UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review	))))))))	**<u>Docket No. EPA-HQ-OAR-2021-0317</u>** *Via regulations.gov* *February 13, 2023*

We submit these comments on behalf of:

THE COLORADO LOCAL GOVERNMENT COALITION OF CITY OF AURORA, BOULDER COUNTY; CITY AND COUNTY OF BROOMFIELD; COMMERCE CITY, THE CITY OF LAFAYETTE; THE CITY OF LONGMONT; THE TOWN OF ERIE, AND COLORADO COMMUNITIES FOR CLIMATE ACTION, CONSISTING OF: ADAMS COUNTY, THE CITY OF ASPEN, THE TOWN OF AVON, THE TOWN OF BASALT, THE CITY OF BOULDER, BOULDER COUNTY, THE TOWN OF BRECKENRIDGE, THE CITY AND COUNTY OF BROOMFIELD, THE TOWN OF CARBONDALE, CLEAR CREEK COUNTY, THE TOWN OF CRESTED BUTTE, THE TOWN OF DILLON, THE CITY OF DURANGO, EAGLE COUNTY, THE CITY OF EDGEWATER, THE TOWN OF ERIE, THE CITY OF FORT COLLINS, THE TOWN OF FRISCO, GILPIN COUNTY, THE CITY OF GLENWOOD SPRINGS, THE CITY OF GOLDEN, THE CITY OF LAFAYETTE, LAKE COUNTY, LARIMER COUNTY, THE CITY OF LONGMONT, THE CITY OF LOUISVILLE, THE TOWN OF LYONS, THE TOWN OF MOUNTAIN VILLAGE, THE TOWN OF NEDERLAND, THE CITY OF NORTHGLENN, OURAY COUNTY, PITKIN COUNTY, THE TOWN OF RIDGWAY, ROUTT COUNTY, THE TOWN OF SALIDA, SAN MIGUEL COUNTY, THE TOWN OF SNOWMASS VILLAGE, SUMMIT COUNTY, THE TOWN OF SUPERIOR, THE TOWN OF TELLURIDE, THE TOWN OF VAIL, AND THE CITY OF WHEAT RIDGE

I. Introduction

The above-referenced local governments, participating together as the Colorado Local Government Coalition ("Colorado LGC" or "LGC") submit the following comments on EPA's proposal to reduce greenhouse gasses ("GHGs") and other harmful air pollutants from the Crude Oil and Natural Gas Source Category under the Clean Air Act ("CAA" or the "Act"), *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, 87 Fed. Reg. 74,702 (Dec. 6, 2022) (the "Proposal" or "NSPS Rule").[1] Rigorous and comprehensive national measures to

[1] These comments revise the signature for Boulder County but are otherwise exactly the same as comments submitted to the docket earlier on Feb. 13, 2023.

curb pollution from this industry are critically necessary to address climate change and regional ozone pollution caused by venting, flaring and leaks.

A subset of the current members of the Colorado LGC[2] submitted comments on the rule EPA proposed in November of 2021, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, 86 Fed. Reg. 63,110 (Nov. 15, 2021) ("Nov. 2021 Proposal"). Those comments discussed the impacts of climate change on Coloradans and expressed support for strong national rules to curb methane pollution. We recommended EPA eliminate emissions from natural-gas powered pneumatic controllers based on rules adopted in Colorado and New Mexico; require annual leak detection and repair ("LDAR") for wells with the potential to emit ("PTE") less than 3 tons per year ("tpy") of methane; prohibit the routine flaring of associated gas based on rules adopted in Colorado and New Mexico; allow the use of advanced monitoring, including participation by the local community, to find and fix leaks more quickly; require quarterly LDAR inspections for idle wells and annual inspections for plugged wells; and require capture or control of other sources of venting, such as pigging, equipment blowdowns, and hydrocarbon liquid transfers. Our 2021 comments set forth the basis for our recommendations, which in many cases stemmed from our own experience as permitters and regulators of oil and gas sources and the experience of leading states, such as Colorado and New Mexico, in regulating oil and gas emissions.

We strongly support many of the provisions in the current proposal as consistent with our prior recommendations and leading state standards. In particular, we commend EPA on the following aspects of its proposal which reflect our 2021 comments: the zero-emission standard for new and existing gas-powered pneumatic controllers; the use of an equipment-based approach to dictate the frequency of LDAR inspections in lieu of the former PTE based approach; the new super-emitter response program that allows third parties (including state or local governments) to conduct inspections for large, i.e., "super-emitter" leaks; the inclusion of idle wells in LDAR and inspection requirements up to the end of a well's life; and the requirement of operators to submit a well closure plan for plugged wells to EPA.

Our comments below include a brief discussion of the need for national rules to reduce ozone precursor emissions and protect disproportionately impacted communities. We support the proposed super-emitter response program as a very useful tool for accomplishing these goals. We provide recommendations for where we believe EPA can and should be more protective of human health and the environment. Specifically, as discussed below, we recommend EPA:

- Ban the routine practice of venting or flaring associated gas from oil wells while providing narrow, specific exemptions for temporary flaring.
- Reduce venting from well completions by requiring capture or control of emissions during the initial flowback stage of well completions and eliminating the technical infeasibility exemption in the separation flowback stage.

[2] Commerce City, the City of Aurora, and the Town of Erie were not part of the 2021 LGC but are part of the current coalition.

- Require annual optical gas imaging inspections for small well sites and wellhead only sites.
- Require operators submit a well closure plan for abandoned wells within 30 days of well approval, rather than within 30 days of well closure, and require review and resubmission of the plan, as necessary, upon transfer of ownership of wells.

II. The Importance of Strong Rules to Reduce Ozone Precursors

The LGC is deeply concerned with oil and gas related air pollution. The Denver metropolitan area has a long history of nonattainment with the various ozone National Ambient Air Quality Standards ("NAAQS"). Studies have identified elevated levels of atmospheric volatile organic compounds ("VOCs") in Colorado's North Front Range. These studies indicate the potential for significant ozone production from these emissions.[3] Denver ranks among the top 10 U.S. metropolitan areas for number of asthma attacks and is the eighth most ozone-polluted city in the United States.[4] The Denver Metro/North Front Range ("DM/NFR") ozone nonattainment area accounts for almost 58% of the state's population, with over 3.3 million people residing in the area. Despite numerous attempts to reduce ozone precursor emissions from the oil and gas sector since 2004, air quality in the DM/NFR is currently classified as Severe nonattainment for the 2008 NAAQS.

