefore be based on BLM's non-binding statements in the preamble to the Proposed Rule; it should be set forth in the rule itself. Indeed, even if the public process were not set forth in the rule, a decision to raise the royalty rate would be a "rule" as defined by the Administrative Procedures Act,[78] and therefore could not be made except in compliance with the notice and comment requirements of that Act. Moreover, the Proposed Rule should state that royalty rates will not be raised on existing leases.

The Proposed Rule should identify the specific factors BLM shall consider in making a decision to raise the royalty rate in advance of any leases to which the increase rate would apply (including, at a minimum, the factors it identified in the preamble to the Rule), and should state that: 1) BLM will give public notice of its intent to raise the royalty rate at least one year in

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[76] 81 Fed. Reg. at 6660.
[77] Oil and Gas Leasing; Royalty on Production, Rental Payments, Minimum Acceptable Bids, Bonding Requirements, and Civil Penalty Assessments, 80 Fed. Reg. 22,148 (Apr. 21, 2015) (advance notice of proposed rulemaking).
[78] 5 U.S.C. § 551(4).

advance of doing so; 2) the notice will include a full explanation of BLM's reasons for believing that a royalty rate increase is needed; 3) the public will be given at least 90 days to comment on the notice; and 4) BLM will respond in writing to the comments it receives before issuing its decision.

Moreover, even though BLM states that it "does not currently anticipate increasing the base royalty rate for new competitively issued lease above 12.5%," it is important to remind BLM that increasing the royalty rate above 12.5% would almost certainly have negative impact on oil and gas production on federal lands. John Dunham & Associates, an economic consultancy, has modeled the impact on federal production under twenty-four scenarios involving varying degrees of change to royalty rates and rental rates on federal leases.[79] Net expected production was calculated at a base royalty rate of 12.5%, and potential increases to 14.75%, 16.75%, 17.75%, and 18.75% with corresponding rental rates of the current $1.50/$2.00 per acre, $2.00 per acre, $3.00 per acre, $4.00 per acre, and $5.00 per acre. Under every scenario, raising royalty rates and rental rates had a negative impact on federal oil and natural gas production. The net result of that lost production is a reduction in federal energy revenues of up to about $51 million.[80]

While federal royalty rates are presently lower than royalty rates in some states,[81] there are good reasons why royalties on federal leaseholds are lower. For federal leases to be attractive to operators compared to leases on state and private lands, the federal lease rate must account for the time and expense involved in obtaining the lease, complying with overlapping state and federal regulations, performing the requisite environmental review required under federal law, and the difficulty involved with accessing federal lands. Our members' experience reveals that the overall cost of developing leases on federal and Indian lands is consistently higher than for similar projects on state and fee lands. While it is reasonable for BLM to attempt to set royalty

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[79] Dunham & Associates' full report describing the modeling efforts and conclusions is attached as Exhibit A to these comments.

[80] *See* Ex. A at 1. It must be noted that the model used for this analysis only assesses development in thirteen western states: Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. Some states with meaningful activity on federal lands, particularly California and Alaska, are not included in the model. As a result, the model likely underestimates the value of lost revenue attributable to higher royalty rates and lease fees.

[81] *See id.* at 3, Table 2.

rates at values that maximize the federal government's return on federal leases, the marketplace sets a limit on how high rates can be before federal leases become an unattractive asset.

Higher royalty rates and associated lease fees impact federal oil and natural gas production in at least two ways: (i) higher costs make marginal projects uneconomical;[82] and (ii) higher costs increase the risk premium that oil and natural gas producers will require before bidding on leases.[83] The extent of the impact on production is likely to vary based on a host of geologic and economic factors. Under current production costs and economic conditions, for example, royalty rate changes may have little impact on projects focused on natural gas because commodity prices make new development uneconomic under any royalty scenario. In legacy oil fields, however, where many drilling permits are issued and the drilling of inexpensive vertical wells is common, the impact of increasing royalties and associated leasing fees is much more significant.

Nor are losses limited to lost royalty revenue. The oil and natural gas industry currently generates more than 173,000 direct jobs (not including additional secondary jobs) in the thirteen states the model analyzes. Depending on which of the twenty-four scenarios examined is ultimately adopted, as many as 1,330 direct jobs could be lost in these states alone. And because workers in the oil and natural gas sector tend to be highly compensated relative to workers in other economic sectors, job losses in oil and natural gas development disproportionately impact overall economic activity.[84]

Under the modeled scenarios, the loss of direct revenue to the federal government from oil and natural gas leasing resulting from a reduction in wells developed due to increased royalty rates and lease fees could be as much as $37 million annually. This represents meaningful losses

[82] Higher costs also mean that projects that are not presently economic are even less likely to occur in the future because more significant economic change is necessary before those projects can become economic. At least one federal agency has concluded that the development of marginally economic projects is already deterred because of the federal government's "regressive fiscal regime." Irena Agalliu, U.S. Dep't. of the Interior, Bureau of Ocean Energy Management, Comparative Assessment of the Fed. Oil & Gas Fiscal System . 5 n.5 (2011), http://www.boem.gov/Oil-and-Gas-Energy-Program/Energy-Economics/Fair-Market-Value/CERA-Final-Report.aspx. Higher royalty rates and lease costs would further exacerbate this existing problem.
[83] One strategy that operators are likely to employ to achieve this risk premium is offering lower bonus bids when bidding on federal leases. *See* discussion *infra* Part II.C.
[84] Ex. A at 10-11.

to the federal government, but also to the states that receive fifty percent of all monies from oil and natural gas production on federal lands within a state's borders.[85] But losses are not limited to the revenues from wells that are not drilled. Federal, state and local governments also stand to lose business, property and personal tax revenue from companies and individuals in the oil and natural gas activity, as well as the benefits of economic activity associated with full employment in the oil and natural gas industry. Modeling results suggest that these losses could well exceed $13.8 million for the federal government alone.

