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June 3, 2014

Mr. Tim Spisak
Senior Advisor, Conventional Energy
Bureau of Land Management
Electronic Submittal: blm_wo_og_comments@blm.gov and tspisak@blm.gov

Re: Comments on Flaring and Venting Public Outreach

Dear Mr. Spisak,

The Colorado Petroleum Association (CPA) welcomes this opportunity to provide comments to the United States Interior Department's Bureau of Land Management (BLM) concerning the potential flaring and venting regulatory changes being considered for oil and gas operations subject to BLM regulatory authority. CPA is a non-profit trade association organized to operate in Colorado. CPA members are involved in all aspects of oil and gas exploration, production, refining, marketing, and transportation. In Colorado, CPA represents its members before local, state, and federal government entities on policy, factual, and legal issues. Colorado's 8.3 million acres of BLM public lands, along with 27 million acres of mineral estate, are concentrated primarily in the western portion of the State. Oil and natural gas development on public land and the mineral estate provides an economic driver for Colorado's economy, with 44,978 Colorado jobs supported by energy and mineral development on Colorado's public lands, generating $9.5 billion in economic activity last year.[1]

CPA has concerns about BLM's proposed air quality control regulations and/or policies being implemented under its resource conservation and royalty payment authority, thus usurping state and federal regulation authorized by the Clean Air Act and state equivalents.

[1] http://www.blm.gov/co/st/en/BLM_Programs/oilandgas.html

The Colorado Department of Public Health and Environment (CDPHE) has existing and recently adopted rules in place to manage oil and gas development air quality issues. Recently adopted Colorado Air Quality Control Commission Regulation No. 7 (Reg. 7) established many of the same requirements under consideration by BLM. CDPHE is in the best position to maintain regulation of air quality on all lands as it has the personnel, budget and expertise necessary to efficiently and effectively implement the rules. Also, CPA does not believe that Colorado BLM field offices have the same level of staffing, budget or air quality expertise to efficiently and effectively implement such a large undertaking as described in BLM's PowerPoint presentations.

In addition, the United States Environmental Protection Agency (EPA) has additional, almost identical, requirements currently in place or being considered for rulemaking during the same time period that BLM proposes to develop these regulations. CPA has serious concerns that BLM could impose slightly different regulations on the same sources as CDPHE and EPA, resulting in compliance complications for our members.

The Mineral Leasing Act (MLA) prohibits conflict with laws of the state: "None of such provisions shall be in conflict with the laws of the State in which the leased property is situated." 30 USC §187; *Ventura County v. Gulf Oil Corp.*, 601 F.2d 1080, 1085 (9th Cir. 1979) *aff'd* 445 U.S. 947("such provisions" means only provisions of preceding sentence, which lists, among other things, the prevention of undue waste and the safeguarding of the public welfare). It assures that BLM shall observe those state standards when drafting lease terms. *Id.* BLM also has a longstanding rule requiring that a decision to allow venting or flaring of gas from an oil well must be supported by engineering, geologic, and economic data; however, this rule does not require the consideration of environmental costs in such decision. *See* NTL-4a. BLM should not impose rules that would render operations uneconomic, in particular when taking into account the relatively modest profit margins on individual leases given the substantial expense of additional controls and the lack of available and reasonably foreseeable pipeline capacity. BLM's proposal does not appear to be aimed solely at waste reduction but rather at efforts to regulate and reduce emissions to the environment – a task that must be left to the relevant state and federal agencies (namely CPDHE and EPA).

The MLA also only requires oil and gas lessees to "use all reasonable precautions to prevent waste of oil or gas developed in the land." 30 U.S.C. § 225. Many of BLM's proposals would go beyond reasonable precautions to prevent waste of oil or gas.

CPA is also concerned that implementation of the proposed changes may exacerbate the current decline in oil and natural gas production on federal lands. According to the Institute for Energy Research, federal regulation increases have resulted in a 40 percent decline in oil production on federal lands since the year 2000. Oil and natural gas wells need to be continually drilled or state and national production will continue to decline. Introducing redundant regulations that cause unnecessary delays in the permitting process will only cause further declines of both oil and natural gas production on federal lands. Such declines will have a severe impact on Colorado's tax revenue and citizen employment, will increase the costs for energy to all consumers, and will increase this country's reliance on imports from less-than-friendly nations.

