REGULATORY ANALYSIS

In performing a regulatory analysis, each rulemaking entity must provide the information requested for the regulatory analysis to be considered a good faith effort. Each regulatory analysis shall include quantification of the data to the extent practicable and shall take account of both short-term and long-term consequences. The regulatory analysis must be submitted to the Air Quality Control Commission Office at least five (5) days before the administrative hearing on the proposed rule and posted on your agency's web site. For all questions, please attach all underlying data that supports the statements stated in this regulatory analysis.

DEPARTMENT:	Colorado Department of Public Health & Environment	**AGENCY:**	Air Quality Control Commission
CCR:	5 CCR 1001-9 and 5 CCR 1001-26	**DATE:**	December 9, 2021

RULE TITLE OR SUBJECT:

REGULATION NUMBERS 7 & 22

Per the provisions of § 24-4-103(4.5)(a), Colorado Revised Statutes, the regulatory analysis must include the following:

Introduction

During the 2019 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes in Senate Bill 19-181 (SB 19-181) (Concerning additional public welfare protections regarding the conduct of oil and gas operations) that include directives for both the Oil and Gas Conservation Commission (OGCC) and this Air Quality Control Commission (Commission). In the same session, the General Assembly adopted House Bill 19-1261 (HB 19-1261), setting statewide greenhouse gas (GHG) reduction goals. The General Assembly declared in HB 19-1261 that "climate change adversely affects Colorado's economy, air quality and public health, ecosystems, natural resources, and quality of life[,]" acknowledged that "Colorado is already experiencing harmful climate impacts[,]" and that "many of these impacts disproportionately affect" certain disadvantaged communities. The goals set in HB 19-1261 seek a 26% reduction of statewide GHG emissions by 2025; 50% reduction by 2030; and 90% reduction by 2050 as compared to 2005 levels. The GHG Pollution Reduction Roadmap (GHG Roadmap) developed by the Colorado Energy Office and CDPHE identifies the largest contributors to state GHG emissions and quantifies the baselines from which these reduction percentages are to be estimated.

In October 2020, the Commission established a target for the sector including oil and gas fugitive emissions (O&G Sector) of a 36% reduction from the 2005 baseline by 2025 and a 60% reduction from the 2005 baseline by 2030 (from an estimated 20.17 million metric tons (MMT) CO_2e to 13 MMT CO_2e by 2025 and 8 MMT CO_2e by 2030). Commission targets for the sector including residential, commercial, and industrial combustion emissions (RCI Sector) include a 20% reduction from 2005 numbers by 2030. House Bill 21-1266 (HB 21-1266), signed into law on July 2, 2021, memorializes these percentage reductions in statute, and provides additional requirements for the rulemakings to achieve these goals.

In this rulemaking action, the Air Pollution Control Division (Division) has proposed requirements for upstream and midstream segment operations to reduce GHG emissions sufficient - when taken in combination with other regulatory and voluntary actions at operations across the state - to achieve the GHG reduction requirements of HB 21-1266. In this action, the Division is not proposing additional regulations applicable to the transmission and storage segment or the distribution segment. The Division is proposing revisions to Regulations Number 7 and 22 to achieve the necessary statewide GHG[1] emission reductions to implement the GHG Roadmap.[2] A more detailed discussion of the legislative requirements for implementing the GHG Roadmap is set forth in Section II.A of the Division's Prehearing Statement, but essentially, the Commission is required to adopt regulations to meet specified percentages of GHG reduction over a

[1] The term "statewide greenhouse gas emissions" is used in the Environmental Justice Act, HB 21-1266. The term "statewide greenhouse gas pollution" is defined in House Bill 19-1261, § 25-7-103(22.5), C.R.S. The Division interprets "statewide" in both contexts to mean GHG emitted in Colorado and over which the state has jurisdiction.
[2] *See* GHG Roadmap, https://drive.google.com/file/d/1jzLvFcrDryhhs9ZkT_UXkQM_0LiiYZfq/view

baseline. The percentages and baselines differ based upon the GHG Roadmap sector in which the equipment and resulting GHG emissions are bucketed.[3] There are two GHG Roadmap sectors at issue in this rulemaking: the O&G Sector and the Industrial Sector. Most methane emissions from upstream and midstream segment activities, along with estimates of methane "leakage" from pipelines in the transmission & storage and distribution segments, are in the O&G Sector.[4] The emissions from fuel combustion equipment at oil and gas sources in the upstream and midstream segments are largely found in the Industrial Sector.[5] This proposal is designed to ensure that the Commission has adopted regulations that - in conjunction with "other laws and rules, as well as voluntary actions taken by local communities and the private sector"[6] - achieve the state's GHG reduction targets.

These proposed requirements build on the extensive regulatory framework to reduce GHGs from the oil and gas sector that Colorado has developed and steadily updated since 2014. Highlights of the Division's proposal for Regulation 7, Part D, include:

- Updating maintenance and performance test requirements for air pollution control equipment, including enclosed combustion devices, in both the State Implementation Plan (SIP) and more broadly on a state-only basis;
- Expanding Approved Instrument Monitoring Method (AIMM) inspection requirements for compressor stations and well production facilities;
- Expanding rod-packing replacement, leak detection and repair (LDAR), and pneumatic controller requirements to natural gas processing plants state-wide;
- Reducing emissions from well liquids unloading, well swabbing, well maintenance activities, and well plugging;
- Implementing new emission reduction requirements for pigging operations and blowdowns of equipment and piping at midstream operations;
- Establishing additional protections for disproportionately impacted communities (DI Communities);
- Enhancing the state's annual emissions reporting program; and
- Ensuring meaningful coordination between the Division and the COGCC.

Highlights of the Division's proposal for Regulation 22, Part B, include:

- Establishing the Midstream Steering Committee and a process for developing a segment-wide regulation to achieve GHG reductions from midstream segment fuel combustion equipment in Section III.;
- Establishing a first-of-its-kind greenhouse gas intensity program to reduce emissions from preproduction and production operations in the upstream segment in Section IV.; and
- Prioritizing reductions of co-pollutants in DI Communities in both programs described above.

This analysis represents information gathered from various stakeholders in an effort to generate the most complete and accurate assessment of the costs and benefits of the proposed strategies. Where additional data was not reasonably available, the Division utilized assumptions that are set forth in this analysis. This analysis builds upon the Rebuttal Economic Impact Analysis (Rebuttal EIA) submitted to the Commission on November 23, 2021, and the Cost Benefit Analysis requested by rulemaking parties and submitted to the Department of Regulatory Agencies on December 3, 2021, and provides additional detail as required by statute. The Division incorporates the content of the Rebuttal EIA and Cost Benefit Analysis into this Regulatory Analysis, and attaches copies of those materials hereto.[7] The Division also refers herein to filings by the Division and other parties in this rulemaking proceeding, incorporated into this RA by reference; these materials are available on the Commission's website in the monthly materials folder for the December 2021 Commission meeting, at: https://drive.google.com/drive/folders/1iMgIcWPMMM-T94eNUovmalU3nNlCaxmn

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3 *See* § 25-7-105(1)(e)(XII) and (XIII), C.R.S.

4 *See* GHG Roadmap, p.IV, Figure 1.

5 Emissions from fuel combustion equipment include both CO_2 and methane. The 2015 baseline emissions in the state's GHG inventory are based on data reported to the U.S. Environmental Protection Agency (EPA).

6 § 25-7-105(1)(e)(II), C.R.S.

7 As RA Attachments 1 and 2.

I. **A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule;**

The proposal affects the oil and gas industry and supporting businesses in Colorado. Companies that will bear the costs of this rule change include oil and gas companies that produce, transport, or process oil or natural gas in the state, including upstream and midstream operators.

Local governments that receive revenue from oil and gas operations may also be impacted by the proposed rules, though there is no indication or evidence that this impact is likely to occur. Since the Commission adopted significant revisions to Regulation 7, there has been no measurable increase in plugging and abandonment of wells, except in Weld County, where production has nonetheless continued to increase exponentially more than offsetting the impact of well shut-ins.

The proposed revisions will benefit those companies that manufacture, distribute, or test flare control devices, manufacture and install flow meters, develop gas recovery technology (e.g., Zero Emissions Vacuum and Compressor units), as well as those companies that provide or support monitoring (leak detection, continuous monitoring, advanced screening) and consulting services. The proposed revisions will also benefit mineral owners, who receive royalty payments based upon the amount of oil or natural gas recovered, and sold, by operators. These revisions ensure more capture of natural gas, where that gas is now currently vented or flared, thus increasing royalty payments.

Further, the proposal broadly benefits all persons in Colorado, especially those who live and work in DI Communities or within proximity of oil and gas operations. Residents of the 8-hour Ozone Control Area, Northern Weld County, and the remainder of the state (ROS) will benefit from the proposed rule revisions through reduced GHG emissions and reduced impact of climate-influenced events, through reduced VOC and other co-pollutant emissions, and improved ozone levels and health outcomes. The cumulative cost of the Division's proposal is significantly less than the social cost of greenhouse gas, even where individual components of the proposal may have costs above the social cost of greenhouse gas. However, the social cost of greenhouse gas does not include the co-benefits to Colorado residents and society at large from reduced emissions of co-pollutants, their harmful impacts, and the impacts to Colorado's economy from reclassifications under the federal ozone nonattainment program (or to its healthcare system from treating health issues caused or worsened by ozone pollution).

II. **To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons;**

For each strategy, the Division's assessments identify the cumulative costs for the affected industry, the estimated air pollution reduction, and the projected cost per unit of air pollution reduced, where such information was reasonably available to the Division. The Division also assessed whether any of the proposed strategies would impose a direct cost on the general public to comply, and determined that based on the available data there will be no direct costs on the general public for any of the proposed requirements. Finally, the Division considered whether there would be any additional costs for the Division to implement the proposed requirements and determined that the proposed revisions could be implemented using existing and anticipated resources. A complete description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons can be found in the Division's Cost Benefit Analysis[8] and Rebuttal EIA[9], attached hereto and incorporated by reference herein.

<u>Surrebuttal Cost Analysis</u>

On December 8, 2021, the Joint Industry Working Group (JIWG) submitted a surrebuttal document alleging, for the first time, errors in the Division and Commission's long-standing analysis of emission reductions from leak detection programs. The Division did not change its calculation methodology for leak detection between its request for hearing submittal in August and its Rebuttal Statement in late October, though the frequency of its leak detection proposal did change. The JIWG's failure to object earlier to the calculation methodology renders its December 8

8 Submitted December 3, 2021. Section 3, Pgs. 4 - 43

9 APCD_REB_EIA

objection untimely.[10] Further, the new JIWG analysis relies upon data submitted to the Division during the 2019 rulemaking process (re: updated component counts) that the Division - and the Commission - ultimately deemed not sufficiently credible or complete to rely upon during that 2019 rulemaking. That data was incomplete, and no information was provided regarding the representative nature of the data provided. The JIWG also suggests that EPA has somehow determined that use of a model plant based methodology is inappropriate, while simultaneously recognizing that EPA uses a model plant based methodology in its recent New Source Performance Standards (NSPS) OOOOb/OOOOc proposal. The JIWG further fails to provide sufficient evidence to suggest that using an approach based upon EPA's federal greenhouse gas reporting program (GHGRP) is a more appropriate approach to estimating reductions. The JIWG appears to assume that because the GHGRP emission factors were published after the Commission's 2014 rulemaking creating the state's LDAR program, that the GHGRP emission factors are *per se* more appropriate to use in calculating emissions for evaluating a LDAR program. This ignores not only that the Commission used this same approach in 2017 and 2019, but also that EPA itself used a method similar to that of the Commission in promulgating NSPS OOOOa and even in revising NSPS OOOOa in more recent years. Further, the JIWG approach fails to take into account that leak detection programs reduce emissions from large emission events, or superemitters, that are not accounted for in fugitive emission calculations - which emission events are lacking from the GHGRP reporting as well, which is well documented in the studies submitted to the Commission during this rulemaking process.[11] JIWG itself noted in its Prehearing Statement that: "the JIWG again highlights that [EPA's GHGRP] is not a complete inventory of emissions, and the program was designed to collect pertinent information nationwide while minimizing reporter burden."[12]

The JIWG also suggests that the Division failed to provide "foundational" information regarding its leak calculations. This is incorrect. The Division provided the JIWG, and other parties, with any information requested that had not been previously provided. The Division noted in its Initial EIA and Final EIA that for purposes of estimation emission reductions from leak detection at well production facilities, the Division was using the same methodology used in previous rulemakings, updating only the gas composition data, which was also provided to parties upon request (including JIWG). Not only has the underlying data been made specifically available to the JIWG in earlier rulemakings (e.g., 2014, 2017, 2019), the JIWG participated in the Statewide Hydrocarbon Emission Reduction stakeholder process, and a presentation on these specific "foundational" data points - i.e., the state's methodology for estimating fugitive emission reductions - was given on January 9, 2019.[13] Further, when JIWG, after 2:00pm on Friday December 3rd, emailed the Division to ask for additional information about the model facility analysis, the Division responded on Tuesday, December 7th, and the development of the model facilities (from the materials used in 2014) was thoroughly explained. The Division has engaged with JIWG multiple times on a variety of specific questions to explain spreadsheets and data points, and has done so for this set of data as well.

The JIWG also notes that EPA's proposed costs are higher than the Division's estimated costs. That is because the Division's estimated costs are based largely on Colorado-specific data, and the long experience Colorado companies have had with leak detection programs. And while the JIWG notes that a significant portion of EPA's costs include recordkeeping and reporting, the Division responds that Regulation 7 already has robust recordkeeping and reporting requirements, and thus companies already have data and operational systems in place, and the incremental cost of recordkeeping and reporting for additional inspections is likely to be minimal.

The Division also notes that the proposed regulatory revisions prioritize reductions of greenhouse gas and co-pollutants in DI Communities in a comprehensive and far-reaching manner. In furtherance of this mission, the Division is proposing to require owners or operators to:

- Perform more frequent leak detection and earlier repair of leaking components in DI Communities (Reg. 7, Pt. D, Section II.E.3);
- Increase LDAR frequency at natural gas compressor stations that are located within DI Communities and within proximity of occupied areas (Reg. 7, Pt. D, Section II.E.3.d);

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10 *See* AQCC's Procedural Rules, Section V.E.6.d, which limits the ability of parties to raise new issues in rebuttal. While the Division acknowledges that the frequency of the leak detection inspections in its proposal changed between prehearing statement and rebuttal, the methodology by which the Division evaluated emission reductions from leak inspections did not change.

11 *See, e.g.,* APCD_PHS_Ex-022; EDF_PHS_Ex-018; CG_PHS_Ex-006.005 and -006.007

12 JIWG_PHS at G-9.

13 A copy of this presentation is enclosed with this Cost Benefit Analysis as RA Attachment 3.

- Perform monthly AIMM inspections at all well production facilities in DI Communities with uncontrolled actual VOC emissions at or over 12 tpy (Reg. 7, Pt. D, Section II.E.4);
- Prioritize flow meter installation in DI Communities (Reg. 7, Pt. D, Section II.B.2.g);
- Prioritize initial performance test schedule of enclosed combustion devices in DI Communities (Reg. 7, Pt. D, Section II.B.2.h);
- Control more well liquids unloading and well swabbing activities in DI Communities (Reg. 7, Pt. D, Section II.G);
- Comply with more stringent control requirements for midstream pigging and blowdown operations in DI Communities (Reg. 7, Pt. D, Section II.H);
- Establish more stringent emission-based thresholds and earlier implementation timelines of capture and control measures in DI Communities for both GHG and co-pollutant emissions in company ERPs pursuant to the forthcoming Midstream Steering Committee guidance document (Reg 22, Part B, Section III.D.4);
- Identify the midstream combustion equipment located within DI Communities and to prioritize reductions in those communities when preparing and submitting company ERPs (Reg. 22, Part B Section II.C.3); and
- Submit GHG Intensity Plans that prioritize reductions in DI Communities and submit annual updates that quantify co-benefits (Reg. 22, Part B, Section IV).

These rules are designed to reduce emissions in DI Communities, and therefore reduce the local health and environmental impacts of oil and gas operations. The Division consulted with community members, community organizations, and parties representing the interests of DI Communities in the creation of and revisions to its proposal.

III. The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues;

The Division references the discussion of this issue found in the Cost Benefit Analysis, beginning on page 4 thereof. The Division anticipates impacts to the Division's workload as part of implementation of its proposal. The Division believes that this workload impact will be handled by current and anticipated staff. The Division has hired or is hiring an Air Quality Policy Engineer, additional performance test coordinators, and program implementation staff. The Division is also currently building a database to manage the annual emission reports submitted by operators under Regulation Number 7, Part D, Section V., and recently hired an engineer to oversee the annual emissions reporting, as well as development of the greenhouse gas intensity verification program. The Division also received funding from the General Assembly's passage of the Environmental Justice Act in 2021 to support the Division's implementation work.

The Division does not anticipate material impacts upon state revenues. State revenues from oil and gas development are largely derived from permitting fees and emissions fees. Neither the Division nor any party presented evidence that the Division's proposal would directly impact permitting fees. The Division does expect that its proposal will result in reduced emissions, which may impact emission fees collected; however, the Division has determined that the benefits of reduced emissions outweigh any impact to the emission fees collected, and further determined that it can implement this proposal even with the prospect of reduced emission fees. The Division does not believe its proposal will result in costs to other agencies.

IV. A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction;

The Division references the discussion of this issue found in the Cost Benefit Analysis, beginning on page 43 thereof. Inaction to the proposed rule has several disbenefits. First, inaction could place the CDPHE in violation of its statutory duties to adopt and implement regulations to achieve the state's GHG targets, which would be meaningfully detrimental to the state's efforts to mitigate climate change. Further, inaction will lead to increased methane/ethane emissions, and could exacerbate the impact of climate related events. Finally, inaction would be detrimental to public health and the environment. Inaction could worsen the state's ozone problem, and could potentially lead to National Ambient Air Quality Standard violations in areas currently attaining the ozone standard(s), which would have significant and negative economic impacts on those areas.

The benefits of inaction include cost savings for owners and operators of oil and gas operations. The costs of inaction outweigh the costs of the Division's proposed rule.

V. A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule; and a description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule.

The primary purposes of this proposal are threefold:

1) Achieve the state's GHG reduction targets for the oil and gas industry;
2) Pursue environmental justice and reduce GHG and co-pollutants in DI Communities; and
3) Reduce ozone forming precursor emissions (a co-benefit of GHG reduction, but nonetheless a standalone priority of the state).

As noted above, oil and gas activities are the largest source of methane in the state, and one of the largest (if not the largest) anthropogenic sources of VOC emissions in the state - both inside and outside the state's current ozone nonattainment areas. Colorado is also unique in that in the ozone nonattainment area, at least, oil and gas operations occur in the urbanized core, in proximity to residences and other occupied areas.

As set forth in more detail in the materials available on the Division's stakeholder process webpage[14], and submitted to the Commission as part of this rulemaking process, the Division evaluated other methods for achieving the purpose(s) of the proposed rules. Initially, the Division evaluated multiple alternative methods to determine the appropriate approach to achieve the state's goals. The Division commenced the stakeholder process on November 5, 2020, and began meeting with stakeholders to identify potential methods and regulatory approaches. In consultation with stakeholders, in March 2021, the Division published its analysis of multiple different approaches and methods. https://drive.google.com/drive/folders/1yvgVG06N57kyCO1GpTgEgsNb6oMJA5Z_

The Division evaluated:
1. Direct regulation of equipment or processes
2. Greenhouse gas intensity program
3. Emission reduction programs

In its August 2021 submission to the Commission, the Division proposed a combination of these approaches to achieve the necessary, and statutorily-mandated reductions, in a cost-effective manner. The Division determined that it could not predict that a strictly direct-regulation based approach would achieve the necessary reductions from upstream operations, though a direct regulation approach was appropriate to ensure methane reductions from midstream operations. Further, a direct regulation only approach would not provide industry with flexibility to identify cost-effective emission reduction strategies across operators' upstream facilities, which have significantly more variation in design and operation than midstream facilities. The Division determined that it did not have sufficient administrative resources or time in which to prepare and implement a "cap"-style emission reduction program, to the extent it incorporated trading. Further, in mid-2021, the legislature adopted the Environmental Justice Act, which limited the Division's ability to propose an off-set based program without first ensuring appropriate tracking. The Division therefore determined that, for the upstream segment, a greenhouse gas intensity program, when paired with targeted direct regulation, was the appropriate approach to balance cost, flexibility, and results.

As for the specific regulations that form the Division's proposal reflected in its Rebuttal Statement, the Division's Rebuttal EIA and the Cost Benefit Analysis outline, in detail, the analyses undertaken by the Division. The Division did evaluate alternatives for specific components of its proposal. Some of those alternatives are reflected in the changes made to the Division's proposal between the request for hearing and the Rebuttal Statement versions. Where stakeholders made a compelling argument that changes were needed to achieve the state's priorities, while ensuring that the program remains the most cost-effective approach, the Division adjusted its proposal accordingly. As reflected in more detail in the Division's Rebuttal Statement and the Cost Benefit Analysis, the Division

[14] https://cdphe.colorado.gov/oil-and-gas-greenhouse-gas-roadmap-stakeholder-process

evaluated alternative approaches submitted by other parties, including industry and other environmental organizations. For example, industry stakeholders opposed more frequent leak inspections. Industry did not, however, propose any alternative schedules or inspection frequencies that: 1) ensure protections for residents of DI Communities as required by the Environmental Justice Act; or 2) achieve sufficient reductions in fugitive emissions and large emission events to meet the state's GHG reduction goals. As another example, industry stakeholders asked the Commission to, instead of requiring control of well liquids unloading activities, to commence a stakeholder process to consider how best to achieve emission reductions from those activities. The Division evaluated this alternative, but determined that a stakeholder process would not meet the applicable statutory requirements or achieve the purpose(s) of the proposed revisions.

Cost-Benefit Analysis

In performing a cost-benefit analysis, each rulemaking entity must provide the information requested for the cost-benefit analysis to be considered a good faith effort. The cost-benefit analysis must be submitted to the Office of Policy, Research and Regulatory Reform at least ten (10) days before the administrative hearing on the proposed rule and posted on your agency's web site. For all questions, please attach all underlying data that supports the statements or figures stated in this cost-benefit analysis.

DEPARTMENT: Colorado Department of Public Health & Environment

AGENCY: Air Quality Control Commission

CCR: 5 CCR 1001-9 and 5 CCR 1001-26

DATE: December 3, 2021

RULE TITLE OR SUBJECT:

REGULATION NUMBERS 7 & 22

Per the provisions of 24-4-103(2.5)(a), Colorado Revised Statutes, the cost-benefit analysis must include the following:

1. The reason for the rule or amendment;

The Division is proposing revisions to Regulation Numbers 7 and 22 to achieve the necessary statewide greenhouse gas ("GHG")[1] emission reductions to implement Colorado's Greenhouse Gas Pollution Reduction Roadmap ("GHG Roadmap") and House Bill 21-1266 (the "Environmental Justice Act").[2] The Commission is required to adopt regulations to meet specified percentages of GHG reduction over a baseline. The percentages and baselines differ based upon the GHG Roadmap sector in which the equipment and resulting greenhouse gas ("GHG") emissions are bucketed.[3] There are two GHG Roadmap sectors at issue in this rulemaking: the Oil and Gas (O&G) Sector and the Industrial Sector. Most methane emissions from upstream and midstream segment activities, along with estimates of methane "leakage" from pipelines in the transmission & storage and distribution segments, are in the O&G Sector.[4] The emissions from fuel combustion equipment at oil and gas sources in the upstream and midstream segments are largely found in the Industrial Sector.[5] This proposal is designed to ensure that the Commission has adopted regulations that - in conjunction with "other laws and rules, as well as voluntary actions taken by local communities and the private sector"[6] - achieve the state's GHG reduction targets.

Another of the Division's primary objectives is to pursue environmental justice, by asking this Commission to adopt regulatory revisions and new programs that meaningfully reduce emissions of GHG and co-pollutants in disproportionately impacted communities ("DI Communities"). The Division's rule proposal prioritizes reductions of GHG and co-pollutants in DI Communities in a comprehensive and far-reaching manner. The proposal for Regulation 7 would, in DI Communities: ensure quicker and more frequent testing of combustion devices; require more frequent leak inspections and earlier repair of leaking components ensure quicker, and more, reductions from certain midstream operations; and require control of more well liquids unloading events. The Division's proposal for Regulation 22 also requires operators who submit various plans to comply with the new programs to evaluate the impacts of their plans on DI Communities and to prioritize reductions therein, along with specific requirements that co-benefit reductions be quantified. These rules are designed to reduce emissions in DI Communities, and therefore reduce the local health and environmental impacts of oil and gas operations. The Division consulted with community members, community organizations, and parties representing the interests of DI Communities in the creation of and revisions to its proposal. The Division submitted a Climate Equity Considerations document in the record of this proceeding that details its outreach efforts.

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[1] "Statewide GHG emissions" is used in the Environmental Justice Act, HB21-1266. "Statewide GHG pollution" is defined in HB19-1261, § 25-7-103(22.5), C.R.S. The Division interprets "statewide" in both contexts to mean GHG emitted in Colorado and over which the state has jurisdiction.

[2] *See* GHG Roadmap, https://drive.google.com/file/d/1jzLvFcrDryhhs9ZkT_UXkQM_0LiiYZfq/view.

[3] *See* § 25-7-105(1)(e)(XII) and (XIII), C.R.S.

[4] *See* GHG Roadmap, p.IV, Figure 1.

[5] Emissions from fuel combustion equipment include both CO_2 and methane. The 2015 baseline emissions in the state's GHG inventory are based on data reported to the U.S. Environmental Protection Agency (EPA).

[6] § 25-7-105(1)(e)(II), C.R.S.

<u>2. The anticipated economic benefits of the rule or amendment, which shall include economic growth, the creation of new jobs, and increased economic competitiveness;</u>

INDUSTRY-WIDE BENEFITS

Many of the proposed revisions are designed to require or incentivize best management practices at oil and gas operations. This benefits Colorado-based energy companies in the current marketplace, in which end users increasingly demand sustainable energy. A recent study of industry-wide efforts in this transitional space has identified twenty non-regulatory initiatives related to emissions reductions applicable to the oil and gas industry, in four different categories: certification programs, company-specific commitments, guidelines, and ratings based on “environmental, social, governance” (ESG) factors.[7]

Such efforts include ONEFUTURE, a membership of over forty-five natural gas companies working to reduce methane emissions from the sector to 1% or less. The ONEFUTURE coalition represents more than 15% of the natural gas value chain, and numerous Colorado operators are members. Another example is the effort led by MiQ, developed by the Rocky Mountain Institute and SystemIQ Ltd., which proposes a “globally-applicable certification system [that] enables all oil and gas producers to be assessed according to the same universal standard.”[8] These standards provide a metric by which “responsibly-sourced gas” can be a driving market factor, and - when combined with the value of the gas recovered through use of these practices and controls - can off-set increases in the cost associated with the production of that gas. These economic benefits are challenging to measure in the context of a particular regulatory proposal. However, looking at the MiQ standard, which relies on three pillars (methane intensity, company culture, and monitoring programs[9]), Colorado’s regulatory program ensures that Colorado operators should easily qualify for the most rigorous MiQ certification. Leaving Colorado operators primed to reap the maximum economic benefit from the new consumer demand for sustainable energy sources.

These rules also ensure more recovery of natural gas - a salable product. By June 2021, the price of natural gas had increased over 50% from the 2020 average, according to Henry Hub pricing; and on August 10, the U.S. Energy Information Administration raised its forecast for third-quarter 2021 natural gas prices to $3.71/MMBtu (or $3.80/MCF).[10] The Division has attempted to account for the economic benefits of additional gas recovery from some of the proposed revisions, but generally notes that collectively, as a whole, there is a significant economic benefit to industry - and royalty owners - from innovative regulatory programs designed to minimize the loss of natural gas during the production process.

[7] *An Overview of Voluntary Emissions Reduction Initiatives for Responsibly Sourced Oil and Gas*, Highwood Emissions Management, May 2021.
[8] Why certification?, MIQ
[9] The Standard, MIQ
[10] Short-Term Energy Outlook - US Energy Information Administration; Natural Gas Price Forecast: 2021, 2022 and Long Term to 2050 - knoema.com

STATEWIDE ECONOMIC BENEFITS

Colorado already has a reputation as a leader in methane detection and monitoring technology and in control strategies. The Division believes its proposal will result in significant growth in this area along with job creation and opportunities for industries relating to oil and gas monitoring and support activities. As one example, the Division's proposal will result in a significant increase in performance testing of enclosed combustion devices. This proposal will necessitate that testing companies expand their capacity by hiring. The Division's proposal also is designed to accommodate new and innovative testing methods, which will foster innovation in Colorado. As another example, the Division's proposal will require more leak detection inspections statewide; some oil and gas operators will need to hire and train more staff to conduct these inspections, while others may employ contractors. As a result of this proposal, the Division is also undertaking a stakeholder process to study advanced screening technologies for use as alternative leak detection methods - bringing more jobs and innovation to Colorado.

3. The anticipated costs of the rule or amendment, which shall include the direct costs to the government to administer the rule or amendment and the direct and indirect costs to business and other entities required to comply with the rule or amendment;

Cost to Government

The Division anticipates impacts to the Division's workload as part of implementation of its proposal. The Division believes that this workload impact will be handled by current and anticipated staff. The Division has hired or is hiring an Air Quality Policy Engineer, additional performance test coordinators, and program implementation staff. The Division is also currently building a database to manage the annual emission reports submitted by operators under Regulation Number 7, Part D, Section V. The Division also received funding from the General Assembly's passage of the Environmental Justice Act in 2021 to support the Division's implementation work.

Cost to Businesses

The Division herein incorporates by reference and attaches the Rebuttal Economic Impact Analysis ("EIA") filed with the Commission in this proceeding on November 23, 2021.

I. Better Performance of Air Pollution Control Equipment

The Division is proposing regulations to optimize and verify performance of air pollution control equipment. This proposal includes:

- Increased monitoring requirements for some air pollution control equipment;
- Use of flow meters; and
- Performance testing of enclosed combustion devices ("ECDs" or "combustion devices").

Currently, Commission regulations, including Regulation Number 7, Part D, Section II, require reductions in hydrocarbon emissions of at least 95% through the use of air pollution control equipment, including ECDs. The Division is proposing the addition of new inspection, maintenance, and performance monitoring requirements of air pollution control equipment in order to ensure that air pollution control equipment is meeting performance efficiency standards.

Based upon operator reported data for 2017 and analysis done by the Division for the Commission's December 2019 Regulation Number 7 rulemaking, the Division identified 4,573 storage tank batteries statewide that are subject to the control requirements of Section II.C (i.e., have emissions greater than 2 tpy VOC). The Division undertook an analysis to determine the average number of combustion devices per tank battery. The Division conducted inspections of 3,312 unique storage tank batteries and identified 5,943 enclosed combustion devices, for an average of 1.79 ECDs per tank battery. For purposes of this analysis, the Division assumed an average of 2 ECDs per storage tank battery, for a total of 9,146 storage tank ECDs as part of this program.

These requirements would also apply to midstream operations. The Division has identified 205[11] compressor stations. Of the 205 compressor stations, 59 are in the 9-County area[12] and 146 are outside the 9-County area. Information provided by operators suggests an average of 1 ECD at a compressor station outside the 8-hour Ozone Control Area and 2 ECDs at a compressor station inside the 8-hour Ozone Control Area. Therefore, the Division determined that there are an additional 264 ECDs to be tested at compressor stations as part of this program.

Using Division APEN and permitting data, as well as data reported to EPA, the Division identified 63 natural gas processing plants in the state that are not on tribal lands. Of these 63 gas plants, the Division's data shows that 32 are in the 9-County area, while 31 are outside. Information received from operators suggests that a gas plant in the 9-County area has between 1-3 ECDs, while a gas plant outside the 9-County area has between 0 and 1 ECD. For purposes of this analysis, the Division assumes gas plants in the 9-County area have 2 ECDs (32 x 2 = 64 ECDs) and gas plants outside the 9-County area have 1 ECD (31 ECDs). Therefore, the Division determined that there are an additional 95 ECDs to be tested at gas plants as part of this program. The Division determined there are a total of 9,505 ECDs subject to this proposal.[13]

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[11] The Division does not currently have the ability to identify compressor stations in the state in the same way as it can identify gas plants or well production facilities. To create a list of compressor stations, the Division started with facilities classified as compressor stations in COGIS and the Division's SIP inventories. The Division merged these lists, removed duplicates, and, where possible, screened permit records to remove those that were misclassified. Based upon information collected during the Statewide Hydrocarbon Emission Reduction (SHER) process and information from the industry, the Division estimates that approximately one-third of the compressor stations operate in the transmission and storage segment (as opposed to the midstream segment), leaving 207 midstream compressor stations statewide. The Division also reviewed the number of unique compressor stations reported pursuant to leak detection and repair (LDAR) reports required by Regulation Number 7 for calendar year 2020, and determined that there are 205 unique compressor stations on non-tribal lands.

[12] The 9-County area includes the 8-hour Ozone Control Area, and all of Larimer and Weld counties.

[13] These numbers do not include ECDs controlling separation equipment or upstream dehydration units. However, the new COGCC regulations should result in a complete phase-out of separator control devices. The Division does not have reasonably available data on the number of ECDs controlling upstream dehydration units.

I.A. Monitoring: Regulation Number 7, Part D, Section II.B.2.f

In Section II.B.2.f, the Division proposes more frequent inspections of air pollution control equipment at oil and gas operations. The proposed rule requires operators to conduct, at minimum, weekly visual inspections of air pollution control equipment. Because the required inspections are visual, no additional monitoring equipment will be required in order to fulfill the inspection requirements. Most, if not all, air pollution control equipment is already subject to weekly inspection requirements under Regulation Number 7, Part D, Section II.C. However, some air pollution control equipment controlling other equipment is not currently subject to all these requirements (though a number of ECDs have permit conditions setting forth a similar level of inspection). The Division is proposing to subject controls on separation equipment to these requirements in revisions to Section II.F, though no new costs are expected from that revision because new Colorado Oil and Gas Conservation Commission ("COGCC") rules mandate capture of gas coming off separation equipment, and only permit use of control equipment where granted a variance from the COGCC.

Air pollution control equipment used to reduce emissions from glycol dehydration units will be newly subject to these inspection requirements. The Division has reached out to the industry to understand how many such devices would be subject to the rules, and of those, how many are not currently inspected at this frequency, but has not yet received a response. Based on the Regulation Number 7, Part D, Section V annual reports, there are one hundred and forty-five (145) dehydration units, sixty-three (63) at upstream operations and eighty-two (82) at midstream operations. Under Section I.H.5, though, air pollution control equipment controlling dehydration units is already subject to weekly inspection requirements, covering the majority of reported dehydration units.

Based upon the foregoing, costs associated with additional inspection and monitoring are assumed to be absorbed into current operation and maintenance practices and carried out by existing personnel. No additional significant equipment or labor costs are expected to be imposed on operators to comply with the proposed inspection and monitoring requirements.

I.B. Flow Meters: Regulation Number 7, Part D, Section II.B.2.g

The Division proposes that operators install and operate flow meters on most ECDs used to comply with Section II control requirements. In the Initial EIA, the Division assumed that most of the state's combustion devices will require the installation of a flow meter, though flow meters are already required for combustion devices controlling separation equipment in most permits. However, in the Division's revisions to its proposal, the Division specified that a single flow meter could be installed under this Section of the rule as long as all streams to the bank of ECDs are captured. That will substantially reduce the economic impact of this proposal.

The Division's proposal does not prescribe any specific brands or types of flow meters that can be used. Based on the analysis of the equipment costs for 22 different flow meters currently on market, the Division used an average cost of $2,439 as the estimate per flow meter in this economic analysis. The useful life of a flow meter varies significantly based on the type and usage of the device, and can range from as few as 5 years to as many as 25. The Division used the estimated useful life of an ECD, 15 years, as a reasonable assessment of useful life for flow meters. The Division had no information on installation costs or annual maintenance or calibration costs for flow meters, and, in the Initial EIA requested that such information be provided by operators.

The Division did not receive any information from operators between the date of the Initial EIA and the Final EIA. The Division determined the annualized cost of a flow meter would therefore be $389.68. It is estimated that, based on the estimated count of affected combustion devices, 9,505, total annualized costs to the industry for flow meters will be approximately $3,703,908.40. For operators with flares subject to performance testing requirements, the cost of flow meters is included in that analysis.

The Division has heard from industry a suggestion that there are other associated costs with the use of flow meters, such as a potential need for site reconfiguration, and, in the Initial EIA, requested that industry provide information about these costs and the necessity therefore. The Division did have some discussions with industry about its proposal for flow meters that resulted in a number of revisions. After the filing of the Division's Final EIA, the Division received additional information in Prehearing Statements from operators (the "Joint Industry Working Group" or "JIWG") related to flow meter costs and additional engineering and installation. The Division conducted an alternative analysis that included additional engineering and installation costs associated with flow meters and additional annual maintenance costs for flow meters. A summary of the Division's analysis of this information is located in Table 1. The Division excluded outliers in the information provided by the JIWG in their cost summaries. The Division stands behind its cost analysis, and offers the Alternative Cost to demonstrate that even making the adjustments suggested as necessary by the JIWG: 1) the proposal remains cost-effective; and 2) cost per ton figures (for VOC/GHG) are nowhere near as high as JIWG suggests.

Table 1: Control Device Performance Economic Impact Revisions

Flow Meter Costs			
	Final EIA	**JIWG PHS**	**Alternative Cost**
Flow Meter Cost	$2,439.00	$5,842.86	$5,842.86
Engineering and Installation	$0.00	$20,183.86	$11,092.58
Total Equipment Cost	$2,439.00	$26,026.72	$16,935.44
Useful Life	15 Years	8.4 Years	15 Years
Annual Maintenance Cost	$0.00	$682.67	$682.67
Annualized Flow Meter Cost[14]	$389.68	$3,781.09	**$3,388.45**

I.C. Performance Testing of Enclosed Combustion Devices: Regulation Number 7, Part D, Section II.B.2.h

The Division's proposal will require performance testing of most ECDs used to comply with Regulation Number 7, Part D, Section II. The Division's proposal would prioritize testing of devices first in DI communities, second in the 8-hour Ozone Control Area (or northern Weld) and last, the remaining devices throughout the state.

[14] Annualized cost for flow meters differs between the JIWG PHS and the Division EIA, as the Division assumes 6% interest per year to create the amortized cost of the equipment, installation, and engineering design. JIWG included no interest in their annualized cost.

The Division estimates that of the 9,505 ECDs subject to the proposed regulation, 28.57% or 2,716 are located inside a DI community, 49.87% or 4,740 are located inside the 8-hour Ozone Control Area (plus Northern Weld) (and not in a DI community), and 21.56% or 2,049 are located outside of the 8-hour Ozone Control Area (plus Northern Weld) (and not in a DI community).[15] Table 2 includes the projected number of flares that will be required to be tested in each compliance deadline year for each location for the first 5 years of the program, as provided for in section II.B.2.h of the proposed rule. For ECDs in DI communities and inside the 8-hour Ozone Control Area, plus Northern Weld, the final year includes devices that will be undergoing a subsequent periodic test.