Oil and gas emissions are also contributing to ozone pollution outside the DM/NFR. Ozone monitors outside the DM/NFR are approaching the 2015 NAAQS. According to Colorado's September 30, 2022, ozone update, the design values (i.e., the three-year average of the fourth maximum recorded 8-hour concentration) for 2020-2022 were violating or approaching the 2015 NAAQS at several locations outside the nonattainment area.[5]

Ozone, a regional pollutant, affects most of Colorado's population, including many of our most vulnerable residents. Colorado counties with significant oil and gas development are plagued with such high levels of ozone that they received an "F" grade for ozone from the American Lung Association in 2021, as well as prior years. Several of these areas have a strong association with pediatric and adult asthma and cardiovascular disease and are home to people of color and people meeting the U.S. Census estimates of poverty.[6] Furthermore, climate change worsens

[3] G. Pétron, *et al*., Journal of Geophysical Research: Atmospheres, Vol. 117, No. D4, "Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study" (Feb. 21, 2012), at p. 17-18, *available at* https://agupubs.onlinelibrary.wiley.com/doi/10.1029/2011JD016360; J.B. Gilman, *et al*., Environmental Science & Technology, Vol. 47, "Source Signature of Volatile Organic Compounds from Oil and Natural Gas Operations in Northeastern Colorado" (Jan. 14, 2013), *available at* https://pubs.acs.org/doi/abs/10.1021/es304119a; R.F. Swarthout, *et al.*, Journal of Geophysical Research: Atmospheres, Vol. 118, No. 18, "Volatile organic compound distributions during the NACHTT campaign at the Boulder Atmospheric Observatory: Influence of urban and natural gas sources" (Aug. 12, 2013), at p. 10,635-36, *available at* https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/jgrd.50722.

[4] L. Fleischman, *et al.*, Clean Air Task Force, "Gasping for Breath: An analysis of the health effects from ozone pollution from the oil and gas industry" (Aug. 2016), at p. 10, *available at* http://www.catf.us/wp-content/uploads/2018/10/CATF_Pub_GaspingForBreath.pdf.

[5] Colorado Air Pollution Control Division, "Summary Table: 2022 Running O3" (updated Sept. 30, 2022), *available at* https://www.colorado.gov/airquality/html_resources/ozone_summary_table.pdf.

[6] American Lung Association: State of the Air, "Report Card: Colorado" (2022), *available at* https://www.lung.org/research/sota/city-rankings/states/colorado.

ozone, in a feedback that is felt most strongly in areas that are home to higher percentages of Hispanic/Latino residents, children living in limited-income households, and residents with health conditions and/or lacking health insurance.[7] Despite ozone forecasts and guidance issued by local governments and state air agencies to help residents avoid ozone exposure, disproportionately impacted community residents are more likely to work outdoors during high-ozone times and to have fewer occupational protections from ambient air pollution.

Local governments in Colorado, including Boulder County, the City and County of Broomfield, the City of Longmont and the Town of Erie have funded or conducted their own air quality studies in their communities to assess local impacts.[8] The results of those studies support the need for increased regulation of the oil and gas industry to improve ozone conditions and reduce greenhouse gas emissions.

Strong national rules, such as those proposed by EPA and with the additional improvements we suggest, will help protect Colorado's most vulnerable communities from harmful air pollution associated with ozone pollution and climate change while also helping Colorado come into attainment with the ozone NAAQS.

III. Super Emitter Response Program

We support the proposed "super-emitter response program." This program will help protect local communities from potentially dangerous emissions by allowing third parties to remotely monitor oil and gas facilities for large leaks. Specifically, as proposed the program contains the following elements:

- Third parties, who have been approved by EPA, may remotely monitor oil and gas facilities for large leaks. EPA proposes a leak threshold of 100 kg/hr.[9]
- Third parties may use remote sensing equipment including aircraft, mobile monitoring platforms, or satellites to detect super-emitters.[10]
- Upon detection of a super-emitter, third parties must notify the owner or operator of the oil and gas facility. The notification must provide detailed information including the location of the emissions, a description of the technology and sampling protocols used to identify emissions, and the date and time of detection and confirmation after data analysis that a super-emitter event was present.
- Third parties must notify EPA and any delegated state entity of the results of inspections. EPA must make such reports available to the public.
- Owners and operators who receive a notification of detection of a super-emitter event must take swift action to confirm if a super-emitter event occurred at one of their sites, and if so, to remedy it. Specifically, an operator must conduct a root cause analysis to identify the cause of the event. This could include conducting a

[7] LGC_PHS_EX-002, J.L. Crooks, *et al.*, Journal of Exposure Science & Environmental Epidemiology, "The ozone climate penalty, NAAQS attainment, and health equity along the Colorado Front Range" (Sept. 10, 2021), at p. 551, *available at* https://www.nature.com/articles/s41370-021-00375-9.
[8] https://bouldair.com/
[9] 87 Fed. Reg. 74702, 74,749 (Dec. 6, 2022).
[10] *Id*.

> follow-up investigation with an IR camera and repairing the source of the leak (e.g., closing a thief hatch on a controlled tank). If the investigation determines that the cause of the event is something other than a malfunction or abnormal emissions, the operator must identify the source of the event in their report to EPA. For example, a maintenance activity where venting is allowed, could be the source of the event. Operators must commence the root cause analysis within 5 calendar days of receipt of the third-party report and must conclude any corrective actions within 10 days of notification, unless additional time is necessary, in which case operators have until thirty days from receipt of the notification.[11] Operators must submit a report to EPA within 15 days of completion of the root cause analysis and corrective action describing the source of emissions, the corrective actions taken, and the compliance status of the affected facility.

The super-emitter program is intended to be a backstop to the LDAR program in that it can help ensure that large leaks or unintentional venting caused by malfunctions or abnormal operations are quickly detected and corrected.

EPA notes that facilities in compliance with the standards it proposes here should not be the source of significant super-emitters because EPA's proposal removes, or requires frequent monitoring, of the largest sources of leaks: controlled tanks; flares; gas-powered pneumatic controllers; and fugitive emissions components.[12] This is because EPA is requiring operators conduct quarterly inspections of controlled tanks and control devices such as flares, is phasing out existing gas-powered pneumatic controllers and requiring new pneumatic controllers to be zero bleed, and requiring frequent inspections of fugitive emissions components. We agree with EPA that the proposed requirements for pneumatic controllers and inspection requirements for control devices and fugitive emissions components located at large well sites will help eliminate or reduce super emitters from these sources. Were EPA to adopt our recommendation to require annual OGI inspections at small well sites and wellhead only sites, we would also agree with EPA that such requirements would help reduce super emitters from fugitive emissions components located at these facilities.

