



May 30, 2014

Mr. Steven Wells, Division Chief
Fluid Minerals Division
Bureau of Land Management
20 M Street, S.E.
Washington, DC 20003

**Re: Venting & Flaring from Oil and Gas Operations on BLM-Managed Leases
Submitted Electronically to blm_wo_og_comments@blm.gov**

Dear Mr. Wells:

With this letter, API provides its comments to the Bureau of Land Management (“BLM”) in response to BLM’s public outreach on venting and flaring from BLM-managed oil and gas operations.¹ API is a national trade association representing over 600 member companies involved in all aspects of the oil and natural gas industry. API’s members include producers, refiners, suppliers, pipeline operators, and marine transporters, as well as service and supply companies that support all segments of the industry. Many of API’s individual member companies operate or perform work on oil and gas leases on lands administered by BLM.

API and its members are dedicated to environmental protection, while economically developing and supplying energy resources for consumers. We are concerned, however, by several aspects of BLM’s public outreach materials regarding the potential promulgation of redundant, burdensome, and premature requirements on API’s members. BLM should ensure that it regulates within the scope of its authority, integrates its efforts with existing rules and efforts by federal and state authorities with jurisdiction over air quality, and upholds longstanding principles governing the economic operation of oil and gas leases. Moreover, in considering venting and flaring options, BLM should adopt a sufficiently comprehensive view that recognizes and addresses permitting delays and other fundamental challenges that currently preclude the installation of pipelines and infrastructure that could further reduce the need for venting and flaring.

¹ See BLM Venting and Flaring Public Outreach (March 19, 2014) (“BLM Outreach Materials”), *available at* http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/energy/oil_and_gas.Par.72011.File.dat/VFoutreach.pdf.

BLM must act within the scope of its existing authority.

- a. BLM has a statutory mandate to provide for the prevention of waste, conservation of oil and gas resources, and assurance of payment of the proper royalty share to the federal government, but not to regulate methane emissions or air quality.

BLM does not have plenary authority to regulate the venting and flaring of gas on federal leases. Pursuant to the Mineral Leasing Act (“MLA”), 30 U.S.C. §§ 181-287, and the Mineral Leasing Act for Acquired Lands, 30 U.S.C. §§ 351-359, BLM has the authority to ensure conservation of the oil and gas resource, prevent waste, and obtain a fair return to the government, including ensuring that the United States receives proper royalties on production from federal leases. *See* 30 U.S.C. §§ 187, 359. This is the basis of BLM’s authority to regulate venting and flaring of natural gas on BLM-managed leases. *See* United States Geological Survey Conserv. Div. Manual, 644.5.1, .2, Waste Prevention, Beneficial Use (“USGS Division Manual”) (June 23, 1980); Notice to Lessees (“NTL”)-4A “Royalty or Compensation for Oil and Gas Lost” (Jan 1, 1980).²

It is a longstanding principle at common law and under the MLA that a lessee commits “waste” if it vents or flares gas that is otherwise economically recoverable. *See* 30 U.S.C. § 225; USGS Division Manual at 1-3. Accordingly, BLM’s longtime standard has been whether it is economic for the lessee to recover the gas. *See, e.g.*, NTL-4A.³ If not, the loss is considered “unavoidable” and the lessee has no royalty or other obligation with respect to the vented or flared gas. *See id.*; *Texaco, Inc.*, 135 IBLA 112 (1996). BLM has reiterated this key economic principle in prior notices, instruction memoranda, and guidance on venting and flaring. *See, e.g.*, NTL-4A. BLM’s latest outreach materials also acknowledge this concept.

Despite this longstanding and consistent interpretation of the statutory standard for “waste,” BLM is now considering whether to change existing standards for determining whether recovery of gas is economic for a lessee, and hence the definition of “waste.” For example, BLM’s presentation materials suggest the creation of a “clear and rigorous economic test” to address venting and flaring of casing head and associated gases. *See* BLM Outreach Materials at 16. BLM cannot interpret the economic standard in a manner inconsistent with its decades-long interpretation and longstanding accepted usage in the regulated community, which involves an assessment of the actual economic conditions relating to an oil and gas operation on a case-by-case basis. *See* NTL-4A; *Maxus Exploration Co.*, 140 IBLA 124 (1997). BLM must continue to factor in the relatively modest profit margins on individual leases or units onshore, the substantial expense of additional controls, and the lack of available and reasonably foreseeable pipeline capacity, and ensure that BLM does not demand capture that renders operations uneconomic. *See* NTL-4A. Contrary to these obligations, BLM’s listed regulatory options modify the longstanding “economic” recovery standard so that venting and flaring controls would be imposed on a greater number of leases and in situations where no “waste,” as historically defined, is occurring.

Relatedly, though BLM has the authority to regulate lease operations to promote the conservation of gas and minimization of waste, potential regulatory options listed by BLM tread on the well-established notion of economic “waste.” Traditional oil and gas law, and the MLA, last amended significantly in 1987, did not contemplate that all gas would be deemed economically recoverable or that all loss would be avoidable. For example, the MLA requires oil and gas lessees to “use all *reasonable* precautions to

² NTL-4A applies broadly to federal and Indian leases. We assume that the terms of any future rule governing venting and flaring would do the same.

³ NTL-4A and subsequent related administrative materials are available at http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/energy/oil_and_gas.Par.50053.File.dat/NTL4A.pdf.

prevent waste of oil or gas developed in the land.” 30 U.S.C. § 225 (emphasis added). Nor is the total prevention of loss economically feasible today. Accordingly, over decades of implementation, BLM has refrained from defining “waste” too broadly, and it must continue to do so to accommodate economic realities and the continuing development of technologies, infrastructure, and markets. The Administrative Procedure Act prevents BLM from straying too far from its decades-long interpretation of “waste” grounded in the MLA. Analogously, prior to NTL-4A, courts prevented BLM from enforcing NTL-4A in a manner that constituted a departure from settled understandings regarding non-payment of royalty on certain production. *See, e.g., Plains Exploration & Production Co.*, 178 IBLA 327, 332-33 (2010) (discussing federal court decisions rejecting NTL-4A requirement that “lessees . . . pay royalty on all oil and gas produced from a lease or unit, . . . reversing the Department’s prior longstanding view”).

- b. BLM needs to assess the effectiveness of the current NTL-4A, identify potential gaps, and analyze how NTL-4A can be amended to fill those gaps.

