October 26, 2015

Administrator, DEQ/AQD
Herschler Building 2-E
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Cheyenne, Wyoming, 82002
307-777-5616 (fax)

VIA Facsimile

Re: Comments on Department of Environmental Quality, Air Quality Division, Update to Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting Guidance

Dear Administrator:

Thank you for accepting these comments submitted by Environmental Defense Fund (EDF) and the Wyoming Outdoor Council (WOC) on the Air Division's plans to update the permitting guidance for oil and gas sources. EDF is a national membership organization with over one million members residing throughout the United States who are deeply concerned about the pollution emitted from oil and natural gas sources. WOC is the State's oldest independent conservation organization and has worked for more than four decades to protect Wyoming's environment and quality of life for future generations.

I. Introduction

We support the Air Division's intent to update the permitting guidance (P-BACT Guidance) for new and modified oil and gas sources located outside the Upper Green River Basin (UGRB) ozone nonattainment area in the newly proposed statewide (SWA) area. Shifting development patterns, the promulgation of a more protective national ambient air quality standard (NAAQS) for ozone, a growing body of scientific literature, as well as recent Environmental Protection Agency (EPA) and Colorado Department of Public Health and Environment (CDPHE) enforcement actions, underscore the need for this update.

We commend the Air Division for proposing to streamline, simplify, and improve the P-BACT guidance for tanks and dehydrators at multi-well (PAD) facilities and truck loading activities, and for extending the green completion requirement to the SWA. However, by failing to propose a P-BACT determination for fugitive emissions (leaks) from well sites and tank batteries, the proposal suffers from a fundamental flaw. We strongly urge the Air Division to propose a quarterly instrument-based leak detection and repair (LDAR) requirement for statewide sources, or at a minimum, set a date certain in the near future by which it will do so. In so doing the Air Division should modify the definition of fugitive emissions in the guidance to ensure that access points on tanks, as well as traditional components, are subject to LDAR. In addition, we strongly urge the Air Division to re-evaluate the existing control thresholds for tanks and dehydrators located at single well facilities, tank batteries and fugitive emissions located in the new SWA in order to provide the same level of air quality protection to residents in the new SWA as afforded to those in the UGRB.

The Air Division is poised to lead and should finalize a quarterly LDAR requirement for the SWA expeditiously in order to retain its status as a national leader on air quality measures. The Air Division should not wait for EPA to finalize its proposed New Source Performance Standard for equipment leaks. Wyoming has always led when it comes to clean air measures. Indeed, EPA looked to Wyoming's requirements for oil and gas sources when it finalized the 2012 NSPS for oil and gas sources,[1] and again recognized Wyoming's LDAR requirement in the UGRB in the recent NSPS proposal.[2] Moreover, reductions in ozone-forming and climate altering pollutants are needed today. The Air Division has proposed to implement the new SWA requirements in January 2016 whereas EPA's proposed NSPS will not be finalized by sometime next summer, at the earliest. Lastly, the people of the SWA deserve the same protections from harmful pollutants as those living in the UGRB. It is incumbent upon the Air Division to not only clean up unhealthy air but also to protect and maintain clean air.[3] A quarterly instrument-based LDAR requirement is a highly cost effective, available measure that should be required statewide.

As the Division is aware, development patterns in Wyoming are rapidly shifting. As we noted in our recent comments on permit application analyses for production facilities in Laramie County in the eastern part of the state (attachment 1), "eighty percent of the some 4,300 oil and gas wells permitted in Wyoming during the past 12 months are in counties with the lowest level of state air quality protection." The Air Division historically has required the most rigorous standards for facilities located in areas with heavy development, and where the development was contributing to air quality problems (namely the Jonah and Pinedale Anticline Development Area and UGRB in western Wyoming). However, developmental patterns are changing, and as they change, so must the P-BACT Guidance.

It is important for the state to ensure that significant sources of ozone precursor emissions such as oil and gas facilities are minimizing emissions to the greatest extent possible in light of the revised eight-hour ozone NAAQS. While the UGRB is the only ozone nonattainment in Wyoming today, it is possible that other areas will be designated nonattainment under the

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[1] See 77 Fed. Reg. 49490, 49526 (August 16, 2012) (noting Wyoming's storage tank provisions as a basis for federal requirements) and 49517 (discussing Wyoming's green completion provisions as a basis for NSPS).

[2] See 80 Fed. Reg. 56593 (Sept. 18, 2015) at 56625 and 56634 (noting Wyoming's pump requirements as a basis for federal requirements) and 56634 (noting Wyoming's well completion and LDAR requirements as foundations for federal requirements).

[3] See Wyoming Environmental Quality Act (stating that "it is hereby declared to be the policy and purpose of this act…to preserve, and enhance, the air…". WYO. STAT. ANN. § 35-11-102.

strengthened ozone NAAQS. We have looked at projected design values for all Wyoming counties using 2012-2014 data published by the EPA. The 2012-2014 design values for some Wyoming counties in the SWA, including Laramie County at 67 ppb, are dangerously close to the new standard of 70 ppb. Frequent instrument monitoring of facilities and the implementation of available, rigorous controls on sources located throughout the state will help ensure that these counties do not fall into nonattainment.

A growing body of scientific data and empirical evidence demonstrate that equipment malfunctions and poor maintenance can lead to significant pollution that is not represented in emission inventories, yet is controllable by frequent site inspections and modern pollution controls. This information, discussed more fully below, underscores the need for a rigorous LDAR program at all well sites and tank batteries across the state, coupled with robust controls on equipment such as completions, tanks, and dehydrators.

I. EDF and WOC Support the Proposed PAD Requirements for Tanks and Dehydrators, Well Completions, and Truck Loading in the New Statewide Area.