Table 2: ECD Testing Schedule

Location of Combustion Devices	Compliance Deadlines (on or before May 1)					
	2023	2024	2025	2026	2027	2028[16]
	Number of ECDs that must be tested by each year end					
Inside DI Community	407	679	815	815	-	407
Inside NAA **(Not in DI Community)**	474	948	948	1422	948	474
Outside NAA **(Not in DI Community)**	102	205	307	410	512	512

The Division assumes that all performance testing of combustion devices will be conducted by third-party testing companies.[17] The Division collected information from flare performance testing companies, testing personnel, operators, and historical Division data to estimate the costs associated with conducting a destruction efficiency test for a combustion device through a third-party testing company. Table 3, below, includes a breakdown of the costs associated with the completion of a performance test for one combustion device; the Division assumes that a performance test for one combustion device can be completed in one day (eight work hours). The figure for labor includes three testing personnel, at an estimated average labor rate of $96 per hour, for eight hours each.

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[15] The Division does not yet have complete data pertaining to each well production facility's location as it relates to the identification of a DI Community. However, based upon the Department's climate data viewer tool, which maps DI communities, the Division was able to determine that these percentages relate to the percent of population residing within a DI community, whether within or without the nonattainment area. The Division applied those percentages to the number of facilities.

[16] The estimate of ECDs tested in 2028 also includes those ECDs that were tested in 2023 and are required to complete testing again after 5 years, per the rule proposal, assuming all ECDs tested in 2023 have to be tested again in 2028 (a conservative assumption).

[17] The Division revised the testing schedule based, in part, on conversations with testing companies about their capacity to do all the required testing in 2022. The Division has heard no further concerns about an inability to ramp up capacity to handle testing over the life of the program. This schedule also does not take into account that devices tested pursuant to a Division-approved test protocol after January 1, 2020, do not have to repeat their "initial test" under this rule, which likely has an impact on the number of initial tests required. ECDs that do not have to repeat the "initial test" do still need to conduct periodic performance testing.

Test protocol preparation and test report preparation are each estimated to take one day to complete. As the test methodology and testing equipment used vary between combustors, the Division used the average hourly equipment rental and preparation costs from a set of potential rates[18] as the estimate for equipment costs. It is assumed that four units of testing equipment will be used for each test. Possible testing equipment used includes, but is not limited to, ionization detectors, O2/CO2 monitors, gas chromatographs, and sampling bags. Consistent with the 2014 and 2019 Regulation Number 7 rulemakings, the Division estimated travel cost as 15% of the labor cost. As set forth in Table 3, the total cost of a performance test for one ECD is estimated to be $6,326.60. For the purposes of this EIA, the Division assumes that one ECD will be tested per trip. In some cases, testing companies may be able to test multiple ECDs at a site during one trip. In such an instance, the travel time cost would only be applied once, while costs associated with labor, test administration, and equipment could potentially increase. In order to standardize the costs associated with testing one ECD, the Division bases cost estimates on the assumption that one ECD is tested per trip and that testing takes one day.

The proposed rule requires that 100% of the total existing ECDs (i.e., those operating as of December 2021) be tested by May 1, 2028. The Division calculated that an average of 1,731 ECDs would be required to be tested each year, for the first five years. As noted below, in Table 3, the cost per year of testing 1,731 ECDs is estimated at $10,951,715.

<table>
<tr><th colspan="5">Table 3: ECD Performance Improvement Costs[19]</th></tr>
<tr><td colspan="5">ECD Performance Testing</td></tr>
<tr><td>Parameter</td><td>Units</td><td>Cost Per Unit</td><td>Units Required Per Test</td><td>Cost Per Test</td></tr>
<tr><td>Labor</td><td>hours</td><td>$96.00</td><td>24</td><td>$2,304.00</td></tr>
<tr><td>Test Protocol</td><td>days</td><td>$700.00</td><td>1</td><td>$700.00</td></tr>
<tr><td>Test Report</td><td>days</td><td>$695.00</td><td>1</td><td>$695.00</td></tr>
<tr><td>Equipment Rental</td><td>components/day</td><td>$352.50</td><td>4</td><td>$1,410.00</td></tr>
<tr><td>Equipment Prep</td><td>components</td><td>$290.00</td><td>4</td><td>$1,160.00</td></tr>
<tr><td>Travel</td><td>hours</td><td>$14.40</td><td>4</td><td>$57.60</td></tr>
<tr><td colspan="5">TOTAL ECD Performance Testing Costs</td></tr>
<tr><td></td><td>Cost per test</td><td>Average Tests per Year</td><td colspan="2">Total Annual Cost</td></tr>
<tr><td>Total Performance Test</td><td>$6,326.60</td><td>1,731</td><td colspan="2">$10,951,715</td></tr>
</table>

[18] Equipment rental and preparation rates were provided by companies that offer ECD testing services.
[19] The change in cost from the Initial EIA is primarily due to the decreased number of annual inspections resulting from an adjustment to the timeline for completing required performance tests.

The Division does not have performance test results for every ECD in the field, from which it can calculate conclusively the emissions benefits of this rule. In order to determine the emission benefits of its proposal, the Division undertook an analysis of failing performance test results collected by the Division to quantify both the percentage of failing tests as compared to devices tested and the scale of a failing test - i.e., when a device fails the test, what is the average of the delta between the test result and the applicable control efficiency requirement. The Division estimates that 9.61% of ECD performance tests fail to demonstrate compliance with the applicable control efficiency requirement. The Division's analysis suggests that an average scale of failure is 11.36% (i.e., based upon an average of failing performance tests, the test results are 11.36% lower than the applicable control efficiency requirement). The Division calculated a performance improvement of 1.09% from its proposal (representing the difference between 93.91% control and 95%).

To calculate emission benefits, the Division applied this percentage to uncontrolled emissions reported for all controlled tank batteries over 2 tpy VOC (from the Division's database).[20] The Division estimated that its proposal would result in a VOC benefit of 2,211 tpy.[21] Using an assumed methane to VOC ratio of 1.01:1 for storage tanks, the Division estimated a greenhouse gas benefit of 56,734 mtCO2e/yr. In its Rebuttal statement, the JIWG states: "It is not clear how APCD's emission estimate increased so significantly; therefore, JIWG compiled Regulation 7 Emission Inventory submittals from operators that represent 73% of statewide production on a 2020 kBOE basis in order to determine the actual uncontrolled emissions from controlled tank batteries over 2 tpy VOC."[22] The Division explained to JIWG multiple times how the Division's emissions estimates were calculated. The Division used its permitting and APEN database to collect reported emissions from storage tank batteries from all sites in the state (all sites subject to control requirements would be required to be in this database). The Division used the operators' reported emissions to evaluate emission reductions from its proposal - a more comprehensive and transparent approach than that taken by the JIWG (which did not provide any data or analysis over and above the one sentence quoted above).

The Division received revised information in the Prehearing Statements from industry that suggest there is additional facility prep required to complete stack tests. A summary of the information provided and a comparison to previously developed costs is in Table 4. The Division conducted an alternative analysis that included additional facility preparation costs not included in its analysis of performance test costs. The Division excluded outliers in the information provided by the JIWG in their cost summaries.

[20] When the Division looked at emissions reported in the annual emissions reports, the Division also calculated uncontrolled emissions reported from separators and dehydrators for July - December 2020. The Division doubled those emissions to account for a full year, and all emissions from separators and dehydrators reported were assumed to reflect 95% control. Based on these inventories, this rule may also reduce emissions from 2,230 separators and 145 dehydrators for an additional 253.48 tpy VOC and 20,390.38 mtCO2e/year.

[21] The majority of these emission reductions are realized from those ECDs controlling tank systems with VOC emissions over 12 tpy.

[22] JIWG_REB_Ex-006.

Table 4: Control Device Performance Economic Impact Revisions			
Performance Test Costs			
	Final EIA	**JIWG PHS**	**Alternative Cost[23]**
Performance Test	$6,326.60	$8,225.00	$6,326.60[24]
Facility Prep by Operator[25]	$0.00	$7,912.50	$3,750.00
Total Performance Test Cost	$6,326.60	$16,137.50	**$10,076.60**

The Division stands behind its cost analysis, and offers the Alternative Cost to demonstrate that even making the adjustments suggested as necessary by the JIWG: 1) the proposal remains cost-effective; and 2) cost per ton figures (for VOC/GHG) are nowhere near as high as JIWG suggests.

I.D. Reporting

The cost of preparing a performance test report is included in the cost information above. The Division is proposing that operators would submit information about the performance tests conducted each year with the existing annual reports required under Section V, which is an absorbable cost. Additional report submittals might be required if an operator fails a performance test; however, the cost of these additional reports is presumed to be negligible and absorbable. The Division received no information from any stakeholders to the contrary.

I.E. Enclosed Combustion Device Performance Cost Effectiveness

Based on an annual cost of its performance test requirements as $10,951,715, and an annualized cost of flow meters of $3,703,908 per year, the Division estimates a total annual cost of $14,655,253. Based on this analysis, the Division has determined that this proposal will result in a cost effectiveness of $6,627 per ton VOC and $258 per mtCO2e.

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[23] The Division reviewed the JIWG PHS and excluded outliers from the operator submittals to determine the appropriate revisions to the facility preparation costs for performance tests as well as the engineering and installation costs for flow meters.
[24] The Division's cost estimate was based on multiple conversations with testing companies and operators, and the Division does not believe it requires adjustment upwards.
[25] The Division's Final EIA cost estimate included facility prep included in the costs provided by the testing company. JIWG insists that there are other preparatory costs.

Table 5: ECD Performance Improvement Cost Effectiveness[26]			
Annual and Total ECD Performance Improvement Costs			
	Cost per test or meter	Annualized Cost	Total Annual Cost
Total Performance Test	$6,326.60		$10,951,715
Flow meter	$2,439.00	$389.68	$3,703,908[27]
Total			$14,655,253
ECD Performance Improvement Cost Per Ton			
	VOC (tpy)	Methane (tpy)	Methane (mtCO2e/yr)
Emission Reductions	2,211	2,234	56,734
Cost per ton Emission Reduction	$6,627		$258

The Division reviewed information provided by industry groups in their Prehearing Statements, including the Joint Industry Workgroup (JIWG) and others[28], and prepared an alternative analysis adjusting the costs associated with the proposed requirements to install and operate flow meters as well as to perform periodic performance tests on enclosed combustion devices. A complete summary of the result is in Table 6.

The JIWG also included emission estimates that were far below those of the Division.[29] The JIWG's revised emissions benefit analysis appears to have been based on survey responses received from a few testing companies (but not actual test reports, nor were any details about the survey responses provided).[30] However, the Division's analysis of emissions benefits was based on actual test report data received and reviewed by the Division, as well as actual emissions estimates in the Division's APEN and permitting database. Therefore, the Division believes that its data is more accurate and reliable, and maintained its Final EIA analysis to calculate the updated costs for comparison.

[26] The emission reduction estimate in Table 5 is a significant increase from the emissions estimate in the initial EIA of 539.59 tpy VOC and 13,843.18 mtCO2e/year. In the initial EIA, the division made an assumption about the emissions based on the counts of storage tanks between 2-6 tpy VOC, 6-12 tpy, 12-20 tpy, and > 20 tpy. For this Cost Benefit Analysis, the Division summed the total uncontrolled VOC emissions reported for each of the above categories to determine the impact of this rule revision. See Storage Tank Inventory 8-12-2021.

[27] These flow meter costs are overly conservative because, under the Division's proposal, a permanent flow meter is not required to be installed on each ECD. However, the Division's proposal does require a flow meter be installed and operating during a performance test (but it can be temporary), so the Division has maintained this assumption in the cost analysis.

[28] See JIWG_PHS_Ex-012.

[29] See JIWG_PHS_Ex-012, p.5; JIWG_REB_Ex-006.

[30] Id.

While the Division stands by the analysis from the Final EIA, even with the alternative calculations made, the requirement to install and operate flow meters and conduct performance tests on enclosed combustion devices remains cost effective.

Table 6: Control Device Performance Economic Impact Revisions			
Flow Meter and Performance Test Costs			
	Final EIA	**JIWG PHS**	**Alternative Cost**[31]
Total Performance Test Cost	$6,326.60	$16,137.50	**$10,076.60**
Annualized Flow Meter Cost	$389.68	$3,781.09	**$3,388.45**
ECD Performance Improvement Cost Per Ton			
	Final EIA	**JIWG PHS**	**Alternative Cost**
VOC Emission Reduction (tpy)	2,211.40	202.97	2,211.40
VOC Cost per ton ($/ton)	$6,627.14	$324,559.89	**$22,451.77**
GHG Emission Reduction (mtCO2e/yr)	56,733.90	5,207.11	56,733.90
GHG Cost per ton ($/mtCO2e)	$258.32	$12,650.84	**$875.14**

I.F. Combustion Device Performance in Section I.

As described in the Division's Prehearing Statement, the proposed revisions to Section I. are a new addition from the Request Proposal and are included to address concerns raised by EPA with previously submitted State Implementation Plan ("SIP") revisions. Based on the analysis done at the time of adoption of those previously submitted SIP revisions in 2017, the Division estimated that a potential of 62 emission points could include a single storage vessel that could have the potential to emit greater than six tpy VOC. Assuming, as done above, that each point used two combustion devices to control emissions, owners or operators may have to conduct performance tests of 124 combustion devices under the proposed revisions to require performance testing of devices controlling emissions from storage vessels, as such vessels are defined under the recommendations in EPA's Control Techniques Guidelines for the Oil and Natural Gas Industry ("Oil and Gas CTG").[32] The Division does not have sufficient information to estimate the potential number of combustion devices controlling emissions from wet seat centrifugal compressors that would require performance testing but, according to EPA's Greenhouse Gas Reporting Rule (GHGRP), no owners or operators report emissions from such compressors in the ozone nonattainment area.

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[31] The Division reviewed the JIWG PHS and excluded outliers from the operator submittals to determine the appropriate revisions to the facility preparation costs for performance tests as well as the engineering and installation costs for flow meters.

[32] Control Techniques Guidelines for the Oil and Natural Gas Industry 2016, EPA.

For the potential 124 combustion devices estimated to be controlling emissions from storage vessels, the Division assumes the costs would be the same or similar to the costs of performance testing and flow meters described above and, in fact, would be included in those cost estimates as these devices would be included in the percentage tested under the proposed requirements in Regulation 7, Section II. Further, because EPA's Oil and Gas CTG and EPA's New Source Performance Standards ("NSPS") OOOOa use the same storage vessel applicability threshold, it is possible that some combustion devices are already tested under the requirements of NSPS OOOOa and, therefore, would not have additional expenditures related to combustion device performance testing.

The Division, as staff to the Commission, requested additional information from stakeholders on the costs associated with this component of its proposal, but did not receive any such information.

II. Midstream Program(s)

The Division is proposing several new regulatory provisions to directly address GHG emissions (and co-pollutants) from the midstream segment of the oil and gas industry. The proposals include the following additional requirements for oil and gas operators in the midstream segment:

- Increased leak detection and repair ("LDAR") inspections for natural gas compressor stations;
- Increased leak detection and repair inspections and valve requirements for gas plants outside of the 8-hour Ozone Control Area;
- Capture and control strategies for certain midstream operations, including pigging and blowdowns;
- Expansion of rod-packing requirements for compressors at gas plants outside of the 8-hour Ozone Control Area;
- Expansion of the gas plant pneumatic controller requirements outside of the 8-hour Ozone Control Area; and
- Long-term planning for GHG reductions from midstream engines and other combustion equipment.

II.A. Leak Detection and Repair: Regulation Number 7, Part D, Section II.E[33]

According to the Division's 2020 state-wide LDAR annual reporting, 551,787 inspections were completed at well production facilities (comprised of 525,433 Audio, Visual Olfactory ("AVO") inspections and 26,354 Approved Instrument Monitoring Method ("AIMM") inspections) and 757 inspections were completed at natural gas compressor stations (all AIMM inspections). From these inspections, 15,617 leaks were discovered at well production facilities and 1,273 leaks were discovered at natural gas compressor stations (all from AIMM). In an analysis of LDAR reporting, it is estimated that across the industry, approximately 86% of LDAR inspections are completed "in-house" by the operator, and 14% are completed by an outside contractor. The costs between completing LDAR in-house and completing LDAR through a contractor differ, as discussed in more detail below.

[33] The cost analysis of this section is also relevant to the upstream LDAR costs evaluated later in this Cost Benefit Analysis.

The Division used the same approach to estimate LDAR inspection costs as in the 2014, 2017, and 2019 rulemaking EIAs supporting LDAR requirements.[34] For in-house inspections, it is assumed that operators use existing personnel to conduct LDAR inspections, but must purchase the leak detection equipment. The majority of leak detection is conducted using either EPA Method 21 or by using an infrared ("IR") camera (by itself or as a screening tool before Method 21). The Division assumed the incremental increase in inspections done to comply with this proposal will all be done using infrared cameras ("FLIR"). In its Initial EIA and Final EIA, the Division assumed that LDAR inspections utilizing an IR camera take 10.6 hours (per facility). However, as discussed in more detail below, based upon information provided by other parties to the rulemaking, the Division adjusted this assumption in its Rebuttal EIA.

The Division updated its cost estimates of an IR camera to reflect current (2021) market prices, and other equipment costs are inflated from 2014 dollars to 2021 dollars, using the U.S. Bureau of Labor Statistics ("U.S. BLS") CPI Inflation Calculator. The Division found the current capital cost of an IR camera to be between $100,430 - $163,366.[35] For the purposes of this analysis, the Division uses the median cost, of $131,898, as the capital cost of one IR camera. Further, IR cameras have an annual maintenance and repair cost of $8,387.[36] All equipment, including IR cameras, are assumed to have a lifespan of 5 years.[37] Table 7 provides an estimate of the capital and recurring costs required for LDAR inspections.

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[34] *See* the Colorado Department of Public Health and Environment Air Pollution Control Division Final Economic Impact Analyses for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7 (5 CCR 1001-9), dated January 30, 2014, September 14, 2017, and December 17-19, 2019.
[35] IR camera capital cost is based on historical Division data as well as current market rates for commercial IR cameras.
[36] Cost is inflated to 2021 dollars from the 2014 value of $7,500/year, using the U.S. BLS CPI Inflation Calculator.
[37] Capital costs are annualized over a five-year period and adjusted for inflation.

Table 7: LDAR Annualized Costs			
Parameter	Capital Costs	Annual Costs	Annualized Total Cost
FLIR Camera:	$131,898		
FLIR Camera Maint/Repair:		$ 8,387	
Photo Ionization Detector	$5,591		
Vehicle	$24,602		
Inspection Staff:		$ 75,000	
Supervision (@20%):		$ 15,000	
Overhead (@10%):		$ 7,500	
Travel(@15%):		$ 11,250	
Recordkeeping (@10%):		$ 7,500	
Reporting (@10%):		$ 7,500	
Fringe (@30%):		$ 22,500	
Subtotal Costs:	$162,091	$154,637	
Annualized Costs:	$43,382.9	$154,637	**$198,020**

The Division used this annualized cost to create an estimated cost per hour for an in-house LDAR inspection. The total annualized cost identified in Table 7 of $198,020 is divided by an assumed 1,880 annual working hours[38] to produce a value for an inspection rate for in-house inspections of $105/hour. Operators also have the option of hiring third-party contractors to complete LDAR inspections, instead of completing the inspections in-house. The hourly cost of using a third-party contractor to complete leak detection is estimated at $137/hour. This estimate is based on the premise that contractors would realize a 30% profit margin above the cost to operators of completing the inspections in-house.

II.A.1. Compressor Station LDAR: Regulation Number 7, Part D, Section II.E.3.d

The Division's proposal would require compressor stations to have a minimum inspection frequency of quarterly, regardless of location. Given that compressor stations inside the 8-hour Ozone Control Area are already at a quarterly frequency, this proposal would impact only the 75 compressor stations outside the 8-hour Ozone Control Area identified by the Division in the Final EIA.[39]

[38] This assumes a 40-hour work week, ten holidays, two weeks of vacation, and one week of sick leave.
[39] Based on 2020 annual LDAR reporting, 75 compressor stations reported a semi-annual LDAR frequency.

Further, the Division is also proposing to require inspections bimonthly (six times per year) at compressor stations inside the 8-hour Ozone Control Area with emissions between 12 and 50 tpy VOC where located in a DI Community or within 1,000 feet of an occupied area. Compressor stations outside of the 8-hour Ozone Control Area within 1,000 feet of an occupied area would also have a bimonthly inspection frequency. This revised analysis replaces the analysis done in the Cost Effectiveness Analysis, III.A.1. Compressor Station LDAR: Regulation Number 7, Part D, Section II.E.4.d. and includes a number of updates to the cost analysis calculation from the Final EIA, including:

- The number of facilities affected by the rule has changed.
- The incremental change to costs associated with repair time[40] is reflected in this analysis.
- The estimated VOC emission reductions per facility were recalculated for the 9-County, Piceance, and remainder of the state, to account for incorrect use of VOC emission factors in the Final EIA.
- The Division estimated the repair hours and emission reductions associated with a new category of LDAR frequency (bimonthly).

The new proposal would require all compressor stations within a disproportionately impacted community or within 1000 feet of an occupied area[41] to be inspected six times per year (across the year, bimonthly). The new proposal also increases all remaining semi-annual inspections to quarterly. The Division assumed that 26.48% of compressor stations in the 9-County area and 32.98% of compressor stations in the Piceance Basin and remainder of state were also in DI Communities. The number of compressor stations affected by this rule proposal is in Table 8.

Table 8: CS LDAR Proposed Frequency[42]

Compressor Station VOC Tier (tpy)	Number of Compressor Stations	Current Frequency	Proposed Frequency
ROS: <12	50	Semi-Annual	Quarterly
ROS: <12 - DI/prox	25	Semi-Annual	6x
Nonattainment Area[43]: <12 - DI/prox	9	Quarterly	6x
>12 - <50 - DI/prox	25	Quarterly	6x

[40] In the Final EIA, the Division attributed the full hours of repair time associated with the quarterly inspection frequency instead of the incremental change that occurred from semi-annual to quarterly.
[41] The Division assumed that the percentage of compressor stations in DI communities also included compressor stations within 1,000 feet of an occupied area. The Division did not have any other reasonably available data.
[42] This table does not include compressor stations for which there is no proposed change.
[43] Section II LDAR frequency does not distinguish between the nonattainment area and the remainder of the state, but Section I LDAR frequency for this category in the nonattainment area is already at quarterly, not semi-annual. For the purpose of this economic impact analysis, the Division accounted for the incremental change from quarterly to six times per year for compressor stations in the nonattainment area affected by this rule.

Inspections

For this analysis, unlike in the Final EIA, the Division assumed that operators would use only infrared (IR) cameras to meet this increased inspection requirement. Table 9 includes a breakdown and analysis of the estimated leak inspection time and costs under the different possible conditions mentioned in the preceding section.

Table 9: CS LDAR Inspection Costs					
# Inspections	Inspection type	Inspection method	Total Inspection hours[44]	Cost per hour	Total cost
268	In-House	FLIR	3,420.4	$105.00	$359,140.74
	Contractor	FLIR	520.2	$137.00	$71,269.04
Totals			**3,940.6**		**$430,409.78**

At hourly inspection rates of $105 per hour for in-house and $137 per hour for contractors, the total cost to operators for completing the new LDAR inspections would therefore be $430,409.78 per year; or $3,948.71 per compressor station per year. Another party to the rulemaking, EDF, estimated a lower cost for these inspections - $326,561.

Leak Repair

The Division made the same assumptions to calculate leak repair costs as in the Final EIA, except this analysis uses the incremental change in repair hours associated with the proposed revisions. The Division also made a scaled assumption of leak rate for the new LDAR frequency of six times per year. Table 10 includes the leak rates assumed along with repair hours calculated according to the methodology laid out previously.

Table 10: CS Repair Hours from LDAR Frequencies		
LDAR Frequency	Leak Rate	Repair Hours
Annual	1.18%	23.2
Semi-Annual	1.48%	29.1
Quarterly	1.77%	34.8
6x	1.92%	37.7
Monthly	2.36%	46.3

[44] The Division assumed 10.6 inspection hours for compressor stations with emissions less than 12 tpy VOC and 28.1 inspection hours for compressor stations with emissions above 12 tpy VOC.

Using these assumed repair hours and the incremental change in frequency as outlined in Table 8, the Division calculated an increase of 600.8 repair hours. At a cost of $82.06/hour, the total repair cost is $49,301.65.

Emission Reductions

The Division uses the same analysis here as the Commission did in 2014, 2017, and 2019 to estimate emission reductions from this program, though broken out by basin as opposed to by compressor station tier.[45] Further, the Division assumes that the inspection frequency of six times per year will gain a 70% reduction in emissions, as seen in Table 11.

Table 11: CS Emission Calculations from LDAR				
Methane Emissions from Model Compressor Station(tpy)				
LDAR Frequency	Emission Reduction	9-County	Piceance	Remainder of State
No LDAR	0%	8.68	27.68	18.18
Annual	40%	5.21	16.61	10.91
Semi-Annual	50%	4.34	13.84	9.09
Quarterly	60%	3.47	11.07	7.27
6x	70%	2.60	8.30	5.45
Monthly	80%	1.74	5.54	3.64
VOC Emissions from Model Compressor Station (tpy)				
LDAR Frequency	Emission Reduction	9-County	Piceance	Remainder of State
No LDAR	0%	7.96	12.17	10.07
Annual	40%	4.78	7.30	6.04
Semi-Annual	50%	3.98	6.09	5.03
Quarterly	60%	3.18	4.87	4.03
6x	70%	2.39	3.65	3.02
Monthly	80%	1.59	2.43	2.01

The total expected emission reductions from this program is outlined in Table 12, below.

[45] In the Final EIA, the Division erroneously attributed the compressor station tier model facility emissions to the calculations for different basins. The Division corrected that in this analysis.

Table 12: CS Emission Reductions from LDAR			
Compressor Station VOC Tier (tpy)	Total VOC Reductions (tpy)	Total Methane Reduction (tpy)	Total Greenhouse Gas Reduction (mtCO2e/yr)
Outside the NAA: <12	54.3	109.0	2,767.5
Outside the NAA: <12 - DI/prox	54.5	109.9	2,791.6
NAA: <12 - DI/prox	7.2	7.8	198.4
>12 - <50 - DI/prox	24.7	43.6	1,106.2
TOTAL	**140.8**	270.2	6,863.7

In its Rebuttal EIA, EDF estimated that this proposal would achieve additional emission reductions of 189.2 tpy VOC and 314.2 tpy methane.

Cost Effectiveness

Combining the annual cost of inspections, $430,409.78, with the annual cost of repairs, $49,301.65, incorporating a recovered natural gas value of $92,904.27, the effectiveness of this requirement is $2,747.89 per ton VOC and $56.36 per mtCO2e. The spreadsheets used to complete this analysis and develop all of these summary tables were submitted as exhibits to the Division's Rebuttal Statement and are incorporated herein by reference.[46]

Table 13: CS LDAR Cost Effectiveness			
LDAR Total Annual Cost			
	Inspection	Repair	TOTAL
Annual Cost	$430,409.78	$49,301.65	$479,711.43
Recovered Natural Gas			$92,904.27
Net Cost			**$386,807.16**
Compressor Station Emissions Reduction and Cost			
Total VOC Emission Reduction (VOC)	Cost per ton VOC	Total GHG Emission Reduction (mtCO2e/year)	Cost per mtCO2e
140.8	$2,747.89	6,863.7	$56.36

EDF also analyzed the Division's proposal and determined a net cost effectiveness of $208.16 per ton methane and $8.33 per ton CO2e.

[46] APCD_REB_EX-014 (APCD, LDAR Cost-Effectiveness Analysis 11-23-2021.xlsx).

II.A.2. LDAR at Natural Gas Processing Plants: Regulation Number 7, Part D, Section II.I

Currently, under Regulation Number 7, Part D, Section I.G, natural gas processing plants in the 8-hour Ozone Control Area must comply with the LDAR program in NSPS OOOO or NSPS OOOOa. Natural gas processing plants outside the 8-hour Ozone Control Area may also be subject to NSPS KKK, NSPS OOOO, NSPS OOOOa, depending on the date of construction. Natural gas processing plants statewide that have storage tanks subject to Section II.C.1 must also conduct AIMM inspections of the storage tanks and associated equipment in accordance with Table 1 in Section II.C.2. Those inspections range from semi-annual to monthly, depending on the VOC emissions estimated from the storage tanks.

The Division has identified 63 natural gas processing plants in Colorado - 38 of which are operating in the DJ Basin. The Division assumes these 38 plants are already subject to LDAR programs under NSPS OOOO or NSPS OOOOa. The Division has identified 25 gas plants outside of the DJ Basin - 18 in the Piceance basin and 7 in the remainder of the state. These numbers do not include gas plants the Division was able to determine are on tribal lands. Based on the Division's review of the Regulation Number 7 annual emissions reports, and the information submitted for fugitive emissions, it appears that many natural gas processing plants outside the 8-hour Ozone Control Area are already subject to NSPS OOOO or NSPS OOOOa for LDAR. However, for purposes of this Cost Benefit Analysis, the Division assumed that all 25 gas plants outside the DJ Basin will need to adjust LDAR frequency to comply with the Division's proposal. This makes the Division's cost analysis overly conservative.

The Division utilized technical supporting information from the Oil and Gas CTG[47] in the analysis of this proposal. Under the Division's proposal, these gas plants would monitor pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines, valves, and connectors to determine if a component is leaking. Under this program, "[v]alves are monitored monthly, connectors are monitored annually, and open-ended lines and pressure relief valves must be monitored within five days after a pressure release event to ensure they are operating without any detectable emissions (e.g. at a concentration less than 500 ppm above background)."[48]

In the Oil and Gas CTG, EPA estimated cost impacts associated with moving from a NSPS VV program to a subpart VVa program for a natural gas processing plant, and determined that the cost in 2012 dollars was between $2,010 - 2,844 per ton VOC[49]. In today's dollars, based upon a gas processing model plant, and assuming a correlation of VOC to methane of 1:1.81, the Division estimates the cost of this proposal as follows:

[47] New Mexico also utilized this data in preparing its economic impact analysis of gas plant LDAR in its recent rule. proposal. *See* https://www.env.nm.gov/air-quality/ozone-draft-rule/ (LDAR Reductions and Costs VOC 5-27-21_erg (06-08-2021)).
[48] Oil and Gas CTG, pp.8-9, 8-10.
[49] Oil and Gas CTG, p. 8-11.

Table 14: Cost and Emissions Reductions for LDAR at Gas Plants					
Pollutant	Annual Emission Reductions Per Gas Plant	Capital Cost (2021$)	Annual Cost (2021$)	Cost of Control (without savings) $/ton	Cost of Control (with savings) $/ton
VOC	4.56 tpy	$10,062.60	$15,343.12	$3,367.22	$2,379.79
Methane	8.27 tpy	$10,062.60	$15,343.12	$72.99	$51.63
Greenhouse Gas	210.2 $mtCO_2e/yr$				

The Division's proposal would also require operators to complete repair within specified time frames (within 2 years or the timeframe under the applicable federal program, whichever is earlier). The Division's proposal also requires operators to mitigate emissions while a component is on the delay of repair list. The Division does not specify how this must be accomplished, but proposed language for the Statement of Basis suggesting two methods that operators are encouraged to consider - drill and tap repair and replacement of leaking valves with valves with Low-E packing. Drill and tap reduces the need for a process shut-down to affect a leak repair, and can reduce fugitive emissions. The Division does not have information to suggest a significant additional cost associated with this proposal, because the Division has no information regarding how many valves cannot be repaired through other means prior to being placed on the delay of repair list. The Division understands that "drill and tap" is an accepted and effective repair method for valves, and that this proposal generally reflects best practice.[50] Leaks from valves are commonly related to valve packing.[51] Low-e packing is a valve packing product, independent of any specific valve, for which the manufacturer has issued a written warranty that the packing will not emit fugitives at greater than 100 parts per million ("ppm"). EPA has advised the Division that low-e valves and packing are the same or very comparable in price to non-low-e valves and packing. According to information from EPA, one vendor, Bonney Forge, claims its low-e packing can reduce emissions of harmful gases by up to 95% versus valves with traditional packing, for minimal cost impacts. The Division expects that operators will consider technically and economically feasible measures to minimize emissions from valves. The Division does not anticipate any additional costs associated with this component of its proposal.

II.B. Midstream Emission Reductions - Pigging and Blowdown Operations: Regulation Number 7, Part D, Section II.H

[50] *See* EPA's LDAR: A Best Practices Guide, Leak Detection and Repair Compliance Assistance Guidance Best Practices Guide; *see also* EPA December 1, 2015 Memorandum from Joseph Wilderwing to Cynthia Reynolds, re: Drill-and-Tap.
[51] See EPA, Leak Detection and Repair: A Best Practices Guide at 12, Table 3.1.

II.B.1. Pigging Operations

In Permit Section (PS) Memo 20-04[52], the Division explained pigging operations as follows:

Raw natural gas is transported from production wells to processing plants through networks of gathering pipelines. Although liquid separation may occur at the well pad, much of the raw natural gas passing through the gathering pipelines is saturated with hydrocarbons other than methane and may contain other components such as water, carbon dioxide, and hydrogen sulfide. During the transportation of this gas through gathering pipeline systems, the gas often experiences a temperature drop and pressure change that causes the hydrocarbons and other components to condense to a liquid phase. These natural gas condensates can accumulate in low elevation segments of the gathering pipelines, impeding the flow of natural gas. To maintain gas flow and operational integrity of the gathering pipelines, operators mechanically push these condensates out of the low elevations and down the pipeline by an operation called "pigging," which involves first inserting a device called a pig into a pig launcher upstream of the pipeline segment where condensates have accumulated. The gas flowing through the pipeline then pushes the pig through the pipeline, allowing the pig to sweep along the accumulated condensates. The pig is removed from the pipeline segment when it is caught in a pig receiver.

The Division is proposing that midstream owners and operators with pigging operations must capture and recover the natural gas emitted during pigging. If that is not feasible, those owners or operators may apply to the Division to utilize air pollution control equipment to control those emissions. The Division's proposal is reasonably targeted at high pressure pigging pipelines and pigging units that exceed specified emission thresholds. The Division's proposal also imposes more stringent requirements upon newly constructed facilities and pigging units, because planning for capture and recovery during construction is more cost-effective.

All midstream owners or operators with pigging operations must additionally employ best practices to reduce emissions associated with pigging. Some of the proposed best management practices are specified in PS Memo 20-04, and therefore should not result in additional costs to operators. See PS Memo 20-04, Sections 6.5 and 6.6. For other proposed best practices, the Division has proposed a feasibility off-ramp, that includes some sensitivity to cost.

The Division used gas speciation data collected by the Division, guidance from the EPA[53] and information received from operators and manufacturers to estimate emissions from pigging events.

[52] Memo 20-04 - Routine or Predictable Gas Venting Emissions Calculation and Instructions on Permitting for Oil and Natural Gas Operations, Permit Section Memo 20-04, APCD, CDPHE, November 6, 2020.

[53] "Quantifying The Potential Impact Of Natural Gas Condensate Holdup On Uncontrolled Volatile Organic Compound Emissions From Pig Receivers During Depressurization In Wet Gas Gathering Operations", EPA Discussion Draft, May 16, 2016.

Cost - Pig Ramps

Pig ramps allow liquids trapped in front of the pig to be captured, and allow liquids on the pig itself to drain before the pig is pulled from the chamber.[54] The inventor of pig ramps, Mark West, has made the schematics available freely on its website. The Division has received cost estimates for each pig ramp of $800-$1,300 per ramp. Taking the median ($1,050) and applying a 6% interest rate results in an annualized cost of $188 per pig ramp. The Division does not have reasonably available information as to how many pig ramps would be necessary to comply with this proposal, and - as staff to the Commission - requested that information from operators. Operators did not provide any documentation or data, but did suggest that pig ramps could have costs in excess of $4,000 per unit. Given that the Division's data came from EPA and the operator that invented the pig ramp, the Division believes its data is reliable. The Division assumes this minimal cost to be absorbable. The Division also amended its proposal to allow for other liquids containment systems, such as process drains. This expansion of compliant practices further reduces the impact.

Cost - Capture: ZEVAC unit and Jumper Lines

In order to comply with the requirement to capture and reduce emissions during pigging operations, for the purpose of calculating costs, the Division assumes operators will use a ZEVAC unit.[55] The Division assumes that a pig launcher and receiver are already on-site.

The Division has recognized that capture may also be effectuated "by routing the gases to a lower pressure system before venting the remaining gases to the atmosphere or to control equipment. Routing to a lower pressure system is achieved with a depressurization line (or, "jumper line") exiting the top of the barrel ... or exiting the top of the pig ball valve. Compressor stations and gas plants have low pressure lines on the site that can receive these depressurization gases and recycle them through the process. Similarly, launchers and receivers along high pressure pipelines are occasionally located near low pressure pipelines that can receive depressurization gases exiting the barrel or pig ball valve."[56] One operator who employed pig ramps and depressurization techniques, along with Zero Emission Vacuum and Compressor (ZEVAC) units reported significant reductions in gas vented and emissions as a result.[57]

Cost data received from EPA suggests that the materials cost for a jumper line is low - about $2,137 per jumper line. And when the savings in materials (*e.g.*, bolts, gaskets, flanges) from a jumper line installed during mainline construction are taken into account, the cost is more in the neighborhood of $1,511 per jumper line. However, the Division acknowledges that it does not have access to other associated costs, such as engineering costs. In its Initial EIA, the Division requested additional cost information from operators. While the Division has heard from operators that costs for a jumper line can theoretically be in the range of $50,000, to date, no supporting materials have been provided.

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[54] Pipeline Launcher/Receiver Emission Reduction Systems

[55] The Division's proposal also contemplates use of control devices as an option where recovery of the gas from pigging operations is not feasible. According to EPA, "[l]arge, high capacity combustion devices are typically available at compressor stations and processing plants and can be used to control pigging gases while meeting the other flaring needs of the facility. There are also numerous low capacity combustion devices available for serving remote launcher/receiver sites." EPA Enforcement Alert (Sept. 2019). Natural Gas Gathering Operations Clean Air Act Enforcement Alert

[56] EPA Enforcement Alert (Sept. 2019). Natural Gas Gathering Operations Clean Air Act Enforcement Alert

[57] See *Methane Reductions in Pigging*, September 2019, Methane Reductions in Pigging

The Division gathered information from a manufacturer of ZEVAC units on the costs associated with ZEVAC units and expected gas recovery under various operating scenarios. The Division does not have reasonably available information about actual pigging operations in Colorado to specify the frequency of pigging operations or the size of the ZEVAC unit that would be necessary for each operator. In its annual emission reports to the Division, one operator submitted its annual emissions reporting 1,343 pigging events in the second half of 2020 alone, for a total of 13,806,040 scf vented, an average of 10,280 scf vented per pigging event. The Division recognizes that not all pigging events vent the same amount of gas; pigging of larger, higher pressure pipelines emit more gas to atmosphere than pigging of smaller, low-pressure pipelines. That operator also reported venting 7,557,500 scf of natural gas from pipeline blowdown events during the same period. However, the Division did not get this level of detailed reporting consistently across all operators; several midstream operators reported no pigging operations. Therefore, an analysis was conducted on three different sized ZEVAC units, small, medium, and large, under both a high frequency and low frequency use of the equipment. The size of the unit affects the speed of the gas recovery process; larger units taking less time. All units are assumed to have a useful life of 10 years. The capital cost of a small ZEVAC unit was found to be $30,000 with maintenance and repair costs of $2,400 per year. Annualizing the capital cost across 10 years, and assuming a 6% interest rate, yields a total annualized cost of $7,773. Under the same assumptions, the capital cost of a medium sized unit is $135,000 with annual maintenance costs of $10,800, for a total annualized cost of $34,976; and the capital cost of a large unit is $245,000 with annual maintenance costs of $19,600, and a total annualized cost of $63,476. In estimating the composition of pollutants in the gas, the Division applied weight percentages of total hydrocarbons of 29.35% VOC, 53.31% methane, and 17.34% ethane.[58]

High frequency pigging assumes the use of 5 pig barrels a day, for 5 days per week, at 50 weeks per year. With high frequency pigging, there are an estimated 1,250 events per year, each releasing an estimated 3,900 scf of gas, for a total annual potential emitted gas of 4,875,000 scf. As noted above, with at least one operator reporting 1,343 pigging events in just the second half of 2020, it is reasonable to assume at least some operators engage in high-frequency pigging operations. Low frequency pigging assumes the use of 1 pig barrel per day, for 3 days per week, at 50 weeks per year. With low frequency pigging, there are an estimated 150 events per year, each releasing an estimated 3,900 scf of gas, for a total annual potential emitted gas of 585,000 scf.