Although NTL-4A has not been revised in nearly 35 years, it provides a precedent that implements the intent of “prevention of undue waste” of the natural resource as required by MLA § 187, while obtaining “maximum ultimate economic recovery” of the resource as required by 43 C.F.R. §§ 3160 & 3161.

The requirements of NTL-4A achieve regulation of venting and flaring by identifying circumstances under which venting and flaring are permissible, requiring reporting, documentation, and consultation with the BLM Supervisor, empowering the Supervisor to require installation of additional measuring equipment, and providing that an operator’s failure to comply will result in compliance being secured by such actions as are provided by law and regulation.

API recommends the following approach as an alternative to the proposals to implement controls on drilling and production operations that BLM representatives discussed during the four public outreach sessions held earlier this spring.

Similar to the Conservation Action Plan in NTL-4A, under Onshore Order No. 3 BLM has allowed for the operator’s development of a site security plan to address how the facility will be inspected and maintained, how reports will be submitted, and other requirements for the security of the well site, instead of establishing prescriptive and specific requirements. In a similar manner, and as an alternative, BLM could allow operators to submit a venting and flaring reduction plan that could detail:

- A review of venting and flaring emissions from the area from the EPA’s Greenhouse Gas Reporting Rule effort;
- Mitigation methods used to reduce the highest emissions sources from venting and flaring; and
- Pipeline evaluations for areas where gas pipelines currently do not exist, including whether or not, and if so when, pipelines are technically, economically, and otherwise feasible.

Such a plan would allow companies to address the highest volume sources of venting and flaring. Operators could determine the most practicable method to reduce venting and flaring appropriate to, and effective for, particular operations. Operators could include EPA and state requirements that are already required as part of their mitigation methods.

- c. The authority to regulate air quality resides exclusively with EPA, states, and Tribes.

BLM cannot promulgate new venting and flaring rules premised on the protection or regulation of air quality. As noted above, BLM’s administration of oil and gas leases is limited to oil and gas resource conservation, waste prevention, and fair economic return to the government. By contrast, the regulation of air quality is solely within the purview of EPA and EPA-authorized state or tribal programs under the

authority granted by Congress in the Clean Air Act (“CAA”), 42 U.S.C. §§ 7401-7671q. *See, e.g.*, 42 U.S.C. § 7410 (providing for State Implementation Plans (“SIPs”) for the attainment and maintenance of established National Ambient Air Quality Standards (“NAAQS”).⁴

The CAA is not fashioned like some environmental statutes where Congress vests authority in the President and leaves to the President the task of delegating responsibilities to implementing agencies. *See, e.g.*, Comprehensive Environmental Response, Compensation, and Liability Act of 1980, 42 U.S.C. §§ 9601-9675; Oil Pollution Act of 1990, 33 U.S.C. §§ 2701-2761. In the case of the CAA, Congress vested program authority in the EPA Administrator and the states. Any exceptions to this general rule are clearly called out and limited. *See, e.g.*, H. Rep. No. 95-1474, at 86 (1978) (explaining that Section 8(a) of the Outer Continental Shelf Lands Act (“OCSLA”) was intended to grant jurisdiction over Outer Continental Shelf (“OCS”) air emissions to DOI, but expressly disclaiming an intent to disturb the responsibilities of the EPA over onshore air quality under the CAA); S. Rep. No. 101-228, at 78 (1989) (explaining that Section 328 of the CAA, which transferred authority over OCS air regulation from the DOI to EPA, was intended to “supersede” section 8(a) of OCSLA for regulating OCS emissions to ensure consistent implementation of air quality laws and regulations); Consolidated Appropriations Act, 2012, H.R. 2055, Pub. L. No. 112-74 (expressly transferring authority over OCS air emissions offshore of the North Slope Borough of Alaska from EPA back to DOI, exempting offshore operators from EPA’s emissions permit requirements). Apart from these limited and explicit exceptions, Congress’ residual expectation of agencies other than EPA was certain: to follow EPA’s lead and direction “to the same extent as any nongovernmental entity.” 42 U.S.C. § 7418.

Neither the CAA nor any other superseding statute grants BLM the authority to regulate air quality and emissions. This omission is both conspicuous and plain in its import: that authority resides exclusively with EPA and the states and tribes. Any attempt by BLM to regulate in this arena would contravene clear Congressional intent.

Congress’ choice not to give BLM this authority is not surprising in view of the fact that BLM lacks the capacity – both technically and legally – to administer an expansive onshore air pollution control program. Air quality protection is neither BLM’s mission nor an area of BLM technical strength. Moreover, as discussed above, BLM is constrained by its long-standing and well-considered views regarding economic natural gas recovery and waste. In view of these constraints, as well as EPA’s technical depth in this area, Congress rationally looked to EPA – and not to BLM – to regulate emissions and air quality on BLM-managed lands. BLM must respect that choice.

d. Exceeding its authority creates risks that BLM is duplicating regulatory action.

Onerous new BLM venting and flaring requirements would duplicate and may even conflict with existing EPA or state rules. The MLA prohibits BLM from promulgating regulations “in conflict with the laws of the State in which the leased property is situated.” 30 U.S.C. § 187. As BLM recognizes in its public outreach presentation, “EPA NSPS require new actions to minimize venting and flaring.” BLM Outreach Materials at 23. Many state environmental agencies also impose their own independently enforceable requirements for minimizing venting and flaring. These existing federal and state requirements will continue to minimize emissions and maximize capture as they are implemented across existing and new leases – the very issues BLM seeks to address in its new planned rule.

⁴ *See also* EPA Order 1110.2 (Dec. 4, 1970) (making EPA’s Air Pollution Control Office responsible for “the conduct of programs for the definition, prevention, and control of air pollution,” and developing a “systematic Federal-state-local regulatory program for stationary source emissions supported by research and development activities, combined with Federal-state-local air quality monitoring, Federal grants to air pollution control agencies, technical assistance, and manpower training”).

Existing rules already impose significant economic and operational burdens on lessees. At best, the anticipated new rule runs the risk of imposing an additional layer of regulatory burden without meaningful benefits; at worst, the rule could lead to contradictory requirements or interpretations among the multiple agencies involved. That is a reason to defer to EPA and states, rather than a “reason for considering the various options” for BLM action as suggested in BLM’s outreach materials. *Id.* at 3.