BLM's approach necessarily and incorrectly presumes that oil and gas activities pose some unidentified significant risk that is not addressed by existing state and federal regulations. As discussed further in these comments, CPA questions the basis for the presumption and the essential nature of BLM's action. CPA firmly believes BLM's proposal to revise NTL-4a is premature and is potentially counterproductive. CPA therefore submits the following more detailed comments regarding the proposed changes.

I. WELL COMPLETIONS

BLM has not demonstrated a need to revise NTL-4a to eliminate Supervisor approval of venting and or flaring during completions. BLM's proposal to require capture, injection, use, combustion or flaring during well completion will result in shut in wells. Specifically, in the event that no transportation options are available, and the Supervisor no longer allows for flaring, the only remaining option is to shut in. Such a drastic result is not warranted in light of the existing Colorado and federal authorities to reduce emission and eliminate waste. CPA describes these authority in more detail below.

A. Colorado

CDPHE requires that gas coming off of a separator, whether from an oil well or gas well, either be: routed to a gas line, controlled or sold:

> Well Operation and Maintenance: On or after August 1, 2014, gas coming off a separator, produced during normal operation from any newly constructed, hydraulically fractured, or recompleted oil and gas well, must either be routed to a gas gathering line or controlled from the date of first production by air pollution control equipment that achieves an average hydrocarbon control efficiency of 95 percent. If a combustion device is used, it must have a design destruction efficiency of at least 98 percent for hydrocarbons.

Regulation 7 XVII.G.

COGCC also regulates waste of natural gas. C.R.S. §§ 34-60-101, *et seq.*; 2 CCR §§ 404-1, *et seq.* More specifically, COGCC prevents waste which includes:

> [T]he escape, blowing, or releasing, directly or indirectly into the open air, of gas from wells productive of gas only, or gas in an excessive or unreasonable amount from wells producing oil, or both oil and gas …in such manner as… unreasonably diminishes the quantity of oil or

> gas that ultimately may be produced, excepting gas that is reasonably necessary to the drilling, completing, testing, and in furnishing power for the production of wells.

C.R.S. §§ 34-60-103(11) (2014).

B. EPA

EPA similarly regulates flaring and venting. Under New Source Performance Standard (NSPS) OOOO (40 CFR 60 Subpart OOOO), EPA requires that hydraulically fractured gas wells on or after January 1, 2015 must comply with the following:

> (1) For the duration of flowback, route the recovered liquids into one or more storage vessels or re-inject the recovered liquids into the well or another well, and route the recovered gas into a gas flow line or collection system, reinject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere. If this is infeasible, follow the requirements in paragraph (a) (3) of this section.
>
> (2) All salable quality gas must be routed to the gas flow line as soon as practicable.
>
> (3) You must capture and direct flowback emissions that cannot be directed to the flow line 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.
>
> (4) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

40 CFR §§ 60.5375(a) (1)-(4). In addition, EPA is currently evaluating whether to expand these requirements to oil wells. Comments on EPA's white paper evaluating this issue will reflect the technical limitations to expanding the requirements to oil wells. Because EPA is already evaluating these issues, however, BLM should defer deciding whether to impose potentially redundant and/or unnecessary regulations until after EPA completes its process.

C. Technical Limitations

If BLM elects to further evaluate reductions of emission from oil well completions, BLM must consider those same technical limitations considered by CDPHE and being further considered by EPA.

Specifically, there are three criteria which must be satisfied in order to capture the gas from completed wells: 1) gas-gathering infrastructure (flare-less completions cannot be performed without pipelines); 2) the gas must be capable of flowing at pressure equal to or greater than the gas pipeline system; and 3) the gas must be of adequate quality to meet the pipeline specification (*i.e.*, no CO_2 or N_2 present).