The super-emitter program will have important benefits for communities affected by air pollution from the oil and natural gas sector including communities disproportionately impacted by air pollution. The program will help reduce community exposure to harmful air toxics that are co-emitted with methane and VOCs. We strongly support EPA's proposal to make publicly available third-party inspection reports so that communities are aware of any potential exposure to harmful emissions.

IV. Opportunities for Improvement

A. Associated Gas Flaring

EPA's Proposed Rule would require operators to capture associated gas from the separator using one of the following options: (1) routing to a sales line; (2) using gas for an onsite fuel source;

[11] 87 Fed. Reg. at 74,750-51.
[12] 87 Fed. Reg. at 74,748.

(3) using the gas for another useful purpose that a purchased fuel or raw material would serve; or (4) reinjection into a well or injection into another well for enhanced oil recovery.[13] EPA proposes to allow flaring only where the operator certifies that it is not feasible to employ one of these options due to technical or safety reasons.[14] This demonstration would need to address the specifics regarding the lack of availability to a sales line, including efforts by the operators to get access to a sales line or to facilitate alternative offsite transport and use of associated gas and show why all potential beneficial uses are not feasible.[15] EPA proposes to require the initial demonstration include "a detailed analysis documenting and certifying the technical or safety reasons" as to why implementing the best system of emission reduction or any of the abatement alternatives is not feasible or safe.[16] EPA proposes operators obtain a certification by a professional engineer or other qualified individual when submitting an initial technical infeasibility demonstration.[17] Subsequently, an operator's annual report must include either a statement that no change has been made at the site since the original certification that would impact the operator's ability to comply versus flare, or if a change has been made since the original certification, a recertification of infeasibility or a statement indicating that compliance can be achieved and a description of how compliance will be achieved.[18] Operators must also include the start date, time, and duration of each instance of venting.[19]

We reiterate the comments we previously submitted to EPA on its initial proposal which called for a nation-wide ban on the wasteful and unnecessary practice of routine flaring. By routine flaring we mean ongoing, continuous flaring in the absence of a method for capturing and selling, putting to beneficial use, or storing associated gas.[20] Leading state examples and the commitments made by multiple operators demonstrate eliminating routine flaring is feasible and cost effective.

As our prior comments made clear, Colorado and New Mexico have largely banned this pernicious practice and we urge EPA to do the same. Colorado's rule provides: "[V]enting and Flaring of natural gas represent waste of an important energy resource and pose safety and environmental risks. Venting and Flaring, except as specifically allowed in this Rule 903, *are prohibited*."[21] Similarly, New Mexico's rule provides: "[V]enting or flaring of natural gas during drilling, completion, or production operations that constitutes waste as defined in 19.15.2 NMAC *is prohibited*. The operator has a general duty to maximize the recovery of natural gas by minimizing the waste of natural gas through venting and flaring. During drilling, completion and production operations, the operator may vent or flare natural gas only as authorized [through

[13] 87 Fed. Reg. at 74,779.
[14] *Id*.
[15] 87 Fed. Reg. at 74,780.
[16] 40 C.F.R. 60.5377b(b)(1).
[17] 87 Fed. Reg. at 74,779-74,780.
[18] 40 C.F.R. § 60.5420b(b)(4)(ii)(B).
[19] 87 Fed. Reg. at 74,780
[20] *See e.g.*, definition of routine flaring as flaring during normal oil production operations in the absence of sufficient facilities or amenable geology to re-inject the produced gas, utilize it on-site, or dispatch it to a market. The World Bank, Zero Routine Flaring by 2030 (ZRF) Initiative, https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/qna#8.
[21] 2 Colo. Code Regs. § 404-1-903.

specific regulations]."[22] Alaska has also largely banned this practice, allowing operators to flare only during specific, narrowly conditioned exceptions.[23]

Numerous operators have committed to eliminate routine flaring as part of the World Bank's Zero Routine Flaring by 2030 Initiative. To date, 54 oil companies and 34 governments have endorsed the "Zero Routine Flaring by 2030" Initiative. Based on satellite estimates and publicly reported flaring data, together the endorsers represent around 60% of global flaring.[24] Exxon Mobile recently announced a commitment to end routine flaring while also expressing support for regulations banning this wasteful practice. [25]

Eliminating routine flaring is a cost-effective way to curb methane emissions. Joint environmental commenters submitted a detailed analysis to EPA in 2021 documenting that the four abatement options EPA proposes here are cost effective.[26] Specifically:

- The Rystad report shows that connecting wells to gathering line infrastructure is not only highly cost-effective but actually profitable for operators, with an average net negative cost of $3.10 per thousand cubic feet (mcf) and $162 per MT of methane flaring avoided.[27]
- Rystad estimates that on average, on-site use of gas nets a profit of $8.60/mcf and $449 per MT of methane flaring avoided.[28]
- Rystad's report finds that on average, CNG trucking will cost operators $1.8/kcf, or $94 per MT of methane flaring avoided.[29] EPA views CNG trucking as falling into the "another useful purpose" category.[30]
- Reinjection costs vary depending on various factors, but Rystad finds that on average, costs are $3.4/mcf, and $177 per MT of methane flaring avoided.[31]

Importantly, the costs of the abatement options are well below EPA's cost-effectiveness threshold. In the November 2021 Proposal and the 2022 Supplemental Proposal, EPA proposes to find that cost-effectiveness values up to $1,970/ton of methane reduction are reasonable for controls identified as BSER.[32]

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[22] N.M. Code R. § 19.15.27.8(A).
[23] 20 Alaska Admin. Code § 25.235(d)(1)-(6) (for example, flaring due to emergencies and safety authorizations for planned lease operations are limited to a maximum of one-hour per event. *See* subsections (1), (2))).
[24] World Bank website, Zero Routine Flaring by 2030 (ZRF) Initiative, https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030.
[25] Exxon has stopped routine flaring of natural gas from production in the top U.S. shale basin and will press for stronger regulations for rivals to do the same. Reuters, *Exxon Halts Routine Gas Flaring in The Permian, Wants Others to Follow* (Jan. 24, 2023). https://www.nasdaq.com/articles/exclusive-exxon-halts-routine-gas-flaring-in-the-permian-wants-others-to-follow
[26] Env't Def. Fund et al., *Comments on Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, Dkt. No. EPA-HQ-OAR-2021-0317-0844 (Jan. 31, 2022) (Hereinafter "Joint Environmental Comments").
[27] Rystad Energy, Cost of Flaring Abatement, Slide 11 (Jan. 31, 2022) (Hereinafter "Rystad"), Ex. W to Joint Environmental Comments.
[28] *Id*.
[29] *Id*.
[30] 87 Fed. Reg. at 74,779.
[31] Rystad, Slide 11.
[32] 87 Fed. Reg. at 74,718.