There are many aspects of the proposal that we support and urge the Air Quality Advisory Board (AQAB) to approve at its hearing on October 28. Specifically, we strongly support the proposal to require 98% control of all tank and dehydrator emissions at PAD facilities upon the first date of production. This is the requirement in the UGRB and for PAD facilities in the current Concentrated Development Area (CDA). We applaud the Air Division for recognizing that this level of control is feasible and cost effective for facilities located in the new SWA. Tanks are the largest source of volatile organic compound (VOC) pollution according to the latest NEI inventory[4] and the 6th largest source of methane according to the latest EPA Subpart W inventory.[5] Yet cost effective controls are available to reduce such emissions. Accordingly, it is critical that the Air Division ensure that its P-BACT determination reflects the level of air pollution reduction achievable by modern pollution control technology, as it appears to be poised to do.

We also support the Air Division's proposal to simplify the dehydrator emissions requirement by allowing for one, rather than two compliance, options. This will aid in compliance and enforcement. It will also help avoid the uncertainty inherent in the prior two-scenario system. Dehydrators are the fourth largest source of VOCs in the 2011 NEI inventory and 5th largest source of methane per the 2014 Subpart W inventory, so these controls are important.

In addition, we support the Air Division's decision to set a P-BACT determination for truck loading emissions in the UGRB and new statewide area as this is the 6th largest source of VOCs in the state per the 2011 inventory. And, we support the proposal to extend the green completion requirement to well completions in the existing statewide area. In light of shifting development patterns, this requirement is necessary to reduce oil well completion emissions.

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[4] Wyoming 2011 NEI inventory for oil and gas production sources.
[5] 2014 Subpart W inventory for Wyoming basins.

However, as explained more fully below, the lack of a proposed P-BACT determination for fugitive emissions, adequate provisions to prevent unintentional tank venting, and the failure to rigorously consider the thresholds for tanks and dehydrators located at single well facilities and tank batteries outside the UGRB, must be addressed in order for Wyoming to retain its position as a national air quality leader.

II. Field Studies Demonstrate the Need for Frequent Instrument-Based Leak Inspections and Controls of Venting.

There is growing scientific consensus demonstrating that actual oil and gas emissions are higher than inventory estimates. This is primarily due to the fact that equipment malfunctions, avoidable operating conditions, and poor maintenance at a small number of sites leads to significant excess emissions (the so called "super-emitter" phenomenon). Importantly, the nature of these excess emission events are random and unpredictable. As a result, the scientific studies strongly support frequent inspections using modern leak detection technology to identify malfunctioning or defective equipment that can lead to leaks at the maximum number of sites possible, as well as the installation of robust pollution controls.

The first of these studies, conducted by an independent team of scientists at the University of Texas, found that emissions from equipment leaks, pneumatic controllers and chemical injection pumps were each 38%, 63% and 100% higher, respectively, than as estimated in national inventories.[6] This study also found that 5% of the facilities were responsible for 27% of the emissions.[7]

Two follow-up studies focusing specifically on emissions from pneumatic controllers and liquids unloading activities at wells found similar results.[8] Specifically, the studies found that 19% of the pneumatic devices accounted for 95% of the emissions from the devices tested, and about 20% of the wells with unloading emissions accounted for 65% to 83% of those emissions. The average methane emissions per pneumatic controller were 17% higher than the average emissions per pneumatic controller in EPA's national greenhouse gas inventory.[9] There can be little doubt that methane emissions have a correlation with VOC emissions, which are much of the focus of Wyoming's P-BACT guidance.

These findings were reiterated again in a series of direct measurement studies focusing on emissions from compressor stations in the gathering and processing segment and in the transmission and storage segment. The gathering and processing study found substantial venting

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[6] Allen, D.T., et al, (2013) "Measurements of methane emissions at natural gas production sites in the United States," *Proc. Natl. Acad.* 2013, 110 (44), available at http://www.pnas.org/content/110/44/17768.full

[7] *See* Allen, D.T., et al, (2014), "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers, " *Environ. Sci. Technol.*, 2015, 49 (1), pp. 633–640 (referencing 2013 Allen study), available at http://pubs.acs.org/doi/abs/10.1021/es5040156.

[8] Allen, D.T. et al., "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings," *Environ. Sci. Technol.*, 2015, 49 (1), pp 641–648, available at http://pubs.acs.org/doi/abs/10.1021/es504016r.

[9] Allen, D.T., et al, (2014), "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers, " *Environ. Sci. Technol.*, 2015, 49 (1), pp 633–640, available at http://pubs.acs.org/doi/abs/10.1021/es5040156.

from liquids storage tanks at approximately 20% of the sampled gathering facilities.[10] Emission rates at these facilities were on average four times higher than rates observed at other facilities and, at some of these sites with substantial emissions, the authors found that company representatives made adjustments resulting in immediate reductions in emissions.

In the study on transmission and storage emissions, the two sites with very significant emissions were both due to leaks or venting at isolation valves.[11] The study also found that leaks were a major source of emissions across sources, concluding that measured emissions are larger than would be estimated by the emission factors used in EPA's reporting program.

Recently *Environment Science & Technology* published the results of a series of coordinated studies conducted at a diverse selection of facilities in the Barnett Shale region.[12] Researchers obtained data using a suite of measurement approaches that included "top-down" atmospheric measurements and "bottom-up" facility-level measurements. Overall, both the top-down and bottom-up studies found emissions higher than those estimated by the EPA's Greenhouse Gas (GHG) Inventory, and in some cases, higher than those reported by operators to EPA under the Mandatory Greenhouse Gas Reporting Program.[13] The bottom up estimate was 1.5 times higher than the EPA GHG inventory.[14] This is consistent with the findings of a 2014 synthesis paper that reviewed over 20 years of technical literature on natural gas emissions in the U.S. and Canada and similarly found measured atmospheric emissions 1.5 times higher than those estimated in the national GHG inventory.[15]

From a policy standpoint, these papers underscore the need for improved emission factors that take into account super emitters,[16] inventories that reflect current activity factors,[17] and air protection policies that ensure operators routinely check for, and expeditiously repair, leaks and control venting.[18] Accordingly, we urge DEQ to require operators outside the UGRB to inspect well sites for malfunctioning or improperly maintained equipment on a frequent basis, e.g., at least quarterly, and to control venting to the maximum extent possible from activities and equipment such as well completions, tanks, and dehydrators that can lead to significant pollution.