When an operator hydraulic fractures a gas well, the primary flowback fluid is natural gas as opposed to oil. Green completions often make economical and technical sense for natural gas wells because it reduces the amount of recoverable natural gas vented or flared into the atmosphere. For oil wells, however, the primary fluid flowing back is oil. In fact, in some cases, the well produces little to no gas and any natural gas produced may not be seen during the flowback process. In other cases, oil wells can be prolific and a substantial amount of gas is produced during the flowback process. No "one size fits all" standard is appropriate for oil wells.

Specialized equipment and trained personnel are also required to safely and effectively flowback and test wells. The equipment currently being used consists of a large, four phase separator (four phases - gas, condensate, water and sand). The separator equipment can handle large amounts of water and solids (frac. sand) during the flowback stimulation and cleanouts. After the fluids are initially separated, the water and oil are piped to production storage tanks and gas is usually piped through the normal production facilities to an additional stage of separation and any treating that may be required (*e.g.* dehydration) prior to sales. Sand is periodically discarded to the reserve pit. Without the use of the flowback equipment, the production separator and dehydrator facilities would have to be oversized in order to hand the fluid flow rates. The flowback equipment requires careful engineering, construction, maintenance and testing to perform the flowback safely. It also requires trained personnel who, along with the equipment, are in limited during periods of high industry activity.

Costs associated with green completions are also considerably higher than other completion techniques. The cost of the green completion flowback equipment is greater than the typical flowback piping that is commonly used. If all flaring or venting of gas during completion operations were to be eliminated, the only option for completions would be to shut the well in during the times when the gas cannot be put into the sales line.

Pipeline location relative to the well is critical to the viability of green completions. A no flaring/venting regime during completions necessarily requires that a "sales line" be near enough to be economically feasible to connect to the well <u>prior to the</u>

completion of the well. In typical high-density infill projects, existing infrastructure and certainty of production make this technique more feasible. In other circumstances, however, the drilling parties or third parties will not lay pipeline to a well unless the anticipated well production will justify the costs of building the line. The gas line must also be permitted and installed which takes a considerable amount of time after it is determined to be economic. If the gathering system is constructed by a third party, the drilling party will also need to negotiate the contractual right to flow into the gas gathering system, which takes additional time. The parties must then obtain the necessary permits and rights-of-way to lay pipeline to the gathering system from the well site. Furthermore, the gas gathering company must have a gas plant permitted, built, and operational to send the gas for processing and sales.

There are additional complications. First, the reservoir needs to be of a quality and pressure to flow back with a full column of water, and have enough wellhead pressure to flow into the sales line, in order to flow a well to a sales line during flowback after fracture stimulation. An over-pressurized interval with good deliverability will usually flow at a high enough pressure to flow back to sales. Overly tight, normally pressured, naturally under-pressured or partially depleted reservoirs will not flow back against line pressure at a rate necessary to clean the gel from the frac stimulation. This is also true if the reservoir is depleted or of poor quality in general. This becomes problematic because the longer the fracture fluid is left downhole, the greater the likelihood that reservoir production will be permanently impeded. If the gas contains impurities (such as sand, free water, too much water vapor, or significant amounts of carbon dioxide or nitrogen) it cannot be placed in a sales line. Typical equipment used during green completions is capable of separating out the condensate, water and solids from the production stream; however the equipment does not remove carbon dioxide or nitrogen. Carbon dioxide and nitrogen are commonly used to assist with flowback and to reduce the likelihood of reservoir production impediment on a partially depleted or under-pressurized zone. The carbon dioxide and nitrogen must be removed from the flowback gas in order to render it pipeline quality.

Cold temperatures can complicate operations on high-pressure gas wells due to hydrate formation freezing off flow lines. The additional piping and equipment necessary for green completions can aggravate this situation. Flowing back to a sales line usually precludes the possibilities of reducing flowing pressures below the hydrate point (which is a function of temperature and pressure). Equipment and design must account for this phenomenon. Control of pressure drops, liberal applications of heat, and generous additions of methanol are all requirements for successful cold weather green completions. Under extreme cold weather conditions, flow back to a flare is usually more prudent as connections are generally less complicated and less prone to freeze up.