BLM should also consider how its new rule would interact with other aspects of the President’s methane strategy, particularly EPA’s consideration of directly regulating methane as a greenhouse gas. EPA is still in the fact-finding phase, with the April 2014 release of several white papers for peer review and public comment. Any EPA final methane rule is not due until 2016. *See* White House, *Climate Action Plan Strategy to Reduce Methane Emissions* (March 2014). Given the inchoate state of EPA’s science and technology review, any BLM prescription of specific steps to reduce gas (and thus methane) emissions would be premature.

- e. Amending long-established standards could unlawfully deprive current lessees of valid existing rights.

BLM must consider that agency actions may not deprive operators of valid existing lease rights. For existing leases, any BLM option that would render uneconomic an operation that otherwise would be economic under existing standards could result in an unconstitutional taking of private property rights. Onshore oil and gas leases confer recognized development rights (hence the relatively greater scope of NEPA review required for onshore leasing decisions than for offshore leasing decisions). *See Conner v. Burford*, 848 F.2d 1441, 1449-51 (9th Cir. 1988); *Sierra Club v. Peterson*, 717 F.2d 1409, 1411, 1414-15 (D.C. Cir. 1983). BLM may subsequently impose reasonable conditions on the lessee’s development rights, but cannot change the standards in effect when the lease was issued and render development economically infeasible. *See, e.g., Conner*, 848 F.2d at 1449-51. If new BLM venting and flaring requirements render operations on existing leases uneconomic, those lessees may have takings claims against the United States for significant compensation. *See Century Exploration New Orleans, Inc. v. United States*, 103 Fed. Cl. 70 (Jan. 24, 2012); *Devon Energy Corp. v. United States*, 45 Fed. Cl. 519 (Dec. 21, 1999). While BLM may have greater latitude to impose more restrictions on leases issued after adoption of a new rule since lessees would be taking their leases with notice of any new requirements, such restrictions may lessen interest in leasing of federal lands and could reduce bonus bids in future lease sales.

Additionally, every oil and gas lease is an enforceable contract between BLM and the lessee, and is subject to all of the same legal constraints as a private contract. *See, e.g., Mobil Oil Exploration & Producing Southeast, Inc. v. United States*, 530 U.S. 604 (2000); *Century Exploration New Orleans, LLC v. United States*, 110 Fed. Cl. 148, 163 (2013); *Amber Res. Co. v. United States*, 68 Fed. Cl. 535 (2005), *aff’d*, 538 F.3d 1358 (Fed. Cir. 2008). For the reasons described above for takings, existing lessees may have an alternate claim that BLM breached the lease contracts by taking action that prevented the lessees from enjoying the benefits of their existing leases. *See Amber Res. Co. v. United States*, 87 Fed. Cl. 16 (2009); *see also* Sec. 701(h) of Pub. L. 94-579 (Oct. 21, 1976) (Federal Land Policy and Management Act enabling statute) (“All actions by the Secretary concerned under this Act shall be subject to valid existing rights.”).

BLM should not impose rules that would render production operations uneconomic, thus depriving the federal government of royalty revenue. By processing permits for pipeline rights-of-way and construction in a more timely manner, BLM could optimally reduce venting and flaring.

As noted above, BLM has a longstanding “economic” recovery standard that is also referenced in NTL-4A:

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

BLM should not impose rules that would render operations uneconomic, in particular taking into account the relatively modest profit margins on individual leases, the substantial expense of additional controls, and the lack of available and reasonably foreseeable pipeline capacity that currently exists in many areas where operators produce oil or natural gas from leases administered by the BLM. For example, any insistence on closer audits or re-verifications could result in substantial time delays and additional expense which could reduce or eliminate the economic value of the lease. Similarly, the application of a new economic “test” would increase the burden on BLM employees tasked with reviewing detailed economic information for each individual lease, increasing costs and potentially adding another layer of bureaucracy to the lease administration process.

The presence or absence of pipeline infrastructure significantly affects the timing of production and an operator’s decision whether to seek approval to vent or flare natural gas associated with crude oil production. The BLM proposals to capture nearly all methane emissions from production operations appear to assume it is as simple as laying a pipeline or installing a small compressor, but this is not the case. Collection and treatment of methane or natural gas production generally involves midstream companies which seek permits for and install gathering lines to collect, separate (e.g., hydrocarbon liquids and produced water), treat (e.g., removal of CO₂, H₂S and other impurities), and compress gas to meet transportation pipeline specifications for the sale of such gas. In addition to the remoteness of leases with oil and gas production or their distance from existing pipeline infrastructure, the timing and sequence of pipeline projects to deliver production from such leases can be affected by operational concerns such as the gathering pipeline’s operating pressure, pressure of the gas source (e.g., the wellhead pressure, the high and/or low-pressure separator pressure, and pressure of tank vapors typically at ounces), and volumes/quality of total gas in the area to justify the economics of gathering and transportation pipeline location(s). Existing gas plants and gathering systems in legacy areas may be at or near capacity, and completion of a distribution system may therefore require construction of a new gas plant(s) as well as new pipelines. Finally, delays that may be experienced in the process of securing permits to install gas pipelines for gathering or for transmission can delay pipeline hook-ups to producing wells, resulting in additional flaring and in deferral of revenue both for the operator and for the federal government or other royalty owner.

In some circumstances, venting and flaring on federal and Indian lands may occur more often or at higher volumes than on adjacent private and state lands because of the delay from the federal government in approving rights-of-way for gas gathering lines over these lands. The North Dakota Petroleum Council Flaring Task Force estimates that 40% of natural gas production is flared at oil wells on the Fort Berthold Indian Reservation, versus 27% on state and private land. Rather than promulgating new regulations, BLM could make a significant difference in quickly capturing methane from new oil wells by simply processing permits for pipeline rights-of-way and construction in a more timely manner.

EPA and the states regulate emissions for the benefit of public health and the environment. There is no need for BLM to develop additional regulations to address methane.

With respect to addressing emissions from exploration and production operations for oil and natural gas, EPA and states have exercised their jurisdiction over environmental protection of air, water and waste

resources. Regulations developed under these authorities apply to operations within BLM's geographical boundaries and jurisdiction; thus, there is no need for BLM to develop regulations concerning environmental impacts as would be suggested by the information that has been shared by BLM in the recent public forums on the subject of venting and flaring. For example, in the presentation offered at the public forums, BLM discussed best available control technology ("BACT"), which has a specific definition in air quality rules and requires analysis of the public health and environmental benefits along with economic costs. As noted above, regulation of emissions for the benefit of public health and the environment falls within the purview of EPA and state programs, typically under the authority granted by Congress in the CAA. EPA's New Source Performance Standards for oil and natural gas ("NSPS OOOO") already require further reductions in methane emissions along with reductions in volatile organic compounds ("VOCs"). Operators must comply with these rules on BLM-managed lands, and there is considerable risk of duplicative regulation if BLM adds its own requirements that may conflict or be redundant with existing EPA rules and state requirements such as NSPS OOOO. As also noted above, BLM is prohibited from developing provisions which "conflict with the laws of the State in which the leased property is situated." 30 U.S.C § 187.

