BEFORE THE COLORADO AIR QUALITY CONTROL COMMISSION

REGARDING OIL & GAS RULEMAKING EFFORTS:	**)**
REGULATION NUMBER 3, PARTS A, B AND C	**)**
REGULATION NUMBER 6, PART A	**)**
REGULATION NUMBER 7	**)**

REBUTTAL PREHEARING STATEMENT OF THE SIERRA CLUB, NATURAL RESOURCES DEFENSE COUNCIL, EARTHWORKS OIL AND GAS ACCOUNTABILITY PROJECT AND WILDEARTH GUARDIANS

The Sierra Club, Natural Resources Defense Council, Earthworks Oil and Gas Accountability Project, and WildEarth Guardians (collectively, the Conservation Groups) respectfully submit their Rebuttal Prehearing Statement.

This Rebuttal Statement also includes final language with regard to one element of the Conservation Groups' Alternative Proposal. See p. 24. The Conservation Groups' Final Economic Impact Analysis for their Alternate Proposal is included in the attached Appendix.

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EXECUTIVE SUMMARY

Calls to weaken the Division's proposed changes to Regulations 3, 6, and 7 (the Division Proposal) are primarily found in the pre-hearing statements of the DGS Client Group, Colorado Oil and Gas Association and Colorado Petroleum Association (collectively, COGA), and to some degree WPX Energy Rocky Mountain LLC. This Rebuttal Statement addresses the prehearing statements of those parties as follows:

First, the Commission should not restrict the new rules to the Denver Metro/North Front Range nonattainment area, as DGS and COGA have proposed. Such a limit would eliminate more than half the producing wells in the state from the rules' coverage and sharply the reduce the emissions benefits from the rules. There is no justification for such a dramatic change in the proposal.

Second, the Commission should reject the changes proposed by DGS, COGA and WPX to the leak detection and repair (LDAR) provisions of the Division Proposal. COGA's and DGS's amendments, which would gut the LDAR program, are based on an economic analysis that grossly inflates the cost of LDAR and a meritless legal argument that the Commission cannot adopt regulations to address emissions of methane and ethane. WPX's proposed changes have many of the same problems.

Third, COGA's proposals to weaken the storage tank provisions of the Division Proposal should also be rejected. Tanks are the largest source of volatile organic compound (VOC) emissions statewide and prior regulation of storage tanks has not achieved the control of VOCs that the Division anticipated.

Fourth, the Commission should reject COGA's request to exempt intermittent-bleed pneumatic controllers from the requirement that pneumatic devices achieve a "low-bleed" rate of 6 scfh or less. Exempting intermittent bleed devices would miss an opportunity to achieve significant emissions reductions.

Fifth, the requirement in the Division Proposal to minimize venting during liquids unloading and well maintenance should be retained. COGA's objection – that this proposal was supposedly not discussed during the stakeholder process – is incorrect. The Conservation Groups and other organizations have advocated for such requirements since the outset of this process.

Sixth, the Commission should not raise the APEN and permitting thresholds in Regulation No. 3 as proposed by COGA. The Division has not asked for these changes and they would violate state and federal law.

Finally, the Conservation Groups include final language with regard to one element of their Alternative Proposal: including transmission and storage compressors downstream of natural gas processing plants under the LDAR rules. The final language clarifies the scope of this proposal in response to questions we have received.

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INTRODUCTION

In their prehearing statements, the Colorado Oil and Gas Association, Colorado Petroleum Association (collectively, COGA), and the DGS Client Group (DGS) assert that they do not "broadly oppose the Proposed Rules as such," and suggest that they offer "mere formatting, clarification and consistency changes." DGS Prehearing Statement (PHS) at ES-2; COGA PHS at 1-2. The substance of DGS's and COGA's argument tells a different story. They staunchly oppose fundamental elements of the Division Proposal, such as its coverage of hydrocarbons like methane and ethane (collectively, methane), and the statewide applicability of the proposed changes.

Moreover, DGS's and COGA's proposed changes to the Division Proposal (presented in a summary table that itself runs 31 pages) would render many of its key provisions ineffective at reducing volatile organic compound (VOC) and methane emissions. Their primary rationale for these changes – that the Division Proposal is not cost-effective – relies on an analysis that grossly overstates the cost of leak detection and repair (LDAR), storage tank emissions management (STEM), and other rules. This Commission should reject DGS's and COGA's position and adopt the Division Proposal with the changes proposed by Conservation Groups.

DISCUSSION

I. THE COMMISSION SHOULD ADOPT STATEWIDE RULES AS PROPOSED BY THE DIVISION.

The most significant way in which DGS and COGA seek to limit the rule is by arguing that it should not apply outside of the Denver Metro/North Front Range nonattainment area (NAA).[1] This change would eliminate more than half the producing wells in the state from the rule's coverage. Of the 46,674 producing wells in the state, 55% are outside the NAA.[2] Accordingly, excluding the attainment areas from the rule would reduce the VOC emission reductions from an estimated 92,000 tpy to approximately 41,400 tpy. It would also significantly reduce methane and toxic pollutant emission benefits.

There is no justification for such a dramatic change in the proposal. Contrary to the arguments presented by DGS, the Commission has ample authority to enact a statewide rule. In fact, it already has done so. In the current proposal, the Division is offering changes to Regulation No. 7, Section XVII, which already applies to oil and gas operations statewide.

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[1] See, e.g., DGS PHS Ex. D; see also DGS PHS at ES-3 to -4, 5-7; COGA PHS at 11-13. A number of county parties also asked for the rule to be limited to the nonattainment area.

[2] According to Colorado Oil and Gas Conservation Commission records, approximately 20,815 of the 46,674 producing wells in Colorado (44.6%) are located in the NAA. See http://cogcc.state.co.us/ .

Furthermore, a statewide rule is necessary to protect the public health of all Coloradans. And the State has a strong interest in ensuring that the air quality throughout the state does not decline to the level of that on the Front Range.

A. The Commission Has Ample Authority under Both the Clean Air Act and the Colorado Air Pollution Prevention and Control Act to Enact Statewide Regulations.

The primary thrust of DGS's argument is that the Clean Air Act and state law mandate a race to the bottom. See DGS PHS Ex. D at 5-11. According to DGS, the State must wait to impose controls on oil and gas pollution in places like the Western Slope and the Four Corners until they are designated as nonattainment areas for ozone and the State does the modeling necessary to support a state implementation plan (SIP) revision. Id.[3] There is no support for this argument. The Commission has clear legal authority to protect the public health of its citizens, even absent a nonattainment designation.

Under the Clean Air Act, national ambient air quality standards (NAAQS) represent the floor for air quality in the United States. While states cannot allow air quality to fall below the NAAQS, they are free to go above and beyond these standards. 42 U.S.C. § 7416; see also C.R.S. § 25-7-105.1(1) (acknowledging the state's ability to adopt regulations "otherwise more stringent than . . . the federal act" under the "powers reserved to the state of Colorado" in the Clean Air Act). Indeed, one of the primary goals of the Clean Air Act is "to protect public health and welfare from any actual or potential adverse effect which . . . may reasonably be anticipate[d] to occur from air pollution . . . notwithstanding attainment and maintenance of all national ambient air quality standards." 42 U.S.C. § 7470(1) (emphasis added). Far from "upset[ting] the [Clean Air Act's] fundamental statutory scheme," as DGS claims, statewide application of the proposed rules is entirely consistent with the purposes of the Clean Air Act. DGS PHS Ex. D at 10.

The Colorado Air Pollution Prevention and Control Act (the Act or Colorado Air Act) also provides the Commission authority to adopt statewide regulations aimed at maintaining cleaner air than the NAAQS. The Commission has "maximum flexibility" to develop air quality regulations and explicit authority to adopt "[e]mission control regulations that are applicable to the entire state." C.R.S. § 25-7-106 (emphasis added). Under the Act, "the Commission shall

[3] DGS argues that in order to impose control measures on oil and gas facilities, the State must meet the standards for designating the area as a nonattainment area. See DGS PHS Ex. D at 7 (arguing that the Division must demonstrate that any proposal would "contribute to bringing the nonattainment area into NAAQS-compliance"); see also id. at 7-10 (arguing that the state is enlarging the nonattainment area boundary without demonstrating that these areas contribute to NAAQS violations).

promulgate such rules and regulations as are consistent with the legislative declaration set forth in section 25-7-102." C.R.S. § 25-7-105. Section 25-7-102 states:

> [I]t is declared to be the policy of this state to achieve the maximum practical degree of air purity in every portion of the state, to attain and maintain the national ambient air quality standards, and to prevent the significant deterioration of air quality in those portions of the state where the air quality is better than the national ambient air quality standards. To that end, it is the purpose of this article to require the use of all available practical methods which are technologically feasible and economically reasonable so as to reduce, prevent, and control air pollution throughout the state of Colorado . . .

C.R.S. § 25-7-102 (emphasis added).

The Commission already exercised this discretion when it adopted statewide controls for oil and gas operations in December 2006, including controls on condensate tanks, glycol dehydrators, and natural gas fired reciprocating internal combustion engines. See Reg. 7, Section XVII. In the Statement of Basis and Purpose, the Commission recognized the regulations as a "proactive measure designed to eliminate air emissions that could threaten attainment of ambient air quality standards." Id. (Basis). The Commission also recognized that the 2006 regulations were simply a "first step in addressing rapidly growing emissions from oil and gas operations throughout the state." Id. (Purpose). The Division's current proposal takes another step in controlling these emissions.

Additionally, by focusing exclusively on ozone pollution, DGS ignores the Commission's authority to regulate other toxic air emissions and greenhouse gases. As described in the Prehearing Statement of Local Community Organizations, the oil and gas industry is a significant source of hazardous air pollutants that are recognized as carcinogenic or acutely or chronically toxic, including benzene, formaldehyde, and hydrogen sulfide. Local Comm. Org. PHS at 4-16; see also C.R.S. § 25-7-103(13) (defining hazardous air pollutant). The Commission has authority to regulate hazardous air pollutants. C.R.S. §§ 25-7-109(2)(h), (4); see also id. § (3)(j) (authorizing regulation of the "[s]torage and transfer of volatile organic compounds and hazardous or toxic gases or other hazardous substances which may become airborne"). As described in the Conservation Groups' Prehearing Statement and this Rebuttal Statement, the Commission also has the authority to regulate the powerful greenhouse gas methane. Because emissions of hazardous air pollutants and methane occur from oil and gas operations statewide, either of these authorities, standing alone, is sufficient to justify statewide regulation of the industry.