Table 15 below demonstrates potential gas recovery (emissions reductions) and cost per ton of pollutants per ZEVAC unit under the various ZEVAC operating conditions. This cost effectiveness analysis does not account for the economic benefit to operators from selling the recovered gas.

[58] As with elsewhere in this Cost Benefit Analysis, the Division utilized gas speciation data submitted to the Division from multiple operators, reviewing over 100 samples of sales gas analysis from across the state, and creating a weighted average by location.

Table 15: Cost and Emission Reductions of ZEVAC Units					
Small ZEVAC unit					
	Annualized cost	VOC captured (tpy)	Greenhouse Gas[59] captured (mtCO2e/yr)	$/ton VOC	$/mtCO2e
High frequency	$7,773.00	40.02	1,844.44	$194.21	$4.21
Low frequency	$7,773.00	4.80	221.33	$1,618.44	$35.12
Medium ZEVAC unit					
	Annualized cost	VOC captured (tpy)	Greenhouse Gas captured (mtCO2e/yr)	$/ton VOC	$/mtCO2e
High frequency	$34,976.00	40.02	1,844.44	$873.90	$18.96
Low frequency	$34,976.00	4.80	221.33	$7,282.47	$158.02
Large ZEVAC unit					
	Annualized cost	VOC captured (tpy)	Greenhouse Gas captured (mtCO2e/yr)	$/ton VOC	$/mtCO2e
High frequency	$63,476.00	40.02	1,844.44	$1,585.99	$34.41
Low frequency	$63,476.00	4.80	221.33	$13,216.54	$286.79

Amount and Value of Recovered Natural Gas

If the use of ZEVAC units will result in the recovery of 4,875,000 scf of natural gas per year, per ZEVAC unit, assuming high-frequency use, and 585,000 scf of natural gas per year, per ZEVAC unit, assuming low-frequency use, the Division calculates natural gas savings (at a price of $4/MCF) of $19,000 per ZEVAC unit per year, for a high frequency use, and $2,340 per ZEVAC unit per year for a low-frequency use. That would materially improve the cost-effectiveness.

[59] Converted from methane to CO2e using AR5.

In its Initial EIA, the Division, as staff to the Commission, requested additional information from stakeholders on the costs associated with this component of its proposal. The Division did receive some additional cost data from operators, associated with the rental of a ZEVAC unit, that included 2 hours' labor, driving costs, and rental costs for an engine-driven air compressor. Industry noted annualized costs of about $556 per pigging event. The Division believes these costs are inappropriately inflated for most pigging events for the following reasons. First, purchasing a ZEVAC unit (or compressor) is more cost-effective than a per-event rental. Second, the Division understands from industry that a large portion of pigging events take place at a natural gas compressor station or natural gas processing plant, in which case there would be no need for travel time or additional labor hours.

II.B.2. Blowdowns of Equipment and Piping

The Division's proposal will require midstream owners and operators to reduce hydrocarbon emissions from blowdowns from equipment and piping at compressor stations and gas plants where those emissions exceed specified thresholds. The Division also proposes requiring best practices for blowdowns including along midstream pipelines. The Division's proposal with the Rebuttal Statement identifies with more specificity which blowdown emissions must be captured or controlled, focusing on blowdowns of compressors, and aggregating emissions from blowdowns of all other equipment and piping (with a physical volume of equal to or greater than 50 cf).

Based on information collected from operators, some operators will be able to route emissions from blowdowns to existing control equipment on-site. One operator indicated that costs to combust blowdown emissions could include the building of a blowdown header and taking blowdowns back to the field or a series of VRUs to draw down the pressure/volume such that it can be handled by the existing ECD or a new combustion device. Others, however, will drawdown line pressure, either naturally with alternative lower pressure gas lines or using ZEVAC units[60] as discussed under the previous section, to capture and retain the natural gas. Some operators may also install ejector units to force gas out of off-line compressors[61] or other equipment and route the gas to a lower pressure fuel gas line.

Many best practices are already identified in PS Memo 20-04. In the Initial EIA the Division - as staff to the Commission - requested additional information from operators on the costs of implementing controls and other practicable best management practices specified in the Division's proposal. The Division did not receive any additional data or materials other than as described above.

Emission Reductions from Pigging and Blowdowns

The Division does not have complete data from operators on how often pigging and blowdown activities are conducted, particularly as differentiated between pigging and other maintenance activities that result in venting of emissions. In order to calculate reductions associated with this proposal, therefore, the Division looked at two sources of data.

[60] Blowdown Emission Reduction White Paper, American Gas Association, August 5, 2020.
[61] Reducing Emissions When Taking Compressors Off-Line, Natural Gas Star, EPA, October 2006.

First, the Division looked at EPA FLIGHT data for 2019[62], and identified the total amount of emissions in CO2e reported by the natural gas gathering and boosting segment and the natural gas processing segment for pigging, venting and blowdowns (to the extent possible). The Division looked at emissions from the 20 natural gas processing plants in Colorado (on non-tribal lands) that reported to EPA and calculated 6,007.84 mtCO2e per year from venting/pipeline blowdown activities. It was more difficult to separate out gathering and boosting facilities that are in Colorado, and on non-tribal lands, but the Division ultimately calculated about 76,000 mtCO2e per year from venting/pipeline blowdown activities reported to EPA.

Initial EIA Analysis

The Division then looked at the emissions reported to the Division by operators in the midstream segment for "venting and blowdowns" and pipeline emissions. For the second half of 2020, midstream operators reported 35,184 events in "venting or blowdowns" and "pipeline" emission activities. From these events, operators reported a total of 184,495 mtCO2e for 2020. Operators also reported 3,584 tons VOC from venting or blowdowns and pipelines for 2020.

Table 16: Initial EIA - Emissions from Venting/Blowdowns/Pigging and Pipelines			
Reported 2020 Emissions with No Control			
Emission Category	Reg. 7 EI 2020 CO2e **(mtCO2e/yr)**	**Reg. 7 EI 2020 VOC (tpy)**	**# Events**
Total Venting/Blowdowns (includes pigging)	164,758.15	1,690.08	69,770
Total Pipeline Venting	19,736.72	1,893.70	598
Total Venting/Blowdowns/Pipeline Venting	**184,494.87**	**3,583.78**	**70,368**
Emissions after 95% Reduction of Venting/Blowdown Emissions			
Total Venting/Blowdowns (includes pigging)	8,237.91	84.50	69,770
Total Pipeline Venting	19,736.72	1,893.70	598
Total Venting/Blowdowns/Pipeline Venting	**27,974.63**	**1,978.20**	**70,368**
Emission Reductions with this Rule			
Total Emission Reductions	**156,520.24**	**1,605.58**	**70,368**

[62] EPA Flight data for 2020 was not available at the time the Division prepared this analysis.

Not accounting for any reductions from pipeline emissions,[63] the Division's proposal could reduce venting and blowdown emissions by 95%, achieving a CO_2e reduction of 156,520 $mtCO_2e$/year. Looking only at VOC emissions from total venting and blowdowns (and not including pipeline venting reported), If the Division's proposal also reduces VOC by 95%, that results in a reduction of 1,606 tpy VOC, a significant and meaningful co-benefit. These numbers are likely conservative because not all midstream operators reported their emissions to the Division.

<u>Update for Final EIA</u>

The Division updated its analysis for the Final EIA based upon data reported for the second half of 2020, broken out by applicability category, reported emissions are as follows:

Table 17: Emissions from Venting/Blowdowns/Pigging and Pipelines

Activity	Number of Events	VOC (tpy)	CO2 (mtCO2e/yr)	CH4 (mtCO2e/yr)	CO2e (mtCO2e/yr)
Compressor Blowdowns	7,376	438.94	460.65	52,812.34	53,272.99
Pigging Operations	12,532	294.79	47.11	19,413.06	19,460.17
Other Facility Venting and Blowdowns	50,747	1,024.10	1,824.29	166,264.17	168,088.46
SUBTOTAL Venting/Blowdown	70,655	1,757.83	2,332.05	238,489.57	240,821.62
SUBTOTAL Pipeline Venting	682	1,916.56	68.65	22,302.24	22,370.89
TOTAL	**71,337**	**3,674.39**	**2,400.70**	**260,791.81**	**263,192.51**

Under the Division's proposal, the industry stakeholders have conveyed to the Division that they expect the pigging applicability thresholds to result in capture or control of more than 85% of the natural gas emitted during pigging operations.[64] The Division's proposal would also ensure capture or control of 95% of the emissions from blowdowns of compressors and other equipment (using the numbers reported above is appropriate because blowdowns where the physical volume is less than 50 cf are not currently reported).

[63] The Division's proposal would require either capture, control or use of BMPs to reduce emissions from pigging pipelines. The Division's proposal would require only the use of BMPs to reduce emissions from other pipeline blowdowns.
[64] APCD_REB_Ex-003.

Thus, under this updated analysis, assuming that the Division's proposal would result in capture or control of 85% of pigging operations (with a 95% capture/control efficiency), and 95% capture/control efficiency of remaining blowdown emissions, the Division's proposal could actually result in even more reductions: 15,676.05.10 mtCO2e/year from pigging activities and 208,122.68 mtCO2e/year from blowdowns, for a total of 223,798.73 mtCO2e/year reduced (and 1,627.93 tpy VOC). When the additional capture of CO2 emissions from this gas stream is included, the total CO2e reductions increase to 228,781 mtCO2e/yr.

Table 18: Emissions from Venting/Blowdowns/Pigging and Pipelines			
Reported 2020 Emissions with No Control			
Emission Category	CO2e (mtCO2e/yr)	VOC (tpy)	# Events
Total Venting/Blowdowns (includes pigging)	240,821.62	1,757.83	70,655
Total Pipeline Venting	22,370.89	1,916.56	682
Total Venting/Blowdowns/Pipeline Venting	263,192.51	3,674	71,337
Emission Reductions with this Rule			
Emission Category	CO2e (mtCO2e/yr)	VOC (tpy)	# Events
Total Emission Reductions	228,781	1,628	71,337

Cost of Pigging and Blowdown Emission Reduction

Based upon information reported to the Division in the annual emission reports under Regulation Number 7, Part D, Section V, and assuming that there are 250 business days in a year (and that blowdowns take place only on business days), there are approximately 282 events per day[65] that would be required to be captured or controlled by this rule. Using an annualized open flare cost of $25,268.95[66], as well as the annualized ZEVAC costs depicted in Table 15 above, and assuming that each event over a business day requires its own portable piece of equipment (such as an ECD or ZEVAC unit)[67], for a total of 282 units required, the average annual cost of this proposal is $9,290,705.

[65] Operators reported 35,328 events in the second half of 2020, as well as emissions for only July - December 2020. The Division assumed that the annual emissions are double those reported for the 6-month period of July - December 2020.
[66] As described in more detail in the well liquids unloading section, later in this Cost Benefit Analysis.
[67] This is an overly conservative assumption. The Division understands that one ZEVAC unit can be deployed multiple times per day. For example, based upon data provided to the Division, the average pigging operation lasts around 15 minutes.

The average cost per ton of emission reductions is $5,707.06 per tpy VOC and $40.78 per mtCO2e/year. These costs, however, do not separate out pigging emissions or specific types of blowdowns (such as compressor blowdowns), but do exclude pipeline emissions which are subject to BMPs but not control requirements in the proposal. Table 19 contains the emissions and costs associated with venting and blowdown emissions, including pigging emissions as described in more detail in Section II.B.1. of this EIA. These costs also do not account for the recovered gas savings from using a ZEVAC or other capture unit.

Table 19: Cost and Emission Reductions for Venting/Blowdown Activities

Control or Capture Device Option	Annualized cost	VOC reduced (tpy)	GHG reduced (mtCO2e/yr)	$/ton VOC	$/mtCO2e
Open Flare	$7,141,510.65	1,627.93	223,798.73[68]	$4,386.86	$31.91
Small ZEVAC unit	$2,196,805.26	1,627.93	228,780.54	$1,349.45	$9.60
Medium ZEVAC unit	$9,884,917.12	1,627.93	228,780.54	$6,072.07	$43.21
Large ZEVAC unit	$17,939,587.12	1,627.93	228,780.54	$11,019.87	$78.41
Overall Average Cost Per Ton				**$5,707.06**	$40.78

II.C. Rod Packing Replacement at Natural Gas Processing Plants: Regulation Number 7, Part D, Section II.B.3.d

Existing regulations require rod packing replacement at natural gas processing plants inside the 8-hour Ozone Control Area. See Regulation Number 7, Part D, Section I.J.2. The Division's proposed regulation would expand that requirement to natural gas processing plants statewide. There may be additional costs of the proposed requirement for owners or operators of reciprocating compressors at natural gas processing plants to replace the rod packing. The Division estimates that there are 31 natural gas processing plants outside the 8-hour Ozone Control Area, with an estimated total of 258 engines.[69] Conservatively assuming all engines existing at the natural gas processing plants are reciprocating engines and would be subject to the proposed requirements, and none of the owners or operators are currently voluntarily replacing rod packing or capturing engine emissions, each of these engines will incur additional costs to comply with the Division's proposal.

[68] CO2 emission reductions are not included when reductions are achieved through flaring.

[69] In 2017, the Division estimated 133 reciprocating compressors at the identified 16 natural gas processing plants. Assuming the same ratio of compressors per gas plant, and using the identified 31 gas plants, the Division estimates 266 reciprocating compressors covered by this rule. These numbers do not reflect that some number of the subject compressors will already be performing the rod-packing replacement.

According to the Oil and Gas CTG, EPA estimated the emission reductions by "comparing the average rod packing emissions with the average emissions from newly installed and worn-in rod packing."[70] The Oil and Gas CTG, Table 5-4, estimates a reduction from rod packing replacement in accordance with these requirements of 4.89 tpy VOC per engine and 17.58 tpy methane. With the number of engines estimated by the Division to be subject to this proposal, the proposal would realize 1,261.62 tpy VOC and 126,997.92 mtCO2e.

The Oil and Gas CTG estimates the capital cost of replacing the rod packing at $4,280, without factoring in the natural gas savings. The Division converted this value from 2012 dollars to 2021 dollars using the U.S. BLS CPI Inflation Calculator, resulting in an updated capital cost of $5,067. Using the same process as the Oil and Gas CTG, the Division determined that the annual cost would be $1,931.79 per engine. Applying this estimate to the emissions estimate reductions noted before yields cost per ton reduced of $394.84 per ton of VOC and $109.84 per ton of CH4 ($3.92 per ton of CO2e). With natural gas savings, the Division concludes - consistent with the Oil and Gas CTG - that this measure is an economic benefit to the operator of a natural gas processing plant.

In addition, there may be minimal costs related to the proposed monitoring and recordkeeping requirements, as discussed above, where an owner or operator is not currently monitoring and keeping compressor records. Throughout the rulemaking process, the Division received no information from any parties suggesting that the Division incorrectly evaluated costs.

II.D. Pneumatic Controller Requirements at Natural Gas Processing Plants: Regulation Number 7, Part D, Section III

The Division's proposal would expand current requirements to use non-emitting pneumatic controllers to natural gas processing plants statewide. Current requirements apply inside the 8-hour Ozone Control Area. See Regulation Number 7, Part D, Section III.C.2. Regulation Number 7 also required that pneumatic controllers placed in service between 2014 and May 1, 2021 be no-bleed where feasible, which applies to gas plants. See Regulation Number 7, Part D, Section III.C.3. There may be costs related to the proposed requirement for owners or operators of natural gas processing plants to ensure that natural gas-driven pneumatic controllers are non-emitting.

Should an owner or operator of a natural gas processing plant convert an existing natural gas-driven pneumatic controller to their instrument air system, the Oil and Gas CTG estimates a capital cost of converting the pneumatic controller at $2,000 and the cost per ton of VOC reduced between $6 and $68 per pneumatic controller.[71] A VOC emissions reduction ranging from 4.18 to 48.7 tpy, depending on the size of the instrument air system, is associated with each natural gas processing plant, or a range of 790.97 to 9,215.40 mtCO2e/year of methane. Because the Division assumed that most of the natural gas processing plants in the 8-hour Ozone Control Area would probably require a medium-to-large air system, an annual VOC emission reduction of 17.5 tpy and methane reduction of 3,311.49 mtCO2e/year represents an average associated with converting pneumatic controllers to system air.[72]

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[70] Control Techniques Guidelines for the Oil and Natural Gas Industry 2016, EPA, p.5-10.
[71] Control Techniques Guidelines for the Oil and Natural Gas Industry 2016, EPA, p.6-16.
[72] Control Techniques Guidelines for the Oil and Natural Gas Industry 2016, EPA, p.6-17, Table 6-7.

The Division estimates that there are thirty-one (31) gas plants outside the 8-hour Ozone Control Area, but does not have data on the number of natural gas actuated pneumatic controllers at these natural gas processing plants. The Oil and Gas CTG assumes that existing natural gas processing plants have already replaced pneumatic controllers with other types of control, such as an instrument air system, and any pneumatic controllers with a bleed rate greater than zero are required due to safety reasons.[73] The Division also checked pneumatic controller data reported to EPA in 2019 under the Greenhouse Gas Reporting Rule, and no Colorado gas plant reported any emissions from pneumatic controllers. The Division also reviewed the submittals from midstream operators to the Division for 2020; only 11 midstream operators reported having any natural gas driven pneumatic controllers, and the Division's review did not identify any natural gas processing plants reporting having gas driven pneumatic controllers. Therefore, the Division believes the cost to owners or operators of natural gas processing plants of the proposed requirements are minimal and limited to documenting, tagging, and maintaining any emitting natural gas-driven pneumatic controllers that are required for safety and/or process purposes. Throughout the rulemaking process, the Division received no information from any parties suggesting that the Division incorrectly evaluated costs.

II.E. Long-Term Planning for CO2e Reduction from Midstream Engines and Other Fuel Combustion Equipment: Regulation Number 22, Part B, Section III

Section 25-7-105(1)(e)(XIII), C.R.S., requires a 20% reduction in industrial emissions from the 2015 baseline by 2030. Included in this category of emissions is methane, CO2, and other greenhouse gas emissions from fuel combustion equipment at midstream facilities, such as engines, boilers, turbines, and heaters. In its efforts to address greenhouse gas emissions from fuel combustion equipment in the midstream segment, the Division is proposing a long-term planning process. By long-term, the Division proposes that operators will have until 2023 to develop their plans, and that additional rulemaking before the Air Commission would not be required until 2024. The program establishes a steering committee that will guide and aid midstream segment operators in the development of plans to meet emission reduction targets.

The Division has not identified a significant economic impact on any industry or party from this proposal. The JIWG complained in its prehearing statement that the Division did not include cost associated with participation.[74] As an initial matter, participation in the steering committee is voluntary and the Division has not identified any costs imposed on midstream segment operators, the Division, or any other potential steering committee participants for the operation and administration of the committee. Between the Initial EIA and the Final EIA, the Division was not provided with any information to suggest that there are such costs. Compliance with the rule includes development of a plan to reduce emissions only, and not implementation of the plan. Individual operators may choose to hire third-party consultants to help develop their emission reduction plans, but because this is not required directly by the rule proposal and hiring of any consulting services would be completely voluntary, those potential costs are not considered in this analysis. Additionally, the Division does not anticipate any costs to the Division for oversight or the review of proposed guidance documents and emissions reduction plans. Administration of this rule will be carried out by existing and anticipated Division staff.

[73] Control Techniques Guidelines for the Oil and Natural Gas Industry 2016, EPA, p.6-16.
[74] JIWG_PHS, at H-3.

II.F. Pneumatic Controller Inspections: Regulation Number 7, Part D, Section III.F.2.f.

To align with the new leak detection and repair frequencies for compressor stations, the Division proposed to update the inspection frequency for gas-driven pneumatic controllers in Section III.F. The proposed revisions build upon the statewide LDAR program in Regulation Number 7 and the Division assumes that owners or operators will incorporate the pneumatic controller inspections into their natural gas compressor station LDAR programs. The Division understands that operators will inspect the gas-driven pneumatic controllers during the same inspection as the Section II.E component inspections, and therefore has determined there are minimal, if any, additional inspection and recordkeeping costs. According to the Final Economic Impact Analysis for the December 2019 rulemaking, as supported by both industry stakeholders and the environmental community, the incremental labor and material costs, costs above those related to the aligned LDAR inspection, are variable and range from insignificant to $600 per facility per year.[75] Further, inspections are only required of gas-driven pneumatic controllers; as operators comply with existing regulations to replace gas-driven pneumatic controllers with non-emitting pneumatic controllers, the cost of inspection and repair of gas driven pneumatic controllers will necessarily also decrease. While performed at minimal cost, these inspections do have the ability to meaningfully reduce emissions, given that malfunctioning pneumatic controllers have been identified by many as significant contributors to excess methane emissions (and are considered a classic “superemitter”). Inspecting gas-driven pneumatics more frequently will mitigate emissions from improperly operating pneumatic controllers.

III. Upstream Program

The Division has proposed several new regulatory provisions to directly address greenhouse gas emissions from the upstream segment of the oil and gas industry. The proposals include the following additional requirements for oil and gas operators in the upstream segment:

- Increased leak detection and repair (LDAR) inspections for well production facilities;
- Greenhouse gas intensity program; and
- Emission reduction requirements for well maintenance and unloading activities.

III.A. Leak Detection and Repair Inspections at Well Production Facilities: Regulation Number 7, Part D, Section II.E.4.e.(i)

The Division has proposed additional requirements for existing well production facilities, statewide and in disproportionately impacted communities. The proposal, if adopted, would require more inspections at most well production facilities, and - consistent with the Environmental Justice Act - ensuring even more frequent inspections within a DI Community (in the 8-hour Ozone Control Area) or within 1,000 feet of an occupied area (statewide). The Division assumed that 26.48% of compressor stations in the 9-County area and 32.98% of compressor stations in the Piceance Basin and remainder of state were also in DI Communities. Further, the Division consulted with stakeholders to conduct an evaluation of how many well production facilities were within 1,000 feet of an occupied area. Based on these discussions, the Division assumed that in the NAA, 16% of well production facilities were within 1,000 feet of an occupied area but not within a DI Community.

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[75] Revisions to Regulation Numbers 3 and 7, December 16-19. 2019, APCD_Final_EIA, pp.29-30.

Outside the NAA, the Division assumed that 9.2% of well production facilities were located within 1,000 feet of an occupied area. From there the Division was able to determine how many well production facilities would be affected, especially where existing regulatory provisions require more frequent inspections at well production facilities within 1,000 feet of an occupied area. The number of well production facilities affected by this rule proposal is in Table 20.

Table 20: WPF Emission Reductions from LDAR

WPF Fugitive VOC Tier (tpy)	Number of WPF	Current Frequency	Proposed Frequency
Other Statewide: <2tpy	5,487	One-time	Annual
NAA: <1tpy and ROS: <2tpy (within 1000 ft, not DI)	802	One-time	Semi-Annual
ROS: <2tpy (DI)	1,478	One-time	Annual
NAA: <1 tpy (DI)	1,183	One-time	Semi-annual
NAA: >1 - <2tpy (not DI or w/in 1000 ft)	679	Annual	Annual
NAA: >1 - <2tpy (DI)	312	Annual	Semi-Annual
NAA: >1,<2 (within 1000 ft, not DI)	189	Annual	Semi-Annual
>2 - <12 tpy	1,808	Semi-Annual	Bimonthly (6x)
>2 - <12 tpy (DI)	702	Semi-Annual	Bimonthly (6x)
>12 - <50 (not DI or w/in 1000 ft) (includes some 2-12 in proximity)	1,066	Quarterly	Bimonthly (6x)
>12 - <50 (DI)	89	Quarterly	Monthly
>12 - <50 (within 1000 ft)	316	Monthly	Monthly
>50	1,134	Monthly	Monthly
TOTAL	**15,245**	**28,220 Inspections**	**52,540 Inspections**

The Division's proposal also allows for specified design alternatives - like pressure management systems and tankless facility design - to take the place of the additional inspections at well production facilities undertaking those design modifications, as long as the facility was inspected at some lesser minimum frequency.

Inspections

The Division's analysis as set forth above results in an increase in 24,320 inspections, statewide, per year. However, this analysis is conservative, as it does not account for the number of sites with design alternatives as described above. For this analysis, the Division assumed that operators would use only IR cameras to meet this increased inspection requirement. Table 21 includes a breakdown and analysis of the estimated leak inspection time and costs under the different possible conditions mentioned in the preceding section. The Division assumed a reduced number of hours per inspection than in the Final EIA or previous rulemaking efforts. The Environmental Defense Fund provided updated information in their prehearing statement and alternate proposal submission, which the Division used in this analysis.[76] The EDF information suggested the Division's average number of hours per inspection was too high.[77] The Division found this information credible, based upon its own understanding of, and experience with, how long it takes to conduct IR camera inspections.

Table 21: WPF LDAR Inspection Costs

Basin/Area	Inspection Type (All AIMM)	# NEW Inspections	Hours per Inspection	Cost per hour	Result: Total cost
9-County Area	In-House	13,173	3.64	$105.00	$5,034,644.16
	Contractor	3,293	3.64	$137.00	$1,642,252.98
Piceance Basin	In-House	4,850	3.64	$105.00	$1,853,822.88
	Contractor	1,213	3.64	$137.00	$604,699.37
Rest of State	In-House	1,433	3.64	$105.00	$547,616.16
	Contractor	358	3.64	$137.00	$178,627.18
Totals		24,320			**$9,861,662.72**

At hourly inspection rates of $105 per hour for in-house and $137 per hour for contractors, the total cost to operators for completing the new LDAR inspections would therefore be $9,861,662.72.

Leak Repair

The Division made the same assumptions to calculate leak repair costs as in the Final EIA, except applied an incremental change in repair hours associated with the proposed revisions. The Division also made a scaled assumption of leak rate for the new LDAR frequency of six times per year. Table 22 includes the leak rates assumed along with repair hours calculated according to the methodology laid out previously.

[76] See EDF_ALT_EX-001-004, pp. 16-17.
[77] Id.

Table 22: WPF Repair Hours from LDAR Frequencies			
LDAR Frequency	Leak Rate	Repair Hours in 9-County Area	Repair Hours in Remainder of State
Annual	1.18%	12.07	7.86
Semi-Annual	1.48%	15.13	9.86
Quarterly	1.77%	18.1	11.79
6x	1.92%	21.17	12.79
Monthly	2.36%	24.13	15.72

Using these assumed repair hours and the incremental change in frequency as outlined in Table 20, the Division calculated an increase of 113,191 repair hours. At a cost of $82.06/hour, the total repair cost is $9,288,452.64. The Division's estimated repair cost is higher than the repair cost estimated by EDF[78]; the Division believes its estimate is conservatively high.

<u>Emission Reductions</u>

The Division used the same model well production facilities for the development of emissions per facility that it used for the Final EIA. Table 23 includes emissions assumed from model facilities for well production facilities with emissions greater than or equal to 2 tpy VOC.

Table 23: WPF Emission Calculations from LDAR - Facilities ≥ 2tpy VOC				
Methane Emissions from ≥ 2tpy VOC Model Well Production Facility (tpy)				
LDAR Frequency	Emission Reduction	9-County	Piceance	Remainder of State
No LDAR	0%	4.56	7.32	5.94
Annual	40%	2.74	4.39	3.56
Semi-Annual	50%	2.28	3.66	2.97
Quarterly	60%	1.82	2.93	2.38
6x	70%	1.37	2.20	1.78
Monthly	80%	0.91	1.46	1.19
VOC Emissions from ≥ 2tpy VOC Model Well Production Facility (tpy)				
LDAR Frequency	Emission Reduction	9-County	Piceance	Remainder of State
No LDAR	0%	5.09	3.05	4.07
Annual	40%	3.05	1.83	2.44
Semi-Annual	50%	2.55	1.53	2.04
Quarterly	60%	2.04	1.22	1.63
6x	70%	1.53	0.92	1.22
Monthly	80%	1.02	0.61	0.81

[78] *See* EDF_REB_EIA, pp.7-8.

However, the model facilities developed for Table 23 were not appropriate to use for well production facilities with emissions less than 2 tpy VOC. The model well production facilities in Table 23 were developed based on data from compressor stations with emissions greater than 2 tpy VOC. The Division lacks emissions data in Air Pollution Emission Notices[79], and the emissions inventory submitted for 2020 emissions reporting did not result in information easily analyzed, for small well production facilities lacking AIRS IDs. Therefore, the Division assumed that both methane and VOC emissions for all well production facilities with emissions less than 2 tpy VOC were: 0.5 tpy with no LDAR inspections, 0.3 tpy for facilities with annual LDAR inspections, and 0.25 tpy for facilities with semi-annual LDAR inspections. Using the emissions per model well production facility outlined above, the Division calculated an emissions reduction of 4,852 tpy VOC, 5,110 tpy methane, and 129,808 mtCO2e/year.

Cost Effectiveness

Combining the annual cost of inspections, $9,861,662.72, with the annual cost of repairs, $9,288,452.64, yields a total gross annual cost of $19,150,115.36. Based on these reductions and associated costs, incorporating a recovered natural gas value of $1,402,665.45, the effectiveness of this requirement is $3,658.02 per ton VOC and $136.72 per mtCO2e. The Division also provided the spreadsheets used to complete this analysis and develop all of these summary tables as part of its Rebuttal Statement.[80] The Division believes its estimated costs are overly conservative, in that the Division understands that many operators already conduct leak inspections more frequently than required by regulation. While the Division understands that operators do not support this component of the Division's proposal, the Division understands that the opposition is driven largely by a concern about the precedent this level of inspection frequency might set in other states or at the federal level. These inspection frequencies were determined to be appropriate for Colorado.

Table 24: WPF LDAR Total Annual Cost			
LDAR Total Annual Cost			
	Inspection	**Repair**	**TOTAL**
Annual Cost	$9,861,662.72	$9,288,452.64	$19,150,115.36
Recovered Natural Gas			$1,402,665.45
Net Cost			**$17,747,449.91**
WPF Emissions Reduction and Cost			
Total VOC Emission Reduction (VOC)	**Cost per ton VOC**	**Total GHG Emission Reduction (mtCO2e/year)**	**Cost per mtCO2e**
4,852	**$3,658.02**	**129,808**	**$136.72**

[79] Because the APEN thresholds are 1 tpy VOC in the NAA and 2 tpy VOC outside the NAA, sources below these thresholds are largely not required to submit APENs.
[80] APCD_REB_EX-014 (APCD, LDAR Cost-Effectiveness Analysis 11-23-2021.xlsx).

EDF estimated methane reductions from the Division's proposal of 54,000 metric tons by 2025 and 65,000 metric tons by 2030. EDF's analysis assumes that "abnormal operating conditions" or "superemitters" would be reduced significantly through additional leak inspections; the Division agrees, though does not adopt EDF's analysis. However, based upon EDF's analysis, the cost-effectiveness of the Division's proposal is $208.16 per ton of methane and $8.33 per ton of CO2e.

III.B. Leak Detection and Repair Inspections at Newly Constructed Well Production Facilities: Regulation Number 7, Part D, Section II.E.4.e(ii)

Inspections

Currently, well production facilities conduct AIMM inspections at a frequency determined by their VOC emissions in accordance with Regulation Number 7, Part D, Sections I.L or II.E, as applicable. As production decreases, and resulting VOC emissions from storage tanks decrease, the inspection frequency also decreases. The Division's proposal would "freeze" newly constructed well production facilities at a monthly AIMM frequency. The Division's proposal would also provide for exceptions where operators are using specified design alternatives, *e.g.*, automated systems that are designed to minimize emissions from storage tanks and combustion devices.

Table 25 below identifies how many additional inspections would be required on average each year, for the first five years of a newly constructed well production facility's operation as a result of the Division's proposal, assuming every facility stays at the proposed monthly schedule.[81]

Table 25: AIMM Inspection Schedule by Area of State

Proposed AIMM Inspection Schedule in Years 1 - 5			
Year of Program	**Existing Regulation Frequency under Section II.E**		
	AIMM Frequency 8-hour Ozone Control Area (not Proximity to Occupied Area)	**AIMM Frequency Proximity to Occupied Area**	**AIMM Frequency ROS (not Proximity to Occupied Area)**
Year 1	Monthly	Monthly	Monthly
Year 2	Quarterly	Monthly	Quarterly
Year 3	Semi-annual	Quarterly	Semi-annual
Year 4	Semi-annual	Quarterly	Semi-annual

[81] The Division conducted an analysis of a small sample of wells spud in 2016 based upon COGCC data (for both inside and outside the 8-hour Ozone Control Area) and compared the year over year decrease in production. The Division then applied this decline rate to estimate how quickly a newly constructed well production facility would drop AIMM frequencies, assuming that in year 1 uncontrolled actual VOC emissions would be over 50 tpy.

Year 5	Annual (NAA)	One-time (ROS) Annual (NAA)	One-time (ROS)
Summary of New Upstream AIMM Inspections Required			
	AIMM Frequency 8-hour Ozone Control Area **(not Proximity to Occupied Area)**	**AIMM Frequency Proximity to Occupied Area**	**AIMM Frequency ROS (not Proximity to Occupied Area)**
Additional AIMM Inspections Through Year 5 Per Facility	39	27	40
Number of New Facilities per year	55	31	5
Average # of Total Inspections Required Each Year	**1,023**	**316**	**93**

The Division looked at COGCC data for 2020 to determine how many new facilities are constructed each year. The Division identified 91 new well sites (based upon unique location IDs) constructed in 2020 - 74 in the 8-hour Ozone Control Area and 17 outside the 8-hour Ozone Control Area.[82] Because current AIMM inspection tier is based upon proximity to an occupied area (see Section II.E, Table 3), the Division applied the percentage of population in a DI community both inside and outside the 8-hour Ozone Control Area to determine how many new well production facilities might be expected to be subject to the proximity requirements. Ultimately, the Division determined that each year, it was assumed that 31 new well production facilities would be constructed in proximity to an occupied area, 55 new well production facilities would be constructed in the 8-hour Ozone Control Area but not in proximity to an occupied area, and five new well production facilities would be constructed outside the 8-hour Ozone Control Area and not in proximity to an occupied area. In the Initial EIA, the Division's cost and emission estimates were based on new inspections at just the facilities added in the first year. In the Final EIA, the Division estimated costs and emission reductions assuming 91 new facilities with a monthly AIMM requirement are added each year through Year 5.

The Division took the same approach to estimate inspection time, inspection costs, and repair costs as with the midstream segment leak detection program for compressor stations. Table 26, below demonstrates the total inspection costs for years 1 through 5, based on the number of new inspections that will be required of new well production facilities in each year. The average annual inspection cost identified in the Division's Rebuttal EIA to all operators across the three areas is $1,828,256; however, in light of the Division's use of revised hours per inspection in relation to inspections of existing sites and an assumption that all inspections completed will use infrared and optical gas imaging technology, the Division in this Cost Benefit Analysis revised its estimate of hours per inspection in relation to this new site inspection program, resulting in a meaningfully lower total inspection cost of $570,742.01.

[82] The Division also reviewed data submitted through its APEN system, and also identified 91 APENs submitted for the first time in 2020, though the Division's data shows 59 new sites in the 9-county area and the remaining 32 sites outside the 9-county area.

Table 26: Average Annual Inspections and Inspection Cost		
Location of Site	Average # of New Inspections **Per Year**	Averaged **Annual Inspection Cost**
8-hour Ozone Control Area (not in proximity to Occupied Area)	1,023	$407,672.87
Proximity to Occupied Area	316	$126,007.98
ROS (not in proximity to Occupied Area)	93	$37,061.17

Leak Repair

In this analysis, the Division uses an average scaled monthly leak frequency rate of 2.36%, based on EPA data.[83] Using a similar approach as before to estimate component repair time and component repair cost, the Division estimates that a total of 19.93 repair hours per year per facility will be required to address leaks discovered by the new inspection requirements. Again using a repair cost rate of $82.06 per hour, total annual repair hours and costs under each AIMM frequency requirement are demonstrated in Table 27, below. The total average annual repair cost is estimated to be $257,093.65.

Table 27: LDAR Repairs - Years 1-5						
8-hour Ozone Control Area (not Proximity to Occupied Area)						
	Number of Affected Facilities, Total	Leak Rate (monthly)	Repair Hours per Facility	Total Repair Hours, all Facilities	Repair Cost per Hour	Total Repair Cost, all Facilities
Year 1	0	2.36%	19.93	0	$82.06	$0.00
Year 2	55	2.36%	19.93	1,096.15	$82.06	$89,950.07
Year 3	110	2.36%	19.93	2,192.30	$82.06	$179,900.14
Year 4	165	2.36%	19.93	3,288.45	$82.06	$269,850.21
Year 5	220	2.36%	19.93	4,384.60	$82.06	$359,800.28
Total over 5 years						**$899,500.69**
Average per year						**$179,900.14**

[83] Control Techniques Guidelines for the Oil and Natural Gas Industry 2016, EPA, p. 8-7.

Proximity to Occupied Area						
	Number of Affected Facilities, Total	Leak Rate (monthly)	Repair Hours per Facility	Total Repair Hours, all Facilities	Repair Cost per Hour	Total Repair Cost, all Facilities
Year 1	0	2.36%	19.93	0	$82.06	$0.00
Year 2	0	2.36%	19.93	0	$82.06	$0.00
Year 3	31	2.36%	19.93	617.83	$82.06	$50,699.13
Year 4	62	2.36%	19.93	1235.66	$82.06	$101,398.26
Year 5	93	2.36%	19.93	1853.49	$82.06	$152,097.39
Total over 5 years						**$304,194.78**
Average per year						**$60,838.96**
ROS (not Proximity to Occupied Area)						
	Number of Affected Facilities, Total	Leak Rate (monthly)	Repair Hours per Facility	Total Repair Hours, all Facilities	Repair Cost per Hour	Total Repair Cost, all Facilities
Year 1	0	2.36%	19.93	0	$82.06	$0.00
Year 2	5	2.36%	19.93	99.65	$82.06	$8,177.28
Year 3	10	2.36%	19.93	199.30	$82.06	$16,354.56
Year 4	15	2.36%	19.93	298.95	$82.06	$24,531.84
Year 5	20	2.36%	19.93	398.60	$82.06	$32,709.12
Total over 5 years						**$81,772.79**
Average per year						**$16,354.56**

Emission Reductions

The Division uses the same analysis here as the Commission did in 2014, 2017, and 2019 to estimate emission reductions from this program (using updated gas speciation data). The Division calculated emission reductions achieved in each area of the state, in each year of the program, based on the total number of facilities entering the program over five years. The Division calculated an average emission reduction achieved per facility, for VOC and methane. The Division then summed up the total emission reductions achieved over the first five years of the program and averaged it to create an annual emission reductions figure, as set forth in the table below.