2. Fluctuating royalty rates

Although it has not been formally proposed, BLM states that it is "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."[86] The purpose of the provision, which BLM refers to as a "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."[87] Such a provision would be both an abuse of the Secretary's discretion and inconsistent with the Rule, and should not be given any further consideration by BLM.

The MLA gives the Secretary the discretion to set the royalty rate for competitive leases, as long as the rate is not less than 12.5%. The Secretary is to use her discretion to set the rate at a level that will insure a fair return to the government for the use of public resources. It would be an abuse of that discretion for the Secretary to use her authority instead to promote her policy to reduce flaring.

The adder provision would also be inconsistent with the Proposed Rule. Under the Proposed Rule, BLM is telling operators of new leases that flaring done in compliance with the

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[85] *See* 30 U.S.C. § 191(a).
[86] Waste Prevention, Production Subject to Royalties, and Resource Conservation, 81 Fed. Reg. at 6660.
[87] *Id.*

1,800 Mcf/month flaring limit will not be considered a "waste" of gas, and will therefore not be subject to a royalty. Under the adder provision, however, BLM would be telling those same operators that unless they flare at a significantly lower rate, "the threshold flaring rate", they will have to pay additional royalty. BLM gives no adequate explanation for this disconnect; it justifies the adder provision solely in terms of its ability to incentivize lease holders to plan ahead for gas capture. But the flaring limit in the rule and the requirement that operators develop waste minimization plans were supposed to provide that incentive. It would be arbitrary to say that flaring in compliance with the rule's 1,800 Mcf/month limit is not a "waste" of gas, and to then turn around and say that compliance with anything less than the adder provision limit would be a "waste" of gas, and would subject operators to a royalty increase.

We endorse the comments submitted to OMB by the Council of Petroleum Accountants Societies on this subject. They demonstrate the impracticability of this provision from an accounting perspective.

D. State or Tribal Variances

As detailed in the preamble, states, tribes, and EPA all have programs that deal in one way or another with the venting and flaring issue. It is thus extremely important that the Proposed Rule contain a variance provision that is workable and that will give timely relief to operators from duplicative or conflicting requirements. We would prefer a general deferral to existing state and tribal programs, but the variance provision offers at least the possibility of eliminating overlapping and duplicative requirements as a means of reducing administrative costs and improving efficiencies. If BLM is unwilling to defer to existing State and tribal programs, the following changes should be made in section 3179.401. Also, a variance provision should be added to the section 3160 to allow for a State to request a variance from the waste minimization plans.

1. The section should state that the request for a variance automatically tolls any deadline for compliance with the federal requirement from which a variance is being sought. Failure to

provide such a provision will make the provision for a variance practically meaningless, as operators will be left in regulatory limbo.

2. The section should state that any request for a variance that is not approved by the BLM State Director within 60 days of its submission shall be deemed approved. This will insure that the variance provision does not become a bottleneck that leaves operators uncertain for indefinite periods of time about the requirements that will apply to them.

3. The provision states that BLM "reserves the right to rescind a variance or modify any condition of approval." This unfettered discretion which allows BLM to revoke a variance for any reasons or no reason at all is clearly unreasonable and should not be part of the Proposed Rule. It will put the plans and investments of operators at continual risk, as operators will always have to reckon with the possibility that BLM will arbitrarily revoke a variance on which they have based their operational and investment decisions.

4. The section should state that States and tribes may appeal any denial of a request for variance or any revocation or modification of a variance. Without the right to appeal BLM's decisions, there is no protection against a completely arbitrary denial or revocation of a variance. Indeed, without a right to appeal, and hold BLM accountable for its decisions, the right to request a variance is of little practical value.

Conclusion

In closing, we reiterate the tremendous progress that America's oil and natural gas industry has made, and will continue to make, in addressing issues associated with venting, flaring, and methane emissions. However, after a careful examination of the Proposed Rule, we have concluded that it is arbitrary and in excess of BLM's authority and should not be promulgated. If BLM nonetheless proceeds with the rule, it needs to be substantially re-written to make it workable for industry and BLM, consistent with the many recommendations that we have made above. At a minimum, BLM should suspend work on the Proposed Rule until it is clear how EPA will regulate air emissions from existing oil and gas sources. This would be consistent with BLM's policy of avoiding duplicative or conflicting federal mandates. In the meantime, we would request that BLM direct its resources toward the timely processing of ROW applications, as that would have a much greater impact upon the reduction of flaring than the Proposed Rule.

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Alby Modiano
President
U.S. Oil and Gas Association

APPENDIX A

MEMORANDUM

TO:	Kathleen Sgamma, VP of Government & Public Affairs, Western Energy Alliance
FROM:	Mike Stojsavljevich
DATE:	April 12, 2016
RE:	Cost-Benefit Analysis of the Impact of Onshore Oil and Gas Leasing (43 CFR 3100), Onshore Oil and Gas Operations (43 CFR 3600), Royalty-Free Use of Lease Production (43 CFR 3178), and Waste Prevention and Resource Conservation (43 CFR 3179)

Executive Summary:

As per your request John Dunham and Associates (JDA) has reviewed *Cost-Benefit Analysis of the Impact of Onshore Oil and Gas Leasing (43 CFR3100), Onshore Oil and Gas Operations (43 CFR 3600), Royalty-Free Use of Lease Production (43 CFR 3178), and Waste Prevention and Resource Conservation (43 CFR 3179)*, which was produced by the Bureau of Land Management (BLM) in January 2016.[1]

This analysis of the proposed rules estimates the costs far exceeding the benefits. The proposed rules are estimated by the BLM give a high end cost of between $117 - $174 million (assuming either a 3 percent or 7 percent discount rate, Environmental Protection Agency (EPA) finalizing or not finalization of Subpart OOOOa, and various methane reduction assumptions).[2]

JDA estimates that the costs exceed $1.26 billion, while the benefits as estimated by the BLM are between $115 - $384 million (assuming either a 3 percent or 7 percent discount rate, EPA finalizing or not finalizing of Subpart OOOOa, and various methane reduction assumptions).[3] A more reasonable estimate of the benefits suggest that they are at best $90 million[4], hence the cost-benefit ratio of the proposed rules is nearly 14:1 cost to benefit.