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[10] Mitchell, A.L., et al, (2015) "Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants," *Environ. Sci. Technol*, 2015, 49 (5), pp 3219–3227, available at http://pubs.acs.org/doi/abs/10.1021/es5052809;

[11] R. Subramanian, et al, (2015) "Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol," *Environ. Sci. Technol*, available at http://pubs.acs.org/doi/abs/10.1021/es5060258.

[12] Harriss et al., "Using Multi-Scale Measurements to Improve Methane Emissions Estimates from Oil and Gas Operations in the Barnett Shale, Texas: Campaign Summary," available at http://pubs.acs.org/doi/abs/10.1021/acs.est.5b02305. The attached word document lists the links for all twelve papers, see attachment 2.

[13] *Id.*

[14] *Id.*

[15] Brandt, et al., "Methane Leaks from North American Natural Gas Systems," available at http://www.sciencemag.org/content/343/6172/733.summary.

[16] Lyon, et al., "Constructing a Spatially Resolved Methane Emission Inventory for the Barnett Shale Region", available at http://pubs.acs.org/doi/abs/10.1021/es506359c.

[17] Harriss, supra note 12.

[18] *See* Lyon, supra note 16.

III. Wyoming Should Adopt a Quarterly Instrument-Based LDAR P-BACT Requirement for Sources Outside the UGRB.

We strongly urge the Air Division and the AQAB to adopt a rigorous LDAR requirement for well sites and tank batteries located outside the UGRB consisting of, at a minimum, quarterly instrument-based inspections for facilities with 4 tons of VOC emissions per year of fugitive components as is the current requirement in the UGRB.

Leaks from components and unintentional venting from access points on storage sites are a major source of VOCs, hazardous air pollutants (HAP) and methane that can be cost effectively reduced. Equipment leaks are the second largest source of methane from production sources in Wyoming, such as well sites, per operator submitted emission reports to EPA. In 2013 operators reported emitting 22,164 tons of methane from equipment leaks in the state. This number increased to 24,634 tons in 2014. Moreover, equipment leaks are the third largest source of VOCs in the state, according to the latest National Emissions Inventory data from 2011, at that time accounting for 12,978 tons of VOCs statewide. Notably this is more than twice the combined VOCs from dehydrators, well venting and blowdowns, truck loading, completions and workovers, stationary engines, heaters and drill rigs. In 2011, area source oil and gas sources in Sublette, Lincoln and Sweetwater counties reported emitting 7,221 tons of VOCs into the atmosphere. The remaining counties in the state reported emitting 5,765 tons. Importantly, the actual amount of VOCs emitted from the counties subject to this P-BACT update is somewhere between 5,765 and 7,221 tons since the UGRB is comprised of only a portion of Lincoln and Sweetwater counties. Even more importantly, the actual amount of emissions from equipment leaks is likely significantly higher as demonstrated by the recent scientific studies discussed above and enforcement actions discussed below.

Not only are frequent instrument-based inspections necessary to detect and remediate equipment leaks and unintentional tank venting, they are also highly cost effective. As illustrated by the attached analysis (attachment 2), performing quarterly *instrument-based* inspections, whether done in-house or through a third-party contractor, is highly cost effective. Indeed, under either scenario the natural gas savings exceed the cost of the entire program. Even if gas savings are not monetized, quarterly LDAR programs are among the most cost effective clean air measures available to dramatically reduce pollution from oil and gas facilities.

The attached spreadsheet is based on cost and emissions information in the ICF International report and an updated LDAR memorandum,[19] and on the final cost benefit analysis prepared by the Colorado Air Pollution Control Division (APCD) in support of the APCD's LDAR program in 2014.[20] Specifically, our analysis utilizes ICF's estimate of the costs to conduct quarterly LDAR in-house for a model 5-well site as the starting point. We increased the inspection time assumed by ICF by three hours per inspection to conservatively account for additional travel time that may be needed to travel to rural wells in Wyoming. This is based on

[19] ICF International, "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries," March 2014. LDAR analysis updated in May 29, 2015. Memorandum from Joel Bluestein to Peter Zalzal.

[20] Colorado Air Pollution Control Division, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7 (February 7, 2014).

Colorado's estimate that it would take operators an additional three hours to travel to wells outside of its Denver Metropolitan ozone nonattainment area.[21]

We also estimated the costs of conducting inspections using a third-party contractor. Colorado assumed a 30% profit margin for contractors that they added to the hourly rate for in-house inspectors.[22] Colorado estimated that a third party contractor could perform an inspection for $134/ hour compared to the $102 it would take an in-house employee. We used this assumption in the attached analysis and increased the hourly in-house inspection rate by 30% to portray the costs of hiring a contractor to perform LDAR inspections.

Per the attached spreadsheet, quarterly *instrument-based* inspections are highly cost effective if operators perform them in-house or hire third-party contractors. Specifically, such inspections result in the following costs and benefits:

- $4,265 per year (in-house), resulting in 10 tons of VOCs and 35 tons of methane reduced. Overall cost effectiveness is $440 per ton of VOC reduced (not accounting for gas savings) and **negative** $281 per ton of VOC reduced (accounting for gas savings).
- $5,544 per year (contractors) with an overall cost effectiveness of $395 per ton of VOC reduced (not accounting for gas savings) and **negative** $327 per ton of VOC reduced (accounting for gas savings).

Many operators can monetize the savings resulting from fixing leaks. In those cases where gas pipelines are available, operators can route the avoided gas losses to sales. In those instances where pipelines are not available currently, operators can often utilize the gas for onsite fuel. And, in many instances, gas infrastructure is in the process of being built and therefore, even if operators cannot route the saved product to sales today, they will be able to do so in the near future.

ICF and Colorado estimate that quarterly instrument-based inspections can achieve a 60% reduction in leaks.[23] Notably, this estimate is based on the assumption that IR cameras and other modern leak detection equipment can effectively detect leaks. It is not based on an estimate of the effectiveness of sensory-based inspection methods such as audio, visual, olfactory.