We urge EPA to revise its proposal to prohibit routine flaring by requiring operators use one of the four abatement methods EPA here proposes. EPA should allow for flaring only during explicit, narrowly tailored, and time-limited, exemptions. Doing so will more clearly and unequivocally prohibit pollution stemming from routine flaring, as well as enhance the enforceability of the rule. Our comments below flesh out our concerns with the proposed approach and recommends an alternative framework for reducing associated gas venting and flaring. These concerns would be addressed if EPA adopted our recommendation to prohibit flaring other than in specific, time-limited, and narrowly tailored, exemptions.

1. The Technical Infeasibility Exemption is Vague and Broad

We have concerns with allowing operators to flare based on a demonstration that one of the four abatement options is "technically infeasible." EPA has not proposed a definition for "technically infeasible." As such, this exemption could apply to a large universe of circumstances identified by operators as falling within this broad exemption. An option that may be technically feasible for one operator may not be deemed feasible by another. From an operator's standpoint, the line between technical infeasibility and economic feasibility may be fluid. Without a clear definition of technical infeasibility, we are concerned that this broad exemption could lead to abuse. At a minimum, it is likely to be inconsistently applied by operators and by regulators. Specifically, and as discussed further below, Colorado promulgated rules to remove the "technical infeasibility" exemption in EPA's reduced emission completion requirements.[33]

Another concern with the technical infeasibility exemption is that it applies equally to both temporary and routine flaring. As the rules implemented in Colorado and New Mexico demonstrate, routine flaring is rarely, if ever, necessary. Both states require operators to demonstrate they will capture, not flare or vent, associated gas during production, at the time operators submit an application for a permit to drill. Specifically, Colorado requires an operator to "commit to connecting to a gathering system . . . or submit a gas capture plan" prior to commencing production. The gas capture plan must describe the operator's "plan for connecting their facilities to a natural gas gathering system or otherwise putting gas to beneficial use."[34] New Mexico requires operators certify that it will be able to connect a new well to a gas gathering system with sufficient capacity to transport all of the gas the operator anticipates the well will produce at the time the operator submits an application for a permit to drill.[35] If an operator cannot make such certification, an operator must either: (1) shut in the well until it can make the necessary certification; or (2) submit a venting and flaring plan that chooses one or more alternative beneficial uses until a gas gathering system is available, including power generation on lease, power generation for grid, compression on lease, liquids removal on lease, reinjection, fuel cell production, or other beneficial use approved by the state.[36] These common-sense requirements reflect the fact that operators have complete control over the decision regarding where and when to drill a new well and when to complete or put such a well into

[33] 5 Colo. Code Regs. § 1001-9-D-VI.D.1.a.
[34] 2 Colo. Code Regs. § 404-1-903.e.
[35] N.M. Code R. § 19.15.27.9.D.(4).
[36] N.M. Code R. §19.15.27.9.D.(5).

production.[37] As such, operators of new wells can address both timing and infrastructure capacity challenges.

Routine flaring from existing wells is equally avoidable or preventable. Operators of existing wells may currently not be connected to gathering lines or may lose their connection due to no fault of their own. In the event of the former, other cost-effective options are available including converting the associated gas to CNG, using it to replace a different fuel source, such as diesel for onsite fuel purposes, converting the gas to electricity, injecting it or reinjecting it.[38] Inclusion of a limited exception for temporary flaring during an upset condition can address an operator's need to flare temporarily in the event an operator loses its connection to a gathering line, for example due to a disruption to the availability of the line caused by events outside its control. Prudent operators should have a plan and necessary equipment in place to address the possibility that they will lose access to takeaway capacity, as this is a known risk associated with producing oil and associated gas. As EPA's proposal recognizes, alternative technologies exist to recover and put to beneficial use associated gas and at least one, if not more, of these alternatives is likely available to operators who lose connection to a gathering line. In addition, operators can temporarily shut-in wells in the event of loss of takeaway capacity while arranging for alternative ways to recover and put to beneficial use associated gas.

As discussed below, Colorado and New Mexico rules do not allow for routine flaring in the event that an operator loses connection to a gathering line.

2. The Technical Infeasibility Exemption Presents an Enforcement Challenge

As proposed, the technical infeasibility exemption places a significant compliance monitoring burden on EPA, or states with delegated air quality programs such as Colorado. While an operator's certified demonstration must be signed and certified as to its truth, accuracy and completeness, there is no requirement that EPA review and approve this demonstration prior to an operator flaring. Rather, operators must retain records of the certified demonstration and provide it to EPA as part of annual reporting. This raises the possibility that flaring will occur in the absence of a truthful, accurate, complete or otherwise adequate demonstration. In order for EPA to identify any problems with the certified demonstration, EPA must review the operator's certified demonstration – this review will necessarily occur after an operator has flared, and even routinely flared for potentially a considerable amount of time. This opens the door to extended periods of flaring and pollution in violation of the rules.

3. Exemptions that Allow for Short-term Flaring

We urge EPA to abandon the broad, unclear technical infeasibility exemption and instead delineate those instances in the rule where temporary flaring is allowed, subject to reasonable, limitations. Doing so is consistent with the approach in Colorado and New Mexico.

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[37] Joint Environmental Comments at 187, 194.
[38] Joint Environmental Comments at 187.

a. Upset Condition

During an upset condition operators may need to flare or vent for a limited period. Notably, upset conditions are conditions outside of the control of an operator that can interrupt the ability of the operator to comply with the proposed standard. An example of an upset condition is temporary loss of connection to, or ability to route gas to, a gathering system. EPA has determined that interruptions of an operator's ability to route gas to a gathering system constitute a technical or safety reason that can justify flaring and is taking comment on requirements to address this circumstance.[39] We agree that interruptions to an operator's connection to a gathering system can result in the need for operators to flare on a temporary basis. However, routine flaring is avoidable and should not be permitted during these circumstances.

Both Colorado and New Mexico allow operators to flare or vent gas for a short period of time during upset conditions or emergencies which include temporary unavailability of access to a gathering line.

The Colorado rules provide a concise, clear definition of upset condition combined with a limit on the amount of time an operator may flare or vent during such circumstances. Colorado allows operators to vent or flare for up to 24 cumulative hours during an upset condition while New Mexico allows operators to vent or flare for up to 8 hours during an emergency. Loss of a connection to a pipeline qualifies as an upset condition under the Colorado rules and an emergency under the New Mexico rules.