Even if BLM had the requisite authority to regulate directly on the basis of environmental protection, there would be no need for BLM to exercise such authority since both EPA and the states are charged with this responsibility and are currently re-analyzing the need for additional environmental protection measures in conjunction with venting and flaring. For BLM to divert its attention and the efforts of its staff professionals to address emissions from exploration and production operations as an environmental matter would represent a duplication of effort. In addition, such efforts would be particularly troubling since BLM lacks EPA's authority to consider minimum standards and environmental benefits required by the CAA to economically justify new controls in other arenas.

The operators of BLM-managed leases must comply with the requirements of the CAA; thus, there is no gap that BLM needs to fill, as explained above. EPA is actively pursuing emission controls for the oil and gas industry. The NSPS provisions in Subpart OOOO were proposed in August 2011, were finalized in September 2012, and have already added emission control requirements for oil and gas operations where sufficient information is available to demonstrate that such controls are economic considering the benefit of VOC reductions. The continuing efforts to revise NSPS OOOO have been ongoing since the Second Quarter of 2010, are expected to continue into 2015, and have required substantial resources and expertise by both EPA and the regulated community.

Methane reductions are co-benefits of these VOC emission reductions. EPA is developing white papers to inform the policy discussion on whether additional emission controls are justified to further reduce methane emissions below the level already obtained by the current NSPS OOOO. As stated above, many of the emission controls BLM is considering either (1) are already required by NSPS OOOO, or (2) have been considered and rejected because of either insufficient data or lack of economic benefit (as determined by EPA with reference to statutory authority BLM does not possess). BLM must take into consideration the operational complexities and, subsequently, the difficulties and inherent inflexibility associated with attempting a "one-size-fits-all" approach to mitigating emissions from the sources identified within the public forum presentation. The attachment to this letter describes source-specific issues of concern in response to BLM's request for comment on the public outreach materials concerning the various sources and options being considered.

Environmental protection measures for existing facilities have diminished marginal value in terms of controlling emissions relative to those installed on new facilities due to the following:

- a. The CAA has provided environmental protection since the early 1970s. When a new protection measure is added, any equipment installed subsequent to such additional protection measure

being in place is considered “new” and must comply with the new CAA air quality protection measure.

- b. Oil and gas well production begins to deplete (i.e., the production rate begins to decline) immediately when placed in service. As a result, emissions from storage vessels are primarily dependent on the production rate. Therefore, if the production rate decreases 50%, these emissions will generally decrease proportionately (i.e., roughly 50%, as well).
- c. Existing facilities that predate emission control standards are unlikely to be economically controlled even considering environmental benefits. In BLM’s case, adding controls may make production uneconomic resulting in the plugging and abandonment of the well and an overall shorter life of the well.
- d. Under the CAA, States are required to create SIPs that (1) protect areas that meet the NAAQS (a.k.a. “attainment areas”) and (2) contain the measures necessary (such as emission controls and offsets) in order to bring areas that do not meet the NAAQS (nonattainment) into attainment.
- e. As part of their SIP to protect attainment areas, most states with oil and gas production require operators to meet emission threshold levels to qualify for permit exemptions or obtain permits for these small sources (a.k.a. minor new source review (“NSR”). Some states also have rules similar to NSPS, but with additional stringency (i.e., Colorado Reg. 7). These rules are reviewed frequently to assure that air quality and public concerns are met.
- f. SIPs for nonattainment areas are more stringent and cover new and existing facilities, and regulations for new facilities do not have the same type of economic constraints that other regulations must consider. Criteria for stringency are entirely based on the level necessary to bring the area into attainment with the NAAQS. The NAAQS are reviewed every 5 years and is typically revised to a more stringent standard in an effort to improve air quality. The ozone NAAQS level is currently under review, and a lower standard is being considered by EPA. The deadline for the new proposal is December 1, 2014, with a final rule by October 1, 2015.

The regulatory structure described above is adequate justification to defer BLM’s consideration of any type of command and control regulatory structure to reduce emissions. This type of regulation already exists and reductions in emissions are being achieved. If BLM decides to move forward with additional requirements, then, at a minimum, the agency should not do so at least until current efforts by EPA (including NSPS, Subpart OOOO, methane white papers, ozone NAAQS review, and the oil and gas emission estimate tool) and state rulemaking efforts (including NAAQS SIP revisions) are completed. The completion of the following efforts, pending significant modification following industry feedback to improve each, will allow the BLM rulemaking to be better informed on both its scope and necessity:

- a. The proposed development of the oil and gas emissions tool which was requested by EPA’s Office of Inspector General as a result of the existing National Emissions Inventory and greenhouse gas data having known inaccuracies
- b. The EPA’s finalization of and responses to comments on multiple methane white papers which review the current knowledge and identify knowledge gaps concerning the regulation of the same sources BLM is considering, and
- c. Potential Subpart OOOO amendments which will include economic assessments of control options, if additional controls, which could achieve further methane reductions as a co-benefit, are recommended;

Additionally, allowing this effort to progress will result in the following

- a. Prevent duplication and likely conflicts with the new regulations resulting in the obligation to revise conflicts (*see* 30 U.S.C § 187);
- b. Likely eliminate the need for BLM to revise their requirements (since the EPA and state requirements will most likely be sufficient); and

- c. Overall, provide more efficient and effective use of federal resources due to elimination of overlapping regulatory processes.

Thank you for considering these comments. API or its members may supplement these comments as BLM's process progresses.

Very truly yours,

A handwritten signature in black ink that reads "Richard Ranger". The signature is written in a cursive, flowing style with a large initial "R".

Richard Ranger
American Petroleum Institute

Attachment – Source-Specific Comments

BLM must take into consideration the operational complexities and, subsequently, the difficulties and inherent inflexibility associated with attempting a “one-size-fits-all” approach to mitigating emissions from the sources identified within the public forum presentation.