1. <u>EPA Overstates LDAR Costs and Underestimates Reductions</u>

EPA recently released a technical support document to accompany its LDAR proposal in its proposed New Source Performance Standards (NSPS) for the oil and gas sector.[24] EPA has proposed to require new well sites and compressor stations to conduct LDAR on a semi-annual basis, with the potential to move to quarterly or annual depending on the percent of leaking components detected after two consecutive semi-annual inspections.

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[21] *Id.*, at p.20-21
[22] *See* Colorado Cost Benefit Analysis for Proposed Revisions to AQCC Regulations, p. 20.
[23] *Id.* at 27 (citing EPA reported data); ICF March 2014 report at 3-10.
[24] EPA, Background Technical Support Document for the Proposed New Source Performance Standards, 40 CFR Part 60, subpart OOOOa (August, 2015).

EDF is in the process of analyzing EPA's proposal and underlying cost effectiveness analysis. Based on our preliminary analysis, we have identified a number of flaws in the analysis that would result in a program that significantly underestimates the emissions subject to LDAR and therefore the reductions associated with it. Therefore, we strongly urge that EPA's assumptions not be used in assessing the costs associated with an LDAR program in Wyoming.

To estimate the cost effectiveness of conducting semi-annual inspections EPA assumed a model well site with 2 wells. Our preliminary analysis suggests this may not be representative of new well sites nationally or in Wyoming. For example, EDF analyzed average well site facilities across a number of studies and analyses including a study conducted at 375 well sites in the city of Fort Worth, Texas,[25] a University of Texas study of 150 gas well sites in 4 different basins,[26] and 20,875 gas wells in the Barnett Shale region.[27] These studies reveal higher average well counts per site in the majority of instances. The average well site in the Fort Worth study has 3 wellheads, 3.2 wellheads per site in the University of Texas studies, and 1.9 wellheads per site in the Barnett study. Notably, a larger model facility will emit more fugitive emissions, which increases the reductions obtainable from LDAR and therefore increases the cost effectiveness of frequent inspections.

To estimate the amount of potential uncontrolled equipment leaks subject to LDAR, EPA relied on outdated emission factors that do not take into account the recent science and inspections documenting the prevalence of super-emitters or modern facility designs. EPA relied on emission factors for leaking components from a 1996 GRI study to estimate component counts at its model 2-well facility and to estimate emissions per component. The GRI study predates the recent measurement studies and enforcement actions discussed herein. Accordingly, the actual cost effectiveness of frequent LDAR is likely greater than the model estimates as the estimate of a facility's potential to emit does not reflect excess emissions due to equipment malfunctions or other avoidable errors.

In addition, EPA's model relies on outdated assumptions regarding the number of potential fugitive emissions at a site. We compared EPA's assumptions to other more recent analysis and studies. Per the Fort Worth study and CDPHE cost benefit analysis used to support CDPHE's methane rules, today's well sites have significantly more components, and therefore greater potential emission sources than EPA's model facility. Specifically, whereas EPA estimates 548 components at its 2-well model facility, the Fort Worth study found 1,826 components at its 3-well facility. As a result, actual equipment leaks are likely significantly higher than EPA's estimates.

IV. EPA and CDPHE Inspections and Enforcement Actions Support Frequent Instrument-Based Inspections Coupled with Appropriate Storage Tank System Design

Recent inspections by EPA and the state of Colorado have revealed that inadequately

[25] City of Fort Worth Natural Gas Air Quality Study, (July 13, 2011), available at http://fortworthtexas.gov/uploadedFiles/Gas_Wells/AirQualityStudy_final.pdf.
[26] See Allen et al., supra note 6.
[27] See studies discussed in Harris, supra note 12.

designed and operated storage tank vapor control systems can result in very significant emissions and leaks.[28] Equipment must be designed to handle the pressure of liquids when transferred from separators to tanks. If the tank vapor system is not adequately sized to handle the peak surge of flash emissions that occur when pressurized liquids dump to the atmospheric storage tanks, then flash emissions do not make it to the control devices. Rather, access points on tanks, such as thief hatches and pressure relief valves that are designed to open during emergencies or maintenance by contrast release during normal operation.

In inspections of 99 storage tank facilities in Colorado's Denver-Julesburg basin in 2012, the Colorado Air Pollution Control Division and EPA found that emissions were not making it to their intended control devices at 60% of the facilities. These inspections formed the basis for a $73 million dollar settlement between Noble Energy, the EPA and the state of Colorado,[29] as well as a recent EPA Compliance Alert.[30] According to EPA, the primary reasons for these detectable emissions are: (1) inadequate design and sizing of vapor control systems; and (2) inadequate vapor control system operation and maintenance practices.

Frequent instrument-based inspections of storage tanks is critical to help operators identify some of the problems that lead to unintentional venting, such as an inadvertently left open thief hatch, improperly seated or designed pressure relief valves or failing gaskets on a hatch. Indeed, frequent instrument-based inspections at various intervals including monthly and quarterly is a central component of Colorado's requirements aimed specifically at addressing unintentional venting from storage tanks.[31]

In addition to frequent inspections, EPA and Colorado have also identified other practices and requirements operators can use to detect storage tank system malfunctions and inadequate designs. These include the following "Storage Tank Emission Management" (STEM) requirements in Colorado:

- Document any training undertaken by operators conducting the monitoring;
- Analyze the engineering design of the storage tank and air pollution control equipment, and where applicable, the technological or operational methods employed to prevent venting;
- Identify the procedures to be employed to evaluate ongoing capture performance;
- Have in place a procedure to update the storage tank system if capture performance is found inadequate;
- Certify that they have complied with the requirement to evaluate the adequacy of their storage tank system.[32]

[28] Consent Decree *U.S. v. Noble Energy*, (No. 1:15 cv 00841, D. CO., April 22, 2015), available at http://www.justice.gov/sites/default/files/enrd/pages/attachments/2015/04/23/lodged_consent_decree.pdf; EPA Compliance Alert, "EPA Observes Air Emissions from Controlled Storage Vessels at Onshore Oil and Natural Gas Production Facilities," Sept. 2015, available at http://www2.epa.gov/sites/production/files/2015-09/documents/oilgascompliancealert.pdf.
[29] *Id.*
[30] *See* Compliance Alert, *supra* note 28.
[31] 5 CCR 1001-9 §, XVII.C.1.d.
[32] 5 CCR 1001-9 §§, XVII.C.2.b.; XIX.N., Statement of Basis, Specific Statutory Authority, and Purpose (Feb. 23, 2014).