Colorado's definition of an Upset Condition is "a sudden unavoidable failure, breakdown, event, or malfunction, beyond the reasonable control of the Operator, of any equipment or process that results in abnormal operations and requires correction." This definition does not include "an operator's negligence, failure to install appropriate equipment, or failure to perform scheduled maintenance."[40] Colorado limits venting and flaring to a period necessary to address the upset, not to exceed 24 cumulative hours and requires operators maintain records of the date, cause, estimated volume of gas flared or vented, and duration of each upset condition.[41] This definition includes "sudden unplanned lack of pipeline capacity."[42] Accordingly, Colorado allows operators to vent or flare associated gas in the event that disruptions to a gathering system interrupt the ability of an operator to route associated gas to a sales line, but only up to 24 cumulative hours.[43]

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[39] 87 Fed. Reg. at 74,780.

[40] COGCC SBP, 800/900/1200 Rule Series, p.76, *available at* https://drive.google.com/drive/u/0/folders/1kTZUgXmhVpOy4gEZ2tSOYVDDvYXupzvA

[41] 2 Colo. Code Regs. § 404-1-903(d)(1)(A).

[42] COGCC SBP, 800/900/1200 Rule Series, p.76.

[43] Colorado also allows operators to request approval to flare for a longer period of time, up to 12 months, in the event of loss of access to a gathering line due to unforeseen circumstances outside of the operator's control. An operator may only request approval once, however. To avail itself of this option, an operator must request permission to flare within 30 days of loss of access to a gathering line, and cannot flare unless approval is granted. This request must be accompanied by detailed information demonstrating why the well cannot be connected to infrastructure, when the well will be connected to infrastructure, options for using the gas, including to generate electricity, gas processing to recover natural gas liquids, or other options for using the gas, an estimate of the volume and content of the gas to be flared and a gas analysis. 2 Colo. Code Regs. § 404-1-903.d.(3).

New Mexico similarly allows for temporary venting or flaring during an emergency. An emergency means "a temporary, infrequent, and unavoidable event in which the loss of natural gas is uncontrollable or necessary to avoid a risk of an immediate and substantial adverse impact on safety, public health, or the environment" other than in certain exceptions. One such exception is "venting or flaring of natural gas for more than eight hours after notification that is caused by an emergency, an unscheduled maintenance, or a malfunction of a natural gas gathering system."[44] In other words, an upstream operator may vent or flare during a temporary, infrequent, and unavoidable event involving loss of connection to a sales line provided the midstream operator notifies the producer of the disruption to the operator of the sales line. However, an upstream operator cannot vent longer than 8 hours in this circumstance.[45]
We recognize that there may be instances when an operator loses connection to a sales line for reasons other than during an emergency of upset condition, such as where the midstream operator ceases to operate the gathering line or where the demand for the gathering line exceeds its capacity. We do not believe flaring or venting should be permitted in these circumstances. These are foreseeable risks that prudent operators can and should plan for. As discussed above, prudent operators should have equipment in place to utilize associated gas for other beneficial purposes (e.g., compression for conversion of natural gas to CNG) in the event of a loss of takeaway capacity. New Mexico does not allow operators to vent or flare during non-emergency losses of takeaway capacity.[46] An operator's failure to limit production when the production rate exceeds the capacity of the related equipment or natural gas gathering system, or exceeds the sales contract volume of the natural gas, do not constitute emergencies during which an operator may vent or flare.[47] Colorado contains a limited exception that allows operators to request permission to flare in the event of loss of connection to a sales line, but this exception is only available once to an operator, and to qualify for it an operator must demonstrate there are no alternative options available to recover the gas.[48] As discussed above, we do not believe such an exception is warranted with proper planning.

We recommend EPA limit flaring (or venting) during an upset condition not to exceed 24 cumulative hours per R.903.d.(1)(A). This would apply in those instances where a disruption to a gathering system or other event causes an interruption to an operator's ability to route the gas to a sales line.

b. During Pipeline, Equipment or Facilities Commissioning

Another circumstance that may give rise to an operator's need to vent or flare on a temporary basis is during the commissioning of pipelines, equipment, or facilities. New Mexico allows operators to vent or flare temporarily during pipeline equipment or facilities commissioning.[49] New Mexico limits waste during this activity to "only for as long as necessary to purge introduced impurities."[50] When starting up operation of new equipment, there is often water (used to hydro test) or solids (from stimulation flowback) that need to be purged from the

[44] N.M. Code R. §19.15.27.7.H.
[45] *Id*. at § 19.15.27.7.H.(4).
[46] *Id*. at § 19.15.27.7.H.(4).
[47] *Id*.
[48] 2 Colo. Code Regs. § 404-1-903.d.(3).
[49] N.M. Code R. § 19.15.27.8.D.(4)(m).
[50] *Id*.

equipment or pipeline. This can only be done be releasing this gas with untreatable impurities to atmospheric tanks which allows for the small volumes of gas to also be released until a stable hydrocarbon stream is achieved. While New Mexico does not limit the amount of time an operator may need to vent or flare during this exception, operators have an incentive to limit venting or flaring to a minimum as the sooner they connect the well to a gathering line, the sooner they are able to route the gas to sales.

c. Where Gas Does Not Meet Pipeline Specifications

Operators may also need to flare temporarily where an operator is connected to a sales line, but natural gas does not meet pipeline specifications, and where the other three compliance options are also unavailable.[51] This occurs where impurities such as nitrogen are present in the associated gas and thus the gas cannot safely be sent to the sales line. New Mexico requires the operator take specific steps to limit flaring during this circumstance as follows: Operators must analyze gas samples twice a week to determine if pipeline specifications have been achieved; must route gas into gathering pipelines when pipeline specifications are met and must provide pipeline specs and NG analyses to division upon request.[52] New Mexico does not include a specific time-limit for this exemption. However, per the example above, operators have a profit incentive to limit flaring or venting.

d. Active and Required Maintenance

A fourth exception is during active or required maintenance. Both Colorado and New Mexico allow for temporary venting and flaring during maintenance activities. Colorado specifies that maintenance must be active and required "to clarify that while venting can be permitted while the maintenance activity is ongoing (for example, while personnel are on-site and performing the maintenance), venting during periods between discovery of the need for maintenance and the performance of the maintenance remains prohibited."[53] Colorado requires operators use best management practices to minimize venting during maintenance and repair activity.
New Mexico similarly allows venting or flaring during repair and maintenance, including blowing down and depressurizing production equipment to perform repair and maintenance.[54]

We recommend EPA allow flaring and venting during active and required maintenance activities, provided not otherwise prohibited by EPA or state rules.

e. Production Evaluation and Production Tests

Colorado and New Mexico allow for temporary flaring during production tests and production evaluations. Colorado defines a production test to mean "a test for determination of a reservoir's ability to produce economic quantities of oil or gas."[55] Colorado defines a production evaluation as "an evaluation of production potential for determination of requirements for infrastructure