Table 28: New WPF Monthly LDAR Emission Reductions by Year				
Year of **Program**	Number of Facilities in **Program**	VOC (tpy)	CH4 (tpy)	GHG (mtCO2e/yr)
1	91	0.00	0.00	0.00
2	182	59.04	57.48	1,460.06
3	273	172.83	180.53	4,585.62
4	364	345.67	361.06	9,171.25
5	455	752.19	802.32	20,379.87
Total		1,329.73	**1,401.38**	**35,596.81**
Annual Reductions, averaged over 5 years		**265.95**	**280.28**	**7,119.36**

Value of Natural Gas Recovered

In Table 29, the Division estimates the value of natural gas recovered from these additional leak inspections.

Table 29: Upstream Recovered Natural Gas Value from Leak Repairs		
Average Annual Recovered Methane (tpy)	Value of Natural Gas ($/ton methane)[84]	Total Annual Value of Recovered Natural Gas
280.28	$274.48	$76,929.81

Reporting

The Division's proposal also requires operators to submit information about leaks detected in their monthly reports under Section VI, for their air quality monitoring during preproduction and early production. This will enable the Division to better evaluate the capability of the air quality monitoring plan to detect leaks. The Division assumed no additional costs associated with this reporting, and no information to the contrary was provided by any party.

Cost Effectiveness

As noted before, the total cost of inspections across operators is estimated to be $570,742.01 per year, and the total cost of repairs across operators is estimated to be $257,093.65 per year. This results in a total annual net cost of $750,905.85, after gas recovery is taken into account.

[84] Based on the recent United States Natural Gas Industrial Price (May 2021), of $4.09/MCF as provided for by the U.S. Energy Information Administration, using an average molecular weight of 24.01 lb/lb-mol of natural gas and 47.08% statewide average of methane by weight.

As outlined in Table 30, the Division estimates an overall cost effectiveness of $2,823.52 per ton VOC and $105.47 per mtCO2e. Operators and industry parties to this rulemaking have not objected to this component of the Division's proposal.

Table 30: Upstream LDAR Total Annual Cost			
LDAR Total Annual Cost			
	Inspection	Repair	TOTAL
Annual Cost	$570,742.01	$257,093.65	$827,835.66
Recovered Natural Gas			-$76,929.81
Net Cost			**$750,905.85**
New WPF AIMM Emissions Reduction and Cost			
Total Annual VOC Emission Reduction (VOC)	Cost per ton VOC	Total Annual GHG Emission Reduction (mtCO2e/year)	Cost per mtCO2e
265.95	**$2,823.52**	7,119.36	**$105.47**

III.C. Greenhouse Gas Intensity for Preproduction Emissions and Production Emissions: Regulation Number 22, Part B, Section IV

The Division is proposing to establish a greenhouse gas intensity program for the upstream segment of the oil and gas industry. This program creates greenhouse gas emission intensity targets, determined on an operator-level basis. The GHG intensity value is a product of total GHG emissions divided by oil and gas throughput. The intensity program will cover preproduction emissions and production emissions.

Based on an analysis of emissions and production data reported to the EPA under the GHGRP, the Division determined that there is currently an extremely wide range of GHG intensities across upstream operators. The reports show operator GHG intensities across the industry that range from 3 to over 100. The Division also calculated GHG intensities based upon 2020 production reported to COGCC and the emissions reported to the Division pursuant to Regulation Number 7, Part D, Sections II.G and V, and found an even broader range of intensities. The Division determined that a GHG intensity program will result in meaningful reduction, while providing operators with the flexibility to identify and achieve cost-effective reductions across their facilities and operations.

To calculate the intensity targets in the proposed regulation, the Division started with the data for the 2005 baseline in the GHG Roadmap inventory for the oil and gas sector, and with the information in the 2015 baseline in the GHG Roadmap inventory for the Industrial sector.

The Division first used the 2005 baseline emissions for the O&G Sector from the GHG Roadmap, a total of 20,205,859 mtCO2e[85], and determined what portion of those emissions were attributable to upstream operations. The Division added up the venting and flaring emissions statewide, with the well production facility fugitive emissions statewide, with 84% of the total "catchall" emissions covering both the upstream and midstream segment.[86] The Division therefore calculated that the upstream baseline in 2005 was 15,184,909 mt CO2e. From there, the Division applied a 36% reduction for 2025, a 50% reduction for 2027, and a 60% reduction for 2030. As it pertains to the Industrial sector, the Division determined that the 2015 baseline for oil and gas emissions in the industrial sector was 2,690,692 mtCO2e, based upon a split of 44/56% (upstream/midstream) of the emissions associated with lease fuel consumption as reported to EPA, and attributing all the natural gas processing fuel consumption to midstream. Based on GHG Roadmap values, the Division also assumed all diesel emissions in the industrial segment from oil and gas activities were associated with upstream operations (880,000 mtCO2e in 2015). The Division assumed no emission reductions were required in 2025, a 10% reduction would be required by 2027, and a 20% reduction is required by 2030.

Using the production forecasts from the GHG Roadmap for both oil and natural gas, the Division calculated a projected total production in BOE (using 5800 scf/BOE) for 2025, 2027, and 2030. The Division then calculated an average intensity in the years 2025, 2027, and 2030 (using the emissions as determined in the preceding paragraph as the numerator and the production forecasts as the denominator). These intensities are shown in Table 31, below in the "Overall Upstream Intensity" column. The Division then calculated majority operator and minority operator targets. Majority operators were defined by production levels of 10,000,000 BOE in calendar year 2022; in 2020, the operators with this level of production represented over 80% of the total production in the state. The majority operator targets were calculated by multiplying the overall upstream intensity target by 70%; the operators with the largest production, and therefore the largest share of the emissions on a mass basis, should have more stringent intensity targets. The Division then multiplied the overall upstream intensity target by 2.2, to get the minority operator target.

Table 31: Calculated Intensities

Year	**Overall Upstream Intensity**	**Majority Operator Target**	Minority Operator Target
2005	80.3356		
2025	15.6329	10.94	34.39
2027	12.0906	8.46	26.60
2030	9.7186	6.80	21.38

From the 2005 baseline in the GHG Roadmap, the Division determined that the intensity program is an enforceable mechanism to ensure operators reduce GHG emissions from the upstream segment of the oil and gas industry in the following amounts:

[85] Updated from the Initial EIA.

[86] To generate an 84/16% split (upstream/midstream) of these catch-all emissions, the Division developed a ratio based on the emissions for covered equipment as reported to EPA under the GHGRP for upstream as compared to midstream gathering and boosting. The Division then applied that ratio to the catch-all emissions (but not the downstream catch-all). The same general approach was used to develop the 44/56% (upstream/midstream) split of lease fuel emissions.

Table 32: Total GHG Reductions Enforced By the Intensity Program	
Year	Total CO2e Reductions from 2020[87] (mtCO2e per year)
by 2025	4,510,867
by 2027	5,452,806
by 2030	6,128,866

These numbers in Table 32 include reductions achieved under other components of the Division proposal (e.g., well liquids unloading controls). These reductions are not expected as a result of the intensity program alone. In fact, these estimates assume that operators will take no steps over and above the emission reduction measures employed in the second half of 2020, and don't account for reductions better attributed to the following rules and requirements, without limitation:

- Additional storage tank controls adopted in late 2019;
- Requirements for storage tank measurement systems and truck liquids loadout adopted in late 2019;
- New reporting and permitting requirements for routine or predictable emissions (ROPE);
- Engine retrofits and reductions adopted in 2020;
- Preproduction flowback controls adopted in 2020;
- Non-emitting pneumatic controller requirements adopted in 2021;
- The impact of COGCC's new regulations, including Rules 303 and 903; or
- Any of the Division's direct regulation proposals in this rulemaking.

The Division's proposal also includes several additional provisions that act as guard-rails to ensure the upstream segment reduces emissions to meet the requirements of §25-7-105(1)(e)(XII), C.R.S. The Division has proposed an even more stringent intensity target for new well production facilities, at 78.5% of the majority operator target. The Division has also proposed a separate new facility intensity target for new well production facilities in the 8-hour Ozone Control Area located in a DI Community, at 10% lower than the baseline new facility intensity target. The Division worked with operators and the Environmental Justice Coalition on these lower targets for new facilities, and based on those conversations believes they are cost-effective and achievable. Operators have more opportunities to design new facilities to reduce the potential for emissions, through use of a tankless facility design, non-emitting pneumatics or other non-gas-driven sources of power (e.g. solar power, electrification), and new COGCC rules require gas capture and best management practices to reduce cumulative impacts. The Division has, as discussed in more detail in other sections of this Cost Benefit Analysis, proposed additional requirements for LDAR inspections and well maintenance emission reductions that - when taken together with the suite of regulations adopted by the Commission over the past several years (e.g., the 2021 pneumatics rule, the 2020 flowback control rule) and the COGCC mission change provisions - make up most of the reductions that the Division expects will achieve the intensity targets, and keep Colorado on track to meet its GHG goals. The Division's intensity program also includes recordkeeping and reporting, which the Division has treated as covered costs under the analysis above. The Division notes that at no point has any industry stakeholder or party raised the spectre of economic infeasibility with respect to the intensity program.

[87] Emission reductions calculated from the reported July - December 2020 emissions, rolled into yearlong emissions by multiplying reported emissions by 2, assuming 2020 production throughput in 2025, 2027, and 2030 with the required intensities applied to majority and minority operators.

Cost Effectiveness of Intensity

The costs associated with meeting GHG intensity targets will range widely across the industry. The EPA provides recommendations for technologies to reduce methane emissions.[88] There are multiple studies and presentations available to operators to find cost effective and technically feasible reductions at different types of well production facilities. The actual costs incurred by implementation of emission control technologies will depend on the amount of emissions that need to be reduced by each operator (at each facility), the technical feasibility of implementing available technologies, and the cost-effectiveness and economic feasibility of the technology. Some operators will make meaningful progress towards the intensity targets through compliance with existing and proposed Commission regulations (*e.g.*, the 2021 pneumatics rule, or this well unloading proposal). However, the Division has determined that the flexibility inherent in an intensity program renders this strategy cost-effective.

The Division reasons that costs associated with reaching intensity targets will be at least as cost effective as the cost effectiveness of direct regulations. In the February 2021 rulemaking on pneumatic controllers, the Final EIA estimated a cost per ton reduction for methane of $499/ton, which converts to $19.65 per metric ton CO2e. If that cost per ton is applied to the emission reductions guaranteed for 2025 by the intensity program - subtracting out the emission reductions in this proposal from other measures affecting the upstream segment - the Division calculates a total cost of $85,497,247.07. As set forth in more detail below, under EDF's analysis, the maximum potential program reliance on intensity to achieve the state's targets is 1,540,087 mtCO2e/year, which based on the Division's estimate of cost per ton described above, results in a maximum cost of the intensity program of $30,262,710 between 2025 and 2030 (no costs are anticipated between now and 2025, given EDF's analysis that existing regulatory requirements are sufficient to meet the state's 2025 targets, upon which the 2025 greenhouse gas intensity targets are based). Thus, the potential maximum cost of intensity ranges from $30,262,710 to $85,497,247. However, the Division does not believe that the intensity program will have anywhere near this level of cost, because so many of the emission reductions guaranteed by the program will result from direct regulations already adopted by the Commission, other permitting programs of the Air Division and the Colorado Oil and Gas Conservation Commission, and voluntary initiatives undertaken by the industry.

Some parties to the rulemaking proceeding, including EDF, presented evidence that current regulatory programs and provisions put the state on track to meet the state's 2025 greenhouse gas goals. These same parties note that meeting the 2030 greenhouse gas goals will necessitate additional reductions of 140,000 tons per year of methane. Assuming that analysis is correct, and accounting only for requirements part of the Division's November 23rd Rebuttal proposal, the Division calculated a potential maximum emission reduction from intensity of 55,003 tons per year of methane (1,540,087 mtCO2e/year). Even the maximum potential program reliance on intensity is conservatively high. First, EDF's estimate of how many tons of emission reductions is still necessary was based on a very conservative estimate of current regulatory programs achieving only 60% of necessary emissions. The Division believes the number is closer to 75-80%, if not higher.

[88] Recommended Technologies to Reduce Methane Emissions | US EPA

Second, because EDF's analysis did not, as the Division understands it, take into account the following additional reductions that the Division expects from either its Rebuttal proposal or other regulatory or voluntary programs in Colorado, without limitation:

- Emissions from "super emitters" or "abnormal operating conditions" at compressor stations;
- Emissions that will be reduced by the Division's proposals in Section II.H that require the use of electrical power for capture and recovery equipment;
- Emissions from improperly operating pneumatics addressed by the increased frequency of inspections in Section III.F of this Rebuttal proposal;
- Emission reductions from voluntary measures;
- Emission reductions from the COGCC mission change rulemaking, such as venting and flaring requirements, permitting provisions, or best management practices.

However, the Division is using (for this analysis) the 60% assumption as well as the undercounted emission reductions listed above as we lack quantifiable data related to the emissions reductions achieved through recent rulemaking activities. The emission reductions attributed to the other proposed regulatory requirements part of this rulemaking, along with the maximum potential program reliance on intensity, is presented in Table 33.

Table 33: Upstream Intensity Emission Reductions by 2030		
Proposed Program	Total Methane Reductions (mt/year)	Source of Emission Estimate
WPF LDAR	64,000	EDF
Pigging/blowdown	9,600	EDF
Rod packing	4,535	Division
Well unloading	4,378	Division
Performance testing	2,026	Division
Gas plant LDAR	188	Division
Compressor station LDAR	270	Division
TOTAL Achieved by 2030	**84,997 mt/year**	**2,379,913 mtCO2e/year**
Maximum Potential Program Reliance On Intensity		
TOTAL Needed to Meet Statutory Targets (per EDF)	**140,000 mt CH4/year**	**3,920,000 mtCO2e/year**
	55,003 mt CH4/year	**1,540,087 mtCO2e/year**

Based on EDF's analysis, the cost of the intensity program between adoption and 2025 would be $0, because the implication of EDF's analysis is that operators will meet their 2025 intensity targets by virtue of regulatory revisions already adopted by the Commission.[89]

Implementation of methane control technologies can result in realized benefits to operators associated with gas recovery. Gas that is reclaimed, rather than being vented to the atmosphere or combusted, can be sold. At a nominal gas price, operators could achieve significant additional revenue from the sale of reclaimed gas. Further, significant economic benefits for operators are derived from this GHG intensity program, because participation in an intensity program can qualify an operator for certification of its product as "green" or "responsibly sourced", thus allowing operators to charge a premium. In the Initial EIA, pursuant to § 25-7-110.5(4)(c), C.R.S., the Division - as staff to the Commission - requested additional information on the costs and other regulatory impacts of an intensity program. The Division received no information between the Initial EIA and the Final EIA.

III.D. Emission Reductions from Well Maintenance and Liquids Unloading Activities, Regulation Number 7, Part D, Section II.G

The Division's proposal would augment existing requirements for best practices to be employed during all well maintenance activities. The Division's proposal would also require the use of technology to minimize the need to conduct well unloading activities or would require the control of unloading emissions. Thus far in 2021, 22 operators have reported conducting well unloading events to the COGCC, and these 22 operators reported a total of 13,593 events by June 30, 2021.[90] Of these events 3,670 are in the 9-County area across 12 operators, while the remaining 9,923 events are outside the 9-County area, across 11 operators. The Division conducted an analysis of average scf of gas vented per event, and determined that there is a statewide average of 14,000 scf of natural gas emitted per well unloading event.[91] The Division analyzed data submitted with registrations for General Permit 11, as well as results from operators that used flow meters to directly measure the amount of gas emitted during well unloading.

III.D.1. Best Practices

Regulation Number 7, Part D, Section II.G has, for years, required operators to use best management practices when conducting well maintenance operations. The Division assumes no significant additional costs will be incurred as a result of the Division's proposal for the use of best practices other than artificial lift. The Division's proposal would require that all wells that undertake well liquids unloading activities install and use artificial lift to reduce emissions from those activities, subject to limited exceptions.

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[89] EDF_ALT_EX-001-004, p. 35.

[90] This is based upon data received by the Division from COGCC in early July 2021, and attached to the Division's Prehearing Statement. Based upon data reported to the Division directly from operators, over 40 operators identified conducting well maintenance events - such as well unloading or well swabbing - in their annual emission reports to the Division for 2020. This suggests that the number of events reported to the COGCC is low, because some operators may not have reported. The Division has not yet been able to determine which operators reporting events to the Division did not report to COGCC.

[91] Based upon studies of well unloading activities, this number is likely very conservative. *See* Allen et al., Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings, 2014.

Plunger Lift Systems

Plunger lift systems use well shut-in pressure build-ups to lift columns of liquid out of the well without the need to vent the gas to the atmosphere.[92] Plunger lifts have a significant economic benefit to the operator - boosting gas production. Automation can further enhance the performance of plunger lifts by monitoring wellhead parameters and thereby optimizing plunger operations.[93] The Division understands that even where the use of plunger lifts does not entirely avoid the need for unloading, the use of the plunger lift can reduce the volume of gas vented per well unloading event.
Natural Gas STAR materials estimate a savings of 500-600 Mcf/year for an average well requiring unloading. Smart automation controllers can also avoid the need for site visits associated with unloading activities, further reducing costs to operators. Maintenance costs are also reduced; plunger lifts can prevent particulate buildup inside the tubing, avoiding or reducing the need to conduct swabbing operations. Based upon information from EPA and other Natural Gas STAR materials, the Division estimates basic plunger lift installation costs of approximately $1900-$7800 (for this analysis, the Division used a median figure of $4,850). This figure includes installing the piping, valves, controller and power supply. Annual maintenance costs are estimated at $700-$1300 (the Division again used a median figure of $1,000), and smart automation controllers are estimated at $11,000 per controller. Assuming a life of 10 years for the plunger lift and smart automation controller, the annualized cost of a plunger lift system is $3,838.

Natural Gas STAR partners have also reported benefits of up to 18,250 Mcf per well in increased gas production. The Division estimated revenue from avoided emissions by calculating the market value of the gas by the volume of avoided emissions. The Division's analysis suggests a conservative average of 14,000 scf per well unloading event. The Division does not have data on how many events are, or could be, entirely avoided - instead of just minimized - through the use of plunger lifts. The Division does, however, understand that most wells in the state that require unloading already employ plunger lifts.

However, assuming that at wells where plunger lift is not currently installed it is installed, and that plunger lifts are installed on new wells as they begin to require unloading, the Division's proposal will achieve emission reductions using a technology that is already widely deployed here in Colorado, with limited additional costs (the cost increase from using smart automation as compared to a regular plunger lift control is negligible). Assuming that plunger lifts would completely avoid the emissions from ⅛ of future unloading events, and assuming those occur on the same frequency as they did in early 2021), the Division's proposal would reduce 389.24 tpy VOC and 17,961.80 tpy CO_2e just from unloading events avoided, with a cost per ton reduced of $10 per ton VOC, $6 per ton methane, and a negligible cost (<$1/ton) for reductions of CO_2e.

III.D.2. Well Unloading Emission Reductions

Under the Division's proposal, operators will be required to capture and recover emissions from well liquids unloading or use air pollution control equipment to combust the hydrocarbons emitted during liquids unloading. Well swabbing is included in these calculations as well swabbing is essentially well liquids unloading that requires the use of a specialized rig (a "swabbing rig").

[92] *Liquids Unloading Options for Natural Gas Wells*, 2012 Natural Gas STAR Annual Implementation Workshop, April 12, 2012.
[93] *Lessons Learned from Natural Gas STAR Partners: Installing Plunger Lift Systems in Gas Wells*, EPA, October 2006.

Control Equipment

The Division's proposal would require the capture or control of emissions from unloading through the use of control equipment. In the Initial EIA, the Division assumed that operators would use a temporary open flare to control emissions during well unloading. The Division assumed that operators would have to rent an open flare for each unloading event. This resulted in a high cost that was adjusted in the Final EIA.

After multiple discussions, the Division now understands that operators will likely comply by purchasing open flares. Then, depending on whether the site configuration has room for a dedicated flare, the operator will either install a dedicated flare or will purchase a portable flare and use it at multiple sites. The Division, therefore, assumed that operators will purchase and operate a flare at each well production facility where unloading controls will be required. While some operators may use a portable flare, which could result in higher annual operating costs (travel, etc.), fewer open flares will need to be purchased, which lowers capital costs. The Division believes its cost analysis therefore remains conservative. Based on COGCC data on the frequency of well unloadings, the Division's proposal would require controls at 526 well production facilities.

To estimate emission reductions, the Division analyzed over 100 samples of gas composition of sales gas, across the DJ Basin, Piceance Basin and the eastern plains. From this data, the Division derived a statewide average gas composition in Table 34. From this gas composition, and using the calculated average scf/event described above, the Division calculated an estimated average lb/event for the following pollutants, broken out by region of the state. The Division also calculated emission reductions assuming a statewide average lb/event, which is in the Division's Rebuttal_Final_EIA and copied below, but presented here are the emission reductions assuming the same proportion of well unloading events occur in the Piceance Basin in the future (⅔ events in the Piceance, ⅓ events in the front range). In the Division's Final EIA, the Division used a statewide average VOC and methane lb/event factor in calculating emissions. In its Prehearing Statement, the JIWG questioned why the Division would not use basin-specific factors where it had the data. The Division believes use of a statewide average is appropriate, but for the Rebuttal Statement, the Division conducted an alternative analysis, updating the calculations for emission amounts, reductions, and cost/ton amounts associated with well unloading. Recognizing the differences in gas compositions and unloading frequencies between DJ Basin and the Piceance Basin, the Division revised the calculations that previously assumed a statewide gas composition and statewide lb/event emission factor, to instead assume emitted gas compositions specific to the two major basins. Given that more unloading events happen in the Piceance than in the DJ Basin, and that Piceance gas has a higher composition of methane and a lower composition of VOC, this alternative analysis results in a decreased VOC emissions benefit but an increased GHG emissions benefit. Assuming 95% control of emissions from well unloading results in a reduction of 1,023.71 tpy VOC and 122,595.94 mt/yr CO_2e (CO_2e reductions only look at methane reductions and would be significantly higher if the Division took into account the global warming potential of ethane).

Table 34: Well Unloading Emissions Data			
Well Unloading	**wt%**	**DJ Basin (lb/event)**	**Piceance (lb/event)**
Methane	53.31%	421.5	516.9
VOC (NMNE)	29.35%	237.5	64.9

Assuming 95% reduction in emissions from well unloading results in a reduction of 2,234.84 tpy VOC and 103,128.16 mtCO2e/yr (calculated only by looking at methane reductions; this number would be significantly higher if the Division took into account the global warming potential of ethane). The Division did not have data on the annual maintenance and operating cost associated with a dedicated open flare. Cost estimates for enclosed combustion devices in previous rulemakings have used a significantly lower annualized maintenance cost; in 2019, the Division assumed just under $3,000 per year for annual maintenance of a flare. Here, the Division attempted to use EPA's cost calculator and derived a higher capital expenditure. In the Initial EIA, the Division - as staff to the Commission - requested information from stakeholders to inform the costs associated with this proposal. The Division did not receive cost information from stakeholders, and continued to use EPA's cost calculator to generate updated conservative cost estimates for the open flares. To be conservative, the Division evaluated this proposal using two different annual maintenance costs; the Division received no information to suggest that the Division's $10k annual maintenance cost was unreasonable. The Division estimates the cost effectiveness of control as set forth below in Tables 35 and 36. Table 35 estimates the cost effectiveness assuming a statewide average lb/event VOC and CH4, while Table 36 uses basin-specific lb/event figures.

Table 35: Well Unloading Control - Emissions and Cost Effectiveness Statewide Average lb/event					
Cost Effectiveness at $10K Annual Maintenance					
Well Site Description	Total VOC Reduced (tpy)	Total CO2e Reduced (mtCO2e/yr)	Annualized Cost at $10K Annual Maintenance	VOC Cost ($/ton)	CO2e Cost ($/ton)
Inside DI Community: **≥6 unloadings per facility**	685.17	31,617.85	$4,512,086.27	$6,585.31	$142.71
Outside of DI Community: **At least 1 well w/ ≥6 unloadings per well**	1,379.59	63,661.97	$7,328,141.06	$5,311.84	$115.11
Outside of DI Community: **≥10 unloadings per facility (Not including those with 1 well ≥6 unloadings per well)**	170.08	7,848.34	$1,443,968.68		
TOTAL	2,234.84	103,128.16	$13,284,196.01		
Average Total Cost Per Ton				$5,944.14	$128.81

Cost Effectiveness at $50K Annual Maintenance					
Well Site Description	Total VOC Reduced (tpy)	Total CO2e Reduced (mtCO2e/yr)	Annualized Cost at $50K Annual **Maintenance**	VOC Cost **($/ton)**	CO2e Cost **($/ton)**
Inside DI Community: **≥6 unloadings per facility**	685.17	31,617.85	$11,654,586.27	$17,009.66	$368.61
Outside of DI Community: **At least 1 well w/ ≥6 unloadings per well**	1,379.59	63,661.97	$18,928,373.06	$13,720.33	$297.33
Outside of DI Community: **≥10 unloadings per facility (Not including those with 1 well ≥6 unloadings per well)**	170.08	7,848.34	$3,729,728.68	$21,929.59	$475.23
TOTAL	2,234.84	103,128.16	$34,312,688.01		
Average Total Cost Per Ton				**$15,353.55**	$332.72

Table 36: Well Unloading Control - Emissions and Cost Effectiveness Basin-Specific lb/event					
Cost Effectiveness at $10K Annual Maintenance					
Well Site Description	Total VOC Reduced (tpy)	Total CO2e Reduced (mtCO2e/yr)	Annualized Cost at $10K Annual Maintenance	VOC Cost ($/ton)	CO2e Cost ($/ton)
Inside DI Community: ≥6 unloadings per facility	313.86	37,586.44	$4,512,086.27	$14,376.30	$120.05
Outside of DI Community: At least 1 well w/ ≥6 unloadings per well	631.94	75,679.61	$7,328,141.06	$11,596.20	$96.83
Outside of DI Community: ≥10 unloadings per facility (Not including those with 1 well ≥6 unloadings per well)	77.91	9,329.90	$1,443,968.68	$18,534.54	$154.77
TOTAL	1,023.71	122,595.94	$13,284,196.01		
Average Total Cost Per Ton				$12,976.57	$108.36

Cost Effectiveness at $50K Annual Maintenance					
Well Site Description	**Total VOC Reduced (tpy)**	**Total CO2e Reduced (mtCO2e/yr)**	**Annualized Cost at $50K Annual Maintenance**	**VOC Cost ($/ton)**	**CO2e Cost ($/ton)**
Inside DI Community: ≥6 unloadings per facility	313.86	37,586.44	$11,654,586.27	$37,133.56	$310.07
Outside of DI Community: At least 1 well w/ ≥6 unloadings per well	631.94	75,679.61	$18,928,373.06	$29,952.65	$250.11
Outside of DI Community: ≥10 unloadings per facility (Not including those with 1 well ≥6 unloadings per well)	77.91	9,329.90	$3,729,728.68	$47,874.18	$399.76
TOTAL	1,023.71	122,595.94	$34,312,688.01		
Average Total Cost Per Ton				$33,518.11	$279.88

Based on the COGCC data, the Division's proposal would require capture or control at approximately 29% of well production facilities with unloadings and would cover 75.5% of the total unloading events at very cost-effective.

III.F. Pneumatic Controller Inspections: Regulation Number 7, Part D, Section III.F.2.f.

To align with the new leak detection and repair frequencies for well production facilities, the Division has proposed to update the inspection frequency for pneumatic controllers to match. The proposed revisions build upon the statewide LDAR program in Regulation Number 7 and the Division assumes that owners or operators will incorporate the pneumatic controller inspections into their natural gas compressor station LDAR programs. The Division understands that operators will inspect the gas-driven pneumatic controllers during the same inspection as the Section II.E component inspections, and therefore has determined there are minimal, if any, additional inspection and recordkeeping costs. According to the Final Economic Impact Analysis for the December 2019 rulemaking, the incremental labor and material costs, costs above those related to the aligned LDAR inspection, are variable and range from insignificant to $600 per facility per year.[94]

[94] Revisions to Regulation Numbers 3 and 7, December 16-19. 2019, APCD_Final_EIA, pp.29-30.

IV. Annual Emissions Inventory Reporting Updates

The Division's proposal also includes updates to Regulation Number 7, Part D requirements for annual emissions inventory reports. The majority of these updates have no associated additional cost and are absorbable costs associated with the existing requirements to prepare and submit annual emission inventory reports. However, the Division is proposing that owners and operators who choose not to use Division-approved default emission factors, and who choose to use site-specific emission factors, must undertake periodic sampling analyses - every three years - to verify the efficacy of those factors on an ongoing basis. These are avoidable costs, because operators may use state default factors.

The Division has nonetheless estimated the costs of sampling. For this Initial EIA, the Division assumes that fifty percent (50%) of sources will use the state default factors and that fifty percent (50%) will use site-specific factors and therefore be subject to the periodic sampling requirements. As noted above, the Division has determined there are 5,808 storage tank batteries statewide, and therefore assumes that operators will conduct periodic sampling at 2,904 locations. The Division assumes that each sampling event will require two samples - one sample of sales gas and one sample of tank vapors.

All composition analyses are assumed to be completed by a third party-testing company. Based upon information provided by operators, the Division estimates an average cost per sample of $535. The Division assumes that two samples will be required per tank battery, for a per-tank battery cost, every five years, of $1,070, which the Division believes is absorbable by operators. Assuming every tank battery in the state chooses to use a site-specific emission factor and therefore must conduct this sampling, the Division estimates an annualized cost (across a 5-year sampling period) of $1,663,297. If fifty percent of tank batteries choose the site-specific option, the annualized cost is $831,648.

Pursuant to § 25-7-110.5(4)(c), C.R.S., the Division requested additional information on the costs and other regulatory impacts on these and any other potentially impacted supporting businesses or industrial sectors. Aside from the information discussed in this Cost Benefit Analysis, the Division did not receive additional information.

V. Summary of Costs to Businesses

The Division has determined that there may be costs related to the proposed revisions potentially impacting owner or operators of oil and gas operations including costs related to additional LDAR inspections, responsive actions, recordkeeping, and reporting; costs related to improving performance of air pollution control equipment; costs related to reducing other greenhouse gas emissions, as well as associated recordkeeping and reporting.

V.A. Summary of Cost Analyses

The Division projects that the Commission's regulations, as modified by this proposal, will reduce greenhouse gas emissions (in CO2e) by approximately 4,878,765 mtCO2e per year[95] at a cost range of approximately $58,230,645 to $141,037,270 per year.

[95] Note that the overall emission reductions changed minimally from the Final EIA, as upstream emission reductions, now also including those from this updated proposal, are accounted for in the intensity program estimate in Table 32.

The overall cost effectiveness for the entire package is between $28.91 and $87.61 per metric ton of CO2e reduced (and the social cost of greenhouse gas as set forth in the Final EIA is $82.95, reflecting a significant benefit to Colorado and the climate through this program).

The Division also estimates its proposal will reduce at least 13,261 tpy of VOC, not including VOC reduced by the intensity program (even though this program will certainly reduce VOC emissions as well). This results in an overall cost effectiveness for this package of between $4,390.98 and $10,635.16 per ton of VOC reduced. The proposal will also have additional unquantified emission benefits through reductions of ethane (which has a significant global warming potential and ozone benefits) and hazardous air pollutants such as benzene.

Based on this analysis, the Division believes the current rule proposal is cost effective. The Division has provided an estimate of costs based on reasonably available information and will consider any additional information provided by stakeholders.

Cost to General Public

The Division additionally assessed whether any of the proposed programs would impose any direct costs on the general public, and determined that based on available data, there will be no direct costs to the general public for any of the programs. The proposal will result in a net benefit for the public based on the social cost of carbon.

I. Social Cost of Greenhouse Gas Analysis

The "social cost of carbon" is a measure of the economic harm from those impacts, expressed as the dollar value of the total damages from emitting one ton of carbon dioxide into the atmosphere. HB 21-1266 states "for a rule that implements § 25-7-105(1)(e) that may materially affect greenhouse gas emissions, the economic impact analysis required by this subsection (4) must include an analysis of the social cost of greenhouse gases related to the estimated emission reductions from the proposed rule." Pursuant to HB 21-1266, this analysis uses the social cost of greenhouse gas estimates, using a 2.5 percent discount rate, provided by the Federal Interagency Working Group on the Social Cost of Greenhouse Gases, pursuant to Federal Executive Order 13990.[96] It is important to note that the social cost of greenhouse gases increases over time, to account for projected increases in the incremental damages and resulting economic impacts of climate change in the future. Table 37 below presents the estimated social benefits of emissions reductions that will result from this proposal from 2023 to 2030. Emission reductions are expected to begin being achieved in 2023. The estimated benefits are discounted to present (2021) dollars using the same discount rate of 2.5 percent.

[96] Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (Feb. 2021)), 5-6, Tables ES-1, ES2, and ES3.

Table 37: Social Cost of Greenhouse Gases				
Year	Social Cost of Carbon ($/mtCO2e)	Emission Reductions (mtCO2e)	Social Benefit	Present Value (2021 $)
2023	$80.34	530,912.98	$42,653,018.02	$40,597,756.59
2024	$81.65	530,912.98	$43,346,390.37	$40,251,432.56
2025	$82.95	4,510,867.00[97]	$374,180,928.52	$338,989,453.46
2026	$84.26	4,510,867.00	$380,072,120.82	$335,928,373.59
2027	$85.56	5,452,806.00	$466,558,439.78	$402,311,880.41
2028	$86.87	5,452,806.00	$473,679,804.41	$398,490,352.01
2029	$88.18	5,452,806.00	$480,801,169.05	$394,615,910.74
2030	$89.48	6,128,866.00	$548,417,058.55	$439,133,092.86

Table 37 presents expected annual emission reductions through 2030. The annual emission reductions are multiplied by the social cost of carbon in each respective year to determine a monetized value of the stream of future damages produced by emissions in each year. As these emissions are being reduced, however, this value also represents the monetized benefit to society of a decrease in emissions and avoided future damages. As the social cost of greenhouse gas increases in each respective year, so does the resulting economic benefit to society. Because the social benefit estimate in each year is from the respective year's perspective, the estimated social benefit in each future year is then discounted to present (2021) dollars in order to account for inflation and understand the value of future benefits from today's perspective.

As Table 38 demonstrates, the benefits to society of avoided damages from greenhouse gas emissions are significant. Table 38 below incorporates both the total estimated annual costs (in present, 2021 dollars) and total estimated annual social benefits (in present, 2021 dollars) to determine a net present value in each respective year. The Division anticipates that after 2024, the benefits to society from reducing emissions far outweigh the costs to operators in achieving the reductions. It is important to note, however, that the scope of the realized benefits is not limited to the areas most impacted by the proposed rules, nor only the State of Colorado, but rather, society as a whole. Looking at years 2023 to 2030, the total net present value is estimated to be $1,662,859,483.52; all a benefit to society.

[97] The Division, again, believes that the majority of these reductions will be achieved earlier. However, the Division - for purposes of this EIA - has calculated social cost of greenhouse gas based upon an analysis that assumes the intensity program will ensure these reductions are achieved in 2025-2030.

Table 38: Net Benefits to Society				
Year	Emission Reductions (mtCO2e)	Present Value of Costs (2021 $)	Present Value of Benefits (2021 $)	Net Present Value (2021 $)
2023	530,912.98	$39,479,989.20	$40,597,756.59	$1,117,767.39
2024	530,912.98	$38,517,062.64	$40,251,432.56	$1,734,369.93
2025	4,510,867.00	$115,033,908.20	$338,989,453.46	$223,955,545.27
2026	4,510,867.00	$112,228,203.12	$335,928,373.59	$223,700,170.47
2027	5,452,806.00	$109,490,929.87	$402,311,880.41	$292,820,950.54
2028	5,452,806.00	$106,820,419.39	$398,490,352.01	$291,669,932.63
2029	5,452,806.00	$104,215,043.30	$394,615,910.74	$290,400,867.44
2030	6,128,866.00	$101,673,212.98	$439,133,092.86	$337,459,879.88

4. Any adverse effects on the economy, consumers, private markets, small businesses, job creation, and economic competitiveness; and

The oil and gas industry plays an important role in Colorado's economy. The industry is a significant employer of highly skilled and well-paid employees. It produces valuable domestic resources that help keep prices low while adding to national stability and security. At the same time, emissions from the oil and gas industry represent a significant portion of the total GHG emissions both in the nonattainment area and throughout the rest of the state. The Division's proposal is intended to achieve significant reductions in air emissions without imposing unreasonable costs that could stifle economic activity. Further, the Division is already aware that some of its proposals are likely to result in a boon to Colorado's economy from oil and gas related service providers. The Division's proposal will result in an increase in high-paying positions related to performance testing of combustion devices. The Division's proposal is also likely to result in more leak inspection technology companies coming to Colorado and hiring here. The Division has heard from other companies that develop gas recovery technology that they are considering opening service centers in Colorado. These additional service providers will not only bring good jobs to Colorado, but they will enhance Colorado's reputation as a leader in oil and gas development and technology.

As discussed above, the Division's proposal is projected to result in a total annual cost to industry of between $58,230,645 to $141,037,270. As with any increase in costs, the costs associated with the Division's proposal could have some adverse impact on economic activity associated with the oil and gas industry in Colorado. However, over the past decade Colorado's oil and gas industry has experienced unprecedented growth, even as Colorado has enacted regulatory measures to ensure that development continues in a protective and responsible manner. Moreover, given the relative size of the costs of the current proposal to the overall size of the industry, the total impact of these costs will likely be minimal.

The Division's proposal is unlikely to have any appreciable negative impact on the economic competitiveness of the industry as a whole. In fact, with the Division's proposed intensity program, the Division believes that its proposal is likely to improve the competitiveness of Colorado's oil and gas industry, because its operators will be well situated to participate in responsibly-source-gas programs and certifications.

While it is unlikely that the costs associated with the proposed revisions will have any meaningfully adverse impacts on the competitiveness of the industry as a whole in Colorado, the costs could incrementally add to the current costs associated with operating marginally producing wells. This could potentially lead to some wells being shut in and the resultant economic consequences of these shut-ins including lost production revenue, lost royalties, lost severance taxes and potentially lost jobs. However, the Division has carefully structured its proposal to impose the largest costs on the larger, higher-producing sites and facilities (*e.g.* more frequent leak inspections at the larger sites), and, through the intensity program, providing operators with the flexibility to determine whether and what additional emission reductions measures are cost-effective.

Finally, it does not appear that the costs associated with the Division's proposal will have any meaningful impact on the general public or small businesses that purchase natural gas and other petroleum products. Oil and natural gas are sold on international and national markets, making it extremely unlikely that any increase in production costs in Colorado will be reflected in prices for Colorado consumers.

5. At least two alternatives to the proposed rule or amendment that can be identified by the submitting agency or a member of the public, including the costs and benefits of pursuing each of the alternatives identified.

No Action Alternative

If the Commission declines to adopt the proposal, the potential emission reductions achievable under the proposed requirements are unlikely to occur. The legislature has acknowledged that climate change impacts Colorado's economy and directed that GHG emissions should be reduced across the many sectors of our economy. Colorado has established specific GHG reduction goals. If Colorado does not adopt the proposed rule, other strategies would need to be identified to meet the statutory directives set forth in Sections 25-7-102(2)(g) and -105(e)(1), C.R.S., established by HB 19-1261 and HB 21-1266. The no action alternative could also result in other negative consequences, related to ozone attainment (i.e. this proposal meaningfully reduces VOC emissions, an ozone precursor), litigation costs (if the state fails to comply with statutory obligations), and, most importantly, health and environmental impacts on Colorado residents, and in particular, residents of disproportionately impacted communities.