The $1.26 billion cost of the proposed rule to the industry is best examined in three primary components. First, based on the costs of implementation outlined in the RIA prepared by the BLM, JDA estimates an economic impact on jobs, wages, and lost output of $997,199,000. Additionally, those economic losses create an additional loss of $114,112,000 in federal and state taxes. Finally, a conservative estimate suggests a total of $174 million in costs associated with implementing the rule.[5] This can be viewed as an annual incremental cost to the industry.[6]

Additionally, a reduction in oil well development from the proposed rules will leave 112.4 million barrels of developable oil in the ground.[7] This undeveloped oil is best viewed as oil that is shut-in due to the regulatory burden of implementing the proposed BLM rules.

Also, the BLM claims benefits of about $23 million in Federal royalties and 16.5 million metric tons of carbon dioxide equivalent emissions. This reasoning does not reflect the current state of the market. JDA estimates that the $23 million dollar figure presented by the BLM would drop to $3.68 million or possibly

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1 U.S. Bureau of Land Management, *Regulatory Impact Analysis for: Revisions to 43 CFR 3100(Onshore Oil and Gas Leasing) and 43 CFR 3600 (Onshore Oil and gas Operations)*, at: www.blm.gov/style/medialib/blm/wo/Communications_Directorate/public_affairs/news_release_attachments.Par.11216.File.dat/VF%20Regulatory%20Impact%20Analysis.pdf

2 Ibid., pages 6-8.

3 Ibid., pages 6-8.

4 Based on JDA estimates

5 Cost estimates rise to $319 million if all rules are implemented, EPA does not finalize Subpart OOOOa, and there are no methane offsets, which we detail below.

6 The economic impact of $1.26 billion is based on $997 million in economic impact, $114 million in lost taxes and $174 million in costs to the industry, which is our low end estimate based on BLM's RIA. JDA's internal cost estimates rise to $319 million and could increase the total economic impact to $1.43 billion.

7 Based on internal JDA estimates

considerably less, even approaching $0 when examining the current pricing environment and understanding the super-cyclical nature of the current oil and gas industry where inventory builds may create a situation where there is no additional demand for oil or gas

Background

This analysis also examines the claims and procedures of the regulatory impacts done by the Bureau of Land Management (BLM) and their proposed rulemaking, which would update 43 CFR Part 3100 (Onshore Oil and Gas Leasing) and 43 CFR Part 3160 (Onshore Oil and Gas Operations) and propose new regulations 43 CFR Chapter II, Subpart 3178 (Royalty-Free Use of Lease Production) and Subpart 3179 (Waste Prevention and Resource Conservation). The proposed Subparts 3178 and 3179 would update and replace the BLM's current policy document Notice to Lessees-4A (or "NTL-4A").

The BLM rule claims to have five specific goals:

1) Modify the requirements that limit the venting and flaring of produced natural gas. The proposed rule would prohibit venting of gas except in certain circumstances, and would limit gas flaring during normal production operations from development oil wells to 7,200 Mcf/month (on average, per well, across all of the producing wells on a lease) for the first year of the rule's implementation, 3,600 Mcf/month/well for the second year of the rule's implementation, and 1,800 Mcf/month/well thereafter. Gas flared from a well that is connected to infrastructure would be royalty-bearing except in certain narrow circumstances, such as emergencies.

2) Limit losses of gas through venting and leaks by placing requirements on other activities and equipment, including well drilling, completions and workovers, production testing, pneumatic controllers and pumps, storage tanks, liquids unloading, and leak detection and repair (LDAR). As a practical matter, many of the proposed requirements would impact only existing equipment or facilities that are not regulated by the EPA's existing New Source Performance Standards (NSPS) Subpart OOOO (nor by the EPA's recently proposed Subpart OOOOa, if that rule is finalized).

3) Conform the BLM's royalty rate provisions for competitive oil and gas leases to the corresponding statutory text, which prescribes a rate "not less than" 12.5 percent.

4) Require the operator to submit additional information to the BLM with its Application for Permit to Drill (APD) for a new oil well. Specifically, the operator must submit its plan to minimize the waste of natural gas from the planned well to the degree reasonably possible.

5) Clarify the parameters for an operator to use production on lease without paying royalties on that production. The changes would ensure that the royalty free use of production applies only to uses on the lease, unit, or CA. The changes would not prohibit the operator from using the production off the lease, unit, or CA, but those uses would incur royalties.

Conduct of a Regulatory Impact Analysis:

As part of the rulemaking process, all Federal regulatory agencies are required to conduct a Regulatory Impact Analysis (RIA). While these analyses are designed to determine if a proposed regulation will have a reasonable effect on the environment while not costing society substantial resources, they are also designed to determine if there are other alternative measures that the regulatory agency should take rather than proposing new rules. Unfortunately, the Bureau of Land Management (BLM), which developed this RIA has built a case for this regulatory endeavor by using outdated data sources and this flawed data and methodology have led to flawed conclusions.