We urge the Wyoming DEQ to adopt a rigorous LDAR program that applies to storage tank access points, as well as components, and also includes the Colorado STEM requirements, to prevent the types of emissions and rule violations that EPA and Colorado have detected from tanks. The current LDAR requirement in the UGRB does not apply to storage tank access points. We believe this is a significant flaw in the UGRB requirement that should be addressed in a future P-BACT update.

V. Control Thresholds

We urge the DEQ to evaluate closely the control thresholds for tanks and dehydrators at single well facilities, tank batteries and fugitive emissions outside the UGRB, and to propose a threshold that will ensure the maximum cost effective emission reductions from these sources. Specifically, we urge DEQ to consider a 4 ton per year (tpy) threshold for tanks, dehydrators and fugitive emissions outside the UGRB. This would harmonize requirements throughout the state and ensure that residents in the eastern and southwestern counties benefit from the same protective air pollution controls.

We support the requirement that tanks and dehydrators at PAD facilities in the new SWA must control emissions by 98% upon the first date of production. We also support the fact that the Air Division has required virtually the same controls for pneumatic pumps and controllers, and liquids unloading activities, for sources located in the UGRB and in the SWA. This demonstrates that it is possible for operators throughout the state to conduct their operations in a similar manner according to the same rigorous control requirements.

We urge the Air Division to review Colorado's recent analysis of the cost to install a flare on a tank or dehydrator. According to the CDPHE, installing a flare equipped with an auto-igniter on a tank with uncontrolled VOC emissions of 6 tpy is cost effective at $1,471 per ton of VOC reduced. This is based on total recurring and one-time costs submitted by Colorado operators of $31,410[33] and annualized costs of $6,286.80 per unit. The CDPHE assumed a 95% effectiveness for the flare. For dehydrators, Colorado assumed the same $6,286.80 annualized costs apply. The state found that applying a flare equipped with an auto-igniter capable of achieving a 95% destruction efficiency to dehydrators with between 2 and 6 tons of uncontrolled VOC emissions is cost effective at $3,309 per ton of VOC reduced and applying the same flare to a dehydrator with 6 tons of uncontrolled VOCs is cost effective at $786 per ton of VOC reduced.[34]

The Air Division has not estimated the costs of controlling tanks and dehydrators in the new statewide area for this update. Rather, it is relying on its analysis from the 2013 update of the P-BACT guidance. At that time, it determined that the average cost effectiveness to control VOC emissions from tanks with 4 tons per year of VOCs was $22,938.[35] Similarly, it estimated

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[33] Final Cost Benefit Analysis at 7. This assumed capital costs of $18,169 for the flare, $1,648 for the auto-igniter, one-time freight and engineering costs of $8,628 and ongoing maintenance costs of $2,965.
[34] *Id.* at 34.
[35] This was based on operator submitted information indicating that the cost of installing a flare ranged from $10,000 (16 inch combuster per Ultra) to $158,620 (102 inch combuster per Shell).

the average cost effectiveness of installing a combuster on a dehydrator at a control threshold of 4 tpy of VOCs to be $21,706 and $14,397 for a dehydrator at a control threshold of 2 tpy of VOCs.

We urge the Air Division to review the Colorado cost-benefit analysis to determine whether the flare cost and cost effectiveness analysis the Air Division relied on in 2013 could be updated.

To shed light on the impact of a 4 and 6 tpy threshold for controlling fugitives in the new SWA we analyzed 18 permit applications for facilities in Campbell, Converse and Laramie counties. This analysis further supports setting a 4 tpy threshold for LDAR. Per this analysis, 8 of the facilities estimated fugitive emissions at or above 4 tpy. Establishing a 4 tpy threshold would result in 45% of the facilities and 72% of the fugitive emissions from the 18 facilities being subject to quarterly inspections. Conversely, were the Air Division to set the LDAR threshold at 6 tons per year, as it has proposed for tanks and dehydrators in the new SWA, only 17% of the facilities and 35% of the fugitive emissions from the 18 facilities would be required to conduct quarterly inspections. While we maintain that LDAR is cost effective and feasible for facilities with less than 4 tons per year, we believe 4 tons per year is the maximum threshold for quarterly LDAR that the Air Division should consider.

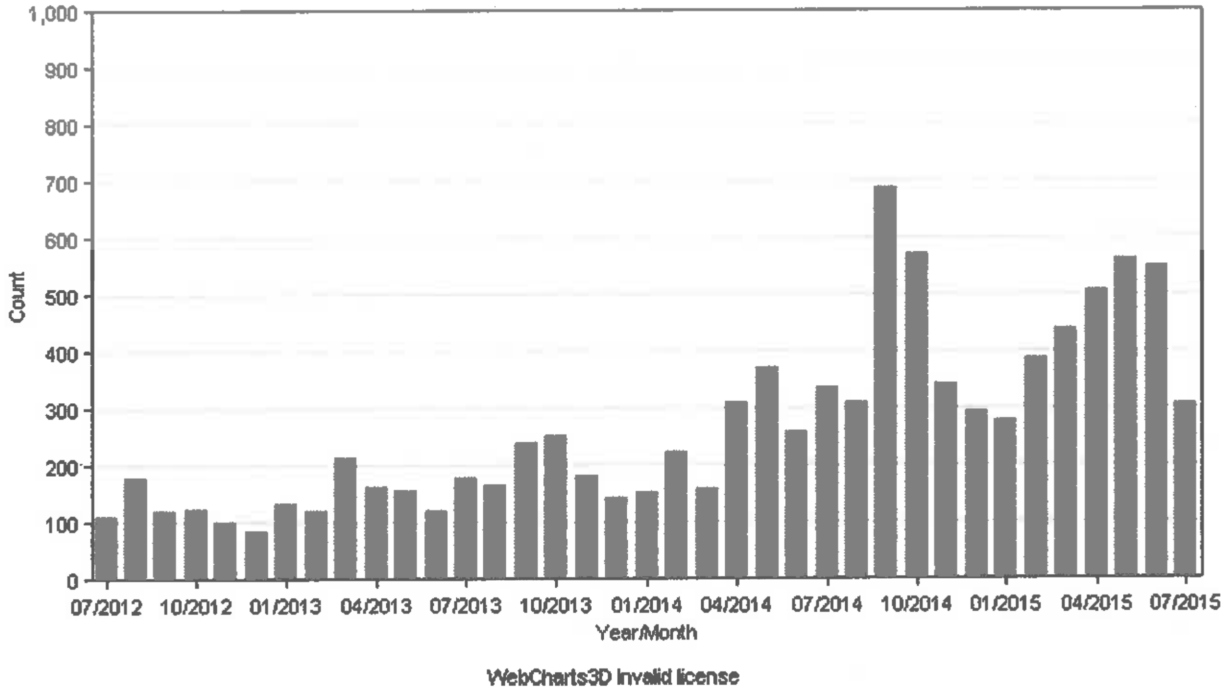
VI. Green Completions for Wells Outside the UGRB