EDF and Conservation Groups Alt Proposal

On October 28, 2021, parties - including the Environmental Defense Fund and the Conservation Groups - submitted an alternate proposal with two components: 1) monthly leak detection at all well production facilities and natural gas compressor stations statewide; and 2) a complete phase-out of gas-driven pneumatic controllers. These parties filed materials (see EDF_ALT_Initial EIA.pdf, attached hereto) suggesting that these proposals, taken together, would reduce between 156,000 to 165,000 tons per year of methane by 2030.

These parties also estimated a potential cost of up to $135,030,593, over and above the Division's proposal (EDF's proposal was additional to the Division's proposal, not "instead of"). While EDF's alternate proposal certainly would have resulted in additional, beneficial emission reductions, the Division determined that a scaled back leak inspection frequency (as proposed by the Division on November 23, 2021) would achieve the majority of the reductions from leak detection at a fraction of the cost.

The Division has in good faith developed this Cost-Benefit Analysis that complies with all requirements of 24-4-103(2.5), C.R.S.

Revised Final Economic Impact Analysis

Per § 25-7-110.5(4)(c), C.R.S.
Proposed AQCC Regulation Number 7, Part D, Sections II and III
Proposed AQCC Regulation Number 22, Part B, Sections III and IV
November 23, 2021
Before the Air Quality Control Commission
Rulemaking Hearing, December 14 - 17, 2021

INTRODUCTION

The Division is proposing revisions to Regulation Numbers 7 and 22 that continue to address the directives in § 25-7-109, C.R.S., as revised by Senate Bill (SB) 19-181 (Concerning Additional Public Welfare Protections Regarding the Conduct of Oil and Gas Operations). These revisions will also address the requirements established in SB 19-096 (Concerning the collection of greenhouse gas (GHG) emissions data), House Bill (HB) 19-1261 (Concerning the reduction of GHG pollution), and recent HB 21-1266 (Environmental Justice, Disproportionately Impacted Communities).

The oil and gas (O&G) industry is a large source of GHG emissions, and the largest anthropogenic source of methane in Colorado. The state GHG Pollution Reduction Roadmap (the GHG Roadmap) identifies sectors and their associated emissions to aid the state in establishing regulatory provisions to achieve the statutory GHG emissions reductions goals. In October 2020, the Commission further refined the state's goals for certain sectors, establishing a goal for the O&G Sector of the GHG Roadmap of 36% reduction by 2025 and 60% reduction by 2030. The Commission established a target for the O&G Sector of 13 million metric tons (MMT) CO_2e by 2025 and 8 MMT CO_2e by 2030. Commission targets for the sector including residential, commercial, and industrial combustion emissions (RCI Sector) include a 20% reduction from 2005 numbers by 2030. HB 21-1266 memorializes percentage reduction goals for the Industrial Sector in statute, and provides additional requirements for the rulemakings to achieve these goals.

To address these directives, the Division is proposing revisions to Regulation Numbers 7 and 22 that: limit emissions from the upstream and midstream segments of the oil and gas industry as identified in the GHG Roadmap through a combination of direct regulations and performance based programs; require increased monitoring and leak detection and repair (LDAR) inspections; achieve reductions of GHG and co-pollutants in disproportionately impacted (DI) communities; and impose additional best management practices and performance testing schedules to ensure the efficacy of air pollution control equipment, specifically enclosed combustion devices (ECDs). These revisions to Regulation Numbers 7 and 22 are primarily proposed on a state-wide and state-only basis; however there is one revision proposed to the State Implementation Plan, which is discussed in Section I.F. of this Final EIA.

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REQUIREMENTS FOR ECONOMIC IMPACT ANALYSIS (EIA)

Section 25-7-110.5(4)(a), C.R.S., sets forth the requirements for the initial and final EIA, as stated below:

> Before any permanent rule is proposed pursuant to this section, an initial economic impact analysis shall be conducted in compliance with this subsection (4) of the proposed rule or alternative proposed rules. Such economic impact analysis shall be in writing, developed by the proponent, or the Division in cooperation with the proponent and made available to the public at the time any request for hearing on a proposed rule is heard by the Commission. A final economic impact analysis shall be in writing and delivered to the technical secretary and to all parties of record five working days prior to the prehearing conference. If no prehearing conference is scheduled, the economic impact analysis shall be submitted at least ten working days before the date of the rule-making hearing. The proponent of an alternative proposal will provide, in conjunction with the Division, a final economic impact analysis five working days prior to the prehearing conference. The economic impact analyses shall be based upon reasonably available data. Except where data is not reasonably available, or as otherwise provided in this section, the failure to provide an economic impact analysis of any noticed proposed rule or any alternative proposed rule will preclude such proposed rule or alternative proposed rule from being considered by the Commission. Nothing in this section shall be construed to restrict the Commission's authority to consider alternative proposals and alternative economic impact analyses that have not been submitted prior to the prehearing conference for good cause and so long as parties have adequate time to review them.

Section 25-7-110.5(4)(c), C.R.S., further provides that:

> The proponent and the Division shall select one or more of the following economic impact analyses. The Commission may ask affected industry to submit information with regard to the cost of compliance with the proposed rule, and, if it is not provided, it shall not be considered reasonably available. The economic impact analysis required by this subsection (4) shall be based upon reasonably available data…

For the purposes of this Final Economic Impact Analysis the Division has chosen to use the methodology set forth in § 25-7-110.5(4)(c)(I), C.R.S.

Additionally: Section 25-7-110.5(4)(f), C.R.S., states:

> For a rule that implements section 25-7-105(1)(e) that may materially affect greenhouse gas emissions, the economic impact analysis required by this subsection (4) must include an analysis of the social cost of greenhouse gases related to the estimated emission reductions from the proposed rule. The analysis must use the most recent assessment of the social cost for those greenhouse gases for which the federal government has determined the cost, and the consideration of the social cost of greenhouse gases must be consistent with existing law

and include use of a discount rate of no more than two and one-half percent; except that the social cost of greenhouse gases that is used may not be lower than that established in 2016, using a two and one-half percent discount rate, by the federal interagency working group on the social cost of carbon or than the final social cost of greenhouse gases, using a two and one-half percent or lower effective discount rate, established by the federal interagency working group on the social cost of greenhouse gases pursuant to federal executive order 13990, dated January 20, 2021, whichever is higher.

For the purposes of the Final Economic Impact Analysis, the Division conducts an analysis of the social cost of greenhouse gas using a two and one-half percent (2.5%) discount rate.

INDUSTRY-WIDE BENEFITS

Many of the proposed revisions are designed to require or incentivize best management practices at oil and gas operations. This benefits Colorado-based energy companies in the current marketplace, in which end users increasingly demand sustainable energy. A recent study of industry-wide efforts in this transitional space has identified twenty non-regulatory initiatives related to emissions reductions applicable to the oil and gas industry, in four different categories: certification programs, company-specific commitments, guidelines, and ratings based on "environmental, social, governance" (ESG) factors.[1]

Such efforts include ONEFUTURE, a membership of over forty-five natural gas companies working to reduce methane emissions from the sector to 1% or less. The ONEFUTURE coalition represents more than 15% of the natural gas value chain, and numerous Colorado operators are members. Another example is the effort led by MiQ, developed by the Rocky Mountain Institute and SystemIQ Ltd., which proposes a "globally-applicable certification system [that] enables all oil and gas producers to be assessed according to the same universal standard."[2] These standards provide a metric by which "responsibly-sourced gas" can be a driving market factor, and - when combined with the value of the gas recovered through use of these practices and controls - can off-set increases in the cost associated with the production of that gas. These economic benefits are challenging to measure in the context of a particular regulatory proposal. However, looking at the MiQ standard, which relies on three pillars (methane intensity, company culture, and monitoring programs[3]), Colorado's regulatory program ensures that Colorado operators should easily qualify for the most rigorous MiQ certification. Leaving Colorado operators primed to reap the maximum economic benefit from the new consumer demand for sustainable energy sources.

These rules also ensure more recovery of natural gas - a salable product. By June 2021, the price of natural gas had increased over 50% from the 2020 average, according to Henry Hub pricing; and on August 10, the U.S. Energy Information Administration raised its forecast for third-quarter 2021 natural gas prices to $3.71/MMBtu (or $3.80/MCF).[4] The Division has attempted to account for the economic benefits of additional gas recovery from some of the proposed revisions, but generally notes that collectively, as a whole, there is a significant economic benefit to industry - and royalty owners - from

[1] *An Overview of Voluntary Emissions Reduction Initiatives for Responsibly Sourced Oil and Gas*, Highwood Emissions Management, May 2021.
[2] Why certification?, MIQ
[3] The Standard, MIQ
[4] Short-Term Energy Outlook - US Energy Information Administration; Natural Gas Price Forecast: 2021, 2022 and Long Term to 2050 - knoema.com

innovative regulatory programs designed to minimize the loss of natural gas during the production process.

COST-EFFECTIVENESS ANALYSIS

The Division's assessment of the costs associated with each of the proposed revisions is set forth below. A cost-effectiveness methodology is employed that identifies cumulative costs for the affected industry, costs for the Division, the estimated air pollution reduction, the projected cost per unit of air pollution reduced, and the resulting social benefit per unit of air pollution reduced. The primary driver of the Division's proposal is the direction and need to reduce greenhouse gas emissions from the oil and gas industry. However, where the Division had information, the Division also attempted to quantify reductions in co-pollutants, such as volatile organic compounds (VOC) that would be realized by these proposals.

The Division additionally assessed whether any of the proposed programs would impose any direct costs on the general public, and determined that based on available data, there will be no direct costs to the general public for any of the programs.

I. Better Performance of Air Pollution Control Equipment

The Division is proposing regulations to optimize and verify performance of air pollution control equipment. This proposal includes:

- Increased monitoring requirements for some air pollution control equipment;
- Use of flow meters; and
- Performance testing of enclosed combustion devices.

Currently, Commission regulations, including Regulation Number 7, Part D, Section II, require reductions in hydrocarbon emissions of at least 95% through the use of air pollution control equipment, including enclosed combustion devices ("ECDs" or "combustion devices"). The Division is proposing the addition of new inspection, maintenance, and performance monitoring requirements of air pollution control equipment in order to ensure that air pollution control equipment is meeting performance efficiency standards.

Based upon operator reported data for 2017 and analysis done by the Division for the Commission's December 2019 Regulation Number 7 rulemaking, the Division identified 4,573 storage tank batteries statewide that are subject to the control requirements of Section II.C (i.e., have emissions greater than 2 tpy VOC). The Division undertook an analysis to determine the average number of combustion devices per tank battery. The Division conducted inspections of 3,312 unique storage tank batteries and identified 5,943 enclosed combustion devices, for an average of 1.79 ECDs per tank battery. For purposes of this analysis, the Division assumed an average of 2 ECDs per storage tank battery, for a total of 9,146 storage tank ECDs as part of this program.

These requirements would also apply to midstream operations. The Division has identified 205[5] compressor stations. Of the 205 compressor stations, 59 are in the 9-County area[6] and 146 are outside the 9-County area. Information provided by operators suggests an average of 1 ECD at a compressor station outside the 8-hour Ozone Control Area and 2 ECDs at a compressor station inside the 8-hour Ozone Control Area. Therefore, the Division determined that there are an additional 264 ECDs to be tested at compressor stations as part of this program.

Using Division APEN and permitting data, as well as data reported to EPA, the Division identified 63 natural gas processing plants in the state that are not on tribal lands. Of these 63 gas plants, the Division's data shows that 32 are in the 9-County area, while 31 are outside. Information received from operators suggests that a gas plant in the 9-County area has between 1-3 ECDs, while a gas plant outside the 9-County area has between 0 and 1 ECD. For purposes of this analysis, the Division assumes gas plants in the 9-County area have 2 ECDs (32 x 2 = 64 ECDs) and gas plants outside the 9-County area have 1 ECD (31 ECDs). Therefore, the Division determined that there are an additional 95 ECDs to be tested at gas plants as part of this program. The Division determined there are a total of 9,505 ECDs subject to this proposal.[7]

I.A. Monitoring: Regulation Number 7, Part D, Section II.B.2.f

In Section II.B.2.f, the Division proposes more frequent inspections of air pollution control equipment at oil and gas operations. The proposed rule requires operators to conduct, at minimum, weekly visual inspections of air pollution control equipment. Because the required inspections are visual, no additional monitoring equipment will be required in order to fulfill the inspection requirements. Most, if not all, air pollution control equipment is already subject to weekly inspection requirements under Regulation Number 7, Part D, Section II.C. However, some air pollution control equipment controlling other equipment is not currently subject to all these requirements (though a number of ECDs have permit conditions setting forth a similar level of inspection). The Division is proposing to subject controls on separation equipment to these requirements in revisions to Section II.F, though no new costs are expected from that revision because new Colorado Oil and Gas Conservation Commission (COGCC) rules mandate capture of gas coming off separation equipment, and only permit use of control equipment where granted a variance from the COGCC.

Air pollution control equipment used to reduce emissions from glycol dehydration units will be newly subject to these inspection requirements. The Division has reached out to the industry to understand how many such devices would be subject to the rules, and of those, how many are not currently inspected at this frequency, but has not yet received a response. Based on the Regulation Number 7,

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[5] The Division does not currently have the ability to identify compressor stations in the state in the same way as it can identify gas plants or well production facilities. To create a list of compressor stations, the Division started with facilities classified as compressor stations in COGIS and the Division's SIP inventories. The Division merged these lists, removed duplicates, and, where possible, screened permit records to remove those that were misclassified. Based upon information collected during the Statewide Hydrocarbon Emission Reduction (SHER) process and information from the industry, the Division estimates that approximately one-third of the compressor stations operate in the transmission and storage segment (as opposed to the midstream segment), leaving 207 midstream compressor stations statewide. The Division also reviewed the number of unique compressor stations reported pursuant to leak detection and repair (LDAR) reports required by Regulation Number 7 for calendar year 2020, and determined that there are 205 unique compressor stations on non-tribal lands.
[6] The 9-County area includes the 8-hour Ozone Control Area, and all of Larimer and Weld counties.
[7] These numbers do not include ECDs controlling separation equipment or upstream dehydration units. However, the new COGCC regulations should result in a complete phase-out of separator control devices. The Division does not have reasonably available data on the number of ECDs controlling upstream dehydration units.

Part D, Section V annual reports, there are one hundred and forty five (145) dehydration units, sixty-three (63) at upstream operations and eighty-two (82) at midstream operations. Under Section I.H.5, though, air pollution control equipment controlling dehydration units is already subject to weekly inspection requirements, covering the majority of reported dehydration units.

Based upon the foregoing, costs associated with additional inspection and monitoring are assumed to be absorbed into current operation and maintenance practices and carried out by existing personnel. No additional significant equipment or labor costs are expected to be imposed on operators to comply with the proposed inspection and monitoring requirements.

I.B. Flow Meters: Regulation Number 7, Part D, Section II.B.2.g

The Division proposes that operators install and operate flow meters on most air pollution control equipment used to comply with Section II control requirements. In the Initial EIA, the Division assumed that most of the state's combustion devices will require the installation of a flow meter, though flow meters are already required for combustion devices controlling separation equipment in most permits. However, in the Division's revisions to its proposal, the Division specified that a single flow meter could be installed under this Section of the rule as long as all streams to the bank of ECDs are captured. That will substantially reduce the economic impact of this proposal.

The Division's proposal does not prescribe any specific brands or types of flow meters that can be used. Based on the analysis of the equipment costs for 22 different flow meters currently on market, the Division uses the average cost of $2,439 as the estimate per flow meter in this economic analysis. The useful life of a flow meter varies significantly based on the type and usage of the device, and can range from as few as 5 years to as many as 25. The Division uses the estimated useful life of an ECD, 15 years, as a reasonable assessment of useful life for flow meters. The Division has no information on installation costs or annual maintenance or calibration costs for flow meters, and, in the Initial EIA requested that such information be provided by operators. The Division did not receive any information from operators between the date of the Initial EIA and this Final EIA. The annualized cost of a flow meter would therefore be $389.68. It is estimated that based on the estimated count of affected combustion devices, 9,505, total annualized costs to the industry for flow meters will be approximately $3,703,908.40. For operators with flares subject to performance testing requirements, the cost of flow meters is included in that analysis.

The Division has heard from industry a suggestion that there are other associated costs with the use of flow meters, such as a potential need for site reconfiguration, and, in the Initial EIA, requested that industry provide information about these costs and the necessity therefore. The Division did have some discussions with industry about its proposal for flow meters that resulted in a number of revisions. However, the Division did not receive any cost information or data regarding the cost of or need for site reconfiguration.

I.C. Performance Testing of Enclosed Combustion Devices: Regulation Number 7, Part D, Section II.B.2.h

The Division's proposal will require performance testing of most ECDs used to comply with Regulation Number 7, Part D, Section II. The Division's proposal would prioritize testing of devices first in DI communities, second in the 8-hour Ozone Control Area (or northern Weld) and last, the remaining devices.

The Division estimates that of the 9,505 ECDs subject to the proposed regulation, 28.57% or 2,716 are located inside a DI community, 49.87% or 4,740 are located inside the 8-hour Ozone Control Area (plus Northern Weld) (and not in a DI community), and 21.56% or 2,049 are located outside of the 8-hour

Ozone Control Area (plus Northern Weld) (and not in a DI community).[8] Table 2 includes the projected number of flares that will be required to be tested in each compliance deadline year for each location for the first 5 years of the program, as provided for in section II.B.2.h of the proposed rule. For ECDs in DI communities and inside the 8-hour Ozone Control Area, plus Northern Weld, the final year includes devices that will be undergoing a subsequent periodic test.

Table 1: ECD Testing Schedule						
Location of Combustion Devices	**Compliance Deadlines (on or before May 1)**					
	2023	**2024**	**2025**	**2026**	**2027**	**2028[9]**
	Number of ECDs that must be tested by each year end					
Inside DI Community	407	679	815	815	-	407
Inside NAA (Not in DI Community)	474	948	948	1422	948	474
Outside NAA (Not in DI Community)	102	205	307	410	512	512

The Division assumes that all performance testing of combustion devices will be conducted by third-party testing companies. The Division collected information from flare performance testing companies, testing personnel, operators, and historical Division data to estimate the costs associated with conducting a destruction efficiency test for a combustion device through a third-party testing company. Table 2, below, includes a breakdown of the costs associated with the completion of a performance test for one combustion device; the Division assumes that a performance test for one combustion device can be completed in one day (eight work hours). The figure for labor includes three testing personnel, at an estimated average labor rate of $96 per hour, for eight hours each. Test protocol preparation and test report preparation are each estimated to take one day to complete. As the test methodology and testing equipment used vary between combustors, the Division uses the average hourly equipment rental and preparation costs from a set of potential rates[10] as the estimate for equipment costs. It is assumed that four units of testing equipment will be used for each test. Possible testing equipment used includes, but is not limited to, ionization detectors, O2/CO2 monitors, gas chromatographs, and sampling bags. Consistent with the 2014 and 2019 Regulation Number 7 rulemakings, the Division estimated travel cost as 15% of the labor cost. As set forth in Table 2, the total cost of a performance test for one ECD is estimated to be $6,326.60. For the purposes of this EIA, the Division assumes that one ECD will be tested per trip. In some cases, testing companies may be able to test multiple ECDs at a site during one trip. In such an instance, the travel time cost would only be applied once, while costs associated with labor, test administration, and equipment could potentially increase. In order to standardize the costs associated with testing one ECD, the Division bases cost estimates on the assumption that one ECD is tested per trip and that testing takes one day.

The proposed rule requires that 100% of the total existing ECDs (i.e., those operating as of December 2021) be tested by May 1, 2028. The Division calculated that an average of 1,731 ECDs would be

[8] The Division does not yet have complete data pertaining to each well production facility's location as it relates to the identification of a DI Community. However, based upon the Department's climate data viewer tool, which maps DI communities, the Division was able to determine that these percentages relate to the percent of population residing within a DI community, whether within or without the nonattainment area. The Division applied those percentages to the number of facilities.

[9] The estimate of ECDs tested in 2028 also includes those ECDs that were tested in 2023 and are required to complete testing again after 5 years, per the rule proposal, assuming all ECDs tested in 2023 have to be tested again in 2028 (a conservative assumption).

[10] Equipment rental and preparation rates were provided by companies that offer ECD testing services.

required to be tested each year, for the first 5 years. As noted below, in Table 2, the cost per year of testing 1,731 ECDs is estimated at $10,951,715.

Table 2: ECD Performance Improvement Costs[11]				
ECD Performance Testing				
Parameter	**Units**	**Cost Per Unit**	**Units Required Per Test**	**Cost Per Test**
Labor	hours	$96.00	24	$2,304.00
Test Protocol	days	$700.00	1	$700.00
Test Report	days	$695.00	1	$695.00
Equipment Rental	components/day	$352.50	4	$1,410.00
Equipment Prep	components	$290.00	4	$1,160.00
Travel	hours	$14.40	4	$57.60
TOTAL ECD Performance Testing Costs				
	Cost per test	**Average Tests per Year**	**Total Annual Cost**	
Total Performance Test	$6,326.60	1,731	$10,951,715	

The Division does not have performance test results for every ECD in the field, from which it can calculate conclusively the emissions benefits of this rule. In order to determine the emission benefits of its proposal, the Division undertook an analysis of failing performance test results collected by the Division to quantify both the percentage of failing tests as compared to devices tested and the scale of a failing test - i.e., when a device fails the test, what is the average of the delta between the test result and the applicable control efficiency requirement. The Division estimates that 9.61% of ECD performance tests fail to demonstrate compliance with the applicable control efficiency requirement. The Division's analysis suggests that an average scale of failure is 11.36% (i.e., based upon an average of failing performance tests, the test results are 11.36% lower than the applicable control efficiency requirement). The Division calculated a performance improvement of 1.09% from its proposal (representing the difference between 93.91% control and 95%).

To calculate emission benefits, the Division applied this percentage to uncontrolled emissions reported for all controlled tank batteries over 2 tpy VOC (from the Division's database).[12] The Division estimated that its proposal would result in a VOC benefit of 2,211 tpy.[13] Using an assumed methane to VOC ratio of 1.01:1 for storage tanks, the Division estimated a greenhouse gas benefit of 56,734 mtCO2e/yr.

[11] The change in cost from the Initial EIA is primarily due to the decreased number of annual inspections resulting from an adjustment to the timeline for completing required performance tests.
[12] When the Division looked at emissions reported in the annual emissions reports, the Division also calculated uncontrolled emissions reported from separators and dehydrators for July - December 2020. The Division doubled those emissions to account for a full year, and all emissions from separators and dehydrators reported were assumed to reflect 95% control. Based on these inventories, this rule may also reduce emissions from 2,230 separators and 145 dehydrators for an additional 253.48 tpy VOC and 20,390.38 mtCO2e/year.
[13] The majority of these emission reductions are realized from those ECDs controlling tank systems with VOC emissions over 12 tpy.

I.D. Reporting

The cost of preparing a performance test report is included in the cost information above. The Division is proposing that operators would submit information about the performance tests conducted each year with the existing annual reports required under Section V, which is an absorbable cost. Additional report submittals might be required if an operator fails a performance test; however, the cost of these additional reports is presumed to be negligible and absorbable.

I.E. Enclosed Combustion Device Performance Cost Effectiveness

Based on an annual cost of its performance test requirements as $10,951,715, and an annualized cost of flow meters of $3,703,908 per year, the Division estimates a total annual cost of $14,655,253. Based on this analysis, the Division has determined that this proposal will result in a cost effectiveness of $6,627 per ton VOC and $258 per mtCO2e.

Table 3: ECD Performance Improvement Cost Effectiveness[14]			
Annual and Total ECD Performance Improvement Costs			
	Cost per test or meter	**Annualized Cost**	**Total Annual Cost**
Total Performance Test	$6,326.60		$10,951,715
Flow meter	$2,439.00	$389.68	$3,703,908[15]
Total			$14,655,253
ECD Performance Improvement Cost Per Ton			
	VOC (tpy)	**Methane (tpy)**	**Methane (mtCO2e/yr)**
Emission Reductions	2,211	2,234	56,734
Cost per ton Emission Reduction	$6,627		$258

I.F. Combustion Device Performance in Section I.

As described in the Division's Prehearing Statement, the proposed revisions to Section I. are a new addition from the Request Proposal and are included to address concerns raised by EPA with previously submitted State Implementation Plan (SIP) revisions. Based on the analysis done at the time of adoption of those previously submitted SIP revisions in 2017, the Division estimated that a potential of 62 emission points could include a single storage vessel that could have the potential to emit greater

[14] The emission reduction estimate in Table 3 is a significant increase from the emissions estimate in the initial EIA of 539.59 tpy VOC and 13,843.18 mtCO2e/year. In the initial EIA, the division made an assumption about the emissions based on the counts of storage tanks between 2-6 tpy VOC, 6-12 tpy, 12-20 tpy, and > 20 tpy. For this final EIA, the Division summed the total uncontrolled VOC emissions reported for each of the above categories to determine the impact of this rule revision. See Storage Tank Inventory 8-12-2021.

[15] These flow meter costs are overly conservative, because under the Division's proposal a permanent flow meter is not required to be installed on each ECD. However, the Division's proposal does require a flow meter be installed and operating during a performance test (but it can be temporary), so has maintained this assumption in the cost analysis.

than six tpy VOC. Assuming, as done above, that each point used two combustion devices to control emissions, owners or operators may have to conduct performance tests of 124 combustion devices under the proposed revisions to require performance testing of devices controlling emissions from storage vessels, as such vessels are defined under the recommendations in EPA's Control Techniques Guidelines for the Oil and Natural Gas Industry (Oil and Gas CTG).[16] The Division does not have sufficient information to estimate the potential number of combustion devices controlling emissions from wet seat centrifugal compressors that would require performance testing but, according to EPA's Greenhouse Gas Reporting Rule (GHGRP), no owners or operators report emissions from such compressors in the ozone nonattainment area. For the potential 124 combustion devices estimated to be controlling emissions from storage vessels, the Division assumes the costs would be the same or similar to the costs of performance testing and flow meters described above and, in fact, would be included in those cost estimates as these devices would be included in the percentage tested under the proposed requirements in Regulation 7, Section II. Further, because EPA's Oil and Gas CTG and EPA's New Source Performance Standards (NSPS) OOOOa use the same storage vessel applicability threshold, it is possible that some combustion devices are already tested under the requirements of NSPS OOOOa and, therefore, would not have additional expenditures related to combustion device performance testing.

The Division, as staff to the Commission, requested additional information from stakeholders on the costs associated with this component of its proposal, but did not receive any such information.

II. Midstream Program(s)

The Division is proposing several new regulatory provisions to directly address greenhouse gas emissions (and co-pollutants) from the midstream segment of the oil and gas industry. The proposals include the following additional requirements for oil and gas operators in the midstream segment:

- Increased leak detection and repair (LDAR) inspections for compressor stations outside of the 8-hour Ozone Control Area;
- Increased leak detection and repair inspections and valve requirements for gas plants outside of the 8-hour Ozone Control Area;
- Capture and control strategies for certain midstream operations, including pigging and blowdowns;
- Expansion of rod-packing requirements for compressors at gas plants outside of the 8-hour Ozone Control Area;
- Expansion of the gas plant pneumatic controller requirements outside of the 8-hour Ozone Control Area; and
- Long-term planning for greenhouse gas reductions from midstream engines and other combustion equipment.

II.A. Leak Detection and Repair: Regulation Number 7, Part D, Section II.E[17]

According to the Division's 2020 state-wide LDAR annual reporting, 551,787 inspections were completed at well production facilities (comprised of 525,433 AVO inspections and 26,354 AIMM inspections) and 757 inspections were completed at natural gas compressor stations (all AIMM inspections). From these inspections, 15,617 leaks were discovered at well production facilities and 1,273 leaks were discovered at natural gas compressor stations (all from AIMM). In an analysis of LDAR reporting, it is estimated that across the industry, approximately 86% of LDAR inspections are completed "in-house" by the operator,

[16] Control Techniques Guidelines for the Oil and Natural Gas Industry 2016, EPA.
[17] The cost analysis of this section is also relevant to the upstream LDAR costs evaluated later in this Final EIA.

and 14% are completed by an outside contractor. The costs between completing LDAR in-house and completing LDAR through a contractor differ, as discussed in more detail below.

The Division uses the same approach to estimate LDAR inspection costs as in the 2014, 2017, and 2019 rulemaking EIAs supporting LDAR requirements.[18] For in-house inspections, it is assumed that operators use existing personnel to conduct LDAR inspections, but must purchase the leak detection equipment. The majority of leak detection is conducted using either EPA Method 21 or by using an infrared (IR) camera (by itself or as a screening tool before Method 21). The Division assumes that it takes 50% less time to conduct leak detection using an IR camera, than using solely Method 21. LDAR inspections using Method 21 take approximately 21.2 hours to complete, while LDAR inspections utilizing an IR camera take 10.6 hours (per facility). It is estimated that 90% of inspections (in-house and contracted) are completed using an IR camera, while 10% are completed using only Method 21.

The Division updated its cost estimates of an IR camera to reflect current (2021) market prices, and other equipment costs are inflated from 2014 dollars to 2021 dollars, using the U.S. Bureau of Labor Statistics (U.S. BLS) CPI Inflation Calculator. The Division found the current capital cost of an IR camera to be between $100,430 - $163,366.[19] For the purposes of this analysis, the Division uses the median cost, of $131,898, as the capital cost of one IR camera. Further, IR cameras have an annual maintenance and repair cost of $8,387.[20] All equipment, including IR cameras, are assumed to have a lifespan of 5 years.[21] Table 4 provides an estimate of the capital and recurring costs required for LDAR inspections.

[18] *See* the Colorado Department of Public Health and Environment Air Pollution Control Division Final Economic Impact Analyses for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7 (5 CCR 1001-9), dated January 30, 2014, September 14, 2017, and December 17-19, 2019.
[19] IR camera capital cost is based on historical Division data as well as current market rates for commercial IR cameras.
[20] Cost is inflated to 2021 dollars from the 2014 value of $7,500/year, using the U.S. BLS CPI Inflation Calculator.
[21] Capital costs are annualized over a five-year period and adjusted for inflation.

Table 4: LDAR Annualized Costs			
Parameter	**Capital Costs**	**Annual Costs**	**Annualized Total Cost**
FLIR Camera:	$131,898		
FLIR Camera Maint/Repair:		$ 8,387	
Photo Ionization Detector	$5,591		
Vehicle	$24,602		
Inspection Staff:		$ 75,000	
Supervision (@20%):		$ 15,000	
Overhead (@10%):		$ 7,500	
Travel(@15%):		$ 11,250	
Recordkeeping (@10%):		$ 7,500	
Reporting (@10%):		$ 7,500	
Fringe (@30%):		$ 22,500	
Subtotal Costs:	$162,091	$154,637	
Annualized Costs:	$43,382.9	$154,637	**$198,020**

The Division used this annualized cost to create an estimated cost per hour for an in-house LDAR inspection. The total annualized cost identified in Table 4 of $198,020 is divided by an assumed 1,880 annual working hours[22] to produce a value for an inspection rate for in-house inspections of $105/hour. Operators also have the option of hiring third-party contractors to complete LDAR inspections, instead of completing the inspections in-house. The hourly cost of using a third-party contractor to complete leak detection is estimated at $137/hour. This estimate is based on the premise that contractors would realize a 30% profit margin above the cost to operators of completing the inspections in-house.

II.A.1. Compressor Station LDAR: Regulation Number 7, Part D, Section II.E.3.d

Inspections

Currently, compressor stations inside the 8-Hour Ozone Control Area are subject to a quarterly LDAR frequency. *See* Reg. 7, Part D, Sec. I.L.1. Compressor stations outside the 8-Hour Ozone Control Area are also subject to a quarterly LDAR frequency if emissions are greater than 12 tpy VOC. *See* Reg. 7, Part D, Sec. II.E.3, Table 2. As set forth earlier in this Final EIA, the Division determined that there were 205 compressor stations in the midstream segment on non-tribal lands in the state. Based upon operator-provided LDAR reports for 2020, which include inspection frequency, the Division determined that there are approximately 75 natural gas compressor stations located outside of the 8-hour Ozone Control Area with emissions under 12 tpy VOC.[23] That is, 75 compressor stations currently do not have an existing quarterly leak inspection requirement.

[22] This assumes a 40 hour work week, ten holidays, two weeks of vacation, and one week of sick leave.
[23] Based on 2020 annual LDAR reporting, 75 compressor stations reported a semi-annual LDAR frequency.

Of these 75 compressor stations, the Division is proposing to increase LDAR frequency where the compressor station is located within a DI community. The Division estimates that ~33%, or 25 compressor stations, are located within a DI community and therefore subject to the proposed quarterly inspection requirements. As a result, each of the affected 25 facilities will have an additional 2 LDAR inspections a year, for a total of 50 annual inspections. The Division does not have reason to believe that additional IR cameras would be necessary to purchase to conduct these inspections, but has included the cost of purchasing an additional camera in the per-hour inspection cost to recognize that the timeline for IR camera replacement may be advanced as a result of these additional inspections.

Table 5 includes a breakdown and analysis of the estimated leak inspection time and costs under the different possible conditions mentioned in the preceding section. Assuming that 86% of LDAR inspections are completed in-house and 14% are completed by a contractor, of the 50 total inspections, about 43 inspections are expected to be completed in-house and 7 contracted out. At 10.6 hours per IR inspection and 21.2 hours per Method 21 inspection, this equates to 576.82 total inspection hours for all operators.

Table 5: LDAR Inspection Costs

# Inspections	Inspection type	Inspection method	Result: Inspection hours	Cost per hour	Result: Total cost
50	In-house	Method 21	90.19	$105.00	$9,470.34
		FLIR	405.87	$105.00	$42,616.53
	Contractor	Method 21	14.68	$137.00	$2,011.53
		FLIR	66.07	$137.00	$9,051.88
Totals			**576.81**		**$63,149.05**

At hourly inspection rates of $105 per hour for in-house and $137 per hour for contractors, the total cost to operators for completing the new LDAR inspections would therefore be $63,149.05 per year; or $2,525.96 per compressor station per year.

Leak Repair

The Division estimated the costs associated with the repair of leaks discovered as a result of the proposed regulation's increased leak detection and repair requirements. The methodology for estimating leak frequency, repair time, and repair cost are consistent with the Division's prior EIAs. The Division uses a quarterly leak frequency rate of 1.77% to estimate the number of leaking components discovered through inspections. This figure is based on an EPA-estimated annual leak frequency of 1.18%[24], scaled for a quarterly leak frequency (similar analyses used by the Division in earlier rulemakings, in 2014 and 2019). Using information provided to the EPA by industry[25], as used in previous EIAs, component repair times are estimated at 0.63 hours for connectors, 0.63 hours for flanges, 0.63 hours for open-ended lines, 16 hours for pump seals, 1.13 hours for valves, and 0.63 hours for any other components. The Division assumes an hourly repair rate of $82.06[26] for all components. Using the estimate for the number of expected leaks per component, the Division estimates that a total of 34.75

[24] Control Techniques Guidelines for the Oil and Natural Gas Industry 2016, EPA, p. 8-7.
[25] *See* "Analysis of Emissions Reduction Techniques for Equipment Leaks," Cindy Hancy, December 21, 2011.
[26] Based on the hourly repair rate of $66.24 from 2009, used in the Division's 2019 Regulation Number 7 EIA, adjusted for inflation to 2021 using the U.S. BLS CPI Inflation Calculator.

repair hours per year per facility will be required to address leaks discovered by the new inspection requirements. At $82.06 per hour, total annual repair cost is estimated at $2,851.82 per facility. Multiplying this estimate by 25 total affected facilities yields an industry-wide annual leak repair cost of $71,295.55.

Emission Reductions

The Division uses the same analysis here as it did in 2014, 2017, and 2019 to estimate emission reductions from this program. The estimated emission reductions from increasing the frequency of LDAR at compressor stations outside of the 8-hour Ozone Control Area and within a DI Community is 41.0 tpy VOC and 2,897.64 mtCO2e/year (methane).

Table 6: Emission Reductions for Compressor Stations ≤ 12 tpy in a DI Community					
Number of CS	Incremental LDAR Program Reduction % (semi annual to quarterly)	VOC Emission Reductions per CS	Total VOC Emission Reductions	Methane Emissions per CS	Total Methane Reduction
25	10%	1.64 tpy	41.00 tpy	4.56 tpy	114.08 tpy
TOTAL Emission Reductions		**41 tpy VOC**		**2,897.64 mtCO2e/yr**	

Value of Natural Gas Recovered

In Table 7, the Division estimates the value of natural gas recovered from these additional leak inspections.

Table 7: Compressor Station Recovered Natural Gas Value from Leak Repairs				
Compressor Station Fugitive VOC Tier (tpy)	Number of Compressor Stations	Total Recovered Natural Gas (tons CH4/year)	Value of Natural Gas ($/ton methane)[27]	Total Annual Value of Recovered Natural Gas
≤ 12 tpy in a DI Community	25	114.084	$222.69	$25,402.90

Cost Effectiveness

Combining the annual cost of inspections, $63,149.05, with the annual cost of repairs, $71,295.55, yields a total gross annual cost of $134,444.60. Based on these reductions and associated costs, the effectiveness of this requirement is $3,279.14 per ton VOC and $46.04 per mtCO2e, without incorporating the estimated annual value of recovered gas of $20,279.62.

[27] Based on the most recent United States Natural Gas Industrial Price (May 2021), of $4.09/MCF as provided for by the U.S. Energy Information Administration, using an average molecular weight of 19.17 lb/lb-mol of natural gas and 72.69% methane by weight for the Piceance basin.

Table 8: Compressor Station LDAR Cost Effectiveness			
LDAR Total Annual Cost			
	Inspection	**Repair**	**TOTAL**
Annual Cost	$63,149.05	$71,295.55	$134,444.60
Recovered Natural Gas	--	--	-$25,402.90
Net Cost	--	--	**$109,041.70**
Compressor Station Emissions Reduction and Cost			
Total VOC Emission Reduction (VOC)	**Cost per ton VOC**	**Total GHG Emission Reduction (mtCO2e/year)**	**Cost per mtCO2e**
41.00	**$2,659.55**	**2,897.64**	**$37.63**

New Mexico recently did a cost analysis of increasing LDAR inspections across different facility types, and likewise concluded that quarterly LDAR is cost effective at compressor stations.[28] New Mexico's analysis demonstrates the cost effectiveness (for VOC) of additional IR camera inspections at compressor stations as follows:

Table 9: New Mexico Summary of the VOC Cost of Control for the Quarterly OGI Monitoring Option based on Model Plants			
Facility Type	**Annual VOC Emission Reduction (tpy)**	**Annual Cost (2019$)**	**$/ton VOC reduced (2019$)**
Gathering and Boosting Station	7.81	$26,030	$3,331
Reference: Table 9-13 of the 2016 CTG.			

The Division, as staff to the Commission, requests additional information from stakeholders on the costs associated with this component of its proposal.