B. The Commission Must Adopt Statewide Rules to Adequately Protect Public Health Throughout Colorado.

DGS is incorrect that the Division has not shown a need for the proposed revisions or that they will lead to a reduction in air pollution. See DGS PHS Ex. D at 1-3. Oil and gas development both inside and outside the nonattainment area is responsible for emissions of ozone precursors, toxic emissions like benzene, and methane—pollution that would be reduced under the Division Proposal. As discussed below, there is already a need for strong statewide regulations to protect the public from the adverse health effects of this oil and gas-related pollution, including ozone and air toxics.[4] Furthermore, it is likely that EPA will lower the ozone NAAQS in the near future. Instead of taking a reactive approach and waiting for federal mandates, the Commission should get ahead of the problem by adopting cost-effective controls now.

With respect to ozone, portions of the Western Slope now qualify as a nonattainment area because the design value at the Rangely Monitor (between 2011 and 2013) is above the NAAQS.[5] Monitoring also shows that many other areas of the state have ozone pollution levels that exceed levels EPA has recognized as having significant health impacts. Although EPA set the NAAQS floor at 0.075 ppm, the agency recognizes that severe adverse health effects occur at ozone levels below this standard, especially for children and adults with asthma.[6] The Clean Air Scientific Advisory Committee, the independent scientific group that provides technical advice to EPA with respect to NAAQS, unanimously found that the current 0.075 ppm standard "fails to satisfy the explicit stipulations of the Clean Air Act [to] ensure an adequate margin of safety for all individuals, including sensitive populations" and has recommended an ozone standard somewhere between 0.060 and 0.070 ppm.[7]

On January 6, 2010, EPA issued a proposal to set the standard within this 0.060-0.070 ppm range "to provide increased protection for children and other 'at risk' populations against an array of O_3 related adverse health effects that range from decreased lung function and increased

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[4] Local Comm. Org. PHS at 4-16; see also, Jan. 30, 2014 letter from Environmental Integrity Project to EPA (showing more than 100 Colorado oil and gas facilities, most on the Western Slope, that emit more than 10,000 pounds per year of toxic chemicals); McKenzie, et al., Birth Outcomes and Maternal Residential Proximity to Natural Gas Development in Rural Colorado (Jan. 28, 2014) (finding association between birth defects and proximity to natural gas wells).

[5] See AQCC, Review of the 2013 Ozone Season, Oct. 17, 2013 Commission Meeting, slides at 5 (Conservation Groups' PHS Appx. p. 102). Although oil and gas development in Utah likely contributes to the violations at the Rangely monitor, there is also a substantial amount of oil and gas development located within Colorado that is contributing to the problem. See Earthjustice, Map of Oil & Gas Basins and Producing Wells in Colorado.

[6] See 75 Fed. Reg. 2938, 2944 (Jan. 19, 2010).

[7] See id. at 2992.

respiratory symptoms to serious indicators of respiratory morbidity including emergency department visits and hospital admissions for respiratory causes, and possibly cardiovascular-related morbidity as well as total non-accidental and cardiopulmonary mortality." 75 Fed. Reg. at 2938, 2944. Although EPA did not finalize this proposal, it is currently working on a new proposal. If EPA lowers the standard as proposed, additional areas of Colorado will fall into nonattainment, including portions of the Western Slope and the Four Corners region.[8] Regardless of whether the EPA acts, reducing ozone pollution to levels well below the current NAAQS will result in public health benefits throughout the state.

Monitors show that major portions of Colorado have ozone levels within or above the 0.060-0.070 ppm range, including the West Slope and Four Corners region. Apart from Rangely, there are nine other monitors on the West Slope with design values above 0.065 ppm.[9] Five monitors in the Four Corners region have design values above 0.065 ppm for the period from 2010 through 2012.[10]

The design values, moreover, represent the three-year average of the fourth highest maximum ozone concentrations – not the highest levels recorded in these regions. There are days where the ozone levels are substantially higher than the design value. For example, according to EPA monitoring data, in 2011 three monitors in La Plata County in the Four Corners region measured eight hour ozone concentrations of 0.086, 0.090, and 0.088 ppm, respectively.[11] A monitor in Garfield County registered eight hour ozone concentrations of 0.078 in 2012.[12] In 2011, two other monitors in Garfield County registered eight hour ozone levels of 0.080 and 0.078.[13] Last winter in Rio Blanco County, eight hour ozone concentrations reached 0.106 ppm.[14] The Division issued eight advisories, or "Action Days," for portions of Moffat County and Rio Blanco County warning that ozone levels had been exceeded or were expected to be exceeded. These advisories warn active children and adults, older adults, and people with asthma to reduce prolonged or heavy outdoor exertion.[15]

DGS's argument that the Division has failed to demonstrate that the proposed rules will reduce ozone pollution outside the nonattainment area is also unavailing. See, e.g., DGS PHS at

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[8] See AQCC, Review of the 2013 Ozone Season, Oct. 17, 2013 Commission Meeting, slides at 14-16.
[9] See id. slides at 5.
[10] See id. slides at 11.
[11] Monitor Values Report, La Plata County (2011). These reports were generated using EPA monitoring data available at http://www.epa.gov/airdata/.
[12] Monitor Values Report, Garfield County (2012).
[13] Monitor Values Report, Garfield County (2011).
[14] Monitor Values Report, Rio Blanco County (2013).
[15] See AQCC, Forecasting Air Quality in Colorado, May 16, 2013 Commission Meeting, slides at 2-3, 5.

ES-1, ES-3 to -4, 5-6. There is a strong link between oil and gas development and ozone precursor emissions. For example, according to the Division's 2011 inventory, in Rio Blanco County oil and gas operations are responsible for 97% of anthropogenic VOC emissions and 87% of anthropogenic NOx emissions.[16] In neighboring Garfield County, oil and gas sources are responsible for 91% of anthropogenic VOC emissions and 78% of anthropogenic NOx emissions.[17] In La Plata County, oil and gas sources are responsible for approximately 70% of anthropogenic NOx emissions.[18] Ozone modeling prepared for the Regional Air Quality Council indicates that oil and gas VOC emissions are expected to rise substantially between now and 2018 in areas outside of the NAA.[19] Accordingly, reductions at oil and gas facilities are critical to reduce ozone precursor emissions statewide.

DGS argues that because oil and gas development is only booming within the D-J Basin, the Commission should stay its hand. See, e.g., DGS PHS Ex. D at 8-9; DGS PHS at ES-3, 5. In doing so, DGS ignores the fact that the majority (55%) of active oil and gas development in the state is located outside the nonattainment area. There are more than 10,000 active wells in Garfield County and approximately 3,000 or more active wells in Yuma, La Plata, Las Animas, and Rio Blanco counties.[20] Moreover, DGS's short-sighted approach ignores the boom and bust reality of oil and gas development.[21] While natural gas prices are currently low, that could easily change leading to another boom outside of the D-J Basin. If the Commission waits to adopt strong regulations until the boom cycle, the industry will be faced with more costly retrofits.

DGS also ignores the fact that the D-J Basin is not contiguous with the NAA. There is substantial development just outside of the boundary of the nonattainment area where DGS admits there will be continued growth in the near term.[22]

DGS also claims that photochemical air quality modeling is required to demonstrate that there will be emission reductions. See, e.g., DGS PHS Ex. D at 2-3, 4, 9-11; DGS PHS at ES-3, 5-7. While the Conservation Groups agree that modeling is important to determine the impact of the proposed rules and ensure compliance with the NAAQS and therefore should be completed as soon as possible, there is no legal requirement to model prior to adopting state-only rules. Although DGS points to various modeling requirements for SIP submittals, see DGS PHS Ex. D

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[16] See CDPHE Spreadsheets of 2011 Emissions Inventory Summaries.
[17] Id.
[18] Id.
[19] See Conservation Groups Opening PHS Ex. C Attachment 6 at 15-16.
[20] Conservation Commission, Colorado Weekly & Monthly Oil & Gas Statistics at 11 (Number of Active Colorado Oil & Gas Wells By County), available at http://cogcc.state.co.us/Library/Statistics/CoWklyMnthlyOGStats.pdf .
[21] See, e.g., id. at 2 (Historic Annual Colorado Drilling Permits).
[22] See Earthjustice, Map of Nonattainment Areas and Producing Wells.

at 10, it acknowledges repeatedly that "the rules being proposed are state-only and not part of Colorado's SIP." Id. at 7, 10. Therefore, the modeling provisions do not apply.

In sum, the Commission has clear legal authority under the Clean Air Act and state law to address oil and gas emissions on a statewide basis even where such revisions are not necessary for NAAQS compliance. And the Commission has an obligation to do so to protect the public health of all Coloradans.

II. DGS's AND COGA's CHANGES TO THE PROPOSED LEAK DETECTION AND REPAIR PROVISIONS SHOULD BE REJECTED.

COGA and DGS also oppose the leak detection rule proposed by the Division. COGA's argument that the Commission should not regulate methane is particularly surprising because it conflicts with COGA's own advocacy of natural gas as a clean fuel that should be expanded as a tool to address global warming. COGA's web site states:

> [H]ere in Colorado, we have abundant resources of clean burning natural gas, making us a part of the shale gas revolution. This revolution is really an opportunity for all of us – an opportunity to reduce pollution, reduce our carbon footprint, reduce our dependence on foreign oil, increase jobs, and ensure long term reliable and affordable energy. If you're concerned with carbon emissions or air pollution, natural gas is a key component of any solution that's going to reduce pollutants - natural gas emits half the carbon dioxide of coal.[23]

COGA's position in this hearing is difficult to reconcile with its public advocacy of natural gas as a "revolution" that will limit "carbon emissions" and "reduce our carbon footprint." COGA opposes rules that are necessary to limit the climate impacts of natural gas, despite the enthusiastic statements on its web site.

COGA's opposition also disregards Governor Hickenlooper's stated goal of "zero tolerance" for methane leaks from oil and gas operations. Conservation Groups' PHS at 9. In any event, COGA's arguments are meritless. Its proposed language would render the LDAR provisions ineffective, and COGA's economic analysis grossly inflates the cost of implementing LDAR.

A. COGA's Changes Would Gut The Proposal.

An examination of the DGS and COGA (collectively, COGA) proposal shows that it is structured not to require effective leak detection and repair, but instead to let operators avoid

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[23] See COGA, http://www.coga.org/index.php/FastFacts/Environmental#sthash.UlBbaQgS.dpbs (emphasis added).

conducting inspections and repairing leaks. The Division estimates that its LDAR proposal would reduce VOC emissions by 15,268 tpy, and methane emissions by 24,781 tpy. Division Initial Economic Impact Analysis (Nov. 15, 2013) (Division EIA) at 18-19. COGA's changes would eliminate most of these air pollution benefits, and could allow many operators to stop doing any instrument-based inspections at all.