The BLM performed an impact analysis for individual rulemakings under the Act's authority. The analysis must contain an analysis of each of the following impacts:

- The costs of compliance,
- Any potential inflationary or recessionary effects,
- Effects on competition with respect to small businesses,
- Effects on consumer costs, and
- Effects on energy use.[8]

This is not a true regulatory impact analysis but rather a general accounting based on outdated data sources of the direct costs of the proposed regulation. More importantly, two long-standing Presidential Executive Orders require all agencies, including the BLM, to conduct an analysis of the benefits and costs of a proposed significant regulatory action, including a comparison of the benefits and costs of alternative regulatory approaches.[9] Executive Order 12866 requires that all regulatory actions be reviewed by the Office of Management and Budget (OMB) and gave the Office broad powers to review and request revisions to all regulatory proposals.

This same Executive Order requires that an agency, including BLM, "Shall ... propose or adopt a regulation only upon reasoned determination that the benefits of the intended regulation justify (emphasis added) its costs."[10]

The Requirements of an RIA:

According to the Office of Management and Budget (OMB), there are 16 key elements that every Regulatory Impact Analysis (RIA) needs to address.[11] The OMB even provides agencies with a detailed primer on how to conduct an RIA in accordance with its guidelines and the underlying Executive Orders.[12] Additional requirements from the various laws governing RIAs such as the Unfunded Mandates Reform Act and the Regulatory Flexibility Act also need to be met by the BLM.

The OMB suggests that each agency include are:

1. A reasonably detailed description of the need for the regulatory action;
2. An explanation of how the proposed regulatory action will meet that need;
3. An appropriate baseline assessment of how the world would look in the absence of the proposed action;
4. An assessment of potentially effective and reasonably feasible alternatives to the proposed regulatory action;
5. An explanation of why the planned regulatory action is preferable to the potential alternatives;
6. An uncertainty analysis;
7. A description and discussion of the distributive impacts of the potential alternatives;
8. A clear, plain-language executive summary including an accounting statement that summarizes the benefit and costs for the regulatory action;
9. A clear and transparent table presenting anticipated benefits and costs.

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8 *Economic impact assessment*, United States Code, Title 42, Chapter 85, Subchapter III, Sec. 7617, at: http://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapIII-sec7617.htm

9 Federal Register, Vol. 58, No. 190, *Executive Order 12866 of September 30, 1993*, Monday, October 4, 1993, at: https://www.archives.gov/federal-register/executive-orders/pdf/12866.pdf

10 Ibid.

11 Office of Management and Budget, *Agency Checklist: Regulatory Impact Analysis*, www.whitehouse.gov/sites/default/files/omb/inforeg/regpol/RIA_Checklist.pdf.

12 Office of Management and Budget, *Regulatory Impact Analysis: A Primer*, at: www.whitehouse.gov/sites/default/files/omb/inforeg/regpol/circular-a-4_regulatory-impact-analysis-a-primer.pdf.

In addition, the OMB states that each regulatory impact analysis:

10. Use the best reasonably obtainable scientific, technical economic information and present it in a clear, complete and unbiased manner;
11. Provide the data, sources and methods used in the RIA to the public via the internet;
12. Quantify and monetize the anticipated benefits from the regulatory action to the extent feasible;
13. Quantify and monetize the anticipated costs from the regulatory action to the extent feasible;
14. Explain and support how the benefits of the intended regulation justify its costs;
15. Ensure that the preferred option has the highest net benefits unless the law requires a different approach;
16. Use appropriate discount rates for benefits and costs expected to occur in the future.

In addition to these 16 items, a proper RIA must examine a number of additional impacts including international effects and the effects on small businesses.

Very few RIAs ever fully follow the OMB guidelines, even though they represent best practices for this sort of analysis. This is definitely the case with the RIA performed by the BLM staff for this proposed rule. Not only does the RIA fail to perform 10 of the 16 checklist items, the analysis presented is biased, and uses many flawed assumptions.

Critique of the Analysis Prepared by the BLM:

This critique examines each of the items suggested by the OMB and outlines particular issues with how the BLM performed this particular study.

1. A reasonably detailed description of the need for the regulatory action: **The RIA does document a need for regulatory action on the part of the BLM.** According to the RIA, a large amount of natural gas is being wasted through venting and flaring at oil and gas production sites on Federal and Indian lands, despite the fact that this gas could be economically captured and delivered to the market. The RIA cites a 2008 GAO estimate that about 128 billion cubic feet of natural gas was either vented or flared from Federal leases, of which 50 billion cubic feet was economically recoverable.[13] The BLM claims that this recoverable volume represents about $23 million in lost Federal royalties and 16.5 million metric tons of carbon monoxide equivalent emissions.

   This reasoning does not reflect the current state of the market. First, the average natural gas price for the full year 2008 was $8.85 per MCF. This compares to a spot price in March of 2016 of just $1.40.[14] This is an 84 percent drop in the price of natural gas since the 2008 time frame which the GAO uses in its report. Based on the 84 percent reduction in the price of natural gas, the $23 million dollar figure presented by the BLM would drop to $3.68 million.

   Further, the RIA states that in 2013, about 98 Bcf of natural gas was vented and flared from Federal and Indian leases. At a $4/Mcf price of natural gas, this volume has a sales value of $392 million and a royalty value of $49 million. Of the 98 Bcf, the BLM estimates that 22 Bcf was vented and 76 Bcf was flared. The agency also estimates that 44 Bcf of the flared gas came from the Federal and Indian mineral estates with 32 Bcf coming from the estates of other mineral owners.[15]

   Therefore, the BLM in its analysis neglects to evaluate the current market landscape in terms of prices and industry dynamics which indicate rising inventory levels of natural gas and the potential for a

13 Op. cit. Regulatory Impact Analysis, page 2.
14 Braziel, E. Russell, The Race To Liquids, Oil & Gas Finance Journal, August 1, 2010, on-line at: www.ogfj.com/articles/print/volume-7/issue-8/features/the-race_to_liquids.html; CNBC.com for March 14, 2016 natural gas price.
15 Op. cit. Regulatory Impact Analysis, page 3.

supply glut. Natural gas prices have been as low as $1.40 per Mcf in March of 2016 or 65 percent lower than the RIA estimate, implying a sales value not of $392 million and a royalty of $49 million but a number closer to $137.2 million in sales and $17.15 million in royalties.