Well Completions

There are important differences between oil wells and gas wells that make oil well reduced emissions completions (RECs) infeasible in many situations. Two key operating requirements that have the most impact on the feasibility of a doing an REC on an oil well are:

- A field-wide gas gathering system with sufficient capacity to handle the initial gas production surge must be in place.
- The oil reservoir must have sufficient pressure and a sufficient volume of associated gas.

A REC is not possible for any hydraulically-fractured oil well that does not meet *both* of these conditions. And, in many cases, flaring is not feasible if the reservoir yields insufficient gas to either operate a separator or operate a combustion device.

Before natural gas production can be sent to a natural gas gathering line, all of following must be done:

- A natural gas gathering line/system must be permitted, installed and operational in the area.
- A contractual right to flow into the gas gathering system with the company that owns the gathering line must exist.
- Acquire necessary permits and right(s)-of-way for the pipeline from the well site to the natural gas gathering system.
- There must be a gas plant to receive the gas for processing.
- The natural gas must meet the specifications of the natural gas gathering line, which often requires treatment (e.g., dehydration and removal of other impurities).
- There must be adequate reservoir pressure to overcome the natural gas gathering line pressure and flow with sufficient velocity to clean up the well and avoid reservoir damage.
- The natural gas gathering line must be operational at the time of the completion.

Furthermore, there are many reasons to complete a well and flow it back *without* a natural gas gathering line or production equipment in place, including, but not limited to:

- Avoiding lease jeopardy by establishing production in paying quantities.
- Excessive waiting time for the necessary permits for installing the pipeline or the production equipment.
- Not yet having all the surface rights secured for installing production equipment.

When each stage of a stimulation program is initially completed, the pressure of the gas may not be sufficient to overcome pipeline pressure and maintain adequate velocity to clean-up the well and reservoir. When this occurs, the well must be flared or vented until enough flowing pressure is available to send gas to the sales pipeline (i.e., the flowing pressure exceeds the pipeline pressure of the system to which it is routed/to enter). This allows clean-up of the well bore and is critical to minimize the potential for formation damage and, therefore, the long-term recoverable reserves from the reservoir. It is possible that sensitive zones can lose productivity due to increased clean-up time required if the line pressure creates a “backpressure” which the well must overcome. Once fracture stimulation is performed,

flowback and clean-up must proceed regardless of whether or not sufficient pressure exists to enable sales; otherwise, severe and permanent reservoir damage is likely, effectively reducing the overall recoverable reserves from the well. Adding compression to overcome line pressure on low energy wells has been attempted several times and found to be infeasible for technical reasons. Furthermore, it adds additional air emissions from the engines used to power the compressors while greatly increasing the cost.

Many oil reservoirs have pressure that is insufficient for wells to naturally flow on their own even after hydraulic fracturing, or they have insufficient pressure to overcome the backpressure of the gas gathering system. This can be evidenced by the prevalence of artificial lift such as rod pumps and the associated pump jacks that are visible across the landscape of many oil producing areas. Also, many reservoirs produce insufficient gas volumes to operate a separator during flowback, which makes both REC and flaring infeasible. Examples of this include reservoirs in the Permian basin in which horizontal drilling is used to extend the life of existing producing formations. Other examples include reservoirs in the north central East Texas basin which produce heavy black oil, also called “dead oil” because there is no associated gas produced with the oil. In this area, gas to operate separation equipment must be purchased as it is not available from well production.

In the Permian Basin of West Texas, many oil wells that are hydraulically fractured do not have sufficient reservoir pressure to flow back on their own, and there is insufficient gas to flare. Instead, following a hydraulic fracture, rod pumps are installed on the wells to artificially lift the fracture fluids where they are routed either to frac tanks or storage vessels. No flowback separators are installed since there is insufficient gas to operate them.

Like gas wells, oil well candidates for REC must be capable of flowing on their own even against the backpressure of the gathering system. Where new plays, such as oil shale plays, meet these criteria RECs are already being practiced where feasible and gas infrastructure exists. For instance, in the Eagle Ford shale in south Texas, RECs are already being conducted where both the required parameters of infrastructure and high reservoir pressure are present. Gas gathering infrastructure is in place for much of the area (due to previous production from non-shale/conventional wells), and sufficient reservoir pressure and gas volumes exist to make a REC feasible.

Reservoirs characterized by the prevalence of artificial lift systems are not good candidates for REC, and flaring is dependent on sufficient gas being present to be separated and combusted.

Where a REC is not feasible, flaring or combusting associated gas that can be separated from the liquids is still the only and best technology to reduce emissions when sufficient gas volumes exist. In certain situations, operators may use a Joule-Thomson skid-mounted processing plant to collect natural gas liquids from stranded gas, but, while this may reduce VOC emissions, flaring is still necessary to control gas emissions.

Only wells with sufficient reservoir pressure to flow against the gathering system backpressure and capable of producing saleable quantities of natural gas are candidates for REC. Without a gas gathering system, flaring is still the next best option to control gas emissions during flowback assuming the gas can be separated from the liquids. While high-pressured oil shales are in the public focus, hydraulic fracturing also occurs in many low-pressure formations that rely on artificial lift to assist flow. These wells are not good candidates for REC. When REC is not feasible, flaring during flowback is the next best option, provided sufficient gas is available.

EPA is currently undergoing an effort, through the development and expert review of white papers, to inform how best to address emissions from these various sources including oil well completions. As

such, BLM should refrain from further regulation of oil well completions until the EPA has completed that effort.

Liquids Unloading

Deliquification of gas wells is a highly complex and technical subject with many approaches and technologies in use. Venting of wells is one technique that is often used in combination with other techniques that depend on reservoir pressure (e.g., plunger lifts) used to assist unloading. Liquid loading of well bores occurs when the gas production rate (velocity) up the well bore is not sufficient to carry liquids up the well bore. When a vertical liquid column builds up in the well bore, the weight of the column (i.e., its hydrostatic head) puts back-pressure on the producing formation, and the production rate declines to the point where the well can no longer flow. Low-rate wells are either impaired by liquids accumulation or are using some deliquification method in order to produce. As the reservoir energy depletes and the production rate declines, a well will reach the stage where liquid-loading begins to be a problem, and one of a portfolio of technologies or techniques will become necessary to help lift liquids using the reservoir's energy. As a well continues to produce and the reservoir energy declines further, a well will reach the stage where the reservoir's energy is insufficient to lift liquids, and artificial lift energy, in the form of pumps, gas lift, etc., will have to be added to continue producing. When the expected production from a well cannot support the investment required to enable deliquification, it will reach the end of its economic life.