1. Eliminating Statewide Applicability:

First, COGA would carve most of the State out of the Division Proposal by limiting its LDAR provisions to the Front Range ozone nonattainment area. COGA PHS at 11-13. As discussed above, this would mean that approximately 55 percent of Colorado oil and gas operations are excluded from the LDAR rules and would cut VOC and methane reductions accordingly.[24]

2. Eliminating Application To Non-VOC Hydrocarbons:

Second, COGA would eliminate the LDAR requirement for components and leaks of non-VOC hydrocarbons. See COGA PHS Attachment D at 3-4 (limiting definition of "component" to those with at least 10 percent VOCs); id. at 23-25 (defining leaks requiring repair in terms of VOC rather than hydrocarbon emissions). This change would further whittle away the methane reduction benefits of the rule. For the reasons discussed below, applying Regulation 7 to methane is within the Commission's authority and will be an important step to ensure that growing natural gas development in Colorado does not exacerbate global warming.

3. Reduced Inspection Frequency and Step-Down Provision:

Third, COGA would establish a less rigorous inspection schedule: no monthly instrument-based inspections would be required for any well production facilities - no matter how large. And those facilities with VOC emissions less than 20 tpy would have only annual inspections, or no regular instrument-based inspections at all. COGA PHS Attachment D at 22. COGA's schedule for compressor stations is similarly relaxed, and (like the Division Proposal) it is based only on fugitive VOC emissions, making inspections even less frequent. Id. at 19-20; Conservation Groups' PHS at 19-20.

Reducing the frequency of inspections as COGA proposes will forego substantial emissions reductions from LDAR. For example, Clean Air Task Force (CATF) data show that reducing inspections from quarterly to semi-annually would increase the remaining emissions from those facilities by 79%. Reducing inspections from quarterly to annually would increase the remaining emissions from those facilities by 213%. See Testimony of David McCabe at 4 (Conservation Groups' PHS Ex. A) (McCabe testimony).

[24] See n. 2, above.

COGA also applies a "step-down" provision that further reduces inspection frequency when a company completes four consecutive inspections without finding leaks requiring repair. For example, a large well production facility subject to monthly instrument-based inspections under the Division Proposal could face only semi-annual inspections under COGA's step-down approach. See COGA PHS Attachment D at 18, 22.

COGA's step-down proposal is problematic for several reasons. It creates an incentive for companies not to identify leaks during inspections. This is not a hypothetical concern. A 2007 report by EPA found "significant widespread noncompliance with [LDAR] regulations" at petroleum refineries and other facilities. EPA, Leak Detection and Repair: A Best Practices Guide at 1 (APCD PHS Ex. IIII). While recognizing that some LDAR regulations allow "skip periods" similar to what COGA proposes, EPA observed: "Experience has shown that poor monitoring rather than good performance has allowed facilities to take advantage of the less frequent monitoring provisions." Id. at 23. It recommended that "[t]o ensure that leaks are still being identified in a timely manner and that previously unidentified leaks are not worsening over time," companies should monitor more frequently. Id.

COGA's step-down proposal also is likely to be widely used because it defines "leak requiring repair" so narrowly (see below). Because numerous leaks will be excluded from the definition of "leak requiring repair," many operators will have little difficulty reducing their inspections under this step-down regime. This will further reduce the pollution benefits of the LDAR rule.

Further, COGA's narrow definition of "leak requiring repair" would make it difficult to evaluate a facility's entitlement to the step-down provisions. Many leaks that would not require repair under COGA's proposal also would be exempted from recordkeeping and reporting requirements (see below). Thus, COGA would not require companies to track many leaks that are found, and as a result, would exacerbate the compliance problem described above by EPA.

Taken together, COGA's relaxed schedule and step-down proposal will significantly reduce the pollution benefits of an LDAR rule. Those foregone emissions reductions will vary by the type and size of facility, but they are likely to be substantial.

4. Narrow Definition Of "Leak Requiring Repair":

Fourth, when companies do conduct inspections, COGA's proposal defines "leak requiring repair" almost out of existence. COGA's proposal includes several changes that water down the requirement for companies to repair leaks:

(a) COGA would allow companies to treat the leak as NOT a "leak requiring repair" if it is repaired immediately. COGA PHS Attachment D at 25. For such leaks, operators would not have to comply with recordkeeping and reporting requirements, or with re-monitoring requirements to ensure the repair was successful. Even worse, the leak could be ignored in evaluating whether leak rates are low enough for the company to skip future inspections (see step-down discussion, above, and off-ramp discussion, below).

COGA's approach invites abuse because many of the most damaging leaks from oil and gas facilities are very simple to address.[25] A large leak could emit for months before being detected at the facility's annual inspection. But if quickly fixed, the company would not have to re-monitor it to ensure the repair was successful, or even include the leak in its recordkeeping and reporting. And the company could disregard the large leak when evaluating whether it is entitled to skip future inspections.

(b) COGA also would limit the repair requirement to components "not otherwise designed to leak." COGA PHS Attachment D at 23. This change would allow companies to avoid repairing equipment that vents by design, such as pressure relief devices. Such devices are designed to leak at some level, but they may malfunction and leak hydrocarbons far in excess of their designed venting. Companies should be required to repair such leaks.

(c) COGA also increases the repair threshold from 2,000 ppm hydrocarbons (500 ppm at existing well production facilities) to 10,000 ppm VOCs when Method 21 or similar methods are used. COGA PHS Attachment D at 23-24. The combination of a 10,000 ppm threshold, and measurement of only VOCs instead of hydrocarbons, will ensure that only a small fraction of total leaks qualify as "leaks requiring repair." COGA cites a number of figures to suggest that VOC leaks under 10,000 ppm are inconsequential, but it notes that up to 30% of emissions from valves at gas processing plants may come from valves screening below 10,000 ppm. Id. COGA's figures, moreover, address only VOCs and ignore the potential for large leaks of methane.

When all the changes above are combined, COGA's proposal will eliminate most of the emissions benefits of the proposed rule. Eliminating the statewide rule by itself would forego more than half of the emissions reductions achieved by the Division's LDAR Proposal. COGA's other proposals would further reduce the effectiveness of LDAR in the Front Range by reducing inspection frequencies and narrowing the definition of a leak requiring repair.

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[25] See, e.g., APCD PHS Ex. JJJJ at slide 13 (implementation involves "fix[ing] on the spot leaks"); TCEQ, Public Health Risks in Shale Gas Development, Presentation at National Academies of Science Workshop on Risks of Unconventional Shale Gas Development, Washington DC (May 30, 2013) at slide 15 (finding that VOC and benzene problems "nearly all arose" from "human or mechanical issues" that could be "quickly remedied"), available at http://sites.nationalacademies.org/DBASSE/BECS/DBASSE_083487 (last viewed Jan. 29, 2014).

But COGA does not stop with eliminating most of the emissions reduction benefits of the rule. It also proposes off-ramp language that would apparently let operators stop doing instrument-based inspections altogether.

5. Off-ramp From Instrument-Based Inspections:

COGA's proposal appears to allow most operators to stop doing any instrument-based inspections at all. Its proposal establishes a "2 percent leak rate" threshold that, if met, would exempt operators from conducting instrument-based inspections. COGA PHS Attachment D at 18 (operator "may skip the next [ ] inspection" by demonstrating that in the previous inspection "less than or equal to 2 percent of components required repair for all Well Production Facilities or Compressor Stations" in the same basin). Because COGA defines "leak requiring repair" so narrowly – and allows actual leaks of any size to be counted as non-leaks if quickly repaired – most compressors and well production facilities likely will fall below the 2 percent threshold.

Moreover, the two percent provision appears to create a <u>permanent</u> exemption from LDAR, because it contains no provisions for later follow-up inspections. It simply provides that the company may "skip the next AIMM inspection" by demonstrating that the "previous AIMM inspection" met the 2 percent threshold. An operator could conduct a one-time effort to inspect and quickly repair the largest leaks in its well production facilities and compressor stations so that less than 2 percent of the largest leaks are left unrepaired. Having done so, the company could repeatedly "skip" future inspections based on the single "previous" inspection effort. Thus, companies in the D-J Basin (the only basin covered by COGA's LDAR proposal) can <u>permanently</u> avoid doing instrument-based inspections.

Even if the proposal were revised to allow only a single skipped inspection, COGA's use of "only" 2% of components leaking in the basin as the threshold for skipping inspections is totally inappropriate. Given the huge number of facilities in a basin, a 2% basin-wide threshold will allow operators to skip inspections while numerous leaks continue to occur. Moreover, leak <u>frequency</u> is an inappropriate proxy for the emissions from a facility. As COGA notes, an API study noted that 92% of reducible (leak) emissions from a facility can come from less than 1% of components. Leak frequency is <u>not</u> an appropriate criterion for allowing facilities to skip or stop cost-effective LDAR inspections.

6. Other Flaws In COGA's Proposal:

COGA's LDAR proposal has numerous other flaws that would make it an ineffective approach for controlling leaks and reducing emissions. These include: (a) significantly delayed effective dates, (b) elimination of the pressure test required by the Staff Proposal for all new well production facilities, (c) changes to the definitions of "difficult, unsafe or inaccessible to monitor" that add ambiguity and thus open the door for companies to neglect inspections, and (d) extending the deadlines for conducting the few repairs actually required under COGA's proposal.[26] These provide more reasons not to adopt the COGA proposal.

In summary, COGA's LDAR's proposal is structured so that operators can avoid conducting inspections and repairing leaks – not to require those repairs. The Commission should reject COGA's proposal and adopt a credible leak detection rule.

B. The Commission Should Also Reject WPX's LDAR Proposal.

WPX Energy Rocky Mountain LLC offers several changes to the LDAR rule that are similar to COGA's submission. WPX's proposal poses many of the same problems as COGA's language.

First, WPX proposes a "step-down" provision that would allow operators to reduce inspection frequencies after two consecutive inspections with only a certain number of leaks. This proposal creates the same incentives as COGA's proposal for operators to conduct shoddy inspections. See pp. 9-10, above. Like COGA, moreover, WPX would reduce inspections even if a substantial number of components have leaked. See WPX PHS at 6 (allowing reduced inspections if two percent of components are leaking). WPX's proposal should also be rejected.