Only wells with sufficient reservoir pressure to flow against the gathering system back pressure and capable of producing saleable quantities of natural gas are candidates for green completions. Without a gas gathering system, flaring is still the next best option to control gas emissions during flowback. For all these reasons, BLM should not eliminate the option of venting and flaring, with Supervisor approval, on BLM managed lands.

II. PRODUCTION TESTS

The need to determine if a well will be successful through production testing is essential to oil and gas operations and BLM should not take any actions that would reduce the efficacy of such production tests.

A. Colorado

The need to flare during production testing is acknowledged in COGCC Rule 912.b.:

COGCC Rule 912. VENTING OR FLARING NATURAL GAS

. . . .

b. Except for gas flared or vented during an upset condition, well maintenance, well stimulation flowback, purging operations, **<u>or a productivity test</u>**, gas from a well shall be flared or vented only after notice has been given and approval obtained from the Director on a Sundry Notice, Form 4, stating the estimated volume and content of the gas. The notice shall indicate whether the gas contains more than one (1) ppm of hydrogen sulfide. If necessary to protect the public health, safety or welfare, the Director may require the flaring of gas. (Emphasis added).

See also C.R.S. §§ 34-60-103(11) (2014).

Current BLM production testing policy permits venting and flaring authorized for up to 30 days or 50 million cubic feet (MMcf) of gas, with such test not to exceed 24 hours. BLM's proposal to reduce the amount of vented or flared gas by more than 50 percent for gas wells and by 80 percent of oil wells significantly impairs an operator's ability to meaningfully determine whether a well economically justifies the contemplated green completions. BLM should allow for production testing as managed by the COGCC, who has the staffing, budget and expertise necessary to promptly assess these issues.

III. LIQUIDS UNLOADING

Liquids unloading is a complicated and nuanced issue which varies on a well-by-well basis dependent upon a myriad of variables, such as geology, depth, formation characteristics, infrastructure, and production flow and characteristics, among others. CPA once again submits that BLM has not demonstrated a need to revise NTL-4a to impose command and control requirements on a process which should instead remain fit for purpose.

A. Colorado

CDPHE already regulates venting during liquids unloading under Reg. 7. Due to the complicated nature of liquids unloading, CDPHE is taking a deliberate and measured approach to identifying potential best management practices:

XVII.H. (State Only) Venting during downhole well maintenance and liquids unloading events

XVII.H.1. Beginning May 1, 2014, owners or operators must use best management practices to minimize hydrocarbon emissions and the need for well venting associated with downhole well maintenance and liquids unloading, unless venting is necessary for safety.

XVII.H.1.a. During liquids unloading events, any means of creating differential pressure must first be used to attempt to unload the liquids from the well without venting. If these methods are not successful in unloading the liquids from the well, the well may be vented to the atmosphere to create the necessary differential pressure to bring the liquids to the surface.

XVII.H.1.b. The owner or operator must be present on-site during any planned well maintenance or liquids unloading event and must ensure that any venting to the atmosphere is limited to the maximum extent practicable.

XVII.H.1.c. Records of the cause, date, time, and duration of venting events under Section XVII.H. must be kept for two (2) years and made available to the Division upon request.

B. EPA

EPA is also taking a deliberate and measured review of venting emissions during liquids unloading. EPA recently issued a draft white paper discussing these complex technological issues. Again, BLM risks duplication or inconsistency with CDPHE requirements and potential EPA programs if it adopts regulation related to liquids unloading.

C. Technical Limitations

BLM must understand that deliquification of gas wells is a highly complex and technical subject with many approaches and technologies. Venting of wells is one such technique, often used in combination with other techniques that depend on reservoir pressure - such as plunger lifts used to assist unloading. Liquid loading of well-bores occurs when the gas production-rate (velocity) is insufficient to carry liquids up the well-bore. When a vertical liquid column builds up in the well-bore, the weight of the column puts back-pressure on the producing formation and the production rate declines to the point where the well stops flowing. Low rate wells are either impaired by liquids accumulation or utilize some deliquification method to encourage production. As the reservoir energy depletes and the production-rate declines, a well will reach the stage where liquids-loading is necessary. Operators often will implement one of a portfolio of technologies or techniques 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 not sufficient 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 and be abandoned.