We support the Air Division's plan to extend the "green completion" (well completion) requirement in effect for the UGRB and the current CDA to wells located statewide and offer below some information to support such an extension to oil wells specifically, in light of the federal reduced emission completion (REC) requirements applicable to gas wells, and the increase in oil production in the state.

Notably, the federal REC requirement that requires the capture and control of completion emissions only applies to "gas" wells, as defined by EPA. Accordingly, operators of oil wells that co-produce gas ("co-producing wells") that do not meet EPA's definition of a gas well are not required to capture or control emissions during completion activities. Completion emissions from co-producing wells can be significant, however, and the same cost effective practices used to control gas well completion emissions can be applied to reduce emissions from co-producing wells.

Permits to drill oil wells have grown in Wyoming as the following chart of requests for oil well permits to the Oil and Gas Conservation Commission demonstrates.[36]

[36] http://wogcc.state.wy.us/AllApdGraphOil.cfm



Approximately 75% of applications for permits to drill in 2014 came from Laramie, Converse and Campbell counties, in the SWA.[37]

1. Co-producing wells emit significant pollution.

Like natural gas wells, co-producing wells emit significant amounts of VOCs, HAPs, and methane during well completion activities.

EDF recently reviewed the best available data regarding completion emissions from co-producing wells.[40] The data included direct measurement of emissions obtained through the University of Texas (UT) Production Study as well as estimates of emissions obtained from three other studies. Relying principally on the direct measurements obtained from the UT Production Study, EDF estimates that completion emissions from co-producing wells range from 3.7 to 101.8 tons of VOCs per completion event and 15.7 to nearly 200 metric tons of methane per event.[41] Importantly, because oil wells typically have a greater percentage of VOCs than gas wells, the VOC emissions from oil well completions may exceed those from gas well completions.[42]

2. The Same Practices and Technologies Are Used to Control Co-Producing Well Emissions as are Used to Control Gas Well Completions.

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[37] Information obtained by EDF from WOGCC website on October 26, 2015.
[40] *See* Peer Reviewed Responses of EDF "Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions And Associated Gas during Ongoing Production" (June 16, 2014) ("EDF Comments to EPA"), available at http://www.epa.gov/airquality/oilandgas/2014papers/attachmentd.pdf.
[41] *Id.* at 1.
[42] *Id.* at 5.

The same equipment is used to capture or control emissions from gas well completions as oil well completions.[43] In the UT Production Study, researchers measured six completions at oil wells. In each instance, operators captured or flared the co-produced gas. In four instances operators used a combination of flaring and capture equipment. In the other two instances, operators flared the gas.[44] Similarly, Colorado has required both oil and gas wells capable of producing 500,000 cubic feet per day of natural gas to use "green completion" practices to control emissions since 2009.[45] Per this requirement, "all saleable quality gas shall be directed to the sales line as soon as practicable or shut in and conserved." [46] Temporary flaring is allowed as a safety measure in certain circumstances such as upsets.[47] Moreover, EPA recently recognized that "the same equipment is used for REC's at gas wells and co-producing oil wells."[48] This information underscores the feasibility of extending the Wyoming green completion requirement to wells located in the SWA.

3. <u>Capturing or flaring co-produced gas is highly cost effective</u>

Requiring green completions at co-producing wells is highly cost effective. Relying on data from multiple sources (data reported to EPA pursuant to its Mandatory Greenhouse Gas Reporting Rule, production data from the Eagle Ford, Permian, Wattenberg and Bakken basins and data from operators participating in the UT Production Study) EDF estimates a median cost effectiveness of $3,314/MT of methane reduced, with a credit for gas savings, for utilizing technologies that capture emissions during completions.[49] For those instances where operators would be allowed to use a flare to control emissions, rather than capture emissions, EDF estimates the use of high efficiency flares ranges from $19-$424 per metric ton of methane reduced. The recent ICF report estimated the use of high efficiency flares to be $97 per metric ton of methane reduced.[50]

EPA estimates the costs of performing a REC range from $700 per day to $6,500 per day, depending on whether necessary equipment must be brought onsite or already exists.[51] The UT Production Study suggests an average oil well completion lasts 3 days. Using EPA's average per day value of $4,146 for REC costs, the costs of performing RECs at oil wells would be just over

[43] Specifically, operators of co-producing wells either utilize gas capture equipment such as tanks and separators to route gas co-produced during oil well completions to sales lines or, if sales lines are unavailable, they combust co-produced gas.
[44] *Id.*
[45] Colorado Oil Gas Conservation Commission Rule 805(b)(3).
[46] *Id.* at (b)(3)(B)(v).
[47] *Id.*
[48] EPA, "Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production", at 25 (April 2014), available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415completions.pdf.
[49] EDF white paper "Co-Producing Wells As a Major Source of Methane Emissions: A review of Recent Analysis", March 2014, available at http://blogs.edf.org/energyexchange/files/2014/03/EDF-Co-producing-Wells-Whitepaper.pdf.
[50] *Id.*
[51] EDF Comments to EPA.