Adding in the economic marginal impact of the additional volume in a market landscape with heavy inventories it could easily be assumed that all of that volume may be much lower and could have a marginal value approaching $0.

2. An explanation of how the proposed regulatory action will meet that need:
   The BLM, with this proposed regulatory action explicitly seeks to enhance waste prevention and resource conservation. Explicitly stated and often discussed is methane reduction. The ability to measure methane reduction and tie it to conservation is not readily achievable. Air quality and pollution control regulations address "negative externalities" which represent the cost of pollution which is borne by society rather than producers. The RIA presupposes that methane emissions impose costs on society, such as negative climate, health, and welfare impacts that are not reflected in the market price of the petroleum produced. This can indicate that there is a need to promulgate regulations that minimize these costs. However, many scholars, including for example, Nobel Lauriat Ronald Coase, have suggested that there are other ways for society to alleviate the consequences of negative externalities. In fact, correcting an externality may impose externalities on different groups of people. This is why the OMB requires that all RIA submissions include an alternatives analysis.

   Without a proper baseline to measure the effects of the regulations, it is impossible to determine if they will meet the need of reducing any economic costs associated with "methane reduction."

3. An appropriate baseline assessment of how the world would look in the absence of the proposed action: **BLM does not provide a "null analysis" in its RIA.** There are no estimates of how this additional volume of natural gas that is brought to market would impact the current price of natural gas.

4. An assessment of potentially effective and reasonably feasible alternatives to the proposed regulatory action: **Only a very general alternatives analysis is presented in the RIA.** Royalty rate alternatives were discussed in general terms with no analysis performed. In fact, only one actual alternative was presented and it related to the flaring of gas. This alternative simply reduced the amount of gas flared to 20 million cubic feet. This is not, as suggested by OMB, a range of potentially effective and reasonably feasible regulatory alternatives including deferral to state or local regulation, the use of economic incentives to encourage the desired behavior, market-oriented approaches, different compliance dates or different requirements depending on firm size. The whole reason for an RIA is to examine alternatives and weigh the costs and benefit of different approaches to achieving the same goal. The BLM's RIA completely fails on this important aspect. Additionally, this arbitrary number does not examine a significant issue, the appropriate amount of venting or flaring to achieve maximum safety.

5. An explanation of why the planned regulatory action is preferable to the potential alternatives: **One alternative was presented, but there is no explanation of why the BLM's preferred regulatory action is preferable. Additionally, very uncertain and potentially unrealistic natural gas price estimates were used.**

6. An uncertainty analysis: The BLM presents a sizable degree of uncertainty in just about every listed benefit that it claims the proposed rule would generate. In fact, the Agency suggests that it cannot even determine what the price of natural gas will be in the future. The BLM states that it "believes" that there are economical and cost-effective measures that operators could take to minimize waste

based on advancements in technology, yet they cite no advancements that would be relevant to minimizing waste.

7. A description and discussion of the distributive impacts of the potential alternatives: While the RIA contains a section labeled *Distributional Effects,* it only examines the impact of the regulations across two categories: Small vs. large businesses and across potential pollution sources. OMB states that the analysis of the distributional effects should examine the impact of the proposed action across the population and economy divided up by a range of demographic and economic categories.[16] **This is not an analysis of the distributional impacts of the proposed rule as laid out in OMB Circular A-4.**

   The need for a distributional analysis is particularly acute in that these regulations are geared toward a single industry – oil and natural gas production. Other methane producing industries are not included. Higher costs in one industry reduce investment and activity in that sector and as such, encourage investment and activity in another. If capital were to move from the production of oil and natural gas to the production of say beef cattle, then the amount of methane produced may actually increase. If this has an effect on "climate change," the effect may be greater. More importantly, since oil and natural gas can be produced in many different countries the regulations may simply transfer activity from the United States to Russia, Mexico, Iraq or Nigeria. This can not only impact the American economy but could also lead to increased methane production.

   Most importantly, the RIA completely fails to examine how the proposed regulations impact different segments of society and different areas of the country, a requirement specifically outlined in OMB Circular A-4.

8. A clear, plain-language executive summary including an accounting statement that summarizes the benefit and costs for the regulatory action: **This is included in the analysis**.

9. A clear and transparent table presenting anticipated benefits and costs: **The analysis presents the calculated benefits and costs in a clear table.**

In addition, the OMB states that each regulatory impact analysis:

10. Use the best reasonably obtainable scientific, technical economic information and present it in a clear, complete and unbiased manner: As with many RIA documents, the agency involved is using the analysis to justify its proposed regulatory action. First the best data are not used. Specifically, data for natural gas prices at the peak of their historical range (2008) are utilized. Additionally, company profitability estimates come a select list of10-K financial filings from 2012-2014 for a sample of companies that are assumed to represent the industry. Survey data is also analyzed second-hand and not provided in raw form to the public.[17] What is even more astounding is that nowhere in the RIA is the volatility and economic hardship of the industry in 2015/2016 even stated. Much of this data is

[16] Specifically Circular A-4 States: *Those who bear the costs of a regulation and those who enjoy its benefits often are not the same people. The term "distributional effect" refers to the impact of a regulatory action across the population and economy, divided up in various ways (e.g., income groups, race, sex, industrial sector, geography). Benefits and costs of a regulation may also be distributed unevenly over time, perhaps spanning several generations. Distributional effects may arise through "transfer payments" that stem from a regulatory action as well. For example, the revenue collected through a fee, surcharge in excess of the cost of services provided, or tax is a transfer payment.*

Your regulatory analysis should provide a separate description of distributional effects (i.e., how both benefits and costs are distributed among sub-populations of particular concern) so that decision makers can properly consider them along with the effects on economic efficiency. See: Office of Management and Budget, *Circular A-4*, September 17, 2003, at: www.whitehouse.gov/omb/circulars_a004_a-4#f.