Liquids unloading venting cannot be eliminated. The production rate of a well, consequent velocity up the well-bore, 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 fluid friction and fluid interference across the reservoir; the flowing friction up the well-bore; the weight of the vertical fluid column in the well-bore; surface equipment and piping pressure losses; and the collection system/flow-line back-pressure. Opening a well-bore to atmospheric pressure (venting a well) removes the effect of the surface equipment/piping pressure-loss and the back pressure from the collection line and increases differential pressure to increase flow rates and velocities, which may enable the well to lift the liquid from the well-bore (unload the well). There are various reservoir-driven techniques operators use in wells experiencing liquids loading to assist in deliquification, which also helps reduce the need for venting. Each of these may be the best solution for a particular time in the life of a reservoir. However, it is a misconception that certain systems (e.g., plunger-lift systems) are the single emission control action for wells where venting for liquids unloading occurs.

BLM should not regulate liquids unloading. CDPHE already regulates liquid unloading in Colorado. EPA is also considering expanding NSPS OOOO to cover liquids unloading.

IV. CASINGHEAD AND ASSOCIATED GASES

BLM appears to believe the reason that operators flare oil wells instead of building gas gathering systems is purely a function of economics. BLM misunderstands that there are several non-economic reasons why oil wells are flared instead of building a gas gathering system, including inability or time sensitivities with obtaining permits and other necessary approvals. As discussed under the Well Completions section and below, there are many factors which drive the decision to build a gas gathering system.

Natural gas produced from an oil well that cannot be sold is known as “stranded” gas. It is stranded because the pipeline infrastructure needed to gather and transport the gas for processing is unavailable. Unlike natural gas fields where infrastructure may be unavailable in 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, insufficient associated gas production volumes may make it uneconomic to gather, process, and sell the produced gas. Or, economic gas gathering infrastructure construction may lag behind the start of new well production. During flowback and continuing into production, stranded gas from high pressure wells is flared for safety and VOC emissions reduction. Without gas gathering infrastructure, green completions are not possible. Because the oil cannot be produced without the casinghead gas or associated gas, a refusal to permit flaring of that gas which is stranded results in the wells being shut-in. This negatively impacts federal, state and local economies. Moreover, and as already discussed above, the process for evaluating whether to build a gathering system, the building of the system, and the associated legal issues such as permitting, rights-of-way, negotiating gas gathering agreements, etc . . . is lengthy.

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 in place and sufficient reservoir pressure and volume of gas. Regulations must accommodate these issues and cannot be just based on an economic analysis. BLM should not require recovery of casing head and associated gas.

V. GAS CONSERVATION PLAN

BLM proposes to require an action plan which would eliminate or minimize venting or flaring from oil wells. It is unclear how BLM would determine when it believes a gas gathering system would be economic. Moreover, the potential requirement that flaring be allowed only when an operator commits to the installation of a gas gathering system puts the proverbial cart before the horse. Venting and flaring are vital to the completion and testing phases of a given well, both of which are part of the process utilized to determine whether a gas gathering system should be built. It also more often the case that companies other than operators control gas gathering systems and such systems, along with pipeline infrastructure, are the last piece of equipment put into place in the production system. How does BLM plan to gather operator commitments when the operator has no control over whether or how soon the infrastructure will be constructed? What exactly constitutes a gas conservation plan?

It appears as though this action plan will only cause delays and less drilling in the future. By requiring commitments from an operator who has no control over the process essentially prevents the operator from producing. Without replaced production, oil and gas development and production will decline from federal properties, and thus, impact Colorado's economy. CPA also again respectfully submits that such plans are unnecessary given the existing Colorado and EPA regulatory regimes.

VI. STORAGE VESSEL/TANK EMISSIONS

BLM should not propose control requirements for storage vessels as they are already regulated by CDPHE Reg. 7 and NSPS OOOO. Existing tanks have lower emissions and controlling existing tanks cost far more than new tanks.