The production rate of a well, consequential velocity up the well bore (also determined by the diameter of the production string), and, hence, the ability to lift liquids, is mostly a function of the differential pressure between the reservoir and the flow-line/collection system and the reservoir's sensitivity to backpressure. In order to flow, the total reservoir pressure must be greater than the total resistance to flow. This resistance is comprised of (1) fluid friction and fluid interference across the reservoir, (2) the flowing friction up the well bore, (3) the weight of the vertical fluid column in the well-bore, (4) surface equipment and piping pressure losses, and (5) the collection system/flow-line back-pressure. Opening a well bore to atmospheric pressure removes the effect of the surface equipment/piping pressure loss and the backpressure from the collection line, thus increasing the differential pressure available to increase flow rates and velocities, which may enable the well to lift the liquid from the wellbore (unload the well) "on its own." Venting of wells is a common practice in low-rate gas well deliquification and is not restricted to wells without deliquification assist technologies (i.e., it may be used on wells with deliquification assistance such as plunger lifts).

There are various reservoir-driven techniques operators use in wells experiencing liquids loading to assist in deliquification, which also helps reduce the need/occasions for venting. Each of these techniques may be the *best* solution, but only during a particular phase of the life of a reservoir. There are several misconceptions related to the "best technique." For example, it is a misconception that plunger-lift systems are the single or best emission control action for wells where venting for liquids unloading occurs. This misconception is further exacerbated by a lack of understanding (even among those purporting plunger lift systems as *the* solution to liquids unloading) of liquids loading and/or plunger lift systems and their appropriate uses, limitations, and efficacy. Plungers work by providing a mechanical barrier between a small volume of water and the gas that is used to transport it up the well bore. The mechanical barrier isolates the gas from the liquids, prevents gas from moving up through the liquids, hence making better use of the gas energy, and helps prevent liquids from falling back into the well bore. If the gas could flow faster, then that mechanical barrier would not be necessary or helpful. Plunger capacity is limited by well depth, differential between reservoir pressure/surface pressure, and the gas/liquid ratio that the well produces. Even plunger-lifted wells reach a point where they lack the reservoir pressure to run a plunger against backpressure with adequate frequency to lift the liquids present. At that point, the operator has the choice of replacing the plunger with a lift method that adds

energy to the system or plugging the well. Operators analyze these wells and have to make the decision to spend capital and operating expense on a pump versus drilling a new well.

Based on available estimates of emissions attributable to liquids unloading, wells with plunger lifts are responsible for more emissions per venting well than wells without plunger lifts. Wells with plunger lifts account for around 70% of emissions attributed to liquids unloading but only represent about 36% of the gas well population. Quite simply, considering plunger lifts to be a venting/emission control technology is not supported by fact or the data. The following table illustrates this dichotomy between assertion and fact.

Well Venting for Liquid Unloading Methane Emission Estimates							
Name	Methane MT's	Total # of Venting Wells	# Venting With Plunger Lift	# Venting Without Plunger Lift	MT's per year per Venting Well	MT's per Venting Well per year with Plunger	MT's per Venting Well per year w/o Plunger
Greenhouse Gas Reporting Program - 2012	276,378	58,663	32,448	26,215	4.711	6.158	2.959
U.S. Inventory of Greenhouse Gas Sources and Sinks - 2013 (2011 Emission Year)	258,667	60,810	23,503	37,307	4.254	4.618	4.024
API/ANGA Report - 2011 data	319,664	65,669	36,806	28,863	4.868	5.207	4.584
UT/EDF Phase 1 Study	162,619			35,828	4.539	not measured	4.539
ICF/EDF Report	277,307	75,399	44,286	31,113	3.678	4.430	2.607
<p>Note: With the exception of the UT/EDF Phase 1 Study this table is U.S. Totals</p> <p>Note 2: The UT/EDF Phase 1 results should be viewed with an abundance of caution. Only 9 well venting instances, all without plunger lift, were measured which is much too small of a population to extrapolate to a national or even sub-national level. Also, the supplemental information for this study indicates that venting may have been triggered on at least some of the wells measured solely to enable measurement. If this is correct, the wells were not liquid loaded, the flow volumes and dynamics would be very different from a liquid loaded well, flow would likely exceed normal production flow of the well, and flow would not be representative of an actual venting to assist unloading.</p> <p>Note 3: The different data sources/studies used different methane concentrations to arrive at methane emission estimates. See the individual studies for information on methane content that was used.</p>							

Although plungers are among the most common tools used in middle-stage deliquification, there is a misconception that plungers eliminate the need to vent to atmosphere. In many cases, wells equipped with plunger lifts are vented to atmosphere to generate the differential pressure necessary to lift the plunger and liquid column up the well bore. While this can be controlled and minimized, it *cannot* be eliminated.

EPA is currently undergoing an effort, through the development and expert review of white papers, to inform how best to address emissions from these sources including liquids unloading. As such, BLM should refrain from further regulation of liquids unloading until the EPA has completed that effort.

Casing Head and Associated Gas

The issues of casing head gas venting/flaring and flaring/venting of associated gas where infrastructure is not present are two very distinct issues. The issue of “stranded gas” is simply lack of infrastructure that provides an outlet for gas while venting of casing head gas is predominately an economic issue related to low-volume/low-pressure gas recovery.

Gas that is produced from an oil well that cannot be sold due to the fact that the pipeline infrastructure needed to gather and transport the gas for processing is not available is known as “stranded” gas. Unlike gas fields, where infrastructure may be unavailable in *only limited* situations such as exploration, delineation, or some leasehold wells, gas gathering infrastructure can be unavailable for oil wells across *an entire field or area*. Lack of available infrastructure occurs for various reasons. For instance, associated gas production volumes may be insufficient to make gathering, processing, and ultimately selling the produced gas economic. Or, economic gas gathering infrastructure construction may lag behind the start of new well production, as currently occurs in the Bakken oil shale formation of the Williston Basin in North Dakota. During flowback and continuing into production, stranded gas from high-pressure wells such as those in the Bakken is flared for reasons of both safety and VOC emissions reduction. Without a gas gathering infrastructure, an oil well REC is not possible. If stranded gas were not allowed to be flared, these oil wells would have to be shut-in/be unable to produce.