Second, WPX offers a change that appears to further reduce inspection frequencies by altering the schedule for well production facilities. The Division Proposal determines inspection frequencies according to emissions from all the "storage tanks" at the facility. Proposed Rule XVII.F.5.d (Jan. 23, 2014 version) (emphasis added). WPX would instead base the calculations on emissions from "the largest . . . single storage tank battery . . . ." WPX PHS at 5. WPX's change could substantially reduce the inspections required for large sites with multiple tanks or tank batteries. For example, under WPX's language, a facility with six 10 tpy tank batteries (totaling 60 tpy) would be treated the same as a site with only one such battery: both facilities would only be subject to only annual inspections. By contrast, the Division Proposal would require monthly inspections at the 60 tpy site. WPX's approach makes little sense, because the potential for leaks and emissions varies based on the total number of tanks at a site – not the size of the single largest tank.

WPX justifies its changes with the assertion that implementing LDAR in western Colorado is supposedly "more difficult due to the remoteness of the facilities, distance between

[26] COGA also proposes that new types of technologies be referenced in the definition of "approved instrument based monitoring method." COGA PHS Attachment D at 3. This change is unnecessary because the Division Proposal already allows the Division to approve other monitoring methods. Id.

facilities, higher elevations, and road conditions." WPX PHS at 7.[27] WPX offers pictures of snowy and muddy roads, and photos of traffic mishaps, but the rationale does not withstand scrutiny. Inspection frequencies under the Division Proposal are already lenient enough that they will not unduly burden operators, even on the Western Slope.

Under the Division Proposal, 88 percent of well production facilities will require instrument-based inspections no more than once every three months. And the remaining 12 percent – the largest facilities – need to be inspected only monthly. Compare Proposed Rule XVII.F Table 4 (Jan. 23, 2014 version) with Division EIA at 19. Similarly, the Division Proposal would not require any compressor stations to be inspected more than once every three months. It is highly unlikely that weather or other conditions will interfere with this schedule by precluding access to a well site or compressor station for months on end.

Moreover, WPX's alternate proposal would still require visiting each facility on a monthly basis for AVO inspections. WPX PHS, Alternate Proposal Ex. D at 12-13. It is unclear why remoteness, elevation, and road conditions present difficulties for instrument-based monitoring but not monthly AVO visits. This inconsistency further undercuts WPX's request for less frequent inspections.

In any case, operators in western Colorado already visit their sites far more frequently than the Division's proposed LDAR schedule requires. WPX does not disclose how often it currently visits or inspects its facilities. But the Forest Service and Bureau of Land Management have estimated that producing wells and compressors in a remote area of southwestern Colorado require daily visits for service, maintenance, and workovers. See Northern San Juan Basin Coal Bed Methane Final EIS at 3-387 to 3-389.[28] And in the Piceance Basin, BLM estimates that companies make an average of almost 3.2 trips per day to each well. Roan Plateau Planning Area Final EIS at 4-105 Table 4-28.[29] It is not too much to expect WPX and other companies to inspect their facilities once every 30 or 90 days.

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[27] WPX also emphasizes that its operations generate less condensate than those in some other parts of the state, and VOC emissions "from our production facilities are also considerably smaller than from other basins." WPX PHS at 4. If so, WPX's LDAR obligations also will be lighter: LDAR inspection frequencies are based on VOC emissions, rather than total hydrocarbon emissions.

[28] Available at: http://data.ecosystem-management.org/nepaweb/nepa_project_exp.php?project=126 (last viewed Jan. 29, 2014).

[29] Available at: http://www.blm.gov/co/st/en/BLM_Programs/land_use_planning/rmp/roan_plateau/documents/final_rmpa_eis.html (last viewed Jan. 29, 2014). The BLM figure includes trips during both the drilling and production phases. Far more traffic, especially by heavy trucks, occurs during drilling than during production. However, the EIS table indicates that regular trips continue during the production phase at rates far exceeding the monthly or quarterly visits required under

C. COGA's Economic Analysis Grossly Overstates The Costs of LDAR and STEM.

COGA justifies taking a wrecking ball to the Division Proposal largely on the ground that it supposedly is not "cost-effective." COGA supports this theory with an initial economic impact analysis predicting that the Division's proposed LDAR rules and STEM provisions will result in sky-high costs of up to $90,000 per ton of VOC controlled. DGS PHS Ex. C at 2. This figure seems implausible on its face – and an analysis of COGA's report shows why it is.

First, COGA understates the emissions reductions from LDAR and STEM in future years by misusing a Canadian study that evaluated the overall effectiveness of such efforts. The study (commissioned by the Canadian Association of Petroleum Producers) found that regulations requiring upstream oil and gas operators to perform regular leak surveys and repairs had reduced fugitive emissions by about 75 percent. DGS PHS Ex. AA at iii, 19. COGA borrows that 75 percent figure, but misapplies it by calculating leak reductions as if the leaks declined 75 percent each year. COGA then calculates each year's leak reduction from that much-reduced base. DGS PHS Ex. C at 10-11, 15-16. For example, using COGA's approach a facility with 100 tons of fugitive emissions would reduce them to 25 tons in year one; 25 to 6 tons in year two; and 6 to 1.5 tons in year three. Id. COGA would treat the benefits of leak detection as dropping rapidly over time: 75 tons of emissions reduced in year one, 19 tons in year two, and only 4.5 tons in year three.

The effect of this approach on COGA's cost-benefit analysis is dramatic. COGA calculates, for example, that VOC leaks from well production facilities with uncontrolled emissions of over 50 tpy will start at 25,835 tons uncontrolled and decrease by 19,454 tons in the first year. Id. at 15-16. The analysis then predicts emissions of 11,186 tons in the second year of LDAR, 4,844 tons in the third year, and 2,097 tons in the fourth year. Id. at 16. However, because COGA calculates emissions reductions from a continually shrinking base, it finds emissions reductions of only 8,423 tons in year two, 3,647 tons in year three, and 1,579 tons in year four. Id. The same analytic approach is used for COGA's calculations of STEM emissions and emissions reductions. Id. at 10-11.

This method is flawed for several reasons. It mischaracterizes the Canadian study, which concluded that fugitive emissions had decreased by 75 percent compared to an eight-year-old 2005 analysis of fugitive emissions from oil and gas operations. DGS PHS Ex. AA at iii.[30]

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the LDAR rule. See Roan FEIS at 4-105 (estimating 404 pickup truck visits per year for each well).

[30] That study suggests that the Canadian LDAR rules have yielded significant reductions in fugitive emissions. CATF's data analysis shows that the Colorado Division Proposal, which takes a different approach than the Canadian program, will cost-effectively achieve greater emissions reductions.

The Canadian survey did not suggest that its 75 percent emissions reductions figure could be compounded annually, as COGA has done. Instead, the study recommends that future emissions calculations use emissions factors generated from the data it presents, which reflect a reduction of 75% from previous emissions factors that were produced before the leak detection requirements were in place. DGS PHS Ex. AA at 29.[31] The Canadian study cannot be interpreted to predict that emissions will decline 75% each year in a compounded fashion as the COGA analysis assumes.

In addition, CATF examined the data from its own study and found no evidence to support COGA's assumption. To the contrary, detected leaks sometimes increased in later years. See Supp. Testimony of David McCabe.

Moreover, even if the recurrence of leaks drops somewhat after the initial surveys, the benefits of LDAR and STEM would not decline over time as COGA assumes. If fewer new leaks are detected each year the program remains in effect, those leak reductions represent only the year-to-year increase of leaks captured – not the total leaks prevented. If a company reduced fugitive emissions at a facility from 100 tons to 1.5 tons over three years, and then halted inspections, those emissions would not remain at 1.5 tons per year. Without ongoing LDAR and STEM, leaks could be expected over time to rebound to 100 tons per year as components began to wear out, etc. As a result, the real benefit of those LDAR inspections remains at 98.5 tpy (100-1.5 tpy) even if relatively few new leaks are discovered at each inspection.[32]

For example, in COGA's analysis of well production facilities over 50 tpy, it calculates emissions reductions of only 1,579 tons VOC in the fourth year of an LDAR program. But the real emissions reduction from LDAR in that year is sixteen times larger: 25,317 tons VOC (25,835 tons pre-LDAR – 518 tons in the fourth year). DGS PHS Ex. C at 15-16.

This miscalculation underlies much of the rapid escalation of cost per ton of VOC benefits predicted by COGA over time. Id. at 10-12. But COGA's analysis has a second fundamental flaw that results in exaggerated cost estimates. If the number of new leaks declines over time, the number and cost of repairs will also decline. COGA, however, assumes that the

[31] The Canadian regulations requiring leak detection and repair have been in place for several years (DGS PHS Ex. AA at 1, 9), and there is no indication in the study that the data was all collected in the first year after the Canadian programs began.

[32] This conclusion is consistent with the standard approach used for assessing the cost-effectiveness of pollution controls. EPA (and the Division) calculate the effectiveness of a control measure like LDAR by comparing (a) the emissions rate achieved by applying the control technology with (b) the baseline rate of uncontrolled emissions. See US EPA New Source Review Workshop Manual at B-37, available at http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf . Effectiveness is not calculated by comparing each year's controlled emissions to the prior year's controlled emissions, as COGA has done. See id.

cost of repairs will remain steady – even while it predicts that the number of leaks needing repair will decline by approximately 75 percent each year. DGS PHS Ex. C at 4; compare id. at 9-10, 14, 18 (constant estimates of annual repair and re-monitoring costs for STEM and LDAR) with 11, 16, 20 (tables depicting declining emissions benefits each year). By doing so, COGA systematically inflates the repair cost for implementing LDAR and STEM.

This error has a substantial impact because COGA's estimates of total costs are dominated by repair costs at some facilities. For example, for facilities with uncontrolled emissions over 50 tpy, leak repair and remonitoring costs represent 79% of estimated LDAR costs. DGS PHS Ex. C at 14. By failing to reduce repair and remonitoring costs along with new leaks, COGA makes LDAR appear much less cost-effective for those facilities.