A. Colorado

CDPHE Reg. 7 has already expanded the requirements of NSPS OOOO to all tanks greater than 6 TPY VOC with a 95 percent control efficiency and 95 percent destruction efficiency for combustion devices (Reg. 7 XVII.C.1.b). CDPHE also added extensive inspection requirements for storage vessels with greater than 6 TPY of VOCs.

B. EPA

Under 40 CFR 60 Subpart OOOO, EPA already requires that new, modified, or reconstructed, or re-hydraulically fractured wells with greater than 6 TPY of VOC emissions must meet a 95 percent capture and destruction efficiency. Furthermore, EPA determined that requiring controls below 6 TPY would not be cost effective. API used EPA's Cost Manual to determine that tanks with emissions less than 12 TPY were not cost effective to control. Using the method prescribed in the EPA Cost Manual, the annual cost of controls is $55,207 for a new storage vessel. Controlling an existing tank costs far more. In order to control an existing tank, retrofits are required in order to keep the vapors from exiting the tank and entering the vapor control system. The thief hatches and pressure relief devices typically have to be replaced with thief hatches with lower inherent leak rates and different seals. New piping must also be installed requiring the well site to be shut in. If piping must be routed underground, this can add further cost for installation. Furthermore, depending on the pressure rating of the tank itself, the entire tank may have to be replaced in order to route it to a vapor control system. The production rate of a well, including the condensate production, also declines over time. For example, the decline of a Bakken well and a Three Forks well shows that production decreases by 70-71 percent over the first year. The 3-year decline is 85-86 percent. The existing wells that are not covered by NSPS OOOO have already had significant production declines which would typically yield emissions below 6 TPY. The second main driver of flash emissions from storage vessels is the pressure of the gas in the separator prior to the tank. The separator pressure is typically driven by the reservoir pressure. Just as the production declines, the reservoir pressure declines as the resources are removed requiring lower separator pressures that also result in lower emissions over time. There is no demonstrated need for additional regulation.

VII. PNEUMATIC DEVICES

BLM should be clearer on the type of controllers it intends to regulate and how. From an emissions perspective, pneumatic controllers can be classified by a combination of their design type and the type of service they perform. The types of controllers are continuous bleed and intermittent vent. The two types of service are on/off and throttling.

A. Colorado

CDPHE already regulates continuous high bleed pneumatic controllers under Reg. 7, which states:

XVIII.C.2.a. All pneumatic controllers placed in service on or after May 1, 2014, must:

XVIII.C.2.a.(i) Emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.; or

XVIII.C.2.a.(ii) Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and use of a no-bleed pneumatic controller is technically and economically feasible.

XVIII.C.2.b. All high-bleed pneumatic controllers in service prior to May 1, 2014, must be replaced or retrofitted by May 1, 2015, such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.

XVIII.C.2.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.2.c.(i) For high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

B. EPA

NSPS OOOO already requires that any continuous bleed pneumatic devices constructed, modified, or reconstructed after October 15, 2013 must have a bleed rate of <6 scfh at well head to the gas plant and a bleed rate of 0 scfh at the gas plant. Based on the definition of reconstructed, most existing high bleed pneumatic devices will be phased out over time. With the amount of gas lost from high bleed pneumatic devices, many companies have voluntarily replaced them. Sometimes high bleed pneumatic devices are required due to the response time, safety, or positive actuation as discussed above. In order to convert a highbleed device to a low bleed device, the pilot orifice must be reduced. With a smaller orifice, plugging of the orifice opening will be a major concern as will controller response time. Also, if the controller is part of a pneumatic system where the valve actuator requires a higher pressure to operate than the advertised supply pressure for low bleed rate performance, the "low bleed" controller operating at a lower pressure than required could very well result in sluggish end-device performance and increase the risk of liquid spills and uncontrolled gas releases

EPA provides allowance for the use of high bleed pneumatic devices under NSPS OOOO, 40 CFR § 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.