$12,000 per event.[52] This does not account for gas savings. For those instances where an operator is able to send the recovered gas to a sales line, the UT Production Study suggests average monetary savings per completion to be $25,630 (assuming $4/Mcf).[53]

VII. Conclusion

Changing development patterns and the new lowered ozone NAAQS calls into question the need to differentiate requirements for sources located in the UGRB and those located elsewhere. Colorado recently issued rules for oil and gas well sites and compressor stations that are uniform across the state, despite the fact that it currently has only one ozone nonattainment area. As demonstrated above, there are a suite of highly cost effective measures,[54] including frequent instrument-based inspections, available to reduce oil and gas emissions and we urge Wyoming to consider requiring the most protective standards possible to sources across the state. The provisions in the UGRB and Jonah and Pinedale Anticline Development Area should be fully considered for implementation in the new statewide area.

We look forward to working with you in the months ahead as the state works on this important guidance update.

Respectfully submitted,

Jon

Jon Goldstein
Elizabeth Paranhos
Environmental Defense Fund

And on behalf of:

Bruce Pendery
Wyoming Outdoor Council

[52] EPA is using 2008 cost information and since RECs have become more prevalent since then, actual costs are likely lower.
[53] EDF Comments to EPA.
[54] ICF International, Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, March 2014.

EDF ENVIRONMENTAL DEFENSE FUND
Finding the ways that work

Wyoming Outdoor Council

Mr. Steve Dietrich, Administrator
Wyoming Department of Air Quality
122 West 25th Street
Cheyenne, WY 82002

VIA Fax (307) 777-5616

July 6, 2015

Re: Comments on Air Quality Permit Application Analyses: A0000587 (Durham 526-0719H), A0000585 (Durham 530-0719H), and A0000714 (Jubilee Sec. 23 PAD).

Dear Mr. Dietrich:

Please accept these comments from the Wyoming Outdoor Council and Environmental Defense Fund on the above-referenced air permit application analyses. The Wyoming Outdoor Council is the state's oldest independent conservation organization. We've worked for more than four decades to protect Wyoming's environment and quality of life for future generations. EDF is a national membership organization with over one million members residing throughout the United States and in Wyoming who are deeply concerned about the pollution emitted from oil and natural gas sources.

While Wyoming has put in place nationally leading requirements to reduce harmful hydrocarbon emissions from oil and gas production sites, unfortunately these requirements are not evenly applied across the state. Strong measures, such as the existing source rules approved by the Environmental Quality Council in May and new and modified source requirements approved by the Air Quality Advisory Board in 2013, apply only in the Upper Green River Basin (UGRB) of southwestern Wyoming. These rules do not apply to sources such as Durham 526-0719H, Durham 530-0719H, and Jubilee Sec. 23 PAD currently under consideration in Laramie County.

As reported by the Casper Star-Tribune in May, 2014, "Eighty percent of the some 4,300 oil and gas wells permitted in Wyoming during the past 12 months are in counties with the lowest level of state air quality protection." We continue to believe that oil and gas production sites in eastern Wyoming, where the lion's share of the state's drilling activity is currently occurring -- including these Laramie County wells currently under consideration -- need stronger requirements to better protect air quality and the health of local residents.

One of the strong requirements the state has put in place to reduce emissions from both new and existing oil and gas sources in the UGRB are frequent instrument based leak detection and repair inspections. While the Jubilee well site (A0000714) contains a relatively stringent voluntary LDAR protocol, the Durham sites (A0000587 and A0000585) do not. Were these wells located in the UGRB, all would be required to conduct quarterly, instrument based inspections to find and fix leaking equipment and reduce emissions of harmful compounds.

At the Jubilee site EOG reports a potential to emit (PTE) of more than 8 tons per year of Volatile Organic Compounds (VOCs). EOG has included in its application a LDAR protocol includes quarterly inspections using IR cameras and detailed recordkeeping and reporting of inspections and repairs. Repairs would be made within seven days on the first attempt, or within seven days of the initial attempt, unless facility shutdown would be necessary. For the Jubilee site we are supportive of the quarterly monitoring, and detailed recordkeeping and reporting which are in line with the state's UGRB requirements. However, we believe quarterly LDAR should be required for all facilities – not implemented on a voluntary, operator by operator, basis.

We have greater concerns with the Durham well sites (A0000587 and A0000585). These sites have a potential to emit (PTE) of 4 tpy of VOCs, but they only require an annual inspection with an IR camera or Method 21. The inspection requirements at the Durham sites are clearly less stringent than what is required in the UGRB for sources with the same potential to emit. It is our view that facilities in eastern Wyoming should be required to inspect with the same frequency as those located in the UGRB. In the UGRB facilities with a PTE of 4 tpy of VOC must conduct quarterly instrument-based inspections and record the dates and times of the inspections. Quarterly inspections provide the minimum oversight necessary to protect human health and the environment.

Quarterly inspections are also very cost effective. During the UGRB existing source rulemaking we estimated the cost effectiveness of quarterly inspections at well sites with 4 tons of VOCs as $1,442 per ton of VOC reduced assuming no credit for gas savings and $480 assuming credit for recovered gas. Operators of well sites are able to monetize the gas savings that accrue from maintaining rigorous leak detection and repair protocols, as they own the gas. Therefore, it is proper to consider the credit for gas savings when evaluating the cost effectiveness of conducting LDAR inspections at well sites.

Notably, DEQ has found significantly higher compliance costs to be reasonable than those we estimate here. Specifically, in updating the permit guidance requirements for new and modified sources in the Basin in 2013, the DEQ determined average costs per ton of VOC reduced of $22,938 to control flash emissions and $21,706 to control glycol dehydrators to be economically reasonable.[1] This further underscores the reasonableness of requiring at least quarterly instrument based inspections at well sites throughout Wyoming.