Before natural gas production can be sent to a natural gas gathering line, all of following must be done, as discussed in the oil-well completions section:

- A natural gas gathering line/system must be permitted, installed and operational in the area.
- A contractual right to flow into the gas gathering system with the company that owns the gathering line must exist.
- Acquire necessary permits and right(s)-of-way for the pipeline from the well site to the natural gas gathering system.
- There must be a gas plant to receive the gas for processing.
- The natural gas must meet the specifications of the natural gas gathering line, which often requires treatment (e.g., dehydration and removal of other impurities).

Venting of casing head gas is practiced in some areas to remove annular pressure from oil wells that are being pumped and increase the flow of oil from the formation to the well-bore. Recovery or flaring of this gas is predominantly an economic challenge rather than a lack of infrastructure although there may be some overlap. Casing head gas vents are typically near atmospheric pressure and recovery requires installation of a very low pressure collection system routed to a VRU type compressor which then discharges to either a low pressure gas system or the suction side of a larger gas compressor. Recovery is rarely economic for these very low volumes of gas. Flaring of casing head gas rather than venting requires the same low pressure collection system to either maintain sufficient back pressure against the casing to enable operation of a flare/combustion device or a VRU style compressor discharging to flare. Such an installation is never economic. Prohibiting venting of casing head gas will decrease oil production in many marginal wells and may render them uneconomic to continue production. EPA is currently undergoing an effort, through the development and expert review of white papers, to inform how best to address emissions from these sources including casing head and associated gas. As such, BLM should refrain from further regulation of this source until the EPA has completed that effort.

Combustion Efficiency Standard

Setting a numeric combustion efficiency standard for flaring during flowback is technically infeasible and impractical. During flowback, liquids are mixed with the gas stream, even during separation, which will prevent a specific combustion efficiency from being achieved. As such, EPA did not include combustion efficiency requirements in the flowback control requirement of NSPS OOOO (40 CFR 60, Subpart OOOO). Section 60.5375(a)(3) contains the following requirement:

You must capture and direct flowback emissions to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.

In the preamble to the proposed NSPS OOOO⁵ EPA further explained:

We believe that, based on the analysis above, REC in combination with combustion is BSER for subcategory 1 wells. We considered setting a numerical performance standard for subcategory 1 wells. However, it is not practicable to measure the emissions during pit flaring or venting because the gas is discharged over the pit along with water and sand in multiphase slug flow. Therefore, we believe it is not feasible to set a numerical performance standard. Pursuant to section 111(h)(2) of the CAA, we are proposing an operational standard for subcategory 1 wells that would require a combination of REC and pit flaring to minimize venting of gas and condensate vapors to the atmosphere, with provisions for venting in lieu of pit flaring for situations in which pit flaring would present safety hazards or for periods when the flowback gas is noncombustible due to high concentrations of nitrogen or CO₂. The proposed operational standard would be accompanied by requirements for documentation of the overall duration of the completion event, duration of recovery using REC, duration of combustion, duration of venting, and specific reasons for venting in lieu of combustion.

Installation of a gas-gathering line in an oil field requires more than an economic analysis to determine whether to install it or not. It requires a gas-gathering system with sufficient capacity be in place, sufficient reservoir pressure, and a sufficient volume of gas. Regulations must accommodate for such realities and cannot be based solely on an economic analysis.

Storage Vessel/Tank Emissions

EPA already requires new, modified, or reconstructed storage vessels with greater than 6 tons per year (TPY) of VOC emissions to be controlled by 95% (including capture and destruction efficiency). Most of the states have adopted these rules or even stricter requirements for storage vessels. Existing tanks have lower emissions due to the decline in production that occurs over time, and very few existing tanks will exceed emissions of even 6 TPY. Controls below the 6 TPY threshold were determined not to be cost effective for *new* storage vessels, and retrofitting *existing* tanks with controls would cost far more. As such, BLM should refrain from control requirements for storage vessels.

⁵ 76 Fed. Reg. 52,758 (Aug. 23, 2011).

Pneumatic Devices

BLM must be clear on the type of controllers that they are reviewing/considering. The presentation mentions neither the type(s) of controller nor the service of such controller(s). From an emissions perspective, pneumatic controllers that emit can be classified by a combination of their design type and the type of service they perform. The two types of controllers are: “continuous-bleed” and “intermittent-vent.” The two types of service are: “on/off” and “throttling.”

Combining the type and service yields the following matrix:

		Type of Service	
		On/Off	Throttling
Type of Controller	Intermittent	Vents on de-actuation with emissions near zero between de-actuation cycles	Vents some gas pressure when valve needs to move towards closed
	Continuous	Bleeds continuously, rate slows while process is “on”, but average rate is ~constant	Bleeds continuously, rate varies with actuation, but average rate is ~constant

Types: As stated above, the two types of controllers are “continuous-bleed” controllers and “intermittent-vent” controllers. Continuous-bleed controllers are designed to bleed gas to the atmosphere on a continuous basis and send a pressure signal to an end device (valve with actuator) by fully or partially blocking the bleed port. Intermittent-vent controllers are typically designed with a small 3-way valve (pilot) that sends a pressure signal to an end device on demand and vents actuation gas to reverse the action on demand. Between actuation/de-actuation cycles intermittent-vent controllers are designed for near zero emissions.

Service: As stated above, the two types of service under which pneumatic controllers operate are “on/off” and “throttling.” The defining characteristic of an on/off controller is that the controller is not required to hold an end-device in an intermediate position (i.e., at the end of a control cycle the control-gas pressure to the end-device goes to zero). The defining characteristic of a throttling controller is that the controller is required to control an end-device in an intermediate position (i.e., the control-gas pressure to the end device is maintained at a pressure between atmospheric and supply pressure).

As shown in the table, both continuous-bleed or intermittent-vent controllers can be either *snap-acting* or *proportional*. However, snap-acting or proportional action is not a defining function of a controller for the purposes of determining emissions.

EPA has defined high-bleed pneumatic controllers in NSPS OOOO and the Greenhouse Gas Mandatory Reporting Rule Subpart W to be those that vent greater than or equal to 6 scf/hr. Continuous low-bleed pneumatic controllers and intermittent pneumatic controllers emit less than 6 scf/hr of gas.

EPA, within NSPS OOOO, already requires that any continuous-bleed pneumatic devices constructed, modified, or reconstructed after 10/15/2013 have a bleed rate of ≤ 6 scfh from the well head to the gas plant and a bleed rate of 0 scfh at the gas plant (achieved by using instrument air). Based on the definition of reconstructed, most existing high-bleed pneumatic devices will be phased out over time.