BLM should not regulate continuous high bleed pneumatic controllers. CDHPE already regulates all continuous high bleed pneumatic controllers. EPA already regulates new, modified, and reconstructed continuous high bleed pneumatic controllers under NSPS OOOO. Both allow legitimate use of continuous high bleed pneumatic controllers where based on functional needs, including but not limited to response time, safety and positive actuation.

VIII. LEAK DETECTION AND REPAIR (LDAR)

BLM should leave leak detection and repair to the state, and under the review and authority of EPA.

A. Colorado

CDPHE already requires and regulates LDAR under Reg. 7 Section XVII.F which includes extensive requirements for LDAR for all compressor stations and well sites. Here is a summary of the requirements because they are too extensive to include in full:

Leak Detection and Repair Program for Well Production Facilities and Natural Gas Compressor Stations

Natural Gas Compressor Stations (XVII.F.3.)

- Beginning 1/1/2015, owners or operators of natural gas compressor stations must inspect components for leaks using an approved monitoring method (XVII.F.3.)
  - Natural gas compressor stations with fugitive VOC emissions 0 < X ≤ 50 TPY, within 90 days after 1/1/2015 or commencing operation if such data is after 1/1/2015. (XVII.F.3.a.)
  - Natural gas compressor stations with fugitive VOC emissions X > 50 TPY, within 30 days after 1/1/2015 or commencing operation if such data is after 1/1/2015. (XVII.F.3.b.)
- Owners or operators must continue conducting approved instrument monitoring method inspections in accordance with the inspection frequency in Table 3. (XVII.F.3.c.)

Table 3 – Natural Gas Compressor Station Component Inspections

Fugitive VOC Emissions (tpy)	**Inspection Frequency**
>0 and < 12	Annually
> 12 and < 50	Quarterly
> 50	Monthly

Well Production Facilities

- Owners or operators of well production facilities constructed on or after October 15, 2014, must identify leaks from components using an approved instrument monitoring method no sooner than 15 days and no later than 30 days after the facility commences operation. (XVII.F.4.a.)
  - This initial test constitutes the first, or only for facilities subject to a one time approved instrument monitoring method inspection, of the periodic approved instrument monitoring method inspections.
  - Approved instrument monitoring method and AVO inspections must be conducted in accordance with the inspection frequencies in Table 4.

Table 4 – Well Production Facility Component Inspections Thresholds (per XVII.F.4.c.)

Well production facilities without storage tanks (tpy)	**Well production facilities with storage tanks (tpy)**	**Approved Instrument Monitoring Method Inspection Frequency**	**AVO Inspection Frequency**	**Phase-In Schedule**

> 0 and < 6	> 0 and < 6	One time	Monthly	January 1, 2016
> 6 and < 12	> 6 and < 12	Annually	Monthly	January 1, 2016
> 12 and < 20	> 12 and < 50	Quarterly	Monthly	January 1, 2015
> 20	> 50	Monthly		January 1, 2015

- Owners or operators of well production facilities constructed before October 15, 2014, must identify leaks from components using an approved instrument monitoring method within (XVII.F.4.b.):
  - 90 days of the Phase-In Schedule in Table 4; or
  - 30 days for well production facilities subject to monthly approved instrument monitoring method inspections; or
  - by January 1, 2016, for well production facilities subject to a one time approved instrument monitoring method inspection.
  - Thereafter, approved instrument monitoring method and AVO inspections must be conducted in accordance with the inspection frequencies in Table 4.
- Estimate the uncontrolled actual VOC emission based on (XVII.F.4.c.):
  - The highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed.
  - If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual VOC emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).

Provisions for Both Compressor Stations and Well Production Facilities

- Details on unsafe, difficult, or inaccessible to monitor requirements are in XVII.F.5

  Leak Determination
- For EPA Method 21, for a facility constructed **before 5/1/14**, a leak is any concentration above (XVII.F.6.a.):
  - 2,000 ppm is a leak for compressor stations
  - 500 ppm for well production facilities
- For EPA Method 21, for a facility constructed on or after 5/1/14, a leak is any concentration above 500 ppm. (XVII.F.6.b.)
- For infra-red camera and AVO monitoring, a leak is any detectable emissions (XVII.F.6.c.)
  - For leaks identified using an approved instrument monitoring method or AVO, owners or operators have the option of either repairing the leak in accordance with the repair schedule or conducting follow-up monitoring using EPA Method 21 within 5 working days of the leak detection. If the

follow-up EPA Method 21 monitoring shows that the emission is a leak as defined above, the leak must be repaired and remonitored. (XVII.F.6.d.)