II.A.2. LDAR at Natural Gas Processing Plants: Regulation Number 7, Part D, Section II.I

Currently, under Regulation Number 7, Part D, Section I.G, natural gas processing plants in the 8-hour Ozone Control Area must comply with the LDAR program in NSPS OOOO or NSPS OOOOa. Natural gas processing plants outside the 8-hour Ozone Control Area may also be subject to NSPS KKK, NSPS OOOO, NSPS OOOOa, depending on the date of construction. Natural gas processing plants statewide that have storage tanks subject to Section II.C.1 must also conduct AIMM inspections of the storage tanks and associated equipment in accordance with Table 1 in Section II.C.2. Those inspections range from semi-annual to monthly, depending on the VOC emissions estimated from the storage tanks.

[28] *See* https://www.env.nm.gov/air-quality/ozone-draft-rule/ (LDAR Reductions and Costs VOC 5-27-21_erg (06-08-2021)).

The Division has identified 63 natural gas processing plants in Colorado - 38 of which are operating in the DJ Basin. The Division assumes these 38 plants are already subject to LDAR programs under NSPS OOOO or NSPS OOOOa. The Division has identified 25 gas plants outside of the DJ Basin - 18 in the Piceance basin and 7 in the remainder of the state. These numbers do not include gas plants the Division was able to determine are on tribal lands. Based on the Division's review of the Regulation Number 7 annual emissions reports, and the information submitted for fugitive emissions, it appears that many natural gas processing plants outside the 8-hour Ozone Control Area are already subject to NSPS OOOO or NSPS OOOOa for LDAR. However, for purposes of this Final EIA, the Division assumed that all 25 gas plants outside the DJ Basin will need to adjust LDAR frequency to comply with the Division's proposal. This makes the Division's cost analysis overly conservative.

The Division utilized technical supporting information from the Oil and Gas CTG[29] in the analysis of this proposal. Under the Division's proposal, these gas plants would monitor pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines, valves, and connectors to determine if a component is leaking. Under this program, "[v]alves are monitored monthly, connectors are monitored annually, and open-ended lines and pressure relief valves must be monitored within five days after a pressure release event to ensure they are operating without any detectable emissions (e.g. at a concentration less than 500 ppm above background)."[30]

In the Oil and Gas CTG, EPA estimated cost impacts associated with moving from a NSPS VV program to a subpart VVa program for a natural gas processing plant, and determined that the cost in 2012 dollars was between $2,010 - 2,844 per ton VOC[31]. In today's dollars, based upon a gas processing model plant, and assuming a correlation of VOC to methane of 1:1.81, the Division estimates the cost of this proposal as follows:

Table 10: Cost and Emissions Reductions for LDAR at Gas Plants

Pollutant	Annual Emission Reductions Per Gas Plant	Capital Cost (2021$)	Annual Cost (2021$)	Cost of Control (without savings) $/ton	Cost of Control (with savings) $/ton
VOC	4.56 tpy	$10,062.60	$15,343.12	$3,367.22	$2,379.79
Methane	8.27 tpy	$10,062.60	$15,343.12	$72.99	$51.63
Greenhouse Gas	210.2 mtCO2e/yr				

The Division's proposal would also require operators to - prior to placing a leak on the delay of repair list - attempt a "drill and tap" repair of a leaking valve. Drill and tap reduces the need for a process shut-down to effect a leak repair, and can reduce fugitive emissions. The Division does not have information to suggest a significant additional cost associated with this proposal, because the Division has no information regarding how many valves cannot be repaired through other means prior to being

[29] New Mexico also utilized this data in preparing its economic impact analysis of gas plant LDAR in its recent rule. proposal. *See* https://www.env.nm.gov/air-quality/ozone-draft-rule/ (LDAR Reductions and Costs VOC 5-27-21_erg (06-08-2021)).
[30] Oil and Gas CTG, pp.8-9, 8-10.
[31] Oil and Gas CTG, p. 8-11.

placed on the delay of repair list. The Division understands that "drill and tap" is an accepted and effective repair method for valves, and that this proposal generally reflects best practice.[32]

The Division, as staff to the Commission, requests additional information from stakeholders on the costs associated with this component of its proposal.

II.B. Midstream Emission Reductions - Pigging and Blowdown Operations: Regulation Number 7, Part D, Section II.H

II.B.1. Pigging Operations

In Permit Section (PS) Memo 20-04[33], the Division explained pigging operations as follows:

> Raw natural gas is transported from production wells to processing plants through networks of gathering pipelines. Although liquid separation may occur at the well pad, much of the raw natural gas passing through the gathering pipelines is saturated with hydrocarbons other than methane and may contain other components such as water, carbon dioxide, and hydrogen sulfide. During the transportation of this gas through gathering pipeline systems, the gas often experiences a temperature drop and pressure change that causes the hydrocarbons and other components to condense to a liquid phase. These natural gas condensates can accumulate in low elevation segments of the gathering pipelines, impeding the flow of natural gas. To maintain gas flow and operational integrity of the gathering pipelines, operators mechanically push these condensates out of the low elevations and down the pipeline by an operation called "pigging," which involves first inserting a device called a pig into a pig launcher upstream of the pipeline segment where condensates have accumulated. The gas flowing through the pipeline then pushes the pig through the pipeline, allowing the pig to sweep along the accumulated condensates. The pig is removed from the pipeline segment when it is caught in a pig receiver.

The Division is proposing that midstream owners and operators with pigging operations must capture and recover the natural gas emitted during pigging. If that is not feasible, those owners or operators may apply to the Division to utilize air pollution control equipment to control those emissions.

All midstream owners or operators with pigging operations must additionally employ best practices to reduce emissions associated with pigging. Some of the proposed best management practices are specified in PS Memo 20-04, and therefore should not result in additional costs to operators. *See* PS Memo 20-04, Sections 6.5 and 6.6. For other proposed best practices, the Division has proposed a feasibility off-ramp, that includes some sensitivity to cost.

The Division used gas speciation data collected by the Division, guidance from the EPA[34] and information received from operators and manufacturers to estimate emissions from pigging events.

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[32] *See* EPA's LDAR: A Best Practices Guide, Leak Detection and Repair Compliance Assistance Guidance Best Practices Guide; *see also* EPA December 1, 2015 Memorandum from Joseph Wilderwing to Cynthia Reynolds, re: Drill-and-Tap.
[33] Memo 20-04 - Routine or Predictable Gas Venting Emissions Calculation and Instructions on Permitting for Oil and Natural Gas Operations, Permit Section Memo 20-04, APCD, CDPHE, November 6, 2020.
[34] "Quantifying The Potential Impact Of Natural Gas Condensate Holdup On Uncontrolled Volatile Organic Compound Emissions From Pig Receivers During Depressurization In Wet Gas Gathering Operations", EPA Discussion Draft, May 16, 2016.

Cost - Pig Ramps

Pig ramps allow liquids trapped in front of the pig to be captured, and allow liquids on the pig itself to drain before the pig is pulled from the chamber.[35] The inventor of pig ramps, Mark West, has made the schematics available freely on its website. The Division has received cost estimates for each pig ramp of $800-$1,300 per ramp. Taking the median ($1,050) and applying a 6% interest rate results in an annualized cost of $188 per pig ramp. The Division does not have reasonably available information as to how many pig ramps would be necessary to comply with this proposal, and - as staff to the Commission - requests that information from operators. The Division otherwise assumes this minimal cost to be absorbable. The Division also amended its proposal to allow for other liquids containment systems, such as process drains. This expansion of compliant practices further reduces the impact.

Cost - Depressurization

The Division would also require operators to employ a best management practice of depressurizing pig launcher and receiver chambers prior to opening, in order to reduce the volume of gas vented to the atmosphere. According to the EPA, "[t]he depressurization emissions from high pressure launchers and receivers can be reduced by routing the gases to a lower pressure system before venting the remaining gases to the atmosphere or to control equipment. Routing to a lower pressure system is achieved with a depressurization line (or, "jumper line") exiting the top of the barrel ... or exiting the top of the pig ball valve. Compressor stations and gas plants have low pressure lines on the site that can receive these depressurization gases and recycle them through the process. Similarly, launchers and receivers along high pressure pipelines are occasionally located near low pressure pipelines that can receive depressurization gases exiting the barrel or pig ball valve."[36] One operator who employed the two best management practices described above (pig ramps and depressurization) and Zero Emission Vacuum and Compressor (ZEVAC) units reported significant reductions in gas vented and emissions as a result.[37]

Cost data received from EPA suggests that the materials cost for a jumper line is low - about $2,137 per jumper line. And when the savings in materials (e.g., bolts, gaskets, flanges) from a jumper line installed during mainline construction are taken into account, the cost is more in the neighborhood of $1,511 per jumper line. However, the Division acknowledges that it does not have access to other associated costs, such as engineering costs. In the Initial EIA, the Division requested additional cost information from operators. While the Division has heard verbally from operators that costs for a jumper line can theoretically be in the range of $50,000, to date, no such supporting materials or any data have been provided.

Cost - ZEVAC unit

In order to comply with the requirement to capture and reduce emissions during pigging operations, for the purpose of calculating costs, the Division assumes operators will use a ZEVAC unit.[38] The Division assumes that a pig launcher and receiver are already on-site.

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[35] Pipeline Launcher/Receiver Emission Reduction Systems

[36] EPA Enforcement Alert (Sept. 2019). Natural Gas Gathering Operations Clean Air Act Enforcement Alert

[37] See *Methane Reductions in Pigging,* September 2019, Methane Reductions in Pigging

[38] The Division's proposal also contemplates use of control devices as an option where recovery of the gas from pigging operations is not feasible. According to EPA, "[l]arge, high capacity combustion devices are typically available at compressor stations and processing plants and can be used to control pigging gases while meeting the other flaring needs of the facility. There are also numerous low capacity combustion devices available for serving remote launcher/receiver sites." EPA Enforcement Alert (Sept. 2019). Natural Gas Gathering Operations Clean Air Act Enforcement Alert

The Division gathered information from a manufacturer of ZEVAC units on the costs associated with ZEVAC units and expected gas recovery under various operating scenarios. The Division does not have reasonably available information about actual pigging operations in Colorado to specify the frequency of pigging operations or the size of the ZEVAC unit that would be necessary for each operator. In its annual emission reports to the Division, one operator submitted its annual emissions reporting 1,343 pigging events in the second half of 2020 alone, for a total of 13,806,040 scf vented, an average of 10,280 scf vented per pigging event. The Division recognizes that not all pigging events vent the same amount of gas; pigging of larger, higher pressure pipelines emit more gas to atmosphere than pigging of smaller, low-pressure pipelines. That operator also reported venting 7,557,500 scf of natural gas from pipeline blowdown events during the same period. However, the Division did not get this level of detailed reporting consistently across all operators; several midstream operators reported no pigging operations. Therefore, an analysis was conducted on three different sized ZEVAC units, small, medium, and large, under both a high frequency and low frequency use of the equipment. The size of the unit affects the speed of the gas recovery process; larger units taking less time. All units are assumed to have a useful life of 10 years. The capital cost of a small ZEVAC unit was found to be $30,000 with maintenance and repair costs of $2,400 per year. Annualizing the capital cost across 10 years, and assuming a 6% interest rate, yields a total annualized cost of $7,773. Under the same assumptions, the capital cost of a medium sized unit is $135,000 with annual maintenance costs of $10,800, for a total annualized cost of $34,976; and the capital cost of a large unit is $245,000 with annual maintenance costs of $19,600, and a total annualized cost of $63,476. In estimating the composition of pollutants in the gas, the Division applied weight percentages of total hydrocarbons of 29.35% VOC, 53.31% methane, and 17.34% ethane.[39]

High frequency pigging assumes the use of 5 pig barrels a day, for 5 days per week, at 50 weeks per year. With high frequency pigging, there are an estimated 1,250 events per year, each releasing an estimated 3,900 scf of gas, for a total annual potential emitted gas of 4,875,000 scf. As noted above, with at least one operator reporting 1,343 pigging events in just the second half of 2020, it is reasonable to assume at least some operators engage in high-frequency pigging operations. Low frequency pigging assumes the use of 1 pig barrel per day, for 3 days per week, at 50 weeks per year. With low frequency pigging, there are an estimated 150 events per year, each releasing an estimated 3,900 scf of gas, for a total annual potential emitted gas of 585,000 scf.

Table 11 below demonstrates potential gas recovery (emissions reductions) and cost per ton of pollutants per ZEVAC unit under the various ZEVAC operating conditions. This cost effectiveness analysis does not account for the economic benefit to operators from selling the recovered gas.

[39] As with elsewhere in this Final EIA, the Division utilized gas speciation data submitted to the Division from multiple operators, reviewing over 100 samples of sales gas analysis from across the state, and creating a weighted average by location.

Table 11: Cost and Emission Reductions of ZEVAC Units					
Small ZEVAC unit					
	Annualized cost	VOC captured (tpy)	Greenhouse Gas [40] captured (mtCO2e/yr)	$/ton VOC	$/mtCO2e
High frequency	$7,773.00	40.02	1,844.44	$194.21	$4.21
Low frequency	$7,773.00	4.80	221.33	$1,618.44	$35.12
Medium ZEVAC unit					
	Annualized cost	VOC captured (tpy)	Greenhouse Gas captured (mtCO2e/yr)	$/ton VOC	$/mtCO2e
High frequency	$34,976.00	40.02	1,844.44	$873.90	$18.96
Low frequency	$34,976.00	4.80	221.33	$7,282.47	$158.02
Large ZEVAC unit					
	Annualized cost	VOC captured (tpy)	Greenhouse Gas captured (mtCO2e/yr)	$/ton VOC	$/mtCO2e
High frequency	$63,476.00	40.02	1,844.44	$1,585.99	$34.41
Low frequency	$63,476.00	4.80	221.33	$13,216.54	$286.79

Amount and Value of Recovered Natural Gas

If the use of ZEVAC units will result in the recovery of 4,875,000 scf of natural gas per year, per ZEVAC unit, assuming high-frequency use, and 585,000 scf of natural gas per year, per ZEVAC unit, assuming low-frequency use, the Division calculates natural gas savings (at a price of $4/MCF) of $19,000 per ZEVAC unit per year, for a high frequency use, and $2,340 per ZEVAC unit per year for a low-frequency use. That would materially improve the cost-effectiveness.

In the Initial EIA, the Division, as staff to the Commission, requested additional information from stakeholders on the costs associated with this component of its proposal. The Division did receive some additional cost data from operators, associated with the rental of a ZEVAC unit, that included 2 hours labor, driving costs, and rental costs for an engine-driven air compressor. Industry noted annualized costs of about $556 per pigging event. The Division believes these costs are inappropriately inflated for most pigging events for the following reasons. First, purchasing a ZEVAC unit (or compressor) is more cost-effective than a per-event rental. Second, the Division understands from industry that a large portion of pigging events take place at a natural gas compressor station or natural gas processing plant, in which case there would be no need for travel time or additional labor hours. The cost per ton and emission reductions expected from the Division’s PHS Proposal is set forth below.

[40] Converted from methane to CO2e using AR5.

II.B.2. Blowdowns of Equipment and Piping

The Division's proposal will require midstream owners and operators to reduce hydrocarbon emissions from blowdowns from equipment and piping at compressor stations and gas plants. The Division also proposes requiring best practices for blowdowns including along midstream pipelines. The Division's proposal with the Prehearing Statement identifies with more specificity which blowdown emissions must be captured or controlled, focusing on blowdowns of compressors, and aggregating emissions from blowdowns of all other equipment and piping (with a physical volume of equal to or greater than 50 cf).

Based on information collected from operators, some operators will be able to route emissions from blowdowns to existing control equipment on-site. One operator indicated that costs to combust blowdown emissions could include the building of a blowdown header and taking blowdowns back to the field or a series of VRUs to draw down the pressure/volume such that it can be handled by the existing ECD or a new combustion device. Others, however, will drawdown line pressure, either naturally with alternative lower pressure gas lines or using ZEVAC units[41] as discussed under the previous section, to capture and retain the natural gas. Some operators may also install ejector units to force gas out of off-line compressors[42] or other equipment and route the gas to a lower pressure fuel gas line.

Many best practices are already identified in PS Memo 20-04. In the Initial EIA the Division - as staff to the Commission - requested additional information from operators on the costs of implementing controls and other practicable best management practices specified in the Division's proposal. The Division did not receive any additional data or materials other than as described above.

Emission Reductions from Pigging and Blowdowns

The Division does not have complete data from operators on how often pigging activities are conducted, particularly as differentiated between pigging and other maintenance activities that result in venting of emissions. In order to calculate reductions associated with this proposal, therefore, the Division looked at two sources of data. First, the Division looked at EPA FLIGHT data for 2019, and identified the total amount of emissions in CO2e reported by the natural gas gathering and boosting segment and the natural gas processing segment for pigging, venting and blowdowns (to the extent possible). The Division looked at emissions from the 20 natural gas processing plants in Colorado (on non-tribal lands) that reported to EPA and calculated 6,007.84 mtCO2e per year from venting/pipeline blowdown activities. It was more difficult to separate out gathering and boosting facilities that are in Colorado, and on non-tribal lands, but the Division ultimately calculated about 76,000 mtCO2e per year from venting/pipeline blowdown activities reported to EPA.

Initial EIA Analysis

The Division then looked at the emissions reported to the Division by operators in the midstream segment for "venting and blowdowns" and pipeline emissions. For the second half of 2020, midstream operators reported 35,184 events in "venting or blowdowns" and "pipeline" emission activities. From these events, operators reported a total of 184,495 mtCO2e for 2020. Operators also reported 3,584 tons VOC from venting or blowdowns and pipelines for 2020.

[41] Blowdown Emission Reduction White Paper, American Gas Association, August 5, 2020.
[42] Reducing Emissions When Taking Compressors Off-Line, Natural Gas Star, EPA, October 2006.

Table 12: Initial EIA - Emissions from Venting/Blowdowns/Pigging and Pipelines			
Reported 2020 Emissions with No Control			
Emission Category	**Reg. 7 EI 2020 CO2e (mtCO2e/yr)**	**Reg. 7 EI 2020 VOC (tpy)**	**# Events**
Total Venting/Blowdowns (includes pigging)	164,758.15	1,690.08	69,770
Total Pipeline Venting	19,736.72	1,893.70	598
Total Venting/Blowdowns/Pipeline Venting	**184,494.87**	**3,583.78**	**70,368**
Emissions after 95% Reduction of Venting/Blowdown Emissions			
Total Venting/Blowdowns (includes pigging)	8,237.91	84.50	69,770
Total Pipeline Venting	19,736.72	1,893.70	598
Total Venting/Blowdowns/Pipeline Venting	**27,974.63**	**1,978.20**	**70,368**
Emission Reductions with this Rule			
Total Emission Reductions	**156,520.24**	**1,605.58**	**70,368**

Not accounting for any reductions from pipeline emissions,[43] the Division's proposal could reduce venting and blowdown emissions by 95%, achieving a CO2e reduction of 156,520 mtCO2e/year. Looking only at VOC emissions from total venting and blowdowns (and not including pipeline venting reported), If the Division's proposal also reduces VOC by 95%, that results in a reduction of 1,606 tpy VOC, a significant and meaningful co-benefit. These numbers are likely conservative because not all midstream operators reported their emissions to the Division.

Update for Final EIA

The Division updated its analysis for this Final EIA based upon data reported for the second half of 2020, broken out by applicability category, reported emissions are as follows:

Table 13: Emissions from Venting/Blowdowns/Pigging and Pipelines					
Activity	**Number of Events**	**VOC (tpy)**	**CO2 (mtCO2e/yr)**	**CH4 (mtCO2e/yr)**	**CO2e (mtCO2e/yr)**
Compressor Blowdowns	7,376	438.94	460.65	52,812.34	53,272.99
Pigging Operations	12,532	294.79	47.11	19,413.06	19,460.17
Other Facility Venting and Blowdowns	50,747	1,024.10	1,824.29	166,264.17	168,088.46
SUBTOTAL Venting/Blowdown	70,655	1,757.83	2,332.05	238,489.57	240,821.62
SUBTOTAL Pipeline Venting	682	1,916.56	68.65	22,302.24	22,370.89
TOTAL	**71,337**	**3,674.39**	**2,400.70**	**260,791.81**	**263,192.51**

[43] The Division's proposal would require either capture, control or use of BMPs to reduce emissions from pigging pipelines. The Division's proposal would require only the use of BMPs to reduce emissions from other pipeline blowdowns.

Under the Division's proposal, the industry stakeholders have conveyed to the Division that they expect the pigging applicability thresholds to result in capture or control of more than 85% of the natural gas emitted during pigging operations. The Division's proposal would also ensure capture or control of 95% of the emissions from blowdowns of compressors and other equipment (using the numbers reported above is appropriate because blowdowns where the physical volume is less than 50 cf are not currently reported). Thus, under this updated analysis, assuming that the Division's proposal would result in capture or control of 85% of pigging operations (with a 95% capture/control efficiency), and 95% capture/control efficiency of remaining blowdown emissions, the Division's proposal could actually result in even more reductions: 15,676.05.10 mtCO2e/year from pigging activities and 208,122.68 mtCO2e/year from blowdowns, for a total of 223,798.73 mtCO2e/year reduced (and 1,627.93 tpy VOC). When the additional capture of CO2 emissions from this gas stream is included, the total CO2e reductions increase to 228,781 mtCO2e/yr.

Table 14: Emissions from Venting/Blowdowns/Pigging and Pipelines			
Reported 2020 Emissions with No Control			
Emission Category	**CO2e (mtCO2e/yr)**	**VOC (tpy)**	**# Events**
Total Venting/Blowdowns (includes pigging)	240,821.62	1,757.83	70,655
Total Pipeline Venting	22,370.89	1,916.56	682
Total Venting/Blowdowns/Pipeline Venting	**263,192.51**	**3,674**	**71,337**
Emission Reductions with this Rule			
Emission Category	**CO2e (mtCO2e/yr)**	**VOC (tpy)**	**# Events**
Total Emission Reductions	228,781	1,628	**71,337**

Cost of Pigging and Blowdown Emission Reduction

Based upon information reported to the Division in the annual emission reports under Regulation Number 7, Part D, Section V, and assuming that there are 250 business days in a year (and that blowdowns take place only on business days), there are approximately 282 events per day[44] that would be required to be captured or controlled by this rule. Using an annualized open flare cost of $25,268.95 [45], as well as the annualized ZEVAC costs depicted in Table 11 above, and assuming that each event over a business day requires its own portable piece of equipment (such as an ECD or ZEVAC unit)[46], for a total of 282 units required, the average annual cost of this proposal is $9,290,705.

The average cost per ton of emission reductions is $5,707.06 per tpy VOC and $40.78 per mtCO2e/year. These costs, however, do not separate out pigging emissions or specific types of blowdowns (such as compressor blowdowns), but do exclude pipeline emissions which are subject to BMPs but not control requirements in the proposal. Table 15 contains the emissions and costs associated with venting and

[44] Operators reported 35,328 events in the second half of 2020, as well as emissions for only July - December 2020. The Division assumed that the annual emissions are double those reported for the 6 month period of July - December 2020.
[45] As described in more detail in the well liquids unloading section, later in this Final EIA.
[46] This is an overly conservative assumption. The Division understands that one ZEVAC unit can be deployed multiple times per day. For example, based upon data provided to the Division, the average pigging operation lasts around 15 minutes.

blowdown emissions, including pigging emissions as described in more detail in Section II.B.1. of this EIA. These costs also do not account for the recovered gas savings from using a ZEVAC or other capture unit.

Table 15: Cost and Emission Reductions for Venting/Blowdown Activities					
Control or Capture Device Option	**Annualized cost**	**VOC reduced (tpy)**	**GHG reduced (mtCO2e/yr)**	**$/ton VOC**	**$/mtCO2e**
Open Flare	$7,141,510.65	1,627.93	223,798.73[47]	$4,386.86	$31.91
Small ZEVAC unit	$2,196,805.26	1,627.93	228,780.54	$1,349.45	$9.60
Medium ZEVAC unit	$9,884,917.12	1,627.93	228,780.54	$6,072.07	$43.21
Large ZEVAC unit	$17,939,587.12	1,627.93	228,780.54	$11,019.87	$78.41
Overall Average Cost Per Ton				**$5,707.06**	**$40.78**

II.C. Rod Packing Replacement at Natural Gas Processing Plants: Regulation Number 7, Part D, Section II.B.3.d

Existing regulations require rod packing replacement at natural gas processing plants inside the 8-hour Ozone Control Area. *See* Regulation Number 7, Part D, Section I.J.2. This proposed regulation would expand that requirement to natural gas processing plants statewide. There may be additional costs of the proposed requirement for owners or operators of reciprocating compressors at natural gas processing plants to replace the rod packing. The Division estimates that there are 31 natural gas processing plants outside the 8-hour Ozone Control Area, with an estimated total of 258 engines.[48] Conservatively assuming all engines existing at the natural gas processing plants are reciprocating engines and would be subject to the proposed requirements, and none of the owners or operators are currently voluntarily replacing rod packing or capturing engine emissions, each of these engines will incur additional costs to comply with the Division's proposal. According to the Oil and Gas CTG, EPA estimated the emission reductions by "comparing the average rod packing emissions with the average emissions from newly installed and worn-in rod packing."[49] The Oil and Gas CTG, Table 5-4, estimates a reduction from rod packing replacement in accordance with these requirements of 4.89 tpy VOC per engine and 17.58 tpy methane. With the number of engines estimated by the Division to be subject to this proposal, the proposal would realize 1,261.62 tpy VOC and 126,997.92 mtCO2e.

The Oil and Gas CTG estimates the capital cost of replacing the rod packing at $4,280, without factoring in the natural gas savings. The Division converted this value from 2012 dollars to 2021 dollars using the U.S. BLS CPI Inflation Calculator, resulting in an updated capital cost of $5,067. Using the same process as the Oil and Gas CTG, the Division determined that the annual cost would be $1,931.79 per engine. Applying this estimate to the emissions estimate reductions noted before yields cost per ton reduced of $394.84 per ton of VOC and $109.84 per ton of CH4 ($3.92 per ton of CO2e). With natural gas savings, the Division concludes - consistent with the Oil and Gas CTG - that this measure is an economic benefit to the operator of a natural gas processing plant.

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[47] CO2 emission reductions are not included when reductions are achieved through flaring.
[48] In 2017, the Division estimated 133 reciprocating compressors at the identified 16 natural gas processing plants. Assuming the same ratio of compressors per gas plant, and using the identified 31 gas plants, the Division estimates 266 reciprocating compressors covered by this rule. These numbers do not reflect that some number of the subject compressors will already be performing the rod-packing replacement.
[49] Control Techniques Guidelines for the Oil and Natural Gas Industry 2016, EPA, p.5-10.

In addition, there may be minimal costs related to the proposed monitoring and recordkeeping requirements, as discussed above, where an owner or operator is not currently monitoring and keeping compressor records.

II.D. Pneumatic Controller Requirements at Natural Gas Processing Plants: Regulation Number 7, Part D, Section III

The Division's proposal would expand current requirements to use non-emitting pneumatic controllers to natural gas processing plants statewide. Current requirements apply inside the 8-hour Ozone Control Area. *See* Regulation Number 7, Part D, Section III.C.2. Regulation Number 7 also required that pneumatic controllers placed in service between 2014 and May 1, 2021 be no-bleed where feasible, which applies to gas plants. *See* Regulation Number 7, Part D, Section III.C.3. There may be costs related to the proposed requirement for owners or operators of natural gas processing plants to ensure that natural gas-driven pneumatic controllers are non-emitting.

Should an owner or operator of a natural gas processing plant convert an existing natural gas-driven pneumatic controller to their instrument air system, the Oil and Gas CTG estimates a capital cost of converting the pneumatic controller at $2,000 and the cost per ton of VOC reduced between $6 and $68 per pneumatic controller.[50] A VOC emissions reduction ranging from 4.18 to 48.7 tpy, depending on the size of the instrument air system, is associated with each natural gas processing plant, or a range of 790.97 to 9,215.40 mtCO2e/year of methane. Because the Division assumed that most of the natural gas processing plants in the 8-hour Ozone Control Area would probably require a medium-to-large air system, an annual VOC emission reduction of 17.5 tpy and methane reduction of 3,311.49 mtCO2e/year represents an average associated with converting pneumatic controllers to system air.[51]

The Division estimates that there are thirty-one (31) gas plants outside the 8-hour Ozone Control Area, but does not have data on the number of natural gas actuated pneumatic controllers at these natural gas processing plants. The Oil and Gas CTG assumes that existing natural gas processing plants have already replaced pneumatic controllers with other types of control, such as an instrument air system, and any pneumatic controllers with a bleed rate greater than zero are required due to safety reasons.[52] The Division also checked pneumatic controller data reported to EPA in 2019 under the Greenhouse Gas Reporting Rule, and no Colorado gas plant reported any emissions from pneumatic controllers. The Division also reviewed the submittals from midstream operators to the Division for 2020; only 11 midstream operators reported having any natural gas driven pneumatic controllers, and the Division's review did not identify any natural gas processing plants reporting having gas driven pneumatic controllers. Therefore, the Division believes the cost to owners or operators of natural gas processing plants of the proposed requirements are minimal and limited to documenting, tagging, and maintaining any emitting natural gas-driven pneumatic controllers that are required for safety and/or process purposes.

II.E. Long-Term Planning for CO2e Reduction from Midstream Engines and Other Fuel Combustion Equipment: Regulation Number 22, Part B, Section III

Section 25-7-105(1)(e)(XIII), C.R.S., requires a 20% reduction in industrial emissions from the 2015 baseline by 2030. Included in this category of emissions is methane, CO2, and other greenhouse gas emissions from fuel combustion equipment at midstream facilities, such as engines, boilers, turbines, and heaters. In its efforts to address greenhouse gas emissions from fuel combustion equipment in the midstream segment, the Division is proposing a long-term planning process. By long-term, the Division proposes that operators will have until 2023 to develop their plans, and that additional rulemaking before the Air Commission would not be required until 2024. The program establishes a steering

[50] Control Techniques Guidelines for the Oil and Natural Gas Industry 2016, EPA, p.6-16.
[51] Control Techniques Guidelines for the Oil and Natural Gas Industry 2016, EPA, p.6-17, Table 6-7.
[52] Control Techniques Guidelines for the Oil and Natural Gas Industry 2016, EPA, p.6-16.

committee that will guide and aid midstream segment operators in the development of plans to meet emission reduction targets.

The Division has not identified a significant economic impact on any industry or party from this proposal. Participation in the steering committee is voluntary and the Division has not identified any costs imposed on midstream segment operators, the Division, or any other potential steering committee participants for the operation and administration of the committee. Between the Initial EIA and the Final EIA, the Division was not provided with any information to suggest that there are such costs. Compliance with the rule includes development of a plan to reduce emissions only, and not implementation of the plan. Individual operators may choose to hire third-party consultants to help develop their emission reduction plans, but because this is not required directly by the rule proposal and hiring of any consulting services would be completely voluntary, those potential costs are not considered in this analysis. Additionally, the Division does not anticipate any costs to the Division for oversight or the review of proposed guidance documents and emissions reduction plans. Administration of this rule will be carried out by existing and anticipated Division staff.

III. Upstream Program

The Division is proposing several new regulatory provisions to directly address greenhouse gas emissions from the upstream segment of the oil and gas industry. The proposals include the following additional requirements for oil and gas operators in the upstream segment:

- Increased leak detection and repair (LDAR) inspections for well production facilities;
- Greenhouse gas intensity program; and
- Emission reduction requirements for well maintenance and unloading activities.

III.A. Leak Detection and Repair Inspections at Well Production Facilities in Disproportionately Impacted Communities: Regulation Number 7, Part D, Section II.E.4.e

Regulation Number 7, Part D, Section II.E.4.d requires well production facilities located within 1,000 feet of an occupied area to inspect in accordance with the frequency specified in Table 3. The Division's proposal in this rulemaking would expand those requirements to all well production facilities in a DI community, whether or not located within 1,000 feet of an occupied area. The Division does not currently have reasonably available data on how many additional facilities would be inspected as a result of this proposal, though it anticipates having that analysis by the submission of the Division's final EIA in this action. Based on information submitted in the 2019 rulemaking, the Division does not expect many facilities in the 8-hour Ozone Control Area to require additional inspections as a result; the Division expects that the majority of new inspections will be at facilities outside the 8-hour Ozone Control Area, given the large size of disproportionately impacted communities as set by HB 21-1266. The Division - as staff to the Commission - requests information from stakeholders to assist in evaluating the costs of this proposal.

III.B. Leak Detection and Repair Inspections at Newly Constructed Well Production Facilities: Regulation Number 7, Part D, Section II.E.4.f

<u>Inspections</u>

Currently, well production facilities conduct AIMM inspections at a frequency determined by their VOC emissions in accordance with Regulation Number 7, Part D, Sections I.L or II.E, as applicable. As production decreases, and resulting VOC emissions from storage tanks decrease, the inspection frequency also decreases. The Division's proposal would "freeze" newly constructed well production facilities at a monthly AIMM frequency. The Division's proposal would also provide for exceptions where operators are using automated systems that are designed to minimize emissions from storage tanks and combustion devices, and where operators continue use of monitoring technology approved by the Division under Regulation Number 7, Section VI, for VOC and methane.

Table 16 below identifies how many additional inspections would be required on average each year, for the first five year,of a newly constructed well production facility's operation as a result of the Division's proposal, assuming every facility stays at the proposed monthly schedule.[53]

Table 16: AIMM Inspection Schedule by Area of State			
Proposed AIMM Inspection Schedule in Years 1 - 5			
Year of Program	**Existing Regulation Frequency under Section II.E**		
	AIMM Frequency 8-hour Ozone Control Area (not Proximity to Occupied Area)	**AIMM Frequency Proximity to Occupied Area**	**AIMM Frequency ROS (not Proximity to Occupied Area)**
Year 1	Monthly	Monthly	Monthly
Year 2	Quarterly	Monthly	Quarterly
Year 3	Semi-annual	Quarterly	Semi-annual
Year 4	Semi-annual	Quarterly	Semi-annual
Year 5	Annual (NAA)	One-time (ROS) Annual (NAA)	One-time (ROS)
Summary of New Upstream AIMM Inspections Required			
	AIMM Frequency 8-hour Ozone Control Area (not Proximity to Occupied Area)	**AIMM Frequency Proximity to Occupied Area**	**AIMM Frequency ROS (not Proximity to Occupied Area)**
Additional AIMM Inspections Through Year 5 Per Facility	39	27	40
Number of New Facilities per year	55	31	5
Average # of Total Inspections Required EachYear	**1,023**	**316**	**93**

[53] The Division conducted an analysis of a small sample of wells spud in 2016 based upon COGCC data (for both inside and outside the 8-hour Ozone Control Area) and compared the year over year decrease in production. The Division then applied this decline rate to estimate how quickly a newly constructed well production facility would drop AIMM frequencies, assuming that in year 1 uncontrolled actual VOC emissions would be over 50 tpy.

The Division looked at COGCC data for 2020 to determine how many new facilities are constructed each year. The Division identified 91 new well sites (based upon unique location IDs) constructed in 2020 - 74 in the 8-hour Ozone Control Area and 17 outside the 8-hour Ozone Control Area.[54] Because current AIMM inspection tier is based upon proximity to an occupied area (*see* Section II.E, Table 3), the Division applied the percentage of population in a DI community both inside and outside the 8-hour Ozone Control Area to determine how many new well production facilities might be expected to be subject to the proximity requirements. Ultimately, the Division determined that each year, it was assumed that 31 new well production facilities would be constructed in proximity to an occupied area, 55 new well production facilities would be constructed in the 8-hour Ozone Control Area but not in proximity to an occupied area, and five new well production facilities would be constructed outside the 8-hour Ozone Control Area and not in proximity to an occupied area. In the Initial EIA, the Division's cost and emission estimates were based on new inspections at just the facilities added in the first year. In this Final EIA, the Division has estimated costs and emission reductions assuming 91 new facilities with a monthly AIMM requirement are added each year through Year 5.

The Division took the same approach to estimate inspection time, inspection costs, and repair costs as with the midstream segment leak detection program for compressor stations. Table 17, below demonstrates the total inspection costs for years 1 through 5, based on the number of new inspections that will be required of new well production facilities in each year. The average annual inspection cost to all operators across the three areas is $1,828,256.

Table 17: Average Annual Inspections and Inspection Cost

Location of Site	Average # of New Inspections Per Year	Averaged Annual Inspection Cost
8-hour Ozone Control Area (not in proximity to Occupied Area)	1,023	$1,305,897.15
Proximity to Occupied Area	316	$403,640.94
ROS (not in proximity to Occupied Area)	93	$118,717.92

Leak Repair

In this analysis, the Division uses an average scaled monthly leak frequency rate of 2.36%, based on EPA data.[55] Using a similar approach as before to estimate component repair time and component repair cost, the Division estimates that a total of 19.93 repair hours per year per facility will be required to address leaks discovered by the new inspection requirements. Again using a repair cost rate of $82.06 per hour, total annual repair hours and costs under each AIMM frequency requirement are demonstrated in Table 18, below. The total average annual repair cost is estimated to be $257,093.65.

[54] The Division also reviewed data submitted through its APEN system, and also identified 91 APENs submitted for the first time in 2020, though the Division's data shows 59 new sites in the 9-county area and the remaining 32 sites outside the 9-county area.
[55] Control Techniques Guidelines for the Oil and Natural Gas Industry 2016, EPA, p. 8-7.

Table 18: LDAR Repairs - Years 1-5						
8-hour Ozone Control Area (not Proximity to Occupied Area)						
	Number of Affected Facilities, Total	**Leak Rate (monthly)**	**Repair Hours per Facility**	**Total Repair Hours, all Facilities**	**Repair Cost per Hour**	**Total Repair Cost, all Facilities**
Year 1	0	2.36%	19.93	0	$82.06	$0.00
Year 2	55	2.36%	19.93	1,096.15	$82.06	$89,950.07
Year 3	110	2.36%	19.93	2,192.30	$82.06	$179,900.14
Year 4	165	2.36%	19.93	3,288.45	$82.06	$269,850.21
Year 5	220	2.36%	19.93	4,384.60	$82.06	$359,800.28
Total over 5 years						**$899,500.69**
Average per year						**$179,900.14**
Proximity to Occupied Area						
	Number of Affected Facilities, Total	**Leak Rate (monthly)**	**Repair Hours per Facility**	**Total Repair Hours, all Facilities**	**Repair Cost per Hour**	**Total Repair Cost, all Facilities**
Year 1	0	2.36%	19.93	0	$82.06	$0.00
Year 2	0	2.36%	19.93	0	$82.06	$0.00
Year 3	31	2.36%	19.93	617.83	$82.06	$50,699.13
Year 4	62	2.36%	19.93	1235.66	$82.06	$101,398.26
Year 5	93	2.36%	19.93	1853.49	$82.06	$152,097.39
Total over 5 years						**$304,194.78**
Average per year						**$60,838.96**
ROS (not Proximity to Occupied Area)						
	Number of Affected Facilities, Total	**Leak Rate (monthly)**	**Repair Hours per Facility**	**Total Repair Hours, all Facilities**	**Repair Cost per Hour**	**Total Repair Cost, all Facilities**
Year 1	0	2.36%	19.93	0	$82.06	$0.00
Year 2	5	2.36%	19.93	99.65	$82.06	$8,177.28
Year 3	10	2.36%	19.93	199.30	$82.06	$16,354.56
Year 4	15	2.36%	19.93	298.95	$82.06	$24,531.84
Year 5	20	2.36%	19.93	398.60	$82.06	$32,709.12
Total over 5 years						**$81,772.79**
Average per year						**$16,354.56**

Emission Reductions

The Division uses the same analysis here as it did in 2014, 2017, and 2019 to estimate emission reductions from this program (using updated gas speciation data). The Division calculated emission reductions achieved in each area of the state, in each year of the program, based on the total number of facilities entering the program over five years. The Division calculated an average emission reduction achieved per facility, for VOC and methane. The Division then summed up the total emission reductions achieved over the first five years of the program and averaged it to create an annual emission reductions figure, as set forth in the table below.