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[51] N.M. Code R. § 19.15.27.8.D.(4)(l).
[52] *Id*.
[53] COGCC SBP, 800/900/1200 Rule Series, p. 84.
[54] N.M. Code R. § 19.15.27.8
[55] 2 Colo. Code Regs. § 404-1-100-15.

capacity and equipment sizing."[56] Colorado allows venting or flaring during both of these events, but only subject to pre-approval from the Director. If the operator has obtained approval, the rules permit venting or flaring up to a period not to exceed 60 days.[57] New Mexico limits venting or flaring during a production test for a period not to exceed 24 hours absent approval for a longer test period.[58]

We recommend EPA allow venting or flaring during this exception yet limit the duration of 24 hours as Colorado has done.

f. Bradenhead Monitoring and Packer Leakage Tests

Limited venting or flaring may also occur when operators conduct monitoring activities to inspect downhole well integrity. Colorado and New Mexico allow operators to vent or flare during bradenhead monitoring.[59] Per the Statement of Basis and Purpose for Colorado's rule, bradenhead monitoring activities should be limited to30 minutes.[60] New Mexico allows operators to conduct packer leakage tests, which is another form of downhole monitoring.[61] In both instances, venting and flaring should be limited to 30 minutes.

B. Well Completions

1. EPA's Proposal

EPA is proposing to maintain the same standards for reduced emission completions (RECs) contained in OOOO and OOOOa.

Current rules require owners and operators of hydraulically fractured oil and gas wells to either capture or combust emissions during the separation phase of completions. Specifically, owners and operators of non-exploratory and non-delineation wells (i.e., Subcategory 1 wells) must capture gas unless it is technically infeasible to do so, in which case such operators may combust gas.[62] Owners and operators of Subcategory 2 wells (i.e., exploratory, delineation and low-pressure wells) are allowed to combust gas using a completion combustion device provided the device has a continuous pilot flame.[63] Where combustion is allowed, operators may vent rather than combust, if combustion would present demonstrable safety hazards or if high heat may negatively impact tundra, permafrost, or waterways.[64]

Current rules do not require operators control or capture gas during the initial flowback stage.[65] Specifically during the initial flowback stage, operators of Subcategory 1 wells must route emissions to a storage vessel or completion vessel (such as a frac tank, lined pit, or other vessel)

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[56] 2 Colo. Code Regs. § 404-1-100-14.
[57] 2 Colo. Code Regs. § 404-1-903.d.(1)(C).
[58] N.M. Code R. §19.15.27.8.D.(4)(k).
[59] N.M. Code R. §19.15.27.8.D.(4).(i).
[60] COGCC SBP, 800/900/1200 Rule Series, p.86.
[61] N.M. Code R. §19.15.27.8.D.(4).(j).
[62] 86 Fed. Reg. at 63,120.
[63] 40 C.F.R. § 60.5375a(f)(3).
[64] *Id.* at § 60.5375a(a)(3)
[65] 40 C.F.R. § 60.5375a(a)(1)(i).

and separator. The operator is required "to have (and use) a separator onsite during the entire flowback period."[66] Notably, there is no requirement that an operator route gas to a control device or capture the gas. Owners and operators of Subcategory 2 wells may also route initial flowback to a separator instead of a combustion device, but only when the separator is available onsite and ready to be put into use "during the entirety of the flowback period,"[67] which includes the initial flowback phase.[68] If an owner or operator uses a separator, any gas in the flowback prior to the time the separator is able to function is "not subject to control under this section."[69]

2. LGC Recommendations

State rules provide templates for EPA to require additional cost-effective pollution reductions from completions. We have several suggestions: (1) require capture or control during the initial flowback stage; (2) remove the technical infeasibility exemption in the separation flowback stage; and (3) extend the REC requirements to conventional wells.

a. Require Control During Initial Flowback

We urge EPA to follow the example set by Colorado and New Mexico, which require control of venting during initial flowback. Colorado Air Quality Control Commission requires operators route flowback to enclosed flowback vessels after drill-out, and route emissions from flowback vessels to a device that achieves "a hydrocarbon control efficiency of at least 95%" or to a combustion device with "a design destruction efficiency of at least 98% for hydrocarbons."[70] Colorado Oil and Gas Conservation Commission rules further require that operators "enclose all [F]lowback vessels..." and adhere to the Air Quality Control Commission rules requiring the use of enclosed and controlled flowback vessels.[71]

New Mexico similarly requires operators "collect and control emissions from each flowback vessel..." and route emissions to a control device that achieves a hydrocarbon control efficiency of at least 95%.[72] Operators must ensure that the control device "operates as a closed vent system...and that unburnt gas is not directly vented to the atmosphere."[73]

As part of the development of the Air Quality Control Commission rule, the Colorado Department of Public Health and the Environment ("CDPHE") conducted a cost-benefit analysis and found its completion requirements were incredibly cost effective, even assuming a worst-case scenario. To estimate the costs of its rule, Colorado assumed operators needed 10 to 15 500 bbl flowback vessels at a multi-well production facility. CDPHE assumed new storage vessels would cost $30,500 and used storage vessels would cost between $7,000 and $19,000; $1,000 in one-time costs; and $500 in annual operation and maintenance costs, assuming a 15-year lifespan

[66] 87 Fed. Reg. at 74,710.
[67] 87 Fed. Reg. at 74,710.
[68] 86 Fed. Reg. at 63,160 (citing 81 Fed. Reg. 35,934) (June 3, 2016).
[69] 87 Fed. Reg. at 74,710.
[70] 5 Colo. Code Regs. § 1001-9-D-VI.D.1.a.
[71] 2 Colo. Code Regs. § 404-1-903.c.(1).
[72] N.M. Code R. § 20.5.20.127.B.(1).
[73] N.M. Code R. § 20.5.20.127.B.(1)(2).

for flowback tanks. Colorado found its annualized cost per flowback tank would be $4,830 and, assuming an average of 12 flowback tanks, the annualized costs per wellsite are $57,958.[74]

b. Remove the Technical Infeasibility Exemption

We recommend EPA remove the technical infeasibility exception for the separation flowback stage for Subcategory 1 wells and only allow for combustion with prior approval, as Colorado has done.[75] As discussed above, broad, undefined technical infeasibility exemptions open the door to abuse and present enforcement challenges. Neither New Mexico nor Colorado includes a technical infeasibility exemption in its completion rules.[76] New Mexico requires operators capture and route natural gas from separation equipment to a flowline or collection system or use the gas on-site.[77] New Mexico permits flaring only if necessary for safety[78] or temporarily if natural gas does not meet gathering pipeline quality specifications.[79] Colorado similarly only permits flaring with pre-approval[80] or if necessary to ensure safety during an upset condition.[81] Safety flaring during an upset condition is limited to 24 hours.[82]

c. Extend RECs to Conventional Wells

Lastly, we recommend that EPA extend its reduced emission completion requirements to non-hydraulically fractured wells, as is the case in Colorado[83] and New Mexico.[84] Per the Statement and Basis for Colorado's rules "the Commission intends for its reduced emission completion standards to apply to all wells, regardless of whether they are hydraulically fractured."[85] New Mexico's rules similarly apply to all wells.[86] EPA gives no reason for exempting non-hydraulically fractured wells from controlling emissions during completions.