Repair and Remonitor

- First attempt to repair a leak must be made no later than 5 working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists. (XVII.F.7.a.)
  - If parts are unavailable, they must be ordered promptly and the repair must be made within 15 working days of receipt of the parts.
  - If shutdown is required, the leak must be repaired during the next scheduled shutdown.
  - If delay is attributable to other good cause, repairs must be completed within 15 working days after the cause of delay ceases to exist.
- Within 15 working days of completion of a repair, the leak must be remonitored to verify the repair was effective. (XVII.F.7.b.)
- Leaks discovered pursuant to the leak detection methods shall not be subject to enforcement by the Division unless the owner or operator fails to perform the required repairs. (XVII.F.7.c.)

Recordkeeping

- The following records must be maintained for 2 years (XVII.F.8.):
  - Documentation of the initial approved instrument monitoring method inspection for new well production facilities (XVII.F.8.a.)
  - The date and site information for each inspection (XVII.F.8.b.)
  - A list of the leaking components and the monitoring method(s) used to determine the presence of the leak (XVII.F.8.c.)
  - The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak (XVII.F.8.d.)
  - The date the leak was repaired (XVII.F.8.e.)
  - The delayed repair list, including the basis for placing leaks on the list (XVII.F.8.f.)
  - The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring (XVII.F.8.g.)
  - A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section XVII.F.5., an explanation stating why the component is so designated, and the plan for monitoring such component(s). (XVII.F.8.h.)
- The owner or operator must submit an annual report on or before 5/31 of each year with the following information for the previous calendar year (XVII.F.9.):
  - The number of facilities inspected (XVII.F.9.a.)
  - The total number of inspections (XVII.F.9.b.)
  - The total number of leaks identified, broken out by component type (XVII.F.9.c.)

- The total number of leaks repaired (XVII.F.9.d.)
- The number of leaks on the delayed repair list as of December 31st (XVII.F.9.e.)

Each report must be accompanied by a certification by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. (XVII.F.9.f.)

B. EPA

EPA has recently issued and solicited comment upon a white paper evaluating LDAR in consideration of potentially expanding NSPS OOOO. BLM should defer deciding whether to impose potentially redundant and/or unnecessary regulations until after EPA completes its process, which might include nationwide LDAR. Moreover, CDPHE already has extensive LDAR requirements for all compressor stations and well production facilities in Colorado.

IX. CONCLUSION

While recognizing BLM's interest in reducing resource waste, BLM's proposed regulatory actions clearly impose air emissions reduction mandates under the guise of "ensur[ing] a fair [royalty] return to the American taxpayer," and CPA recommends BLM not amend NTL4a. Colorado's oil and gas exploration and production industry air emissions are appropriately regulated and managed by the proper state and federal agencies. Unlike BLM, the State of Colorado and EPA have the proper funding, personnel, and expertise to manage Colorado's air resources effectively and have done so for decades. BLM's proposal to require air quality controls is unnecessary, redundant, and potentially contradictory to the in-place state and federal regulatory structure. The proposals BLM suggests will likely result in additional delays in permitting, production, and revenue delivery to federal, state, and local governments. Colorado's economy greatly depends on mineral revenues, and any disruption in revenue flow is certain to impact the state's economy on numerous levels. Furthermore, the Mineral Leasing Act (MLA), 30 U.S.C. § 187, prohibits conflict with laws of the state, and the state already regulates to prevent waste and protect the public welfare. As CPA clearly articulates herein, the State of Colorado is and continues to appropriately regulate the sources contemplated by BLM's proposal in conjunction with EPA, and BLM's proposal potentially conflicts with Colorado law.

Sincerely,

Stan Dempsey, Jr.

Stan Dempsey, Jr.
President, Colorado Petroleum Association