Third, COGA totally ignores the economic benefit to companies from reducing leaks of natural gas, a primary product of their facilities. Whatever COGA's view of the environmental benefit from reducing methane and VOC emissions, it undeniably provides a substantial economic benefit. While COGA's analysis is silent on the volume of methane emission reductions, LDAR at well production facilities and compressors can be expected to reduce methane emissions by nearly 25,000 tpy. Division EIA at 18-19. This conserved gas will substantially reduce the net costs to operators from LDAR and in some cases will yield a net benefit. For example, the CATF study found that the value of gas saved by repairs almost always paid for the cost of those repairs: 97 percent of emissions come from leaks for which repairs have a positive net present value, and about 90 percent of emissions are from leaks with a repair payback time of less than one year. By omitting the value of natural gas saved from its analysis, COGA further undercuts its complaint about the cost effectiveness of the Division Proposal.[33]

COGA's analysis provides an extreme example of a well-documented phenomenon. Regulated industries routinely oppose new environmental and safety regulations with greatly

[33] In addition, COGA criticizes the Division's EIA as failing to comply with the Colorado Air Act because it does not compare the cost-effectiveness of the Division Proposal with other possible alternatives. DGS PHS Ex. D at 3-4. This argument mis-reads the Act, which does not require an EIA to compare the impacts of different alternatives. See C.R.S. § 25-7-110.5(4). The provision of the Act cited by COGA merely requires that the packet of notice materials provided to the public must identify: "The range of regulatory alternatives, including the no-action alternative, to be considered in adopting the proposed rule." C.R.S. § 25-7-110.5(1)(f). It does not require an analysis of those alternatives in the EIA. Id. The Division's notice package satisfies the alternatives disclosure requirement of Section 25-7-110.5(1)(f). Moreover, the Division will be producing its Cost Benefit Analysis and Regulatory Analysis in advance of the February 19-22 hearing, and several parties (including the Conservation Groups) have submitted alternative proposals that include economic impact analyses. The Commission will have ample information about the costs and benefits of different alternatives to make a fully-informed decision.

exaggerated predictions about compliance costs. One review found that, in eleven of twelve cases studied, actual regulatory costs were less than half of the pre-regulation estimates. For example, prior to passage of the 1978 Surface Mining Control and Reclamation Act, compliance cost estimates ranged from $6 to $12 per ton of coal. Actual costs for eastern coal operations ranged only from 50 cents to $1 per ton.[34] And prior to the 1990 amendments to the Clean Air Act, predictions estimated that reducing sulfur emissions would cost $1,500 per ton. In reality, it cost about $150 per ton as of 2000.[35] This disparity occurs because once laws are enacted, companies have an incentive to implement them efficiently rather than constructing worst-case scenarios in an effort to prevent their adoption. Here, data from actual implementation of leak detection programs in Canada (not to mention support from the three largest operators in Colorado) demonstrate that a rigorous LDAR program will be highly cost effective.

Finally, both the Division and the COGA analyses disregard an important issue because they focus solely on the cost of reducing methane emissions. They ignore the substantial environmental, economic, and public health benefits of those methane reductions. While those benefits (sometimes called the "social cost of carbon") are difficult to quantify, they are significant.[36] For example, one calculation method would place the social cost of carbon emissions at up to $1,600 per metric ton of methane, while more recent assessments indicate the value may be substantially higher. EPA RIA at 4-32; see also, id. at 4-31 to 4-34 (discussing difficulties in calculating social cost of carbon). Conservatively using a figure of $1,600/ton, the Division Proposal could yield carbon reduction benefits of more than $39 million per year. These benefits would dwarf the expected direct cost of implementing the Division's LDAR proposal. Division EIA at 18-19.

D. The Commission Has Authority to Regulate Methane.

Finally, COGA's argument that the Commission lacks authority to regulate methane fails. COGA PHS Attachment A. As described by the Division and in the Conservation Groups'

[34] Goodstein, Polluted Data, American Prospect (Nov. 16, 2001), available at: http://www.prospect.org/cs/articles?article=polluted_data (last viewed Jan. 30, 2014).

[35] Ackerman and Heinzerling, Priceless: On Knowing the Price of Everything and the Value of Nothing at 37-38 (The New Press 2004) (collecting examples of studies comparing actual and predicted regulatory compliance costs).

[36] The EPA defines the "social cost of carbon" as "the net present value of the flow of monetized damages from a one metric ton increase in CO2 emissions in a given year (or from the alternative perspective, the benefit to society of reducing CO2 emissions by one ton)." EPA, Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry (EPA RIA) at 4-29, available at: http://www.epa.gov/ttn/ecas/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf . The social cost of carbon assesses, for example, changes in agricultural productivity, human health, property damages from flood risk, and ecosystem services lost because of climate change. Id.

Prehearing Statement, the plain language of the Colorado Air Act expressly authorizes the Commission to adopt regulations addressing emissions of "hydrocarbons." C.R.S. § 25-7-109(2)(c); Conservation Groups' PHS at 13-14. COGA offers a variety of theories for why the Commission cannot exercise that authority here. At bottom, COGA appears to advocate that the Commission simply defer meaningful action on methane leaks from the oil and gas sector and that it leave the problem to the federal government. COGA's theory is flatly inconsistent with the plain language of the Act, the federal Clean Air Act, and other applicable laws.

1. The Division Proposal Is Not Inconsistent With Federal Law.

Much of COGA's brief is devoted to the claim that regulating hydrocarbons somehow conflicts with federal law. This theory involves two arguments: (a) that the state rules are preempted by the Clean Air Act; and (b) that they violate the direction in state law to "take into consideration" federal requirements. Both arguments fail.

a. The Division Proposal Is Not Preempted By Federal Law.

COGA's argument that these rules may be preempted by the Clean Air Act conflicts with the plain language of that federal statute. The Clean Air Act expressly provides that it does <u>not</u> pre-empt state actions like those Colorado has proposed. The Clean Air Act states that except with regard to mobile sources, "nothing in this chapter shall preclude or deny the right of any State . . . to adopt or enforce (1) any standard or limitation respecting emissions of air pollutants or (2) any requirement respecting control or abatement of air pollution." 42 U.S.C. § 7416. When EPA has adopted a federal emission standard or limitation, however, the state law may not be "less stringent" than the federal counterpart. <u>Id</u>. In other words, the Clean Air Act does not foreclose states from acting when EPA has not done so. And when EPA has adopted an emissions standard, that rule establishes a floor for state limitations, but not a ceiling.

This Clean Air Act provision forecloses COGA's preemption argument. Hydrocarbons like methane represent "air pollutants" under the Clean Air Act, just as they do under Colorado's Act. 42 U.S.C. § 7602(g) (defining air pollutant as "any . . . physical [or] chemical . . . substance or matter which is emitted or otherwise enters the ambient air"); <u>see also</u> <u>Massachusetts v. EPA</u>, 549 U.S. 497, 528-29 (2007) (Clean Air Act definition of "air pollutant" includes carbon dioxide); 74 Fed. Reg. 66496, 66497 (Dec. 15, 2009) (EPA finding that methane is an air pollutant that may reasonably be anticipated to endanger public health and welfare). Moreover, because EPA has not directly regulated methane emissions, there is no federal methane emissions "floor" with which Colorado's rules could conflict.[37] The Division Proposal is not preempted.

b. Addressing Methane at the State Level Does Not Violate the Colorado Air Act's Direction to "Take Into Consideration" Federal Recommendations and Requirements.

COGA also argues that by regulating methane, the Division Proposal would violate the Colorado Air Act. This theory finds no support in the language of the statute. The Act does not require Colorado to "follow" federal requirements," or "defer action" pending the adoption of federal requirements. Instead, the Act merely directs that in promulgating emission control regulations, the Commission shall "take into consideration . . . Federal recommendations and requirements." C.R.S. § 25-7-109(1)(b)(II).[38]

Between the materials presented by the Division, see Memorandum of Notice for Reg. 7 Revisions at 6; Draft Statement of Basis and Purpose, and the submittals by COGA and other parties, the Commission has all the information necessary to "consider" federal requirements. Section 109(1)(b)(II) poses no obstacle to regulation of hydrocarbons.

COGA's theory boils down to a policy argument that because the federal government has not yet acted, Colorado should not do so. This claim fails because there is no inconsistency between state action on carbon pollution and any federal initiatives. The White House itself has recognized that federal action on greenhouse gases (GHGs) has been slow in coming, and praised the leadership of states that have moved to fill the void.

The White House's 2013 Climate Change Action Plan highlights state laws "that have taken steps to move to cleaner electricity sources" and laments that: "Despite this progress at the state level, there are no federal standards in place to reduce carbon pollution from power plants."

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[37] Even COGA acknowledges that the cases it cites are not on point. COGA PHS Attachment A at 10. Some of its cases addressed common law claims like nuisance, rather than emissions standards adopted by state agencies that are allowed by Section 7416. Other cases involved motor vehicles fuels, which are subject to different requirements under the Clean Air Act, or addressed state laws that were alleged to conflict with an existing federal emissions requirement. See id. at 10-11. None of these circumstances apply to the Division Proposal.

[38] COGA also raises several other arguments regarding the Division's compliance with the Act. For example, COGA asserts that the Division has not adequately explained why the Division Proposal departs from the requirements of federal law. See DGS PHS Ex. D at 14-20; C.R.S. § 25-7-110.5(5). This claim largely rehashes issues addressed elsewhere in this prehearing statement, such as whether the record supports adopting statewide rules or going beyond the floor set by the Subpart OOOO New Source Performance Standards (NSPS OOOO), or whether the Division Proposal is cost-effective. The Division's approaches are well-supported by the record and the law.

Executive Office of the President, The President's Climate Action Plan (June 2013) at 6. Rather than suggest that these state initiatives are inconsistent with federal policy, the Plan calls for federal agencies to "build[ ] on the leadership of states and local governments." Id.

The White House Plan also identifies methane leaks from oil and gas operations as a problem meriting attention from both state and federal governments. The Plan directs the administration to "work collaboratively with state governments, as well as the private sector, to reduce methane emissions . . . ." Id. at 10-11. Similarly, while EPA deferred regulation of methane emissions in NSPS OOOO, it made no suggestion that state action would be inappropriate or pre-empted. See 77 Fed. Reg. 49490, 49513 (Aug. 16, 2012). State action on GHGs generally – and methane emissions from the oil and gas sector specifically – is entirely consistent with federal law and policy.

COGA's assertion that "EPA's authority . . . to regulate GHGs at stationary sources is undecided," COGA PHS Attachment A at 5, only underscores the value of prompt state action. COGA's references to litigation regarding EPA's regulation of GHG emissions under the federal Clean Air Act have no bearing on this Commission's legal authority to act under state law. If anything, to the extent federal GHG initiatives face attack in the courts, it becomes even more important for states to address the issue to avoid years of further delay. See Massachusetts v. EPA, 549 U.S. 497, 521 (2007) (noting that "EPA's steadfast refusal to regulate greenhouse gas emissions presents a risk of harm to Massachusetts that is both 'actual' and 'imminent'").

2. The Commission Need Not Wait For More Inventory Data On Hydrocarbon Emissions.

Next, COGA argues that regulating methane emissions is inconsistent with the state's policy regarding air pollution, which the Commission must "consider[ ]" in adopting emissions controls. See C.R.S. § 25-7-109(1)(b)(I) ("In the formulation of each emission control regulation, the commission shall take into consideration the following . . . The state policy regarding air pollution, as set forth in section 25-7-102"). COGA quotes language from the state policy about the importance of a "current and accurate inventory of actual emissions of air pollutants," and argues that more inventory data is needed before the Commission can regulate methane.