Table 19: New WPF Monthly LDAR Emission Reductions by Year				
Year of Program	**Number of Facilities in Program**	**VOC (tpy)**	**CH4 (tpy)**	**GHG (mtCO2e/yr)**
1	**91**	0.00	0.00	0.00
2	**182**	59.04	57.48	1,460.06
3	**273**	172.83	180.53	4,585.62
4	**364**	345.67	361.06	9,171.25
5	**455**	752.19	802.32	20,379.87
Total		**1,329.73**	**1,401.38**	**35,596.81**
Annual Cost, averaged over 5 years		**265.95**	**280.28**	**7,119.36**

Value of Natural Gas Recovered

In Table 20, the Division estimates the value of natural gas recovered from these additional leak inspections.

Table 20: Upstream Recovered Natural Gas Value from Leak Repairs		
Average Annual Recovered Methane (tpy)	**Value of Natural Gas ($/ton methane)[56]**	**Total Annual Value of Recovered Natural Gas**
280.28	$274.48	$76,929.81

Reporting

The Division's proposal also requires operators to submit information about leaks detected in their monthly reports under Section VI, for their air quality monitoring during preproduction and early production. This will enable the Division to better evaluate the capability of the air quality monitoring plan to detect leaks. The Division assumes no additional costs associated with this reporting.

[56] Based on the recent United States Natural Gas Industrial Price (May 2021), of $4.09/MCF as provided for by the U.S. Energy Information Administration, using an average molecular weight of 24.01 lb/lb-mol of natural gas and 47.08% statewide average of methane by weight.

Cost Effectiveness

As noted before, the total cost of inspections across operators is estimated to be $1,828,256.00 per year, and the total cost of repairs across operators is estimated to be $257,093.65 per year. This results in a total annual cost of $2,024,139.40, after gas recovery is taken into account. As outlined in Table 21, the Division estimates an overall cost effectiveness of $9,973.02 per ton VOC and $357.33 per mtCO2e.

Table 21: Upstream LDAR Total Annual Cost			
LDAR Total Annual Cost			
	Inspection	**Repair**	**TOTAL**[57]
Annual Cost	$1,828,256.00	$257,093.65	$2,085,349.66
Recovered Natural Gas			-$76,929.81
Net Cost			**$2,008,419.84**
New WPF AIMM Emissions Reduction and Cost			
Total Annual VOC Emission Reduction (VOC)	**Cost per ton VOC**	**Total Annual GHG Emission Reduction (mtCO2e/year)**	**Cost per mtCO2e**
265.95	**$7,551.97**	**7,119.36**	**$282.11**

III.C. Greenhouse Gas Intensity for Preproduction Emissions and Production Emissions: Regulation Number 22, Part B, Section IV

The Division is proposing to establish a greenhouse gas intensity program for the upstream segment of the oil and gas industry. This program creates greenhouse gas emission intensity targets, determined on an operator-level basis. The GHG intensity value is a product of total GHG emissions divided by oil and gas throughput. The intensity program will cover preproduction emissions and production emissions.

Based on an analysis of emissions and production data reported to the EPA under the GHGRP, the Division determined that there is currently an extremely wide range of GHG intensities across upstream operators. The reports show operator GHG intensities across the industry that range from 3 to over 100. The Division also calculated GHG intensities based upon 2020 production reported to COGCC and the emissions reported to the Division pursuant to Regulation Number 7, Part D, Sections II.G and V, and found an even broader range of intensities. The Division determined that a GHG intensity program will result in meaningful reduction, while providing operators with the flexibility to identify and achieve cost-effective reductions across their facilities and operations.

To calculate the intensity targets in the proposed regulation, the Division started with the data for the 2005 baseline in the GHG Roadmap inventory for the oil and gas sector, and with the information in the 2015 baseline in the GHG Roadmap inventory for the Industrial sector. The Division first used the 2005 baseline emissions for the O&G Sector from the GHG Roadmap, a total of 20,205,859 mtCO2e[58], and determined what portion of those emissions were attributable to upstream operations. The Division added up the venting and flaring emissions statewide, with the well production facility fugitive

[57] The recovered natural gas cost and the net costs were incorrect in the Final EIA Table 21. The correct values are included in this table. The cost per ton of VOC and GHG were correct in the original table, and are unchanged in this version.
[58] Updated from the Initial EIA.

emissions statewide, with 84% of the total “catchall” emissions covering both the upstream and midstream segment.[59] The Division therefore calculated that the upstream baseline in 2005 was 15,184,909 mt CO2e. From there, the Division applied a 36% reduction for 2025, a 50% reduction for 2027, and a 60% reduction for 2030. As it pertains to the Industrial sector, the Division determined that the 2015 baseline for oil and gas emissions in the industrial sector was 2,690,692 mtCO2e, based upon a split of 44/56% (upstream/midstream) of the emissions associated with lease fuel consumption as reported to EPA, and attributing all the natural gas processing fuel consumption to midstream. Based on GHG Roadmap values, the Division also assumed all diesel emissions in the industrial segment from oil and gas activities were associated with upstream operations (880,000 mtCO2e in 2015). The Division assumed no emission reductions were required in 2025, a 10% reduction would be required by 2027, and a 20% reduction is required by 2030.

Using the production forecasts from the GHG Roadmap for both oil and natural gas, the Division calculated a projected total production in BOE (using 5800 scf/BOE) for 2025, 2027, and 2030. The Division then calculated an average intensity in the years 2025, 2027, and 2030 (using the emissions as determined in the preceding paragraph as the numerator and the production forecasts as the denominator). These intensities are shown in Table 22, below in the “Overall Upstream Intensity” column. The Division then calculated majority operator and minority operator targets. Majority operators were defined by production levels of 10,000,000 BOE in calendar year 2022; in 2020, the operators with this level of production represented over 80% of the total production in the state. The majority operator targets were calculated by multiplying the overall upstream intensity target by 70%; the operators with the largest production, and therefore the largest share of the emissions on a mass basis, should have more stringent intensity targets. The Division then multiplied the overall upstream intensity target by 2.2, to get the minority operator target.

Table 22: Calculated Intensities

Year	Overall Upstream Intensity	Majority Operator Target	Minority Operator Target
2005	80.3356		
2025	15.6329	**10.94**	**34.39**
2027	12.0906	**8.46**	**26.60**
2030	9.7186	**6.80**	**21.38**

From the 2005 baseline in the GHG Roadmap, the Division determined that the intensity program is an enforceable mechanism to ensure operators reduce GHG emissions from the upstream segment of the oil and gas industry in the following amounts:

Table 23: Total GHG Reductions Enforced By the Intensity Program

Year	Total CO2e Reductions from 2020[60] (mtCO2e per year)
by 2025	4,510,867
by 2027	5,452,806
by 2030	6,128,866

[59] To generate a 84/16% split (upstream/midstream) of these catch-all emissions, the Division developed a ratio based on the emissions for covered equipment as reported to EPA under the GHGRP for upstream as compared to midstream gathering and boosting. The Division then applied that ratio to the catch-all emissions (but not the downstream catch-all). The same general approach was used to develop the 44/56% (upstream/midstream) split of lease fuel emissions.
[60] Emission reductions calculated from the reported July - December 2020 emissions, rolled into year long emissions by multiplying reported emissions by 2, assuming 2020 production throughput in 2025, 2027, and 2030 with the required intensities applied to majority and minority operators.

These numbers in Table 23 include reductions achieved under other components of the Division proposal (e.g., well liquids unloading controls). These reductions are not expected as a result of the intensity program alone. In fact, these estimates assume that operators will take no steps over and above the emission reduction measures employed in the second half of 2020, and don't account for reductions better attributed to the following rules and requirements, without limitation:

- Additional storage tank controls adopted in late 2019;
- Requirements for storage tank measurement systems and truck liquids loadout adopted in late 2019;
- New reporting and permitting requirements for routine or predictable emissions (ROPE);
- Engine retrofits and reductions adopted in 2020;
- Preproduction flowback controls adopted in 2020;
- Non-emitting pneumatic controller requirements adopted in 2021;
- The impact of COGCC's new regulations, including Rules 303 and 903; or
- Any of the Division's direct regulation proposals in this rulemaking.

The Division's proposal also includes several additional provisions that act as guard-rails to ensure the upstream segment reduces emissions to meet the requirements of §25-7-105(1)(e)(XII), C.R.S. The Division has proposed an even more stringent intensity target for new well production facilities, at 78.5% of the majority operator target. The Division has, as discussed in more detail in other sections of this Final EIA, proposed additional requirements for LDAR inspections and well maintenance emission reductions that - when taken together with the suite of regulations adopted by the Commission over the past several years (e.g., the 2021 pneumatics rule, the 2020 flowback control rule) and the COGCC mission change provisions - make up most of the reductions that the Division expects will achieve the intensity targets, and keep Colorado on track to meet its GHG goals. The Division's intensity program also includes recordkeeping and reporting, which the Division has treated as covered costs under the analysis above.

Cost Effectiveness of Intensity

The costs associated with meeting GHG intensity targets will range widely across the industry. The EPA provides recommendations for technologies to reduce methane emissions.[61] There are multiple studies and presentations available to operators to find cost effective and technically feasible reductions at different types of well production facilities. The actual costs incurred by implementation of emission control technologies will depend on the amount of emissions that need to be reduced by each operator (at each facility), the technical feasibility of implementing available technologies, and the cost-effectiveness and economic feasibility of the technology. Some operators will make meaningful progress towards the intensity targets through compliance with existing and proposed Commission regulations (e.g., the 2021 pneumatics rule, or this well unloading proposal). However, the Division has determined that the flexibility inherent in an intensity program renders this strategy cost-effective.

The Division reasons that costs associated with reaching intensity targets will be at least as cost effective as the cost effectiveness of direct regulations. In the February 2021 rulemaking on pneumatic controllers, the final EIA estimated a cost per ton reduction for methane of $499/ton, which converts to $19.65 per metric ton CO2e. If that cost per ton is applied to the emission reductions guaranteed for 2025 by the intensity program - subtracting out the emission reductions in this proposal from other measures affecting the upstream segment - the Division calculates a total cost of $85,497,247.07. However, the Division does not believe that the intensity program will have anywhere near this level of cost, because so many of the emission reductions guaranteed by the program will result from direct regulations already adopted by the Commission, other permitting programs of the Air Division and the Colorado Oil and Gas Conservation Commission, and voluntary initiatives undertaken by the industry.

[61] Recommended Technologies to Reduce Methane Emissions | US EPA

Implementation of methane control technologies can result in realized benefits to operators associated with gas recovery. Gas that is reclaimed, rather than being vented to the atmosphere or combusted, can be sold. At a nominal gas price, operators could achieve significant additional revenue from the sale of reclaimed gas. Further, significant economic benefits for operators are derived from this GHG intensity program, because participation in an intensity program can qualify an operator for certification of its product as “green” or “responsibly sourced”, thus allowing operators to charge a premium.

In the Initial EIA, pursuant to § 25-7-110.5(4)(c), C.R.S., the Division - as staff to the Commission - requested additional information on the costs and other regulatory impacts of an intensity program. The Division received no information between the Initial EIA and this Final EIA.

III.D. Emission Reductions From Well Maintenance and Liquids Unloading Activities, Regulation Number 7, Part D, Section II.G

The Division’s proposal would augment existing requirements for best practices to be employed during all well maintenance activities. The Division’s proposal would also require the use of technology to minimize the need to conduct well unloading activities or would require the control of unloading emissions.

Thus far in 2021, 22 operators have reported conducting well unloading events to the COGCC, and these 22 operators reported a total of 13,593 events by June 30, 2021.[62] Of these events 3,670 are in the 9-County area across 12 operators, while the remaining 9,923 events are outside the 9-County area, across 11 operators.

The Division conducted an analysis of average scf of gas vented per event, and determined that there is a statewide average of 14,000 scf of natural gas emitted per well unloading event.[63] The Division analyzed data submitted with registrations for General Permit 11, as well as results from operators that used flow meters to directly measure the amount of gas emitted during well unloading.

III.D.1. Best Practices

Regulation Number 7, Part D, Section II.G has, for years, required operators to use best management practices when conducting well maintenance operations. The Division assumes no significant additional costs will be incurred as a result of the Division’s proposal for the use of best practices other than artificial lift. The Division’s proposal would require that all wells that undertake well liquids unloading activities install and use artificial lift to reduce emissions from those activities, subject to limited exceptions.

[62] This is based upon data received by the Division from COGCC in early July 2021, and attached to the Division’s Prehearing Statement. Based upon data reported to the Division directly from operators, over 40 operators identified conducting well maintenance events - such as well unloading or well swabbing - in their annual emission reports to the Division for 2020. This suggests that the number of events reported to the COGCC is low, because some operators may not have reported. The Division has not yet been able to determine which operators reporting events to the Division did not report to COGCC.
[63] Based upon studies of well unloading activities, this number is likely very conservative. *See* Allen et al., Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings, 2014.

Plunger Lift Systems

Plunger lift systems use well shut-in pressure build-ups to lift columns of liquid out of the well without the need to vent the gas to the atmosphere.[64] Plunger lifts have a significant economic benefit to the operator - boosting gas production. Automation can further enhance the performance of plunger lifts by monitoring wellhead parameters and thereby optimizing plunger operations.[65] The Division understands that even where the use of plunger lifts does not entirely avoid the need for unloading, the use of the plunger lift can reduce the volume of gas vented per well unloading event. Natural Gas STAR materials estimate a savings of 500-600 Mcf/year for an average well requiring unloading. Smart automation controllers can also avoid the need for site visits associated with unloading activities, further reducing costs to operators. Maintenance costs are also reduced; plunger lifts can prevent particulate buildup inside the tubing, avoiding or reducing the need to conduct swabbing operations. Based upon information from EPA and other Natural Gas STAR materials, the Division estimates basic plunger lift installation costs of approximately $1900-$7800 (for this analysis, the Division used a median figure of $4,850). This figure includes installing the piping, valves, controller and power supply. Annual maintenance costs are estimated at $700-$1300 (the Division again used a median figure of $1,000), and smart automation controllers are estimated at $11,000 per controller. Assuming a life of 10 years for the plunger lift and smart automation controller, the annualized cost of a plunger lift system is $3,838.

Natural Gas STAR partners have also reported benefits of up to 18,250 Mcf per well in increased gas production. The Division estimated revenue from avoided emissions by calculating the market value of the gas by the volume of avoided emissions. The Division's analysis suggests a conservative average of 14,000 scf per well unloading event. The Division does not have data on how many events are, or could be, entirely avoided - instead of just minimized - through the use of plunger lifts. The Division does, however, understand that most wells in the state that require unloading already employ plunger lifts.

However, assuming that at wells where plunger lift is not currently installed it is installed, and that plunger lifts are installed on new wells as they begin to require unloading, the Division's proposal will achieve emission reductions using a technology that is already widely deployed here in Colorado, with limited additional costs (the cost increase from using smart automation as compared to a regular plunger lift control is negligible). Assuming that plunger lifts would completely avoid the emissions from ⅛ of future unloading events, and assuming those occur on the same frequency as they did in early 2021), the Division's proposal would reduce 389.24 tpy VOC and 17,961.80 tpy CO2e just from unloading events avoided, with a cost per ton reduced of $10 per ton VOC, $6 per ton methane, and a negligible cost (<$1/ton) for reductions of CO2e.

III.D.2. Well Unloading Emission Reductions

Under the Division's proposal, operators will be required to capture and recover emissions from well liquids unloading or use air pollution control equipment to combust the hydrocarbons emitted during liquids unloading. Well swabbing is included in these calculations as well swabbing is essentially well liquids unloading that requires the use of a specialized rig (a "swabbing rig").

Control Equipment

The Division's proposal would require the capture or control of emissions from unloading through the use of control equipment. In the Initial EIA, the Division assumed that operators would use a temporary

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[64] *Liquids Unloading Options for Natural Gas Wells*, 2012 Natural Gas STAR Annual Implementation Workshop, April 12, 2012.
[65] *Lessons Learned from Natural Gas STAR Partners: Installing Plunger Lift Systems in Gas Wells*, EPA, October 2006.

open flare to control emissions during well unloading. The Division assumed that operators would have to rent an open flare for each unloading event. This resulted in a high cost that has been adjusted in this Final EIA.

After multiple discussions, the Division now understands that operators will likely comply by purchasing open flares. Then, depending on whether the site configuration has room for a dedicated flare, the operator will either install a dedicated flare or will purchase a portable flare and use it at multiple sites. The Division, therefore, assumed that operators will purchase and operate a flare at each well production facility where unloading controls will be required. While some operators may use a portable flare, which could result in higher annual operating costs (travel, etc.), fewer open flares will need to be purchased, which lowers capital costs. The Division believes its cost analysis therefore remains conservative. Based on COGCC data on the frequency of well unloadings, the Division's proposal would require controls at 526 well production facilities.

To estimate emission reductions, the Division analyzed over 100 samples of gas composition of sales gas, across the DJ Basin, Piceance Basin and the eastern plains. From this data, the Division derived a statewide average gas composition as a percentage of total hydrocarbons in Table 24. From this gas composition, and using the calculated average scf/event described above, the Division calculated an estimated average lb/event for the following pollutants.

Table 24: Well Unloading Emissions Data

Well Unloading	wt% of TOC	DJ Basin (lb/event)	Piceance (lb/event)
Methane	53.31%	421.5	516.9
VOC (NMNE)	29.35%	237.5	64.9

Assuming 95% reduction in emissions from well unloading results in a reduction of 2,234.84 tpy VOC and 103,128.16 CO2e (calculated only by looking at methane reductions; this number would be significantly higher if the Division took into account the global warming potential of ethane). The Division did not have data on the annual maintenance and operating cost associated with a dedicated open flare. Cost estimates for enclosed combustion devices in previous rulemakings have used a significantly lower annualized maintenance cost; in 2019, the Division assumed just under $3,000 per year for annual maintenance of a flare. Here, the Division attempted to use EPA's cost calculator and derived a higher capital expenditure. To be conservative, the Division evaluated this proposal using two different annual maintenance costs. The Division estimates the cost effectiveness of control as set forth below:

Table 25: Well Unloading Control - Emissions and Cost Effectiveness					
Cost Effectiveness at $10K Annual Maintenance					
Well Site Description	**Total VOC Reduced (tpy)**	**Total CO2e Reduced (mtCO2e/yr)**	**Annualized Cost at $10K Annual Maintenance**	**VOC Cost ($/ton)**	**CO2e Cost ($/ton)**
Inside DI Community: ≥6 unloadings per facility	685.17	31,617.85	$4,512,086.27	$6,585.31	$142.71
Outside of DI Community: At least 1 well w/ ≥6 unloadings per well	1,379.59	63,661.97	$7,328,141.06	$5,311.84	$115.11
Outside of DI Community: ≥10 unloadings per facility (Not including those with 1 well ≥6 unloadings per well)	170.08	7,848.34	$1,443,968.68		
TOTAL	2,234.84	103,128.16	$13,284,196.01		
			Average Total Cost Per Ton	$5,944.14	$128.81
Cost Effectiveness at $50K Annual Maintenance					
Well Site Description	**Total VOC Reduced (tpy)**	**Total CO2e Reduced (mtCO2e/yr)**	**Annualized Cost at $50K Annual Maintenance**	**VOC Cost ($/ton)**	**CO2e Cost ($/ton)**
Inside DI Community: ≥6 unloadings per facility	685.17	31,617.85	$11,654,586.27	$17,009.66	$368.61
Outside of DI Community: At least 1 well w/ ≥6 unloadings per well	1,379.59	63,661.97	$18,928,373.06	$13,720.33	$297.33
Outside of DI Community: ≥10 unloadings per facility (Not including those with 1 well ≥6 unloadings per well)	170.08	7,848.34	$3,729,728.68	$21,929.59	$475.23
TOTAL	2,234.84	103,128.16	$34,312,688.01		
			Average Total Cost Per Ton	**$15,353.55**	**$332.72**

Based on the COGCC data, the Division's proposal would require capture or control at approximately 29% of well production facilities with unloadings and would cover 75.5% of the total unloading events.

In the Initial EIA, the Division - as staff to the Commission - requested information from stakeholders to inform the costs associated with this proposal. The Division did not receive cost information from stakeholders, but used EPA's cost calculator to generate updated conservative cost estimates for the open flares.

IV. Annual Emissions Inventory Reporting Updates

The Division's proposal also includes updates to Regulation Number 7, Part D requirements for annual emissions inventory reports. The majority of these updates have no associated additional cost and are absorbable costs associated with the existing requirements to prepare and submit annual emission inventory reports. However, the Division is proposing that owners and operators who choose not to use Division-approved default emission factors, and who choose to use site-specific emission factors, must undertake periodic sampling analyses - every three years - to verify the efficacy of those factors on an ongoing basis. These are avoidable costs, because operators may use state default factors.

The Division has nonetheless estimated the costs of sampling. For this Initial EIA, the Division assumes that fifty percent (50%) of sources will use the state default factors and that fifty percent (50%) will use site-specific factors and therefore be subject to the periodic sampling requirements. As noted above, the Division has determined there are 5,808 storage tank batteries statewide, and therefore assumes that operators will conduct periodic sampling at 2,904 locations. The Division assumes that each sampling event will require two samples - one sample of sales gas and one sample of tank vapors.

All composition analyses are assumed to be completed by a third party-testing company. Based upon information provided by operators, the Division estimates an average cost per sample of $535. The Division assumes that two samples will be required per tank battery, for a per-tank battery cost, every three years, of $1,070, which the Division believes is absorbable by operators. Assuming every tank battery in the state chooses to use a site-specific emission factor and therefore must conduct this sampling, the Division estimates an annualized cost (across a 3 year sampling period) of $2,467,213. If fifty percent of tank batteries choose the site-specific option, the annualized cost is $1,233,607.

Pursuant to § 25-7-110.5(4)(c), C.R.S., the Division requests additional information on the costs and other regulatory impacts described in this initial EIA on these and any other potentially impacted supporting businesses or industrial sectors.

V. Social Cost of Greenhouse Gas Analysis

The "social cost of carbon" is a measure of the economic harm from those impacts, expressed as the dollar value of the total damages from emitting one ton of carbon dioxide into the atmosphere. HB 21-1266 states "for a rule that implements § 25-7-105(1)(e) that may materially affect greenhouse gas emissions, the economic impact analysis required by this subsection (4) must include an analysis of the social cost of greenhouse gases related to the estimated emission reductions from the proposed rule." Pursuant to HB 21-1266, this analysis uses the social cost of greenhouse gas estimates, using a 2.5 percent discount rate, provided by the Federal Interagency Working Group on the Social Cost of Greenhouse Gases, pursuant to Federal Executive Order 13990.[66] It is important to note that the social cost of greenhouse gases increases over time, to account for projected increases in the incremental damages and resulting economic impacts of climate change in the future. Table 26 below presents the estimated social benefits of emissions reductions that will result from this proposal from 2023 to 2030. Emission reductions are expected to begin being achieved in 2023. The estimated benefits are discounted to present (2021) dollars using the same discount rate of 2.5 percent.

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[66] Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (Feb. 2021)), 5-6, Tables ES-1, ES2, and ES3.

Table 26: Social Cost of Greenhouse Gases				
Year	**Social Cost of Carbon ($/mtCO2e)**	**Emission Reductions (mtCO2e)**	**Social Benefit**	**Present Value (2021 $)**
2023	$80.34	530,912.98	$42,653,018.02	$40,597,756.59
2024	$81.65	530,912.98	$43,346,390.37	$40,251,432.56
2025	$82.95	4,510,867.00[67]	$374,180,928.52	$338,989,453.46
2026	$84.26	4,510,867.00	$380,072,120.82	$335,928,373.59
2027	$85.56	5,452,806.00	$466,558,439.78	$402,311,880.41
2028	$86.87	5,452,806.00	$473,679,804.41	$398,490,352.01
2029	$88.18	5,452,806.00	$480,801,169.05	$394,615,910.74
2030	$89.48	6,128,866.00	$548,417,058.55	$439,133,092.86

Table 26 presents expected annual emission reductions through 2030. The annual emission reductions are multiplied by the social cost of carbon in each respective year to determine a monetized value of the stream of future damages produced by emissions in each year. As these emissions are being reduced, however, this value also represents the monetized benefit to society of a decrease in emissions and avoided future damages. As the social cost of greenhouse gas increases in each respective year, so does the resulting economic benefit to society. Because the social benefit estimate in each year is from the respective year's perspective, the estimated social benefit in each future year is then discounted to present (2021) dollars in order to account for inflation and understand the value of future benefits from today's perspective.

As Table 27 demonstrates, the benefits to society of avoided damages from greenhouse gas emissions are significant. Table 27 below incorporates both the total estimated annual costs (in present, 2021 dollars) and total estimated annual social benefits (in present, 2021 dollars) to determine a net present value in each respective year. The Division anticipates that after 2024, the benefits to society from reducing emissions far outweigh the costs to operators in achieving the reductions. It is important to note, however, that the scope of the realized benefits is not limited to the areas most impacted by the proposed rules, nor only the State of Colorado, but rather, society as a whole. Looking at years 2023 to 2030, the total net present value is estimated to be $1,662,859,483.52; all a benefit to society.

[67] The Division, again, believes that the majority of these reductions will be achieved earlier. However, the Division - for purposes of this EIA - has calculated social cost of greenhouse gas based upon an analysis that assumes the intensity program will ensure these reductions are achieved in 2025-2030.

Table 27: Net Benefits to Society				
Year	Emission Reductions (mtCO2e)	Present Value of Costs (2021 $)	Present Value of Benefits (2021 $)	Net Present Value (2021 $)
2023	530,912.98	$39,479,989.20	$40,597,756.59	$1,117,767.39
2024	530,912.98	$38,517,062.64	$40,251,432.56	$1,734,369.93
2025	4,510,867.00	$115,033,908.20	$338,989,453.46	$223,955,545.27
2026	4,510,867.00	$112,228,203.12	$335,928,373.59	$223,700,170.47
2027	5,452,806.00	$109,490,929.87	$402,311,880.41	$292,820,950.54
2028	5,452,806.00	$106,820,419.39	$398,490,352.01	$291,669,932.63
2029	5,452,806.00	$104,215,043.30	$394,615,910.74	$290,400,867.44
2030	6,128,866.00	$101,673,212.98	$439,133,092.86	$337,459,879.88

IMPACTS TO DIVISION

The Division anticipates impacts to the Division's workload as part of implementation of its proposal. The Division believes that this workload impact will be handled by current and anticipated staff. The Division has hired or is hiring an Air Quality Policy Engineer, additional performance test coordinators, and program implementation staff. The Division is also currently building a database to manage the annual emission reports submitted by operators under Regulation Number 7, Part D, Section V.

SUMMARY AND CONCLUSION

The Division prepared this Final Economic Impact Analysis in accordance with the requirements of § 25-7-110.5), C.R.S. Specifically, the Division utilized the methodology identified in § 25-7-110.5(4)(c)(III), C.R.S.

The Division has determined that there may be costs related to the proposed revisions potentially impacting owner or operators of oil and gas operations including costs related to additional LDAR inspections, responsive actions, recordkeeping, and reporting; costs related to improving performance of air pollution control equipment; costs related to reducing other greenhouse gas emissions, as well as associated recordkeeping and reporting.

The Division projects that the proposal will reduce greenhouse gas emissions (in CO2e) by approximately 4,881,917.92 mtCO2e per year at a cost range of approximately $41,478,663.66 to $126,975,910.73 per year. The overall cost effectiveness for the entire package is between $8.50 and $25.68 per metric ton of CO2e reduced. The Division also estimates its proposal will reduce at least 8,289.66 tpy of VOC, not including VOC reduced by the intensity program (even though this program will certainly reduce VOC emissions as well). The proposal will also have additional unquantified emission benefits through reductions of ethane (which has a significant global warming potential and ozone benefits) and hazardous air pollutants such as benzene. Tables 28 and 29, setting forth the Division's cost-effectiveness analysis, do not take into account the social cost of greenhouse gas as discussed in the Section V of this Final EIA.

Table 28: Cumulative Cost Effectiveness[68]		
	GHG (mtCO2e)	**VOC (tons)[69]**
Total Average Emissions Reduced Per Year	4,881,917.92	8,289.66
Total Cost Effectiveness - No Cost Attributed to Intensity		
Total Annual Cost	$41,478,663.66	
Total Cost Effectiveness	$8.50/mtCO2e	$5,003.67/ton VOC
Total Cost Effectiveness - Cost Attributed to Intensity		
Total Annual Cost	$126,975,910.73	
Total Cost Effectiveness	$26.01/mtCO2e	$15,317.39/ton VOC

In the Initial EIA, the Division included no costs associated with the intensity program in the summary and overall cost effectiveness analysis. As discussed in this document above, the Division had difficulty estimating the cost of the intensity program as many of the emission reduction efforts toward this intensity goal are those already required and considered in past economic impact analyses by this Commission, or others. However, that seemed to potentially skew the cost effectiveness of this program significantly downward.

Therefore, to be conservative in this Final EIA, the Division also attributed a cost of $19.65 per metric ton CO2e reduction to the intensity program, which is reflected in both Tables 28 and 29. In these tables, you can see the summary of cost effectiveness both with and without the cost attribution for emission reductions credited to the intensity program for this purpose of this rule. The total emission reductions and costs considered in this overall costs analysis are listed in Table 29, broken out by rule program.

[68] Total emission reductions decreased from the Initial EIA due to the revisions to the reductions associated with the intensity program. The Division used the 2025 numbers for the intensity program in this Final EIA instead of the 2030 numbers. Also, the Division subtracted out from the 2025 intensity numbers those emission reductions associated with other components of this package that achieve reduction from the upstream segment.
[69] There are no assumed VOC emission reductions associated with the intensity program accounted for in this summary of VOC reductions, though there are likely to be emission reductions associated with the intensity program for VOC.

Table 29: Total Emission Reductions				
Rule Proposal	**Section of Rule**	**Total CO2e Reductions (mtCO2e/Year)**	**Total VOC Reductions (tpy)**	**Total Annual Costs**
Control Equipment Performance	Reg. 7, Section II.B	56,733.90	2,211.40	$14,655,253.00
Compressor Station LDAR	Reg. 7, Section II.E	2,897.64	41.00	$109,041.70
Gas Plant LDAR	Reg. 7, Section II.I	5,255.00	114	$383,578.00
Pigging/Blowdowns	Reg. 7, Section II.H	228,781.00	1,628	$9,290,705.04
Pneumatics at Gas Plants	Reg. 7, Section III	--	--	$0.00
Rod Packing at Gas Plants	Reg. 7, Section II.B.3	126,997.92	1,261.62	$498,143.51
Upstream LDAR	Reg. 7, Section II.E	7,119.36	798.87	$2,024,139.40
Upstream Intensity By 2025	Reg. 22, Section IV	4,351,005[70]	--	$85,497,247.07
Well Unloading	Reg. 7, Section II.G	103,128.16	2,234.84	13,284,196.01
Sampling	Reg. 7, Section V	--	--	$1,233,607
	TOTAL	**4,881,917.92**	**8,289.66**	
Cost Effectiveness Summary				
Cost Effectiveness without Intensity Cost		$8.50	$5,003.67	$41,478,663.66
Cost Effectiveness with Intensity Cost		$26.01	$15,317.39	$126,975,910.73

Based on the above analyses, the Division believes the proposed revisions are cost-effective. The Division has provided an estimate of costs based on reasonably available information and will consider any additional information provided by stakeholders. The Division as staff to the Commission requests that affected industry or any interested party submit information with regard to the cost of compliance with these proposed rule revisions.

[70] The intensity reductions included in this rule are based on the 2025 intensity target emission reductions, minus the emission reductions included in this rule for other aspects of the upstream GHG program.

REBUTTAL ALTERNATIVES AND REVISIONS TO FINAL EIA

The Division has made revisions[71] and updates to the Final Economic Impact Analysis, submitted with the Division's Rebuttal Statement, including:

- Better Performance of Air Pollution Control Equipment (Final EIA Section I.)
    - Alternative cost analysis for flow meters and performance tests using industry provided data, for comparison
    - Alternative analysis, but does not replace the analysis completed previously

- Leak Detection and Repair at Compressor Stations (Final EIA Section II.A.1.)
    - Revision and replacement of LDAR analysis for compressor stations, due to a revision in the Division's proposal
    - Replaces analysis of compressor station LDAR done previously

- Pneumatics Inspection Schedule for Compressor Stations (New Section)
    - New analysis for proposed new inspection frequency for pneumatic devices

- Leak Detection and Repair Inspections at Well Production Facilities (Final EIA Section III.A.)
    - Revision and replacement of LDAR analysis for well production facilities, due to a revision in the Division's proposal
    - Replaces analysis for well production LDAR from III.A., but does not replace the analysis completed previously

- Pneumatics Inspection Schedule for Well Production Facilities (New Section)
    - New analysis for proposed new inspection frequency for pneumatic devices

- Emission Reductions From Well Maintenance and Liquids Unloading Activities (Final EIA Section III.D.)
    - Alternative cost analysis for well unloading activities, to account for gas composition and unloading frequency differences within the state
    - Alternative analysis, but does not replace the analysis completed previously

- Greenhouse Gas Intensity Program (Final EIA Section III.C.)
    - Alternative analysis of the costs and emissions benefits based upon the EDF Initial EIA

I. Better Performance of Air Pollution Control Equipment

The Division reviewed information provided by industry groups, including the Joint Industry Workgroup (JIWG) and others[72], and adjusted the cost analysis associated with the proposed requirements to install and operate flow meters as well as to perform periodic performance tests on enclosed combustion devices. A complete summary of the result is in Table 30. The Division conducted an alternative analysis that included additional facility preparation costs not included in its analysis of performance test costs, engineering and installation costs associated with flow meters, and additional annual maintenance costs for flow meters. The Division excluded outliers in the information provided by the JIWG in their cost summaries.

[71] The Division also corrected typographical or transcription errors throughout this document, but true alternatives and revisions to the costs analysis are contained in this Rebuttal section.
[72] *See* JIWG_PHS_Ex-012.

The JIWG also included emission estimates that were far below those of the Division.[73] The JIWG's revised emissions benefit analysis appears to have been based on responses (but not actual test reports) received from a few testing companies.[74] However, the Division's analysis of emissions benefits was based on actual test report data received and reviewed by the Division, as well as actual emissions estimates in the Division's APEN and permitting database. Therefore, the Division believes that its data is more accurate and reliable, and maintained its Final EIA analysis to calculate the updated costs for comparison.

Table 30: Control Device Performance Economic Impact Revisions

Performance Test Costs			
	Final EIA	**JIWG PHS**	**Alternative Cost[75]**
Performance Test	$6,326.60	$8,225.00	$6,326.60[76]
Facility Prep by Operator[77]	$0.00	$7,912.50	$3,750.00
Total Performance Test Cost	$6,326.60	$16,137.50	**$10,076.60**
Flow Meter Costs			
	Final EIA	**JIWG PHS**	**Alternative Cost**
Flow Meter Cost	$2,439.00	$5,842.86	$5,842.86
Engineering and Installation	$0.00	$20,183.86	$11,092.58
Total Equipment Cost	$2,439.00	$26,026.72	$16,935.44
Useful Life	15 Years	8.4 Years	15 Years
Annual Maintenance Cost	$0.00	$682.67	$682.67
Annualized Flow Meter Cost[78]	$389.68	$3,781.09	**$3,388.45**
ECD Performance Improvement Cost Per Ton			
	Final EIA	**JIWG PHS**	**Alternative Cost**
VOC Emission Reduction (tpy)	2,211.40	202.97	2,211.40
VOC Cost per ton ($/ton)	$6,627.14	$324,559.89	**$22,451.77**
GHG Emission Reduction (mtCO2e/yr)	56,733.90	5,207.11	56,733.90
GHG Cost per ton ($/mtCO2e)	$258.32	$12,650.84	**$875.14**

[73] *See* JIWG_PHS_Ex-012, p.5.
[74] Id.
[75] The Division reviewed the JIWG PHS and excluded outliers from the operator submittals to determine the appropriate revisions to the facility preparation costs for performance tests as well as the engineering and installation costs for flow meters.
[76] The Division's cost estimate was based on multiple conversations with testing companies and operators, and the Division does not believe it requires adjustment upwards.
[77] The Division's Final EIA cost estimate included facility prep included in the costs provided by the testing company. JIWG insists that there are other preparatory costs.
[78] Annualized cost for flow meters differs between the JIWG PHS and the Division EIA, as the Division assumes 6% interest per year to create the amortized cost of the equipment, installation, and engineering design. JIWG included no interest in their annualized cost.

While the Division stands by the analysis from the Final EIA[79], even with the alternative calculations made, the requirement to install and operate flow meters and conduct performance tests on enclosed combustion devices remains cost effective.

II. Midstream Program(s)

The Division has revised the proposal for leak detection and repair of compressor stations with uncontrolled actual emissions less than 50 tpy of VOC, both in and out of DI Communities. The Division has also proposed to increase the inspection frequencies for pneumatic controllers at compressor stations to match the proposed leak detection and repair frequencies.

II.A. Leak Detection and Repair: Regulation Number 7, Part D, Section II.E

The Division has revised the proposal for inspections of compressor stations from quarterly for those outside of the nonattainment area ("NAA") that are also located in DI Communities, to require quarterly inspections for all compressor stations with uncontrolled actual emissions below 12 tpy VOC. However, given that compressor stations inside the NAA are already at a quarterly frequency, this would impact only the 75 compressor stations identified by the Division in the Final EIA.[80] Further, the Division is now proposing to require inspections bimonthly (six times per year) at compressor stations inside the NAA with emissions between 12 and 50 tpy VOC located in a DI Community or within 1000 feet of an occupied area. Compressor stations outside of the NAA within 1,000 feet of an occupied area would also have a bimonthly inspection frequency. This revised analysis replaces the analysis done in the Cost Effectiveness Analysis, III.A.1. Compressor Station LDAR: Regulation Number 7, Part D, Section II.E.d. and includes a number of updates to the cost analysis calculation from the Final EIA, including:

- The number of facilities affected by the rule has changed.
- The incremental change to costs associated with repair time[81] is reflected in this analysis.
- The estimated VOC emission reductions per facility were recalculated for the 9-County, Piceance, and remainder of the state, to account for incorrect use of VOC emission factors in the Final EIA.
- The Division estimated the repair hours and emission reductions associated with a new category of LDAR frequency (bimonthly).

The new proposal would require all compressor stations within a disproportionately impacted community (in the NAA) or within 1000 feet of an occupied area (statewide)[82] to be inspected six times per year (across the year, bimonthly). The new proposal also increases all remaining semi-annual inspections to quarterly. The Division assumed that 26.48% of compressor stations in the 9-County area and 32.98% of compressor stations in the Piceance Basin and remainder of state were also in DI Communities. The number of compressor stations affected by this rule proposal is in Table 31.

[79] Cost Effectiveness Analysis, I.E. Enclosed Combustion Device Performance Cost Effectiveness, p.12.
[80] Based on 2020 annual LDAR reporting, 75 compressor stations reported a semi-annual LDAR frequency.
[81] In the Final EIA, the Division attributed the full hours of repair time associated with the quarterly inspection frequency instead of the incremental change that occurred from semi-annual to quarterly.
[82] The Division assumed that percentage of compressor stations in DI communities also included compressor stations within 1,000 feet of an occupied area. Because the Division believes that the number of facilities outside the nonattainment area in a DI community is fewer than the number of facilities outside the nonattainment area that are within 1,000 feet of an occupied area, this assumption makes the Division's analysis conservative.