[17] This specific survey data was analyzed by Carbon Limit (a consulting firm).

now out of date and not indicative of either the pricing environment for oil or gas, nor are the company financial filings reflective of the current financial state of the industry.

BLM bases its assumptions on the benefits related to reduced methane emissions, on past Environmental Protection Agency (EPA) analysis and on pronouncements from a Federal interagency working group. The RIA states that BLM has estimated "the quantity of methane reduction using emissions factors and reductions data made available by EPA."[18] BLM also states that it estimates the social cost of methane using the values presented by Marten et al (2014), EPA's analysis of Subpart OOOOa and EPA's New Source Standards for Municipal Solid Waste Landfills. Further, BLM states that they estimated social cost of carbon dioxide on the Interagency Working Group on Social Cost of Carbon.[19]

This is not a complete analysis and is clearly biased because the BLM must first have established that those methane emissions that might be prevented by this rule actually impact "climate change" in some way. OMB requires agencies to establish a baseline which represents the agency's best assessment of what the world would be like absent the action. This baseline needs to focus on benefits and costs that accrue to citizens and residents of the United States. According to OMB, where the agency chooses to evaluate a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately.[20] Nowhere in the document does the BLM document any baseline cost of climate change on the economy of the United States. As such it is impossible to determine if the benefits anticipated by the BLM even accrue to the American economy. It is also impossible to determine if they have any meaningful effect on the overall factor being measured, that is the perceived economic cost of "climate change."
Without a proper baseline to measure the effects of the regulations, it is impossible to determine if they will meet the need of reducing any economic costs associated with "climate change."

Additionally, the entire benefits calculation done by BLM is based on an EPA analysis which in itself is based on an extremely fragile examination of the "climate change" benefits. The values are not derived from any models presented in the study, but rather from a book published in 2000 which purports to measure the cost of supposed "climate change" due to carbon dioxide (CO2) emissions.[21]

The EPA analysis which BLM incorporates, states that although several researchers that had directly estimated the social cost of non-CO2 GHG emissions, there was considerable variation among these published estimates both in terms of the models and assumptions. Furthermore, none of the other published estimates of the social cost of non-CO2 GHG were consistent with the CO2 estimates developed by an interagency working group (IWG) that included other executive branch agencies which used three integrated assessment models (IAMs) to develop the CO2 estimates used in this RIA. These CO2 estimates were first released in February 2010 and updated in 2013. In other words, the analysis uses assumptions unilaterally decided on by the Federal Government to measure a social cost of CO2 emissions.

Also, BLM goes on to suggest that a paper published by Marten (2014) provides the first set of published methane estimates in the peer-reviewed literature that are consistent with the modeling assumptions underlying the CO2 estimates. What the agency fails to mention is that the authors of this paper are all staff of the EPA. In fact, the Marten article does not even generate its own estimates of the potential economic benefits of reduced methane emissions, but rather calculates estimates of

18 Op. cit. Regulatory Impact Analysis, page 32.

19 Ibid

20 Office of Management and Budget, *Regulatory Impact Analysis: A Primer*, at: www.whitehouse.gov/sites/default/files/omb/inforeg/regpol/circular-a-4_regulatory-impact-analysis-a-primer.pdf.

21 Nordhaus, William D. and Joseph Boyer, Warming the world : economic models of global warming, Massachusetts Institute of Technology, 2000. Available on line at: http://eml.berkeley.edu/~saez/course131/Warm-World00.pdf

climate impacts of methane relative to CO2. In doing this the authors come up with a range of values of from $349 and $1,183 per ton, a 239 percent difference. In short, the figures used to calculate the purported benefits are based on an EPA sponsored paper that examines data on CO2 and makes a number of assumptive jumps to methane impacts. Even this paper admits to an extreme level of variation in its modeled figures.

This particular failing of the RIA is critical. In fact, this entire RIA presents little in the way of actual analysis. Rather it ties together a number of policy statements, and uses policy documents to support them. The RIA first determines that the production of oil and gas leads to the emissions of methane. From this point, the entire calculation of benefits is based on findings that are determined by the BLM to be self-evident, but which are not supported by facts. First, all of the literature cited about potential "climate change" costs of methane actually discusses CO2. The BLM bases their analysis on EPA, which then uses a paper produced by its own staff, which describes internal procedures used by EPA to translate methane into CO2 equivalents. While this paper may appear in a "peer-reviewed" journal, the paper and the journal were about internal bureaucratic processes, not chemistry.[22] In other words, it is saying "trust us" we know how this works.

BLM then multiplies these derived CO2 equivalents by a cost factor that comes not from independent research, but rather from an internal Administration working group. As such, these cost figures are not determined in an unbiased and independent manner, but by the agency that is promulgating the regulations. In fact, the entire process hinges on the unsupported assumption that the minor levels of methane emissions identified as coming from oil and natural gas developments have a negative effect on the economy. The entire analysis can be summarized by the simple statement, "Methane emissions have a negative effect on the economy because we (the BLM) say so." **This suggests that the RIA might not have been conducted in a non-biased manner.**

11. Provide the data, sources and methods used in the RIA to the public via the internet: While the report is extensively cited, much of the source material is not readily available or is not available without some additional cost. **The BLM does not provide a library of the materials or data used in its analysis that is available to the public without additional cost.**

12. Quantify and monetize the anticipated benefits from the regulatory action to the extent feasible: **The RIA does not demonstrate a way to monetize the proposed benefits, but only quantifies a purported economic benefit from the regulatory action which is between $255 and $384 million annually depending upon various assumptions**.[23] There are some major analytical leaps to monetize these benefits, and the actual figures are all based on 2008 commodity prices, material lifted from 10-K reports from 2012-2014, and survey data from 2012 – 2014, which was analyzed second hand by a firm called Carbon Limits which focuses on climate change mitigation.[24]

    Also for example, the largest line item, leak detection and repair (LDAR) compromises $88-$119 million dollars of the $255 to $384 million benefit (roughly one third). In regards to this, the BLM states that "the impacts of an LDAR requirement are uncertain."