Here again, COGA misreads the Act. Section 25-7-109, and the state policy in Section 25-7-102, do not make a finalized inventory a prerequisite for regulation. See C.R.S. § 25-7-109. The language quoted by COGA (and the rest of the state policy) are simply matters to be considered. The Division's pre-hearing filings, and other parties' submittals, give the Commission ample information to meet this requirement. Moreover, nothing in the Division Proposal in any way impairs the Commission's ability to maintain its emissions inventory, or prevents the development of the State's draft GHG inventory. If anything, implementation of the new rules may provide better data that will improve the inventory.

Third, COGA's argument relies on a very selective quotation from the state policy. It neglects to quote the first half of the policy, which states in part:

> [I]t is declared to be the policy of this state to achieve the <u>maximum practical degree of air purity in every portion of the state</u> . . . . To that end, it is the purpose of this article to require the use of all available practical methods which are technologically feasible and economically reasonable so as <u>to reduce, prevent, and control air pollution throughout the state of Colorado</u> . . . .

C.R.S. § 25-7-102 (emphasis added). The State Policy, read as a whole, emphasizes the need for reducing air pollution. It does not direct the Commission to defer all action while collecting data.

COGA also notes that the EPA deferred regulation of methane under its NSPS OOOO rule in order to obtain more data from the federal GHG reporting program, 77 Fed. Reg. at 49513, and that Colorado's own GHG inventory is still in draft form. COGA PHS Attachment A at 3-4. While more data is still being developed, there is no reason to believe that beginning to address methane leaks now will only "render[ ] minimal environmental and health benefits" or "defeat the purpose" of taking public comment on the State's inventory. <u>Id.</u> As discussed below, ample existing evidence points to the oil and gas sector as a significant source of methane emissions, and addressing those emissions through regulation will only assist efforts to improve inventory data on the exact scale of those emissions.

3. The Oil and Gas Sector Represents a Significant Source of Methane Emissions.

COGA next contends that the Commission cannot regulate methane emissions from oil and gas production because they have not been shown to be "significant." C.R.S. § 25-7-109(1)(a)(I). Again, this claim misreads the statute. The Act directs that "as promptly as possible, the commission shall adopt . . . emission control regulations which require the use of effective practical air pollution controls:

> (I) For each significant source or category of significant sources of air pollutants;
>
> (II) For each type of facility, process, or activity which produces or might produce significant emissions of air pollutants."

<u>Id.</u>

This statutory language refutes COGA's argument in several ways. First, it states that the Commission "shall adopt" regulations for "each type" of activity "which produces or might produce significant emissions of air pollutants." This language does not require a definitive finding of significance before the Commission may act.[39] Instead, it requires that in the face of uncertainty – where emissions "might" be significant – the Commission should err on the side of environmental protection.

Second, the statute directs the Commission to act "as promptly as possible" in adopting such regulations. C.R.S. § 25-7-109(1)(a). This language undercuts COGA's argument that the Commission should wait for new federal laws or more study by the Commission's greenhouse gas working group before taking any steps to address methane emissions.

Moreover, the Act requires the Commission to act because there is ample evidence that hydrocarbon emissions from oil and gas exploration are "significant." While COGA's prehearing statement describes natural gas as "an important part of the solution, much more than it is part of the problem," COGA PHS Attachment A at 7, recent research suggests otherwise. As the Conservation Groups noted in their PHS, empirical research indicates that oil and gas operations in Colorado leak large amounts of methane and do so at a rate that may even eliminate any climate advantage natural gas has over coal. Conservation Groups PHS at 7-9. The Commission should not wait to start addressing these emissions.

COGA also points to figures in Colorado's draft GHG inventory that identify oil and gas as the state's sixth-largest source category today. See COGA PHS Attachment A at 6 (mischaracterizing inventory as calling oil and gas the "third lowest emitter of GHGs"); COGA PHS Ex. C at 6. But the inventory figures also indicate that oil and gas emits GHGs that are the equivalent of approximately 1.45 million cars – nearly half the automobiles registered in Colorado.[40] If that does not qualify as "significant," it is difficult to imagine what emissions source in Colorado would meet COGA's definition of the term. Moreover, while oil and gas is ranked as the sixth largest Colorado source category today, it is expected to grow substantially in the future. The draft inventory estimates that GHG emissions from the oil and gas sector will increase by 13 percent over the next 16 years. COGA PHS Ex. C at 6. In contrast, GHG emissions from every currently larger category will drop or grow to a much smaller degree over that same period. Id.

[39] Similarly, Section 109(1)(b)(V) directs the Commission to consider "the extent to which the emission to be controlled is significant." This language plainly does not require a finding that the emissions are significant before the Commission can act.

[40] Compare COGA PHS Ex. C at 6; EPA Greenhouse Gas Equivalencies Calculator, http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results ; Colorado Dep't of Transportation, Transportation Facts (2011) at 27, available at: http://www.coloradodot.info/library/FactBook/FactBook2011 .

The fact that the Commission is also working on a broader strategy for addressing GHGs is no reason to delay all action in the oil and gas sector. The scope of the problem is enormous, and beginning to address climate change will require multiple strategies affecting different industries. Taking this opportunity to reduce leaks from the oil and gas sector is not "inequitable" and does not unfairly single out one industry. See COGA PHS Attachment A at 7. It simply pursues the low-hanging fruit of GHG emissions reductions.

4. The Commission Is Not Required To Solve The Climate Crisis By Itself.

Next, COGA contends that the Commission may not adopt hydrocarbon controls because they are not "effective." C.R.S. § 25-7-109(1)(a). According to COGA, the Regulation 7 changes are not "effective" because by they will not by themselves measurably reduce climate change.

The United States Supreme Court rejected this line of argument several years ago. In Massachusetts v. EPA, the Court dismissed the EPA's claim that federal regulation of GHGs from new motor vehicles would be insufficient by itself to mitigate global climate change. The Court explained: "Agencies, like legislatures, do not generally resolve massive problems in one fell regulatory swoop. . . . They instead whittle away at them over time, refining their preferred approach as circumstances change and as they develop a more nuanced understanding of how best to proceed." 549 U.S. at 524.

The law allows Colorado to start "whittl[ing] away" at global warming by addressing this State's contribution to it. COGA's argument to the contrary relies on a line of federal cases that have no application here. The cases COGA cites address whether private parties can sue in federal court over greenhouse gas emissions – not whether state governments (like Colorado and Massachusetts) have authority to regulate those emissions.[41] If anything, the cases cited by COGA support the need for the Commission to act because they view government agencies – rather than federal courts – as the appropriate venue for addressing difficult policy issues like climate change. For example, the Supreme Court case cited by COGA stated: "The expert agency is surely better equipped to do the job than individual district judges issuing ad hoc, case-

[41] For example, Washington Envt'l. Council v. Belton held that a conservation group lacked standing to sue under the U.S. Constitution because, given the global scale of climate change emissions, the group could not show that its injuries were caused by the specific defendants in question or that a ruling against those defendants would have an impact on climate change that could redress Plaintiffs' injuries. 732 F.3d 1131, 1141-46 (9th Cir. 2013); see also, Native Village of Kivalina v. ExxonMobil Corp., 696 F.3d 849 (9th Cir. 2012) (concurring opinion) (same). American Elec. Power v. Connecticut, 131 S. Ct. 2527 (2011), held that common-law claims (ie, legal rules fashioned by judges) challenging GHG emissions were preempted by the Clean Air Act. It said nothing about the authority of state agencies to adopt regulations addressing the issue.

by-case injunctions. Federal judges lack the scientific, economic, and technological resources an agency can utilize in coping with issues of this order." American Elec. Power Co., Inc. v Connecticut, 131 S. Ct. 2527, 2539-40 (2011).

COGA's position also has much farther-reaching implications than it acknowledges. If Colorado cannot regulate GHGs until it shows that a state regulation "in isolation" will have a "causal nexus with respect to" the impacts of global warming, COGA PHS Attachment A at 6, then no amount of additional inventory data or study is likely to produce that authority. The scale of worldwide GHG emissions likely is too large for Colorado alone to materially reduce climate change by itself.

In effect, COGA's "effective" regulation argument does not ask for more study or "good science." Instead, it would require the Commission to abandon any effort to adopt rules addressing carbon pollution in Colorado. This would be an absurd result that is not called for by the Act. This Commission has ample legal authority to address Colorado's contribution to global climate change. Especially given the limited progress being made at the federal level, Colorado should not delay exercising its authority.

III. THE DEFINITION OF "NATURAL GAS COMPRESSOR STATION" SHOULD BE REVISED TO INCLUDE TRANSMISSION AND STORAGE SEGMENT COMPRESSORS DOWNSTREAM OF NATURAL GAS PROCESSING PLANTS.

In their Prehearing Statement, the Conservation Groups proposed that the definition of "natural gas compressor station" in proposed Rule XVII.A.10 (Jan. 23, 2014 version) be amended so that it is not limited to those compressors upstream of the natural gas processing plant. This change would require downstream facilities to conduct leak detection and repair in compliance with proposed Rule XVII.F. Conservation Groups' PHS at 21. Other parties have raised questions about the scope of this change. In response, we offer the following final regulatory language to clarify the scope of the proposal. The definition of "natural gas compressor station" would be modified as follows from the January 23, 2014 Division Proposal:

> "Natural Gas Compressor Station" means a facility, located downstream of well production facilities, which contains one or more compressors designed to move natural gas at increased pressure from fields, in transmission pipelines, or into storage, except for compressors located at a natural gas processing plant. For purposes of this definition, a compressor is "located at a natural gas processing plant" if it is below the inlet of the plant and above the point of custody transfer to the transmission and storage segment. ~~compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.~~

This definition (which borrows language from the definition in NSPS OOOO) is intended to cover the compressors addressed by the Division Proposal, but also to require LDAR at downstream compressor stations in the natural gas transmission and storage segment (transmission compressor stations). See EPA, The Natural Gas Production Industry (graphic identifying different segments of industry). The definition would not apply to compressors located at natural gas processing plants.[42]

Transmission compressor stations represent an important gap in the coverage of NSPS OOOO that should be addressed with this rulemaking. Initially, EPA included transmission compressors in its 2011 proposed rule for NSPS OOOO. This group of compressors was dropped from the final rule because EPA was uncertain whether the VOC emissions reductions alone would justify the cost and compliance burden of regulating them. 77 Fed. Reg. at 49523. In doing do, however, EPA described transmission compressors as "an important set of sources to regulate." Id.