Sometimes high-bleed pneumatic devices are required due to the response time, safety, or positive actuation as discussed above. In order to modify a high-bleed device to function as a low-bleed device, the pilot orifice must be reduced which reduces the rate that gas is available to actuate the device. With a smaller orifice, however, plugging will be a major concern as will controller response time. EPA provides allowance for the use of high-bleed pneumatic devices under NSPS OOOO under 60.5390(a):

(a) The requirements of paragraph (b) or (c) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than 6 standard cubic feet per hour is required based on functional needs, including but not limited to response time, safety and positive actuation.

EPA is currently undergoing an effort, through the development and expert review of white papers, to inform how best to address emissions from these sources including pneumatic devices. As such, BLM should refrain from further regulation of pneumatics until the EPA has completed that effort.

Leak Detection and Repair (LDAR)

Defining what a leak *is* and *is not* must be done carefully for any regulation. Examples of what should be considered “leaks” include those VOC/methane emissions from:

- Equipment components traditionally included in the LDAR program as prescribed in the NSPS and NESHAP regulations, such as, valves, connectors, pump seals, sampling connections, compressor seals, pressure relief devices, and open-ended lines. Leaks from such components are typically caused by the failure of a seal, gasket, packing, O-ring, etc., due to normal wear, improper installation, improper maintenance, or other reasons.
- Thief hatch seals on an oil/condensate/produced water storage tank that are found leaking, *if* the tank is connected to a control device via a closed vent system.

Examples of what should not be considered “leaks” include VOC/methane emitted from:

- All cases where a piece of equipment is operating properly and as designed, such as:
 - Pneumatic devices;
 - Thief hatches and vents on oil/condensate/produced water storage tanks when open as designed (e.g., thief hatch during sampling or gauging operations, vents to atmosphere on tanks that are not tied to a control device via a closed vent system);
 - Enardo and pressure relief devices when opening at the pre-set pressure as designed (including weighted thief hatches designed for pressure relief);
 - Truck vents during loading; and
 - Vents or exhaust stacks on process equipment, such as heaters, engines, glycol dehydrators, amine units, sulfur recovery unit tail gas thermal oxidizers, etc.
- All cases of equipment malfunction. Historically, emissions associated with equipment malfunction have been addressed under the “malfunction” or similar provisions in various permitting, NSPS and NESHAP programs when emissions from the process equipment are normally controlled or the process equipment operates normally in a closed system without an emissions point.
- Compressor seals. Traditionally, compressor seals are included in EPA’s LDAR regulations for the chemical and refining industry. However, in EPA’s current effort addressing VOC/methane emissions from the O&G industry, a separate technical white paper is being developed for compressors. Additionally, in EPA’s latest regulation on the oil and gas industry, namely, NSPS

Subpart OOOO, compressors are not included in the LDAR provisions. Rather, they are addressed in separate sections which require emission controls, and/or maintenance practices that are different from the traditional LDAR program. Therefore, emissions from compressor seals should not be included as part of leaks.

There are several different ways to detect leaks from components. Each method has a different cost, level of detection, gas detected, deployment method, ease of use, and ease of logging the data. Audio, Visual, Olfactory (AVO) monitoring is one of the simplest and most effective methods for leak detection and does not require a monitoring device. Most leaks at natural gas and oil production sites can be easily found using one's senses. This type of LDAR program does not require the purchase or rental of equipment nor the training of personnel on the equipment. It can be done by the operators that are already at the well sites, and the repairs can be made by the operators at the time the leak is found unless it requires replacement of equipment or a more extensive repair is needed.

Infrared cameras such as the forward-looking infrared (FLIR) camera are another method used to detect leaks. However, the equipment is expensive and requires training for proper use and interpretation of the results. The cameras cost is approximately \$100,000 plus the costs for required training, calibration, and maintenance. Well sites can be greater than an hour apart which will require some operators to purchase multiple cameras to monitor all of their sites. As such many smaller operators will not be able to afford the cost of the cameras and associated training. Few LDAR companies exist who are qualified to perform monitoring in the remote areas of the BLM lands, which would pose a problem when attempting to contract such work.

Most LDAR programs have been historically required at discrete locations such as refineries and chemical plants. These operations typically fulfill LDAR requirements using EPA's Method 21 in conjunction with a VOC monitoring instrument such as an Organic Vapor Analyzer (OVA) or Toxic Vapor Analyzer (TVA). This method is not very practical for dispersed oil and gas facilities. Method 21 typically requires third-party contractors who are specially trained. Each fugitive component must be tagged and monitored separately. It can take a day to analyze only 500 components. Method 21 monitoring is far more expensive than FLIR monitoring and does not easily identify the source of the leak (when compared to FLIR monitoring). In addition, for components in close proximity to one another, it may be difficult to identify which component is actually leaking. EPA concluded that fugitive monitoring of well pads using Method 21 was not cost effective. In the Technical Support Document for the NSPS OOOO Proposal, EPA included costs for well pads for Method 21 on Table 8-13 showing the cost is as high as \$267,386/ton of VOCs. Therefore, this method is not recommended by API for use at oil and gas production sites.

Many well sites are remotely located, and most are unmanned facilities. Inspection and maintenance visits may occur anywhere from weekly to twice per month (as a typical average), depending on the location and time of year. In some areas, winter weather makes it difficult to visit sites resulting in extended periods between site visits. Sites can be as far as an hour apart, which can limit the number of locations that can be monitored each day. Historical LDAR programs using Method 21 have typically been at refineries and chemical plants where contracted LDAR monitoring teams are located on-site to do the leak detection. Subsequent work orders are then created on a daily basis for the necessary repairs by the on-site operators. Drive time is not a factor in these refinery/chemical plant programs as it would be for dispersed, unmanned oil and gas sites.

The recordkeeping requirements of most LDAR programs are the most laborious part of the program. For the traditional EPA Method 21 monitoring, each component must be individually tagged and noted in a system that tracks the readings, the repairs, and the re-readings of the component. For dispersed, unmanned sites, keeping tags on components and tracking all the records of readings, repairs, and re-

readings would be extremely burdensome. Furthermore, the cost of such an effort would be extremely high. Recordkeeping for leak detection and repairs at oil and gas production sites needs to be minimal and simple.

As mentioned previously for other sources, EPA is currently undergoing an effort, through the development and expert review of white papers, to inform how best to address emissions from various sources including equipment leaks. As such, BLM should refrain from further regulation of equipment leaks until the EPA has completed that effort.