    Also, flaring requirement estimates show a potential $7 to $16 million cost (not benefit).

[22] Peer review is not a euphemism for fact. Many journals publish papers on topics that the reviewers are not familiar with. Papers may be published because the present an interesting data set, a new process, or a formal analysis. In this case, the paper was published because it described an internal EPA process, not because it presented the results from a chemical experiment.

[23] Op. cit. Regulatory Impact Analysis, page 6.

[24] Op. cit. Regulatory Impact Analysis, page 222.

The old data, broad ranging estimates and potential negative values significantly lower the actual benefits. Utilizing current data and modern analytical techniques would bring the total benefit $90 million.

13. Quantify and monetize the anticipated costs from the regulatory action to the extent feasible: According to the RIA, the costs to implement the proposed regulations could reach $174 million per year.[25] This is well below the actual cost of implementing the rules as proposed. In fact, JDA estimates that the total cost of implementation of the proposed rules to the industry is a staggering $1.26 billion dollars on an annual basis.

The cost components are in eight categories: Flaring Requirements, Well Completion, Pneumatic Controllers, Pneumatic Pumps, Liquids Unloading, Storage Tanks, LDAR, Administrative burden.

These numbers are derived primarily from certain key assumptions contained in the RIA and cited by the BLM. These are:

- A total of 37,000 – 38,000 wells are potentially impacted by LDAR inspections
- Flaring limits affect no more than the RIA's stated 1,111 well sites
- Flare metering rules affect no more than 635 sites
- Well drilling, completions and maintenance proposed rules will affect no more than 1,575 wells
- Liquids unloading proposed rules affect more than 1,550 well
- There are no additional exploration leasing and permitting costs

Table 1 presents the eight components and the costs per well.

Table 1
Costs by Component[26]

Affected Component	Cost per well	Number of affected wells
Flaring (total including limits and metering)	$73,583	1,111
Well Completion	$7,619	1575
Pneumatic Controllers	$384	15,600
Pneumatic Pumps	$307.69	8775
Liquids Unloading	$3,871	1550
Storage Tanks	$20,625	3,200
LDAR	$3,736.00	38,000
Administrative burden	$67.34	38,000
Total	$110,193	

The BLM's high end estimate would be the lowest reasonable cost estimate. However, the number of wells serviced per year could be much higher than 38,000 and potentially double the amounts listed above, which could drive these costs much higher. If the given range is $117 - $174 million, doubling of the wells service count would increase the cost range to $234 - $348 million.

14. Explain and support how the benefits of the intended regulation justify its costs:

[25] Op. cit. Regulatory Impact Analysis, page 81.
[26] Assumes that there are no additional remediation costs as no exploration or new wells are being produced.

Any benefits at all rely on two criteria, the recovery and sale of natural gas and natural gas liquids and the assumed benefits of reduced methane emissions.

From a macro level the recovery and sale of natural gas and gas liquids is a highly questionable endeavor in these market conditions, The RIA states that the BLM is "unable to account for existing LDAR programs, and that these benefits likely overstate the true benefit of the rule."[27] The LDAR benefit is the largest benefit component of the rule.

Further, market dynamics continue to be highly volatile as commodities specifically natural gas are currently perceived to be super-cyclical with global demand weakening inventory build may take years to work themselves out. During this period of time adding additional volume to the market could very well not be feasible.

Additionally, in regards to methane benefits, the science is unclear as to whether a social cost benefit exists for reduced methane. As discussed in point 10 above, BLM bases their methane benefit on EPA analysis, which rests on a potentially unstable academic foundation. Without further analysis and robust debate, the BLM cannot assume that there is any benefit at all to reduced methane emissions.

15. Ensure that the preferred option has the highest net benefits unless the law requires a different approach: **A new estimate based on 2016 data, specifically prices should be conducted to reflect accurate net benefits.**

16. Use appropriate discount rates for benefits and costs expected to occur in the future: The BLM discounts its cost estimates using discount rates of three percent and seven percent; however, these are applied individually as separate analyses, and not used appropriately to discount effects on private capital (7 percent) and effects on private consumption (3 percent) as suggested by the OMB. **The discounting performed in the RIA is, therefore, not properly conducted.**

The Economic Impact of the Proposed Rules:

Table 2
Reduction in Oil Well Development Due to Proposed Rules

State	Estimated BLM Wells	Estimated Lost Wells	Well Loss Percent	Potential Lost Barrels of Oil
Arizona	2	-	0.00%	-
Colorado	6,878	(934)	-13.58%	(4,664,186)
Montana	2,819	(115)	-4.07%	(855,323)
Nebraska	31	(31)	-100.00%	(24,849)
Nevada	118	-	0.00%	-
New Mexico	30,490	(1,330)	-4.36%	(12,209,466)
North Dakota	1,874	(1,335)	-71.23%	(87,290,963)
South Dakota	87	(8)	-9.73%	(2,290)
Utah	8,909	(416)	-4.67%	(3,589,667)
Wyoming	31,647	(537)	-1.70%	(3,726,608)
Total	82,855	(4,707)	-5.68%	(112,363,352)

27 Op. cit. Regulatory Impact Analysis, page 130.

The costs imposed by the proposed rules would significantly impact the economic dynamics of the oil and gas industry. Based on JDA's dynamic model of the oil and natural gas industry, it is likely that as many as 4,700 fewer oil wells would be undertaken as a result of the rules.