EPA's rationale for exempting transmission compressors does not apply to this rulemaking. Unlike NSPS OOOO, the Division Proposal addresses methane as well as VOCs. And these compressors generate significant methane emissions: EPA has reported that they produce more than 15% of all methane from oil and gas operations in the United States.[43] As noted in the Conservation Groups' Prehearing Statement, applying LDAR to transmission compressors will yield very cost-effective reductions in methane emissions. The Commission should take this opportunity to fill a significant gap in the coverage of NSPS OOOO.

In many cases, moreover, transmission compressor stations do emit substantial amounts of VOCs. In Colorado, at least 17 transmission segment compressor stations have Title V permits, and they include VOC permit limits that range as high as 387 tpy. Supp. testimony of Maureen Barrett at 2.[44]

Moreover, subjecting transmission compressors to LDAR requirements would not represent a dramatic expansion of the Division's authority because it already is issuing permits for sources in this segment. In fact, several companies operating transmission compressors

[42] Reg. 7, Section XII.G.1, requires application of the LDAR provisions from 40 C.F.R. Part 60, Subpart KKK to natural gas processing plants.
[43] McCabe testimony at 9; see also, EPA, Directed Inspection and Maintenance at Compressor Stations (Oct. 2003).
[44] A few of these permits include some limited leak detection requirements, but they are incomplete and applied inconsistently. For example, the permit for Encana's West Douglas compressor station (a facility permitted to emit 106 tpy VOCs) has a provision for "voluntary" leak detection involving an undefined "maintenance plan." The permit for DCP Midstream's Enterprise station (permitted for 93 tpy VOCs) requires only AVO monitoring. Barrett Supp. testimony at 2.

already are parties to this rulemaking. See Barrett Supp. testimony at 2. Requiring LDAR at transmission compressors also is unlikely to involve any greater burden than at their upstream counterparts. Almost all of the 17 Title V permitted-transmission compressor stations in Colorado already are subject to permit conditions that require monthly or quarterly inspections for other purposes. Barrett Supp. testimony at 2. The Commission should extend its LDAR rule to cover transmission compressors.

IV. COGA'S CHANGES TO THE PROPOSED STORAGE TANK REQUIREMENTS SHOULD BE REJECTED.

The primary change that COGA seeks with respect to storage tank controls is to replace the Division's strict requirement to "route all hydrocarbon emissions to air pollution control equipment" and "operate without venting . . . during normal operations" with a much watered down requirement to "operate to the minimize Uncontrolled Releases to the maximum extent practicable." See COGA PHS Attachment D at 5 (defining Uncontrolled Releases), 12. There is no justification for creating such a large loophole for storage tanks, which are the largest source of VOC emissions statewide. As the Division has recognized, prior regulation of storage tanks has not achieved the control of VOCs that the Division anticipated because some systems are inadequately designated, leading to over-pressurization and a failure to capture tank emissions. See APCD PHS at 15; Conservation Groups PHS at 25.

Although COGA claims that the Division's "without venting" standard is too rigid and "operationally infeasible," it fails to offer any explanation for why the Division's proposed language does not cover all of COGA's concerns. COGA PHS Attachment D at 12 (claiming, for example, that venting is required for "safety of equipment and personnel."). The Division's proposal already includes a broad exemption where "venting is reasonably required for maintenance, gauging or safety of personnel and equipment." Id. Unlike COGA's proposal, however, the Division appropriately places the burden on the operator to demonstrate that venting falls within the exemption. See APCD PHS at 15.

COGA also argues that revisions are necessary because tanks inevitably leak. See COGA PHS Attachment D at 5-6. However, the Division's proposal applies to venting and not leaking, which is governed by the LDAR provisions. See APCD Statement of Basis and Purpose at 5. Moreover, even where tanks are designed to leak at some level, they may malfunction and leak far in excess of the design rate. Companies should be required to repair such leaks.

COGA also seeks to extend the dates for new facilities to comply with the storage tank provisions from May 2014 to January 2015. See, e.g., COGA PHS Attachment D at 11, 12 (XVII.C.1.b(i), (iv), (c)(i)). However, COGA provides no evidence that any such extension is necessary. The Division Proposal provides existing facilities with a year to comply. Proposed

Rule XVII.C.1(b)(i)(b) (Jan. 23, 2014 version). There is no justification for providing additional time for new facilities that will be well aware of the control requirements at the planning stages.

COGA also seeks to add language to the definition of a storage tank indicating that it only applies to "permanent" storage tanks. See COGA PHS Attachment D at 5 (XVII.A.12). This proposed change is unnecessary and will add confusion because the definition of storage vessel in NSPS OOOO already includes an exemption that covers temporary storage tanks:

> Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel since the original vessel was first located at the site.

40 C.F.R. § 60.5430 (definition of storage vessel). Adding the requirement that tanks be "permanent" without defining what that means only creates confusion.

V. THE COMMISSION SHOULD NOT EXEMPT INTERMITTENT-BLEED PNEUMATIC CONTROLLERS.

There is one notable exception to COGA's insistence that the Division Proposal be limited to the Front Range nonattainment area: it has no objection to applying statewide the Rule XVIII requirement to install low-bleed pneumatic devices. COGA PHS Attachment D at 29. Instead, DGS and COGA ask for language making clear that the rule covers only continuous bleed devices, and not intermittent bleed pneumatics. Id. (requesting that "continuous bleed" be added to the Rule XVIII.C.2.a requirement for new controllers).

COGA describes this change as serving only "to maintain consistency between state and federal regulations." Id. But the proposal would have a substantial impact on emissions. As discussed in the Conservation Groups' Prehearing Statement, most pneumatics in the Piceance Basin appear not to be continuous bleed devices, and there appear to be no continuous bleed devices in the D-J Basin that are high-bleed. Conservation Groups PHS at 28-29. Thus, COGA's change would ensure that this rule has very little impact on emissions in Colorado. Id. In contrast, bringing existing intermittent bleed devices under the 6 scfh limit will likely yield significant emissions reductions. See McCabe testimony at 10 (estimated intermittent bleed device emissions of 17 scfh); see also, EPA, Methane Emissions from the Natural Gas Industry – Vol. 12: Pneumatic Devices (June 1996) at 43 (finding average intermittent bleed rates of 21 scfh (511 scfd) at onshore oil and gas production sites in United States). The Commission should reject COGA's language, and ensure that the rule addresses intermittent-bleed devices as proposed by the Conservation Groups. See Conservation Groups PHS Ex. D at 34-37 (alternate proposal language).

Applying the rule to intermittent bleed devices appears to be entirely feasible. The American Petroleum Institute (API) has stated: "Achieving a bleed rate of < 6 SCF/hr [as would be required under the Division Proposal] with an intermittent vent pneumatic controller is quite reasonable since you eliminate the continuous bleeding of a controller." API, Technical Review of Pneumatic Controllers at 7 (Oct. 10, 2011). In fact, API advocated intermittent-bleed devices to achieve the 6 scfh bleed rate, rather than continuous low-bleed devices. Id.

The Commission should ensure that its rule covers intermittent-bleed devices.

VI. THE COMMISSION SHOULD NOT STRIKE THE REQUIREMENT TO MINIMIZE VENTING DURING WELL MAINTENANCE AND LIQUIDS UNLOADING.

COGA and DGS also seek to delete proposed Rule XVII.H, which would require companies to control venting during liquids unloading and other well maintenance. The basis for this request is that the proposed language was "not part of the Division's original draft" and supposedly was not discussed during the stakeholder process. COGA PHS Attachment D at 27-28. This is incorrect: the Conservation Groups and other organizations have advocated since the outset of the process for such controls. See, e.g., March 21, 2013 Conservation Group Comments at 16-18; March 21, 2013 Environmental Defense Fund Comments at 13-14.[45]

DGS also suggests that certain technologies "may not be technologically or economically feasible" at some well sites. DGS PHS at 14-15. This is a non-issue because the Division's proposed language provides ample flexibility for operators. It requires best management practices and minimizing venting "to the extent possible." Proposed Rule XVII.H. The proposed rule is not an especially restrictive provision.

Liquids unloading represents a very significant source of methane and VOC emissions in Colorado. Technologies to minimize venting, such as plunger lifts, are available and economically feasible in this state. The Commission should adopt proposed Rule XVII.H, with the additional recordkeeping requirements proposed by the Conservation Groups. Conservation Groups PHS at 29-30.

[45] Both letters are available at: http://www.colorado.gov/cs/Satellite/CDPHE-AP/CBON/1251635574914 .

VII. THE COMMISSION SHOULD NOT RAISE THE APEN AND PERMITTING THRESHOLDS IN REGULATION 3.

During the stakeholder process, the Division considered proposing to raise the Air Pollution Emission Notice (APEN) and construction permitting thresholds in Regulation 3 in order to reduce permit processing workloads. Ultimately, however, the Division chose not to propose these changes to the Commission. The Division has explained that the primary workload issue comes as a result of the "catch all" provisions contained in Regulation No. 3, which it does propose to eliminate. See APCD PHS at 2, 6-7.

While the Division has determined that changes to the APEN and permitting thresholds are unnecessary, COGA asks the Commission to impose them anyway. COGA proposes (1) revising APEN reporting thresholds for criteria pollutants from 1 tpy to 2 tpy within the NAA, and (2) raising construction permit thresholds within the NAA from 2 tpy to 25 tpy and outside the NAA from 5 tpy to 25 tpy. These changes should be rejected because they would reduce public health protection in Colorado and violate state and federal law.

A. The State Must Have a Robust and Accurate Emission Inventory and Strong Permitting and Enforcement Program for Oil and Gas Sources

The Colorado Air Act recognizes the importance of air pollution reporting and permitting requirements. As stated in the Act:

> [A] current and accurate inventory of actual emissions of air pollutant from all sources is essential for the proper identification and designation of attainment and nonattainment areas, the determination of the most cost-effective regulatory strategy to reduce pollution, the targeting of regulatory efforts to achieve the greatest health and environmental benefits, and the achievement of a federally approved clean air program.[46]

The Act provides specific "incentives to achieve the most accurate and complete inventory possible and to provide for the most accurate enforcement program achievable based upon that inventory."[47] The primary method for obtaining inventory data is by requiring operators of sources of pollution to file APENs.[48] The primary enforcement tools are construction and operating permits.[49]

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[46] C.R.S. § 25-7-102.
[47] Id.
[48] See id. § 25-7-114.1.
[49] See C.R.S. §§ 25-7-114.2, 114.3.