C. LDAR

1. EPA's Proposal

The EPA has proposed different inspection programs depending on the size and type of equipment at well sites and centralized production facilities. Specifically, the type of monitoring (e.g., optical gas imaging ("OGI") or audio, visual, and olfactory inspections ("AVO")) and the

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[74] CDPHE, Air Quality Control Commission, Cost Benefit Analysis for Proposed Revisions to AQCC Regulation No. 7, p. 23 (September 4, 2020), *available at* https://downloads.regulations.gov/EPA-HQ-OAR-2021-0668-0758/attachment_5.pdf.
[75] 5 Colo. Code Regs. § 1001-9-D-II.H.3.f.
[76] 2 Colo. Code Regs. § 404-1-903.c.(1).
[77] N.M. Code R. § 19.15.27.8.C.(2)
[78] *Id*. at § 19.15.27.8.C.(2)(b).
[79] *Id*. at § 19.15.27.8.C.(3).
[80] 2 Colo. Code Regs. § 404-1-903.c.(3)(A) (allowing flaring if approved on gas capture plan); *Id*. at 903.c.(3)(B) (allowing flaring if approved by Director and accompanied by justification for need to flare, plans to capture the gas, and estimate of anticipated flaring amount and duration).
[81] *Id*. at 903.c.(3)(C).
[82] *Id*.
[83] *Id*. at 903.c.(1).
[84] N.M. Code R. § 19.15.27.8.C.
[85] COGCC SBP, 800/900/1200 Rule Series, at p. 81.
[86] N.M. Code R. § 19.15.27.8.C.

frequency of inspections depends on the complexity of the site and the type of equipment present: more frequent inspections are required at complex sites with failure-prone equipment.

EPA proposes to require quarterly OGI inspections and bimonthly AVO inspections at well sites and centralized production facilities with major production and processing equipment. This includes: (1) one or more controlled storage vessels; (2) one or more control devices; (3) one or more natural gas-driven pneumatic controllers or pumps; and (4) two or more other major production and processing equipment.[87] EPA notes that these sites contain leak-prone equipment that can result in very large leaks, i.e., super-emitters.[88]

EPA proposes only AVO inspections at small well sites and single wellhead only sites. Small well sites are single wellhead well sites that do not contain any controlled storage vessels, control devices, gas-powered pneumatic controllers or pumps and include only one other piece of major production and processing equipment such as a separator, uncontrolled storage vessel, compressor or glycol dehydrator, or any affected or designated facility.[89] EPA estimates that approximately 12% of well sites nationwide meet this definition.[90] Surface casing valves and thief hatches on uncontrolled storage vessels are the most likely emissions sources at these well sites.[91] EPA notes that AVO is a reliable method for identifying such leaks and thus proposes quarterly AVO inspections for small well sites.[92] Single wellhead only well sites are well sites that contain one or more wellheads and no major production and processing equipment.[93] EPA finds that the most likely cause of a leak at a single wellhead only well site would be an open valve that allows venting from the wellhead. This is based on the results of a recent U.S. DOE marginal well study.[94] EPA proposes only AVO (i.e., quarterly AVO) requirements for these well sites based on its belief that OGI cameras are not necessary to identify venting from well heads.[95]

EPA proposes semi-annual OGI inspections and quarterly AVO inspections at multi-wellhead only sites. These are wellhead only sites with two or more wellheads. EPA finds that these sites can have large leaks from the same equipment present at single-wellhead sites (e.g., surface casing valves) which are identifiable with AVO, but also will have smaller leaks from piping and connections that are not identifiable with AVO.[96] Thus, EPA proposes semi-annual OGI inspections and quarterly AVO inspections at multi-wellhead only sites.

2. LGC Recommendations

We support EPA's proposed definition of the affected facility as the collection of fugitive emissions components located at a well site or centralized production facility with no

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[87] 87 Fed. Reg. at 74,723.
[88] 87 Fed. Reg. at 74,735.
[89] 87 Fed. Reg. at 74,723.
[90] *Id*.
[91] *Id*.
[92] *Id*.
[93] 87 Fed. Reg. at 74,723.
[94] 87 Fed. Reg. at 74,729.
[95] *Id*.
[96] 87 Fed. Reg. at 74,732.

exemptions. This is an improvement over the 2021 proposal which exempted low-PTE well sites from LDAR. However, we have concerns with the proposed AVO-only requirements for small well sites and single wellhead only sites. As demonstrated by our prior comments, small well sites can have leaks.[97] In addition, we do not share EPA's conviction that AVO is an effective method for identifying leaks.

State rules demonstrate the feasibility of requiring annual inspections at well sites with low emissions or the potential for emissions, a group that likely overlaps considerably with EPA's single wellhead only and small well sites categories. We recommend that EPA require annual OGI for single wellhead only and small well sites, based on rules adopted by Colorado and New Mexico. While we do appreciate the proposed AVO inspections, OGI methods can detect leaks that a human may not be able to detect. AVO inspections, in contrast to OGI inspections, rely on a person's senses of smell, hearing and sight to achieve maximum emissions reductions. Such senses may not be as reliable as instruments. Moreover, EPA may require operators retain video footage demonstrating that OGI inspections in fact occurred and documenting the results of those inspections. The same is not true for AVO inspections. Absent a way to document reliably that an operator, or more likely a contractor, conducted a thorough AVO inspection, we fear this requirement will be abused and will not lead to the emissions reductions EPA expects.