Table 3
Economic Impact of Proposed Rules

State	Direct Jobs	Total Jobs	Direct Wages	Total Wages	Direct Output	Total Output
Colorado	(313)	(461)	$ (31,354,725)	$ (40,564,096)	$ (111,825,404)	$ (135,583,684)
Montana	(22)	(35)	$ (1,891,244)	$ (2,442,224)	$ (6,906,425)	$ (8,671,377)
Nebraska	(4)	(4)	$ (203,759)	$ (218,971)	$ (823,259)	$ (871,976)
New Mexico	(284)	(432)	$ (22,738,385)	$ (29,643,023)	$ (88,125,869)	$ (109,183,574)
North Dakota	(936)	(1,777)	$ (101,895,616)	$ (144,462,783)	$ (253,428,069)	$ (377,768,038)
South Dakota	(1)	(2)	$ (51,516)	$ (92,917)	$ (228,566)	$ (395,277)
Utah	(103)	(202)	$ (8,035,385)	$ (12,813,377)	$ (27,294,340)	$ (42,191,094)
Wyoming	(118)	(144)	$ (11,446,685)	$ (12,736,722)	$ (50,313,519)	$ (54,363,414)
Entire United States	(1,780)	(3,845)	$ (177,617,315)	$ (308,296,515)	$ (538,945,451)	$ (977,199,362)

By reducing new oil and natural gas development, and potentially reducing continuing operation of marginal fields, the proposed regulations could have significant impacts on employment in regions where there are developments on BLM lands. This is particularly important considering that the industry is already suffering substantial job losses due to the current low market prices for petroleum products. Based on models developed by John Dunham and Associates for Western Energy Alliance, these proposed rules could result in as many as 1,780 lost jobs for people directly involved with oil and natural gas development and production, and as many as 3,850 jobs once all supplier and induced impacts are taken into account.[28] These are real people with real jobs, currently receiving as much as $308.3 million in wages and benefits. All told, the economy could lose as much as $977.2 million in overall economic output annually.

This lost economic activity will have a significant and direct fiscal effect, that in and of itself would be larger than any potential benefits that might result from the proposed rules. It is estimated that the annual fiscal effect of the proposed rules would be as high as $114.1 million, of which $65.6 million represents lost federal taxes. The remaining $48.5 million in lost revenues would be seen by states and local governments that depend in part of revenues from the development of oil and natural gas fields.

Table 4
Fiscal Impact of Proposed Rules

State	Federal Taxes	State Taxes	Total Taxes
North Dakota	$ (26,243,000)	$ (11,087,000)	$ (37,330,000)
Colorado	$ (7,591,000)	$ (4,964,000)	$ (12,554,000)
New Mexico	$ (5,548,000)	$ (4,771,000)	$ (10,319,000)
Wyoming	$ (3,162,000)	$ (2,272,000)	$ (5,434,000)
Utah	$ (2,130,000)	$ (2,026,000)	$ (4,155,000)
Montana	$ (464,000)	$ (337,000)	$ (800,000)
Nebraska	$ (7,000)	$ (21,000)	$ (28,000)
South Dakota	$ (8,000)	$ (7,000)	$ (15,000)
United States	$ (65,601,000)	$ (48,511,000)	$ (114,112,000)

Conclusions:

28 Based on John Dunham and Associates, *Western Oil & Natural Gas Employs America*, prepared for Western Energy Alliance, 2014, at: www.westernenergyalliance.org/employsamerica

A careful analysis of the facts laid out in the RIA leads to one clear conclusion, and that is that the costs of $1.26 billion annually to the economy far outweigh even the highest end BLM benefit estimate of $384 million.[29] This is based on a price for natural gas of $2.00/Mcf.[30]

This year, natural gas prices have dropped to as low as $1.57 per million BTU and $1.40 Mcf according to the EIA and media sources cited above. Discounting the idea that a reduction in potential methane emissions would have any benefit on the environment that could be monetized[31], a more reasonable calculation of the potential benefit of the proposed rule would be $90 million.

With a cost of $1.26 billion and a potential benefit of just $90 million, this rule does not produce a net social benefit.

In addition to not completing the RIA in accordance with published OMB guidelines, the BLM included a number of assumptions that were on their face either false, or should not have been used as part of this type of analysis. The most glaring problem is the BLM's inflated commodity price estimate which underlies the entire economic benefit claimed. BLM fails to acknowledge that at current commodity prices the oil and natural gas industry is in its biggest bear market in 30 years, and implementing this extremely expensive rule would have a very adverse impact in such a depressed market, and will lead to lost development on federal lands. Additionally, BLM fails to address the fact that the rule in its imposition of a no venting standard would lead to unsafe drilling, completion and storage practices, which is not examined in any real depth in the RIA.

The BLM's failure to conduct a <u>comprehensive</u> alternative analysis was clearly in violation of the OMB guidelines. An alternatives analysis may have shown that the proposals could actually lead to increased and significant economic costs to the oil and gas industry.

Given such flawed analysis and self-reported doubts by the BLM in the RIA, it is very possible that a new analysis would find significantly varied results.

[29] Op. cit. Regulatory Impact Analysis, pages 6-8.

[30] Op. cit. Regulatory Impact Analysis, page 42.

[31] The benefits as laid out by the BLM are also speculative at best as they rely on passage of EPA Subpart OOOOa and rely on certain assumptions that methane gas reductions have a social cost benefit.