Given the importance of the emissions inventory, the Act permits only those sources that are of "minor significance" to be exempted from the APEN filing requirements.[50] Likewise, only "minor or insignificant sources of air pollution" which have a "negligible impact on air quality" may be exempted from construction permits.[51] Indeed, Regulation 3 currently states that sources may be exempted from APEN and permitting requirements only if they "by themselves or cumulatively as a category are deemed to have a negligible impact on air quality."[52]

A robust and accurate emissions inventory is also critical to ensure compliance with the Clean Air Act. Under the Act, the State must ensure that its nonattainment SIP for the Denver Metropolitan and Northern Front Range Area includes "a comprehensive, accurate, current inventory of actual emissions from all sources of the relevant pollutant or pollutants."[53] The inventory is a critical component of regional photochemical ozone modeling to determine compliance with the ozone NAAQS.[54] Furthermore, because Regulation No. 3 is part of the state SIP, the State cannot raise the thresholds in the ozone nonattainment area absent a showing that it will not "interfere with any applicable requirement concerning attainment and reasonable further progress."[55]

Despite these legal requirements, the lack of reliable inventory data regarding oil and gas emissions has been a significant problem for state and federal regulators. The Office of the Inspector General recently found that EPA needs to improve air emission data for the oil and gas industry. As the report recognized, "[l]imited data from direct measurements, poor quality emission factors, and incomplete [national emission inventory] data hamper EPA's ability to assess air quality impacts from oil and gas production activities."[56] The report goes on to state that as a result of the limited data, "human health risks are uncertain, states may design incorrect

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[50] C.R.S. § 25-7-114.1(2).
[51] C.R.S. § 25-7-114.2.
[52] Reg. 3, Part A.II.D.1 and Part B.II.D.1.
[53] 42 U.S.C. § 7502(c)(3). Likewise, under Section 110(a)(2)(F), Colorado must have an adequate stationary source monitoring system as part of its infrastructure SIP. EPA approved Colorado's infrastructure SIP for ozone in May 2011 based, in part, on requirements requiring stationary sources to report their emissions on a regular basis through APENs. 76 Fed. Reg. 28707, 28712 (May 18, 2011).
[54] See, e.g., ENVIRON, Final Emissions Technical Memorandum No. 4a, at 2 (June 7, 2012) (WRAP Phase III).
[55] 42 U.S.C. § 7410(l).
[56] U.S. EPA, Office of Inspector General, EPA Needs to Improve Air Emissions Data for the Oil and Natural Gas Production Sector, Report No. 13-P-0161 (Feb. 20, 2013), available at http://www.epa.gov/oig/reports/2013/20130220-13-P-0161.pdf.

or ineffective emission control strategies, and EPA's decisions about regulating industry may be misinformed."[57]

In Colorado, there are already significant gaps in the data that is reported through APENs. In the 2008 inventory, 49% of oil and gas NOx sources and 35% of VOC sources in the Denver-Julesburg Basin, and 55% of oil and gas NOx sources and 31% of VOC sources in the Piceance Basin, did not report emissions.[58] These gaps are the result of emissions that fall under the thresholds as well as specific exemptions for the oil and gas industry.[59]

A recent study of the Denver-Julesburg Basin confirms the need to ensure the most accurate inventory of oil and gas sources possible. The study documented atmospheric concentrations of VOCs higher than would be expected on the basis of current inventory data. The study suggests that current inventories underestimate methane emissions by at least a factor of two.[60]

APENs and construction and operating permits are also an integral part of the enforcement program.[61] APENs notify the Division of the presence of sources of pollution within the state. They must include important information regarding the location, ownership, and nature of the facility as well as an estimate of the quantity and composition of any expected pollution.[62] Accordingly, APENs are critical informational tools for the Division with respect to knowing what pollution sources are operating within the state.

Permits also provide the Division with critical information about the location and ownership of emission sources and the location, quantity, and quality of the permitted emissions.[63] As part of the permitting process, the Division must determine whether the source will comply with all applicable air quality control standards and emission control regulations, including requirements of the nonattainment and attainment program.[64] Accordingly, permits provide one place to consider all the standards that may apply to any one source.

[57] Id. at 10.
[58] ENVIRON at 19, 26.
[59] See, e.g., Reg. 3, Part A.II.D.1.
[60] Gabrielle Petron *et al*, Hydrocarbon Emissions Characterization in the Colorado Front Range—A Pilot Study, 117 Journal of Geophysical Research-Atmospheres D04304 (Feb. 21 2012).
[61] See C.R.S. §§ 25-7-114.1 to 114.3.
[62] C.R.S. § 25-7-114.1.
[63] See C.R.S. § 25-7-114.4.
[64] See, e.g., Reg. 3, Part B.III.B.5, III.D.1.

Permits also provide for "inspection, monitoring, record-keeping, and reporting" that is critical for enforcement.[65] For example, prior to obtaining a construction permit, the applicant must also supply the Division with a plan for maintaining and operating all pollution control equipment and a method of recordkeeping to demonstrate compliance.[66] Permits also provide authority for the Division or its representatives to enter a facility for the purposes of inspection and enforcement.[67]

B. Raising APEN and Construction Permitting Thresholds is Unnecessary and Conflicts with State and Federal Law.

Because Regulation No. 3 is part of the state SIP, the State cannot raise the thresholds in the ozone nonattainment area absent a showing that it will not "interfere with any applicable requirement concerning attainment and reasonable further progress."[68] COGA has not made such a demonstration in support of their request. In the past, EPA has rejected Colorado's attempt to "relax existing SIP requirements" by adding additional APEN exemptions.[69] Because the current APEN and permitting proposals similarly "relax existing SIP requirements," they are also likely to be rejected by EPA.

COGA's request to increase the construction permitting threshold for VOCs—by more than 12 times in the nonattainment area (from 2 tpy to 25 tpy) and more than five times outside the nonattainment area (from 5 tpy to 25 tpy)—should also be rejected because it will hamper the Division's enforcement efforts. Based on a query of the state databases from February 2013, the Division estimates that there are 7,600 to 9,500 point sources at facilities emitting less than 25 tpy.[70] Accordingly, COGA's proposed changes are likely to lead to a significant reduction of the permits issued in the state and hamper the Division's enforcement efforts with respect to oil and gas sources.[71]

Additionally, if the APEN threshold is raised, the State will have less information available about small sources, further decreasing the accuracy of the inventory, and reducing the State's ability to effectively regulate. Although the sources covered by this change, standing

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[65] C.R.S. § 25-7-114.4.
[66] Reg. 3, Part B.III.G.7.
[67] See id. Part C.V.C.16.b.
[68] 42 U.S.C. § 7410(l).
[69] 76 Fed. Reg. 61054, 61054 (Oct. 3, 2011); see also 76 Fed. Reg. 4271, 4274 (Jan. 25, 2011).
[70] APDC, 2013 Rulemaking April Stakeholder Meeting, slides at 13.
[71] The Division's proposal to raise the permitting thresholds would be compounded by raising the APEN permitting thresholds. Only emissions points requiring APENs are considered when calculating whether a facility has total uncontrolled emissions that meet the permitting thresholds. Reg. 3, Part B.II.D.3. Accordingly, if the Division raises the APEN threshold within the nonattainment area as COGA suggests, it will further decrease the number of sources that may be subject to permitting.

alone, represent a relatively small piece of the overall emissions pie, the Division's analysis shows that the number of small sources is growing rapidly within the nonattainment area. Permits for sources between 1 tpy and 2 tpy more than tripled between 2007 and 2012.[72] The State must have accurate information about these smaller sources to determine the best path forward for NAAQS compliance.

For example, the lack of information about smaller sources has already led the Division to refuse to regulate heater-treaters, which the Division concedes are a cumulatively significant source of NOx emissions. Heater-treaters used to remove oil, condensate, and water from the natural gas at or near the well head before the gas is sent down the production line.[73] There is an APEN exemption for these emission sources, and they may also fall below reporting thresholds. As the Division recognized as part of its Regional Haze Plan, information regarding heater-treater emissions is "scarce" because the emissions are exempted from APEN reporting.[74] However, because of the large and growing number of heater-treaters in the state—26,000 are expected by 2018—the Division estimates that they will cumulatively represent the largest single area source of NOx emissions by 2018 (22,901 tpy).[75] Although the Division recognized that these "cumulative emissions make this a significant source category," it determined that it was unable to regulate the source due to the lack of information.[76] As this example demonstrates, information regarding emissions from relatively small sources is important for combating ozone pollution in Colorado.

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[72] APCD, 2013 Rulemaking April Stakeholder Meeting, slides at 15.

[73] Regional Haze Plan, App. D, Heater-Treaters, at 5 (2011) (stating the heater-treaters fall within the exemption for "fuel burning equipment that uses gaseous fuel and has a design rate of less than or equal to 5 million BTUs/hour" found in Reg. 3, Part A.II.D.1.k and Part B.II.D.1.e), available at http://www.colorado.gov/cs/Satellite/CDPHE-AP/CBON/1251595092457.

[74] Id. at 1, 5.

[75] Id.

[76] Id. at 5; Colorado Regional Haze State Implementation Plan (SIP) at 109.

CONCLUSION

For the reasons stated above and in the Conservation Groups' Prehearing Statement, the Commission should adopt the Division Proposal with the changes described in our Alternative Proposal.

Date: January 30, 2014

Respectfully submitted,

Michael S Freeman

Michael S. Freeman
mfreeman@earthjustice.org
Robin L. Cooley
rcooley@earthjustice.org
Earthjustice
1400 Glenarm Place, Suite 300
Denver, CO 80202
(303) 623-9466
(303) 623-8083 (fax)

COUNSEL FOR SIERRA CLUB, NATURAL RESOURCES DEFENSE COUNCIL, EARTHWORKS OIL AND GAS ACCOUNTABILITY PROJECT AND WILDEARTH GUARDIANS

Benjamin Longstreth
blongstreth@nrdc.org
Natural Resources Defense Council
1152 15th Street NW
Washington, DC 20005
202-513-6256
202-289-1060 (fax)

COUNSEL FOR NATURAL RESOURCES DEFENSE COUNCIL

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CERTIFICATE OF SERVICE

I hereby certify that on the 30th day of January 2014, I served the foregoing **REBUTTAL STATEMENT OF THE SIERRA CLUB, NATURAL RESOURCES DEFENSE COUNCIL, EARTHWORKS OIL AND GAS ACCOUNTABILITY PROJECT AND WILDEARTH GUARDIANS** by electronic mail on all parties listed on the Commission's Party Status List.

/s/ Michael S. Freeman