The rapid oil and gas development in Wyoming's eastern counties demonstrates the need for rigorous pollution control measures throughout the state. The Department of Environmental Quality (DEQ) has been a leader in implementing cost effective, rigorous controls to reduce VOC and hazardous air pollutant emissions from oil and gas activities in the UGRB for over a decade. The residents of the eastern counties deserve the same level of protection from harmful emissions as those in the western part of the state. Moreover, extending the UGRB protections statewide will provide regulatory certainty to industry and even the playing field among operators.

DEQ is entrusted with the duty to "preserve, and enhance the air" in Wyoming.[2] To fulfill this mandate, DEQ must take steps to ensure that pristine air quality is protected from degradation. Requiring that operators employ leading, cost effective pollution control measures such as frequent instrument based inspections is necessary to protect the air quality in the eastern counties. We therefore urge DEQ to require the same level of controls throughout the state when approving of new or modified oil and gas sources.

Thank you for considering these comments.

Sincerely,

Bruce Pendery
WOC

Jon Goldstein
EDF

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[1] Department of Environmental Quality, Division of Air Quality, Proposed Revisions to the Chapter 6, Section 2 Oil and Gas Production Facilities Permitting Guidance, Technical Support Document, 4, 6 (Sept. 2013).

[2] Wyoming Environmental Quality Act, 35-11-102.

Quarterly and Annual OGI LDAR Cost-Effectiveness Calculation [1]

Surveryor:	Well Pad LDAR Conducted by Operator			Well Pad LDAR Conducted by Contractor		
Frequency:	Quarterly	Semi-Annual	Annual	Quarterly	Semi-Annual	Annual
Methane Mcf Overall [2]	3,058	3,058	3,058	3,058	3,058	3,058
VOC emissions (mt)	16.14	16.14	16.14	16.14	16.14	16.14
Methane emissions (mt)	58.10	58.10	58.10	58.10	58.10	58.10
CH4/VOC Ratio	3.60	3.60	3.60	3.60	3.60	3.60
% Reduction	60%	50%	40%	60%	50%	40%
Methane Mcf reduced	1,835	1,529	1,223	1,835	1,529	1,223
VOC reduction (mt)	9.68	8.07	6.46	9.68	8.07	6.46
CH4 reduction (mt)	34.86	29.05	23.24	34.86	29.05	23.24
Time per Inspection (hrs)	5.7	5.7	5.7	5.7	5.7	5.7
Inspections per year	4	2	1	4	2	1
Inspection Time (hrs/yr)	22.7	11.3	5.7	22.7	11.3	5.7
Hourly Cost ($/hr)	$101.64	$101.64	$101.64	$132.13	$132.13	$132.13
Initial set-up Cost, $	$230.51	$230.51	$230.51	$299.66	$299.66	$299.66
Inspection Cost, $/yr	$2,305.10	$1,152.55	$576.27	$2,996.63	$1,498.31	$749.16
Repair Cost, $	$1,728.82	$1,440.69	$1,152.55	$2,247.47	$1,872.89	$1,498.31
Total Cost, $	$4,264.43	$2,823.74	$1,959.33	$5,543.76	$3,670.87	$2,547.13
Recovered gas value [3], $	$6,984.57	$5,820.48	$4,656.38	$6,984.57	$5,820.48	$4,656.38
Net cost, $	-$2,720.15	-$2,996.73	-$2,697.05	-$1,440.82	-$2,149.61	-$2,109.25
$/mt VOC-No gas credit	**$440.42**	**$349.95**	**$303.53**	**$572.54**	**$454.94**	**$394.59**
$/mt CH4-No gas credit	**$122.34**	**$97.21**	**$84.31**	**$159.04**	**$126.37**	**$109.61**
$/mt VOC-Gas credit	**-$280.93**	**-$371.39**	**-$417.82**	**-$148.80**	**-$266.41**	**-$326.76**
$/mt CH4-Gas credit	**-$78.04**	**-$103.16**	**-$116.06**	**-$41.33**	**-$74.00**	**-$90.77**
$/Mcf CH4-No gas credit	**$2.32**	**$1.85**	**$1.60**	**$3.02**	**$2.40**	**$2.08**
$/Mcf CH4-Gas credit	**-$1.48**	**-$1.96**	**-$2.21**	**-$0.79**	**-$1.41**	**-$1.72**

OGI Hourly LDAR Cost Calculation [4]

Labor		Capital and Initial Costs	
Inspection Staff	$75,000	Infrared Camera	$122,200
Supervision (@ 20%)	$15,000	Photo Ionization Detector	$5,000
Overhead (@10%)	$7,500	Truck	$22,000
Travel (@15%)	$11,250	Recordkeeping System	$14,500
Recordkeeping (@10%)	$7,500	**Total**	**$163,700**
Reporting (@10%)	$7,500	Hours/yr	1,880
Fringe (@30%)	$22,500	Hourly Labor Rate	$77.79
Subtotal Costs	**$146,250**	Training Hours	80
		Training Dollars	$6,223
		Amortized Capital +Training	**$44,825**
		Annual Labor	**$146,250**
		Annual Total Cost	**$191,075**
Total Hourly Cost (LDAR conducted by operator)			**$101.64**
Total Hourly Cost (LDAR Conducted by contractors, 30% profit margin) [5]			**$132.13**

Notes:

[1] Analysis compiled by EDF based on (1) ICF quarterly IR camera LDAR analysis and (2) additional assumptions. These assumptions include an additional 3 hours for inspection time to account for increased travel time (per CO COst-Benefit analysis assumptions), and decreased repair time for semi-annual and annual inspections (equal to 2X the inspection time for annual and 2.5X for semi-annual, rather than 3X the inspection time for quarterly).

[2] For well pads, methane content of natural gas assumed to be 78.8%.

[3] Costs are based on gas value of $3/Mcf gas. The original analysis used $4/Mcf, but this has been updated to reflect current prices.

[4] Hourly costs for IR Camera LDAR based on annualized rate of 5-year, 10%.

[5] Hourly cost for contractor includes 30% profit margin, per the CO Cost-Benefit Analysis Assumption.