Colorado and New Mexico require instrument-based inspections for small wells, and New Mexico requires instrument-based inspections for wellhead only facilities. Colorado requires all well production facilities that commence operation on or after May 1, 2022, to conduct monthly instrument-based inspections, regardless of size or emissions potential.[98] The only exceptions to this is for facilities which are not home to leak-prone equipment (i.e., facilities without storage tanks, natural gas-fired reciprocating internal combustion engines and gas-powered pneumatic devices)[99] or those that contain robust monitoring for leak prone equipment (i.e., those that install an automatic pressure management and pilot light system on controlled storage tanks).[100] Such facilities must conduct instrument-inspections semi-annually or annually, depending on emissions potential.[101] Well production facilities that commenced operation before May 1, 2022 must conduct at least annual instrument-based inspections.[102]

New Mexico requires at least annual OGI inspections of ***all*** well sites, including wellhead only well sites.[103] New Mexico's proposal has the support of the local community and national environmental groups.[104]

[97] LGC Comments, EPA's Proposal to Reduce Greenhouse Gasses and other Pollutants from the Crude Oil and Natural Gas Source Category under the Clean Air Act, p. 10-15 (Jan. 31, 2022).
[98] 5 Colo. Code Regs. § 1001-9-D-II.E.4.e.(ii)
[99] 5 Colo. Code Regs. § 1001-9-D-II.E.4.f.(i).
[100] 5 Colo. Code Regs. § 1001-9-D-II.E.4.f.(ii)
[101] 5 Colo. Code Regs. § 1001-9-D-II.E.4.f.
[102] 5 Colo. Code Regs. § 1001-9-D-II.E.4, Table 5.
[103] N.M. Code R. § 20.2.50.116.
[104] Community and Environmental Parties Joint Proposed Statement of Reasons, New Mexico Environmental Improvement Board rulemaking in the Matter of Proposed New Regulation, 20.2.50 NMAC, Oil and Gas Sector, Ozone Precursor Pollutants (Jan. 20, 2022), *available at* https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/2022-01-20-EIB-No.-21-27-Comty.-and-Envt.-Parties-Proposed-Statement-of-Reasons-pj.pdf.

D. Abandoned and Idle Wells

1. EPA's Proposal

EPA is proposing to include idle wells in LDAR inspections and is proposing specific inspection and other requirements prior to permanent well closure activities. Specifically, operators of idle wells must conduct LDAR inspections "when the wells at the site are shut-in or idled and could be put back into production at a later date."[105] Monitoring must continue until "the well site has been properly closed" and "the OGI survey indicates no emissions are present."[106] If any emissions are identified, the owner or operator would be required to take steps to eliminate those emissions and resurvey prior to well closure. The EPA is proposing that once the OGI survey indicates no emissions are present, the well site would be considered closed and no further fugitive emissions monitoring would be required.

EPA also proposed that operators must develop and submit a well closure plan within 30 days of the cessation of production from all wells at the well site or centralized production facility. The plan would include: (1) the steps necessary to close all wells at the well site, including plugging of all wells; (2) the financial requirements and disclosure of financial assurance to complete closure; and (3) the schedule for completing all activities in the closure plan. EPA is also proposing to require owners and operators to report, through the annual report, any changes in ownership at individual well sites so that it is clear who is responsible until the site is plugged and closed.

2. LGC Recommendations

We appreciate EPA's acknowledgement that emissions from idle wells are, in some cases, "very large,"[107] and EPA's proposal for monitoring until no emissions are detected by OGI. In Colorado operators must continue to conduct LDAR inspections at shut-in wells provided such wells remain under pressure.[108] In addition, Colorado requires operators conduct Bradenhead monitoring and testing on a monthly basis for wells an operator intends to plug and abandon, as indicated by inclusion on an operator's out-of-service list, until the operator plugs and abandons the well.[109] Operators must also conduct an AVO or other inspection of each out of service well annually to confirm integrity of the wellhead.[110] New Mexico requires annual Method 21 or OGI inspections at idle wells, beginning 30 days after a well is placed into idle status.[111]

We also support the requirement that an operator submit a well closure plan. However, we recommend EPA require operators submit this plan at the beginning of a well's life (specifically within 30 days of receipt of approval to drill a well) rather than at the end of a well's life. This is necessary to ensure that operators have an adequate plan in place to ensure the proper plugging

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[105] 87 Fed. Reg. at 74,736.
[106] *Id.*
[107] 87 Fed. Reg. at 74,736.
[108] Colorado APCD PS Memo 14-04, p.10, (May 16, 2022), *available at* https://cdphe.colorado.gov/air-permitting-guidance-memos.
[109] 2 Colo. Code Regs. § 404-1-434.d.(11).A.
[110] 2 Colo. Code Regs. § 404-1-434.d.(11).D.
[111] N.M. Code R. § 20.2.50.116.C.(3)(g).

and abandonment of all wells. The time when an operator is best positioned to put aside resources to cover the costs of properly plugging, abandoning, and reclaiming any environmental contamination, is during the initial phase of well development. It is then that a well is most productive and the operator has access to a steady revenue stream from hydrocarbon production. Waiting to require a well closure plan until a well is at the end of its life, and thus at the tail end of its productive, revenue-generating life, could lead to the submission of inadequate plans.

We also recommend EPA require operators review, and revise if appropriate, well closure plans for all wells they acquire in an asset transfer transaction. Purchasers should be required to update well closure plans if any circumstances covered by the well closure plan have changed. Specifically, purchasers must provide EPA with an updated well closure plan if any of the following has changed since the original submission of the well closure plan: the steps necessary to close all wells at the well site, including plugging of all wells; the financial requirements and disclosure of financial assurance to complete closure; and the schedule for completing all activities in the closure plan. This will ensure well closure plans remain relevant and up to date.

V. Conclusion

We appreciate and support EPA's Proposal to require robust controls to limit VOC and methane emissions from new, modified, and existing oil and gas sources, and look forward to EPA finalizing a strong rule which further reduces harmful pollutants from the oil and gas industry.

Respectfully submitted this 13th day of February, 2023.

On Behalf of City of Aurora

Jeffrey S. Moore, P.G.
Manager, Oil & Gas Division, City of Aurora

Elizabeth Paranhos
Tracy Kozak
Counsel for the City of Aurora

On Behalf of Boulder County

Claire Levy
Chair, Board of County Commissioners
Boulder County

On Behalf of the City and County of Broomfield

Elizabeth Paranhos
Tracy Kozak
deLone Law, Inc.
Counsel for the City and County of Broomfield

On Behalf of Commerce City

Rosemarie Russo
Environmental Planner III
LEED & Well Building AP

On Behalf of the City of Lafayette

Elizabeth Paranhos
Tracy Kozak
deLone Law, Inc.
Counsel for the City and County of Broomfield

Jeff Brasel, Director, Planning & Building, City of Lafayette

On Behalf of City of Longmont

Jane Turner, PE, PhD
Air Quality & Oil and Gas Program Manager
Strategic Integration, City of Longmont

On Behalf of Town of Erie

David Frank, Energy & Environment Program Specialist, Town of Erie

On Behalf of Colorado Communities for Climate Action

Jacob Smith, Executive Director
Colorado Communities for Climate Action