Table 31: CS LDAR Proposed Frequency[83]			
Compressor Station VOC Tier (tpy)	Number of Compressor Stations	Current Frequency	Proposed Frequency
ROS: <12	50	Semi-Annual	Quarterly
ROS: <12 - DI/prox	25	Semi-Annual	6x
Nonattainment Area[84]: <12 - DI/prox	9	Quarterly	6x
>12 - <50 - DI/prox	25	Quarterly	6x

Inspections

For this analysis, unlike in the Final EIA, the Division assumed that operators would use only infrared (IR) cameras to meet this increased inspection requirement. Table 32 includes a breakdown and analysis of the estimated leak inspection time and costs under the different possible conditions mentioned in the preceding section.

Table 32: CS LDAR Inspection Costs					
# Inspections	Inspection type	Inspection method	Total Inspection hours[85]	Cost per hour	Total cost
268	In-House	FLIR	3,420.4	$105.00	$359,140.74
	Contractor	FLIR	520.2	$137.00	$71,269.04
Totals			**3,940.6**		**$430,409.78**

At hourly inspection rates of $105 per hour for in-house and $137 per hour for contractors, the total cost to operators for completing the new LDAR inspections would therefore be $430,409.78 per year; or $3,948.71 per compressor station per year.

Leak Repair

The Division made the same assumptions to calculate leak repair costs as in the Final EIA, except this analysis uses the incremental change in repair hours associated with the proposed revisions. The Division also made a scaled assumption of leak rate for the new LDAR frequency of six times per year. Table 33 includes the leak rates assumed along with repair hours calculated according to the methodology laid out previously.

[83] This table does not include compressor stations for which there is no proposed change.
[84] Section II LDAR frequency does not distinguish between the nonattainment area and the remainder of the state, but Section I LDAR frequency for this category in the nonattainment area is already at quarterly, not semi-annual. For the purpose of this economic impact analysis, the Division accounted for the incremental change from quarterly to six times per year for compressor stations in the nonattainment area affected by this rule.
[85] The Division assumed 10.6 inspection hours for compressor stations with emissions less than 12 tpy VOC and 28.1 inspection hours for compressor stations with emissions above 12 tpy VOC.

Table 33: CS Repair Hours from LDAR Frequencies		
LDAR Frequency	Leak Rate	Repair Hours
Annual	1.18%	23.2
Semi-Annual	1.48%	29.1
Quarterly	1.77%	34.8
6x	1.92%	37.7
Monthly	2.36%	46.3

Using these assumed repair hours and the incremental change in frequency as outlined in Table 31, the Division calculated an increase of 600.8 repair hours. At a cost of $82.06/hour, the total repair cost is $49,301.65.

Emission Reductions

The Division uses the same analysis here as it did in 2014, 2017, and 2019 to estimate emission reductions from this program, though broken out by basin as opposed to by compressor station tier.[86] Further, the Division assumes that the inspection frequency of six times per year will gain a 70% reduction in emissions, as seen in Table 34.

Table 34: CS Emission Calculations from LDAR				
Methane Emissions from Model Compressor Station(tpy)				
LDAR Frequency	Emission Reduction	9-County	Piceance	Remainder of State
No LDAR	0%	8.68	27.68	18.18
Annual	40%	5.21	16.61	10.91
Semi-Annual	50%	4.34	13.84	9.09
Quarterly	60%	3.47	11.07	7.27
6x	70%	2.60	8.30	5.45
Monthly	80%	1.74	5.54	3.64
VOC Emissions from Model Compressor Station (tpy)				
LDAR Frequency	Emission Reduction	9-County	Piceance	Remainder of State
No LDAR	0%	7.96	12.17	10.07
Annual	40%	4.78	7.30	6.04
Semi-Annual	50%	3.98	6.09	5.03
Quarterly	60%	3.18	4.87	4.03
6x	70%	2.39	3.65	3.02
Monthly	80%	1.59	2.43	2.01

[86] In the Final EIA, the Division erroneously attributed the compressor station tier model facility emissions to the calculations for different basins. The Division corrected that in this analysis.

The total expected emission reductions from this program is outlined in Table 35, below.

Table 35: CS Emission Reductions from LDAR			
Compressor Station VOC Tier (tpy)	Total VOC Reductions (tpy)	Total Methane Reduction (tpy)	Total Greenhouse Gas Reduction (mtCO2e/yr)
Outside the NAA: <12	54.3	109.0	2,767.5
Outside the NAA: <12 - DI/prox	54.5	109.9	2,791.6
NAA: <12 - DI/prox	7.2	7.8	198.4
>12 - <50 - DI/prox	24.7	43.6	1,106.2
TOTAL	**140.8**	**270.2**	**6,863.7**

Cost Effectiveness

Combining the annual cost of inspections, $430,409.78, with the annual cost of repairs, $49,301.65, incorporating a recovered natural gas value of $92,904.27, the effectiveness of this requirement is $2,747.89 per ton VOC and $56.36 per mtCO2e. The Division is also providing the spreadsheets used to complete this analysis and develop all of these summary tables as part of this Rebuttal.[87]

Table 36: CS LDAR Cost Effectiveness			
LDAR Total Annual Cost			
	Inspection	Repair	TOTAL
Annual Cost	$430,409.78	$49,301.65	$479,711.43
Recovered Natural Gas			$92,904.27
Net Cost			**$386,807.16**
Compressor Station Emissions Reduction and Cost			
Total VOC Emission Reduction (VOC)	**Cost per ton VOC**	**Total GHG Emission Reduction (mtCO2e/year)**	**Cost per mtCO2e**
140.8	**$2,747.89**	**6,863.7**	**$56.36**

II.B. Pneumatic Controller Inspections: Regulation Number 7, Part D, Section III.F.2.f.

To align with the new leak detection and repair frequencies for compressor stations, the Division has proposed to update the inspection frequency for gas-driven pneumatic controllers in Section III.F. The proposed revisions build upon the statewide LDAR program in Regulation Number 7 and the Division assumes that owners or operators will incorporate the pneumatic controller inspections into their natural gas compressor station LDAR programs. The Division understands that operators will inspect the gas-driven pneumatic controllers during the same inspection as the Section II.E component inspections,

[87] APCD_REB_EX-014 (APCD, LDAR Cost-Effectiveness Analysis 11-23-2021.xlsx).

and therefore has determined there are minimal, if any, additional inspection and recordkeeping costs. According to the Final Economic Impact Analysis for the December 2019 rulemaking, as supported by both industry stakeholders and the environmental community, the incremental labor and material costs, costs above those related to the aligned LDAR inspection, are variable and range from insignificant to $600 per facility per year.[88] The Division, as staff to the Commission, requests that owners or operators of natural gas-driven pneumatic controllers provide Colorado specific cost information concerning the proposed revisions if it conflicts with the foregoing.

III. Upstream Program

The Division has updated the cost analysis for both leak detection and repair inspections at well production facilities as well as for well maintenance and liquids unloading activities.

III.A. Leak Detection and Repair Inspections at Well Production Facilities Statewide and in Disproportionately Impacted Communities: Regulation Number 7, Part D, Section II.E.

In addition to the new facility LDAR requirements analyzed in the Final EIA,[89] the Division has proposed additional requirements for existing well production facilities, statewide and in disproportionately impacted communities. This analysis replaces the previous analysis completed in Cost Effectiveness Analysis, III.A. Disproportionately Impacted Communities: Regulation Number 7, Part D, Section II.E.4.e.

The new proposal would require all well production facilities within a DI Community (in the NAA) or within 1,000 feet of an occupied area (statewide) to be inspected at a higher frequency, and increases the minimum inspection frequency from a one-time inspection to at least annual. The Division assumed that 26.48% of compressor stations in the 9-County area and 32.98% of compressor stations in the Piceance Basin and remainder of state were also in DI Communities. Further, the Division consulted with stakeholders to conduct an evaluation of how many well production facilities were within 1,000 feet of an occupied area. Based on these discussions, the Division assumed that in the NAA, 16% of well production facilities were within 1,000 feet of an occupied area but not within a DI Community. Outside the NAA, the Division assumed that 9.2% of well production facilities were located within 1,000 feet of an occupied area. From there the Division was able to determine how many well production facilities would be affected, especially where existing regulatory provisions require more frequent inspections at well production facilities within 1,000 feet of an occupied area. The number of well production facilities affected by this rule proposal is in Table 37.

[88] Revisions to Regulation Numbers 3 and 7, December 16-19. 2019, APCD_Final_EIA, pp.29-30.
[89] Cost Effectiveness Analysis, III.B. Leak Detection and Repair Inspections at Newly Constructed Well Production Facilities: Regulation Number 7, Part D, Section II.E.4.f, p. 29.

Table 37: WPF Emission Reductions from LDAR			
WPF Fugitive VOC Tier (tpy)	Number of WPF	Current Frequency	Proposed Frequency
Other Statewide: <2tpy	5,487	One-time	Annual
NAA: <1tpy and ROS: <2tpy (within 1000 ft, not DI)	802	One-time	Semi-Annual
ROS: <2tpy (DI)	1,478	One-time	Annual
NAA: <1 tpy (DI)	1,183	One-time	Semi-annual
NAA: >1 - <2tpy (not DI or w/in 1000 ft)	679	Annual	Annual
NAA: >1 - <2tpy (DI)	312	Annual	Semi-Annual
NAA: >1,<2 (within 1000 ft, not DI)	189	Annual	Semi-Annual
>2 - <12 tpy	1,808	Semi-Annual	Bimonthly (6x)
>2 - <12 tpy (DI)	702	Semi-Annual	Bimonthly (6x)
>12 - <50 (not DI or w/in 1000 ft) (includes some 2-12 in proximity)	1,066	Quarterly	Bimonthly (6x)
>12 - <50 (DI)	89	Quarterly	Monthly
>12 - <50 (within 1000 ft)	316	Monthly	Monthly
>50	1,134	Monthly	Monthly
TOTAL	**15,245**	**28,220 Inspections**	**52,540 Inspections**

<u>Inspections</u>

The Division's analysis as set forth above results in an increase in 24,320 inspections, statewide, per year. For this analysis, the Division assumed that operators would use only IR cameras to meet this increased inspection requirement. Table 38 includes a breakdown and analysis of the estimated leak inspection time and costs under the different possible conditions mentioned in the preceding section. The Division assumed a reduced number of hours per inspection than in the Final EIA or previous rulemaking efforts. The Environmental Defense Fund provided updated information in their prehearing statement and alternate proposal submission, which the Division used in this analysis.[90] The EDF information suggested the Division's average number of hours per inspection was too high.[91]

[90] See EDF_ALT_EX-001-004, pp. 16-17.
[91] Id.

Table 38: WPF LDAR Inspection Costs					
Basin/Area	**Inspection Type (All AIMM)**	**# NEW Inspections**	**Hours per Inspection**	**Cost per hour**	**Result: Total cost**
9-County Area	In-House	13,173	3.64	$105.00	$5,034,644.16
	Contractor	3,293	3.64	$137.00	$1,642,252.98
Piceance Basin	In-House	4,850	3.64	$105.00	$1,853,822.88
	Contractor	1,213	3.64	$137.00	$604,699.37
Rest of State	In-House	1,433	3.64	$105.00	$547,616.16
	Contractor	358	3.64	$137.00	$178,627.18
Totals		24,320			**$9,861,662.72**

At hourly inspection rates of $105 per hour for in-house and $137 per hour for contractors, the total cost to operators for completing the new LDAR inspections would therefore be $9,861,662.72.

Leak Repair

The Division made the same assumptions to calculate leak repair costs as in the Final EIA, except this analysis uses the incremental change in repair hours associated with the proposed revisions. The Division also made a scaled assumption of leak rate for the new LDAR frequency of six times per year. Table 39 includes the leak rates assumed along with repair hours calculated according to the methodology laid out previously.

Table 39: WPF Repair Hours from LDAR Frequencies			
LDAR Frequency	Leak Rate	Repair Hours in 9-County Area	Repair Hours in Remainder of State
Annual	1.18%	12.07	7.86
Semi-Annual	1.48%	15.13	9.86
Quarterly	1.77%	18.1	11.79
6x	1.92%	21.17	12.79
Monthly	2.36%	24.13	15.72

Using these assumed repair hours and the incremental change in frequency as outlined in Table 37, the Division calculated an increase of 113,191 repair hours. At a cost of $82.06/hour, the total repair cost is $9,288,452.64.

Emission Reductions

The Division used the same model well production facilities for the development of emissions per facility that it used for the Final EIA. Table 40 includes emissions assumed from model facilities for well production facilities with emissions greater than or equal to 2 tpy VOC.

Table 40: WPF Emission Calculations from LDAR - Facilities ≥ 2tpy VOC				
Methane Emissions from ≥ 2tpy VOC Model Well Production Facility (tpy)				
LDAR Frequency	Emission Reduction	9-County	Piceance	Remainder of State
No LDAR	0%	4.56	7.32	5.94
Annual	40%	2.74	4.39	3.56
Semi-Annual	50%	2.28	3.66	2.97
Quarterly	60%	1.82	2.93	2.38
6x	70%	1.37	2.20	1.78
Monthly	80%	0.91	1.46	1.19
VOC Emissions from ≥ 2tpy VOC Model Well Production Facility (tpy)				
LDAR Frequency	Emission Reduction	9-County	Piceance	Remainder of State
No LDAR	0%	5.09	3.05	4.07
Annual	40%	3.05	1.83	2.44
Semi-Annual	50%	2.55	1.53	2.04
Quarterly	60%	2.04	1.22	1.63
6x	70%	1.53	0.92	1.22
Monthly	80%	1.02	0.61	0.81

However, the model facilities developed for Table 40 were not appropriate to use for well production facilities with emissions less than 2 tpy VOC. The model well production facilities in Table 40 were developed based on data from compressor stations with emissions greater than 2 tpy VOC. The Division lacks emissions data in Air Pollution Emission Notices[92], and the emissions inventory submitted for 2020 emissions reporting did not result in information easily analyzed, for small well production facilities lacking AIRS IDs. Therefore, the Division assumed that both methane and VOC emissions for all well production facilities with emissions less than 2 tpy VOC were: 0.5 tpy with no LDAR inspections, 0.3 tpy for facilities with annual LDAR inspections, and 0.25 tpy for facilities with semi-annual LDAR inspections. Using the emissions per model well production facility outlined above, the Division calculated an emissions reduction of 4,852 tpy VOC, 5,110 tpy methane, and 129,808 mtCO2e/year.

Cost Effectiveness

Combining the annual cost of inspections, $9,861,662.72, with the annual cost of repairs, $9,288,452.64, yields a total gross annual cost of $19,150,115.36. Based on these reductions and associated costs, incorporating a recovered natural gas value of $1,402,665.45, the effectiveness of this requirement is $3,658.02 per ton VOC and $136.72 per mtCO2e. The Division is also providing the spreadsheets used to complete this analysis and develop all of these summary tables as part of this Rebuttal.[93]

[92] Because the APEN thresholds are 1 tpy VOC in the NAA and 2 tpy VOC outside the NAA, so sources below these thresholds are largely not required to submit APENs.
[93] APCD_REB_EX-014 (APCD, LDAR Cost-Effectiveness Analysis 11-23-2021.xlsx).

Table 41: WPF LDAR Total Annual Cost			
LDAR Total Annual Cost			
	Inspection	**Repair**	**TOTAL**
Annual Cost	$9,861,662.72	$9,288,452.64	$19,150,115.36
Recovered Natural Gas			$1,402,665.45
Net Cost			**$17,747,449.91**
WPF Emissions Reduction and Cost			
Total VOC Emission Reduction (VOC)	**Cost per ton VOC**	**Total GHG Emission Reduction (mtCO2e/year)**	**Cost per mtCO2e**
4,852	**$3,658.02**	**129,808**	**$136.72**

III.B. Pneumatic Controller Inspections: Regulation Number 7, Part D, Section III.F.2.f.

To align with the new leak detection and repair frequencies for well production facilities, the Division has proposed to update the inspection frequency for pneumatic controllers to match. The proposed revisions build upon the statewide LDAR program in Regulation Number 7 and the Division assumes that owners or operators will incorporate the pneumatic controller inspections into their natural gas compressor station LDAR programs. The Division understands that operators will inspect the gas-driven pneumatic controllers during the same inspection as the Section II.E component inspections, and therefore has determined there are minimal, if any, additional inspection and recordkeeping costs. According to the Final Economic Impact Analysis for the December 2019 rulemaking,the incremental labor and material costs, costs above those related to the aligned LDAR inspection, are variable and range from insignificant to $600 per facility per year.[94] The Division, as staff to the Commission, requests that owners or operators of natural gas-driven pneumatic controllers provide Colorado specific cost information concerning the proposed revisions if it conflicts with the foregoing.

III.C. Well Maintenance and Liquids Unloading Activities, Regulation Number 7, Part D, Section II.G

In the Division's Final EIA, the Division used a statewide average VOC and methane lb/event factor in calculating emissions. In its Prehearing Statement, the JIWG questioned why the Division would not use basin-specific factors where it had the data. The Division believes use of a statewide average is appropriate, but for the Rebuttal Statement, the Division conducted an alternative analysis, updating the calculations for emission amounts, reductions, and cost/ton amounts associated with well unloading. Recognizing the differences in gas compositions and unloading frequencies between DJ Basin and the Piceance Basin, the Division revised the calculations that previously assumed a statewide gas composition and statewide lb/event emission factor, to instead assume emitted gas compositions specific to the two major basins.

To estimate emission reductions, the Division analyzed over 100 samples of gas composition of sales gas, across the DJ Basin, Piceance Basin and the eastern plains. From this data, the Division derived a representative gas composition for DJ Basin and Piceance Basin. From these gas compositions, and

[94] Revisions to Regulation Numbers 3 and 7, December 16-19. 2019, APCD_Final_EIA, pp.29-30.

using a representative emitted volume of 14,000 scf/event, the Division calculated an average lb/event in Table 42 for the following pollutants.

Table 42: Well Unloading Emissions		
Pollutant	**DJ Basin (lb/event)**	**Piceance (lb/event)**
Methane	421.5	516.9
VOC (NMNE)	237.5	64.9

Given that more unloading events happen in the Piceance than in the DJ Basin, and that Piceance gas has a higher composition of methane and a lower composition of VOC, this alternative analysis results in a decreased VOC emissions benefit but an increased GHG emissions benefit. Assuming 95% control of emissions from well unloading results in a reduction of 1,023.71 tpy VOC and 122,595.94 mt/yr CO2e (CO2e reductions only look at methane reductions and would be significantly higher if the Division took into account the global warming potential of ethane).

The Division did not have data on the annual maintenance and operating cost associated with a dedicated open flare. Cost estimates for enclosed combustion devices in previous rulemakings have used a significantly lower annualized maintenance cost; in 2019, the Division assumed just under $3,000 per year for annual maintenance of a flare. Here, as in the Final EIA, the Division attempted to use EPA's cost calculator and derived a higher capital expenditure. To be conservative, the Division evaluated this proposal using two different annual maintenance costs. The Division estimates the cost effectiveness of control as set forth in Table 43.

Table 43: Well Unloading Control - Emissions and Cost Effectiveness					
Cost Effectiveness at $10K Annual Maintenance					
Well Site Description	Total VOC Reduced (tpy)	Total CO2e Reduced (mtCO2e/yr)	Annualized Cost at $10K Annual Maintenance	VOC Cost ($/ton)	CO2e Cost ($/ton)
Inside DI Community: ≥6 unloadings per facility	313.86	37,586.44	$4,512,086.27	$14,376.30	$120.05
Outside of DI Community: At least 1 well w/ ≥6 unloadings per well	631.94	75,679.61	$7,328,141.06	$11,596.20	$96.83
Outside of DI Community: ≥10 unloadings per facility (Not including those with 1 well ≥6 unloadings per well)	77.91	9,329.90	$1,443,968.68	$18,534.54	$154.77
TOTAL	1,023.71	122,595.94	$13,284,196.01		
Average Total Cost Per Ton				$12,976.57	$108.36
Cost Effectiveness at $50K Annual Maintenance					
Well Site Description	Total VOC Reduced (tpy)	Total CO2e Reduced (mtCO2e/yr)	Annualized Cost at $50K Annual Maintenance	VOC Cost ($/ton)	CO2e Cost ($/ton)
Inside DI Community: ≥6 unloadings per facility	313.86	37,586.44	$11,654,586.27	$37,133.56	$310.07
Outside of DI Community: At least 1 well w/ ≥6 unloadings per well	631.94	75,679.61	$18,928,373.06	$29,952.65	$250.11
Outside of DI Community: ≥10 unloadings per facility (Not including those with 1 well ≥6 unloadings per well)	77.91	9,329.90	$3,729,728.68	$47,874.18	$399.76
TOTAL	1,023.71	122,595.94	$34,312,688.01		
Average Total Cost Per Ton				$33,518.11	$279.88

Based on the COGCC data, the Division's proposal would require capture or control at approximately 29% of well production facilities with unloadings and would cover 75.5% of the total unloading events.[95]

In the Initial EIA, the Division - as staff to the Commission - requested information from stakeholders to inform the costs associated with this proposal. The Division did not receive cost information from

[95] APCD_PHS_EX-023.

stakeholders, but used EPA's cost calculator to generate updated conservative cost estimates for the open flares.

III.D. Upstream Intensity Program, Regulation Number 7, Part D, Section II.G

The Division, in response to concerns of various parties, in particular various non governmental organizations and local public health agencies, has developed an alternative emission reduction and costs analysis associated with the intensity program. This analysis does not replace, but supplements, the analysis in the Division's Final EIA.

Accounting only for requirements part of the Rebuttal proposal and analyzed throughout this document, this analysis demonstrates a potential maximum emission reduction from intensity of 1,540,087 mtCO2e/year. Even the maximum potential program reliance on intensity is conservatively high. First, EDF's estimate of how many tons of emission reductions is still necessary was based on a very conservative estimate of current regulatory programs achieving only 60% of necessary emissions. The Division believes the number is closer to 75-80%, if not higher. Second, because EDF's analysis did not, as the Division understands it, take into account the following additional reductions that the Division expects from either its Rebuttal proposal or other regulatory or voluntary programs in Colorado, without limitation:

- Emissions from "super emitters" or "abnormal operating conditions" at compressor stations;
- Emissions that will be reduced by the Division's proposals in Section II.H that require the use of electrical power for capture and recovery equipment;
- Emissions from improperly operating pneumatics addressed by the increased frequency of inspections in Section III.F of this Rebuttal proposal;
- Emission reductions from voluntary measures;
- Emission reductions from the COGCC mission change rulemaking, such as venting and flaring requirements, permitting provisions, or best management practices.

However, the Division is using (for this analysis) the 60% assumption as well as the undercounted emission reductions listed above as we lack quantifiable data related to the emissions reductions achieved through recent rulemaking activities. The emission reductions attributed to the other proposed regulatory requirements part of this rulemaking, along with the maximum potential program reliance on intensity, is presented in Table 44.

Table 44: Upstream Intensity Emission Reductions by 2030		
Proposed Program	Total Methane Reductions (mt/year)	Source of Emission Estimate
WPF LDAR	64,000	EDF
Pigging/blowdown	9,600	EDF
Rod packing	4,535	Division
Well unloading	4,378	Division
Performance testing	2,026	Division
Gas plant LDAR	188	Division
Compressor station LDAR	270	Division
TOTAL Achieved by 2030	**84,997 mt/year**	**2,379,913 mtCO2e/year**
Maximum Potential Program Reliance On Intensity		
TOTAL Needed to Meet Statutory Targets (per EDF)	**140,000 mt CH4/year**	**3,920,000 mtCO2e/year**
Maximum Potential Program Reliance on Intensity to Meet Targets	**55,003 mt CH4/year**	**1,540,087 mtCO2e/year**

Based on EDF's analysis, the cost of the intensity program between adoption and 2025 would be $0, because the implication of EDF's analysis is that operators will meet their 2025 intensity targets by virtue of regulatory revisions already adopted by the Commission.[96] As set forth above, under EDF's analysis, the maximum potential program reliance on intensity to achieve the state's targets is 1,540,087 mtCO2e/year, which based on the Division's estimate of cost in the Final EIA, results in a maximum cost of the intensity program of $30,262,710.

IV. Rebuttal Emissions and Costs Summary

The Division prepared this Revised Final Economic Impact Analysis in accordance with the requirements of § 25-7-110.5), C.R.S. Specifically, the Division utilized the methodology identified in § 25-7-110.5(4)(c)(III), C.R.S.

The Division has determined that there may be costs related to the proposed revisions potentially impacting owner or operators of oil and gas operations including costs related to additional LDAR inspections, responsive actions, recordkeeping, and reporting; costs related to improving performance of air pollution control equipment; costs related to reducing other greenhouse gas emissions, as well as associated recordkeeping and reporting.

IV.A. Summary of All Rebuttal Cost Analyses

The Division summarized all of the changes to the costs resulting from the Rebuttal revision to the economic impact analysis in Table 45. All of the revisions made in this Rebuttal revision to the Final EIA would result in a net decrease of $2,214,720 to the total cost of the proposal.

[96] EDF_ALT_EX-001-004, p. 35.

Table 45: Cost Summary of all Rebuttal Alternatives and Revisions					
Cost Summary of Revisions and Additions to Final EIA					
Rule Proposal	**Section of Rule**	**Total CO2e Reductions (mtCO2e/Year)**	**Total VOC Reductions (tpy)**	**Total Annual Costs**	**Change from Original Proposal**
Compressor Station LDAR	Reg. 7, Section II.E	6,864	141	$386,807	+$277,765
Upstream LDAR	Reg. 7, Section II.E	129,808	4,852	$17,747,450	+$17,747,450
Pneumatics at Compressor Stations	Reg. 7, Section III	--	--	--	$0
Pneumatics at Well Production Facilities	Reg. 7, Section III	--	--	--	$0
Cost Summary of Alternative Analyses to Final EIA					
Rule Proposal	**Section of Rule**	**Total CO2e Reductions (mtCO2e/Year)**	**Total VOC Reductions (tpy)**	**Total Annual Costs**	**Change from Original Proposal**
Control Equipment Performance	Reg. 7, Section II.B	56,734	2,211	$49,649,855	+$34,994,602
Well Unloading	Reg. 7, Section II.G	122,596	1,024	$13,284,196	$0
Upstream Intensity By 2025	Reg. 22, Section IV	0	---	$0	-$85,497,247
Upstream Intensity By 2030	Reg. 22, Section IV	1,540,087	---	$30,262,710	-$55,234,537

IV.B. Summary of New and Updated Rebuttal Revisions to Final Economic Impact Analysis

The Division projects that the Commission's regulations, as modified by this proposal, will reduce greenhouse gas emissions (in CO2e) by approximately 4,878,765 mtCO2e per year[97] at a cost range of approximately $59,503,879 to $142,310,503 per year. The overall cost effectiveness for the entire package is between $29.17 and $89.62 per metric ton of CO2e reduced (and the social cost of greenhouse gas as set forth in the Final EIA is $82.95, reflecting a significant benefit to Colorado and the climate through this program).

The Division also estimates its proposal will reduce at least 13,261 tpy of VOC, not including VOC reduced by the intensity program (even though this program will certainly reduce VOC emissions as

[97] Note that the overall emission reductions changed minimally from the Final EIA, as upstream emission reductions, now also including those from this updated proposal, are accounted for in the intensity program estimate in Table 29.

well). This results in an overall cost effectiveness for this package of between \$4,486.99 and \$10,731.17 per ton of VOC reduced. The proposal will also have additional unquantified emission benefits through reductions of ethane (which has a significant global warming potential and ozone benefits) and hazardous air pollutants such as benzene.

Based on this analysis, the Division believes the current rule proposal is cost effective. The Division has provided an estimate of costs based on reasonably available information and will consider any additional information provided by stakeholders. The Division as staff to the Commission requests that affected industry or any interested party submit information with regard to the cost of compliance with these proposed rule revisions.

Estimation of Fugitive Emissions from Well Production Facilities and Compressor Stations

SHER Team Upstream/Midstream Subgroup

January 9, 2019

Curtis Taipale

Colorado Department of Public Health & Environment

Air Pollution Control Division

Planning and Policy Program

COLORADO
Air Pollution Control Division
Department of Public Health & Environment

Methodology for estimating WPF fugitive emissions

- Based on O&G producer data reported on APEN forms
  - APEN Form 205 - provides data on condensate storage tank batteries: oil production, number of tanks, VOC emissions etc.
  - APEN Form 203 - provides data on VOC content of oil and gas streams and component counts for fugitive emissions

Example Data Reported on APEN Form 205

Tank Battery Name[10]: **17929 -2 H** Number of tanks: **3**

Location[11] (QQ Sec. Twp. Range.): **NWNW 21 N W** County: **Weld** Total tank capacity [bbl]: **1500**

Calendar year for which "Actual" data applies[12]: **2012** Year(s) tank(s) were placed in service[13]: **2012**

Control Description[14]: **Combustor** Control Efficiency[15]: **95%**

Condensate Throughput[16] [bbl/year] Requested[17]: **N/A** Maximum for PTE calculation[18]: **24,972**

Actual[19]: **20,810** While Controls Operational[20] **20,810**

Other equipment at facility[21]: **(1) Produced Water Storage Tank, Tank Truck Loadout, Fugitives**

Comments: **APEN submitted to cover new facility**

Estimated emissions at throughputs listed above. ***Use N/A for requested throughput / emission values unless requesting an individual permit***

☐ Check if the Division is to calculate emissions. ☒ Check if site-specific emission factors provided to calculate emissions[22].

Pollutant[23]	Emission Factor [lb/bbl]	Battery PTE[24]	Requested Emissions[17] Uncontrolled[25]	Requested Emissions[17] Controlled[26]	Actual Emissions[19] Uncontrolled	Actual Emissions[19] Controlled
VOC [tons/year]	**0.3**	**3.3**	**N/A**	**N/A**	**2.8**	**0.1**
NOx [tons/year]	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
CO [tons/year]	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
Benzene [lbs/year]	**0.003**	**71.6**	**N/A**	**N/A**	**59.7**	**3.0**
n-Hexane [lbs/year]	**0.025**	**627.5**	**N/A**	**N/A**	**522.9**	**26.1**

Wells serviced by this tank or tank battery[27]

API #: **05-123-34** Name: **-2 H** ☒ Newly Reported Well

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Example Data Reported on APEN Form 203

Section 05 – Stream Constituents

Identify the VOC & HAP content of each applicable stream.

Stream	VOC (wt. %)	Benzene (wt. %)	Toluene (wt. %)	Ethylbenzene (wt. %)	Xylene (wt. %)	n-Hexane (wt. %)
Gas	0.3139	0.0012	0.0009	0.0001	0.0003	0.0063
Heavy Oil (or Heavy Liquid)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Light Oil (or Light Liquid)	1.000	0.033	0.033	0.033	0.033	0.033
Water/Oil	1.000	0.033	0.033	0.033	0.033	0.033

☒ Submit a representative gas and liquid extended analysis (including BTEX) to support emission calculations

FORM APCD-203

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Page 1 of 2

Section 08 – Emission Factor Information

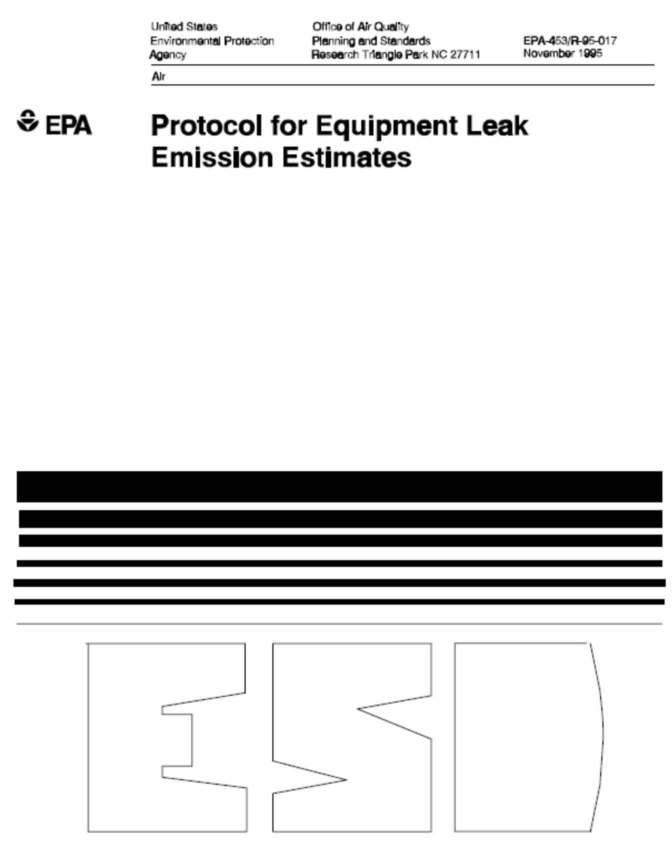
Identify the emission factor used to estimate emissions under "E.F.", along with the units relating to the emission factor (e.g. lb/hr/component).

☒ **Check this box if you used Table 2-4 of U.S. EPA's *1995 Protocol for Equipment Leak Emission Estimates* to estimate emissions. You do not need to enter the emission factors below if checked.**

Equipment Type	Service											
	Gas			Heavy Oil (or Heavy Liquid)			Light Oil (or Light Liquid)			Water/Oil		
	Count[1]	E.F.	Units	Count[1]	E.F.	Units	Count[1]	E.F.	Units	Count[1]	E.F.	Units
Connectors	724			0			214			26		
Flanges	0			0			0			0		
Open-Ended Lines	0			0			0			0		
Pump Seals	0			0			0			0		
Valves	87			0			41			4		
Other	0			0			0			0		

[1] Count shall be the actual or estimated number of components in each type of service used to calculate the "Actual Calendar Year Emissions" below. ☒ Estimated Count ☐ Actual Count conducted on the following date: ____________

- Emission factors based on 1995 EPA document *"Protocol for Equipment Leak Emission Estimates"*
  - Use Table 2-4 emission factors



United States Environmental Protection Agency | Office of Air Quality Planning and Standards Research Triangle Park NC 27711 | EPA-453/R-95-017 November 1995

Air

EPA

Protocol for Equipment Leak Emission Estimates

TABLE 2-4. OIL AND GAS PRODUCTION OPERATIONS AVERAGE EMISSION FACTORS (kg/hr/source)

Equipment Type	Service[a]	Emission Factor (kg/hr/source)[b]
Valves	Gas	4.5E-03
	Heavy Oil	8.4E-06
	Light Oil	2.5E-03
	Water/Oil	9.8E-05
Pump seals	Gas	2.4E-03
	Heavy Oil	NA
	Light Oil	1.3E-02
	Water/Oil	2.4E-05
Others[c]	Gas	8.8E-03
	Heavy Oil	3.2E-05
	Light Oil	7.5E-03
	Water/Oil	1.4E-02
Connectors	Gas	2.0E-04
	Heavy Oil	7.5E-06
	Light Oil	2.1E-04
	Water/Oil	1.1E-04
Flanges	Gas	3.9E-04
	Heavy Oil	3.9E-07
	Light Oil	1.1E-04
	Water/Oil	2.9E-06
Open-ended lines	Gas	2.0E-03
	Heavy Oil	1.4E-04
	Light Oil	1.4E-03
	Water/Oil	2.5E-04

From Final Economic Impact Analysis for the 2014 Regulation Number 7 Hearing (page 25)

Table 34: Well Production Facility Leak Inspection Emission Reductions

Uncontrolled VOC at Tank Battery Tier [tpy]	Number of Facilities	LDAR Program Reduction %	Fugitive VOC Emissions for each Tank Battery [tpy]	Total VOC Reduction [tpy]	Fugitive Methane-Ethane Emissions for each Tank Battery [tpy]	Total Methane-Ethane Reduction [tpy]
DJ/NAA						
> 6 to ≤ 12	1,095	40%	4.6	1,971.0	7.0	3,066.0
> 12 to ≤ 50	2,600	60%	4.6	7,280.0	7.0	10,920.0
> 50	811	80%	4.6	3,000.7	7.0	4,541.6
Subtotal:	**4,506**			**12,251.7**		**18,527.6**
Remainder of State						
> 6 to ≤ 12	313	40%	3.9	500.8	7.5	939.0
> 12 to ≤ 50	324	60%	3.9	745.2	7.5	1,458.0
> 50	167	80%	3.9	517.7	7.5	1,002.0
Subtotal:	**804**			**1,763.7**		**3,399.0**
Total:	**5,310**			**14,015.4**		**21,926.6**

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Department of Public Health & Environment

DMNFR NAA (DJ Basin) O&G Well Production Facilities - Fugitive Emissions from Component Leaks

Composite Model based on Twenty (20) - APCD Form 203 APENs

							Gas Service Count							Light Oil Service Count						
Facility	County	Oil Production (bbl)	Reported Fugitive VOC (tpy)	Uncont. Actuals - Tank Battery VOC (tpy)	VOC Emission Factor (lb/BBL)	Number of Wells	VOC [wt %]	Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other	VOC [wt %]	Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other
1	Weld	20,810	3.08	3.3	0.3	1	31.39%	724	0	0	0	87	0	100.00%	214	0	0	0	41	0
2	Weld	29,200	3.36	7.59	0.4932	1	39.06%	28	24	0	0	19	11	99.85%	84	40	1	2	21	15
3	Weld	109,500	2.4	7.4	0.1348	1	3.50%	576	8	9	0	56	35	29.20%	520	24	7	2	72	15
4	Weld	23,400	2.58	72.5	6.2	2	25.64%	419	56	18	0	66	11	99.53%	126	4	8	0	21	0
5	Weld	167,900	11.13	182.9	2.18	3	30.52%	1318	143	72	0	220	38	99.42%	490	276	33	0	119	0
6	Weld	27,180	6.72	56.98	4.19	8	25.23%	1198	186	46	0	193	27	99.63%	274	8	18	0	47	0
7	Weld	51,260	2.4	351.1	13.7	6	3.50%	576	8	9	0	56	35	29.20%	520	24	7	2	72	15
8	Weld	54,750	3.33	12.3	0.45	1	39.06%	28	24	0	0	19	11	99.85%	84	40	1	2	21	15
9	Weld	146,000	2.4	9.6	0.1314	1	3.50%	576	8	9	0	56	35	29.20%	520	24	7	2	72	15
10	Weld	16,235	1.21	21.8	2.683	1	23.60%	1156	6	12	0	117	28	100.00%	539	2	0	0	66	5
11	Weld	5,764	1.18	39	13.7	3	29.20%	0	18	0	0	0	5	29.20%	107	31	9	0	33	33
12	Weld	48,915	4.31	76.6	7.66	7	23.60%	4735	62	15	0	510	74	100.00%	1884	12	11	0	285	8
13	Weld	21,900	3.25	6.82	0.611	1	28.96%	28	24	0	0	19	11	99.92%	84	40	1	2	21	15
14	Weld	9,640	5.77	66.0	13.7	4	34.07%	1396	15	0	0	124	3	100.00%	431	0	0	0	79	0
15	Weld	27,375	2.79	4.73	0.35	1	35.96%	28	27	0	0	19	11	99.63%	84	40	1	2	21	15
16	Weld	17,720	2.45	121.4	13.7	3	23.40%	438	64	0	0	80	25	100.00%	174	48	0	0	18	0
17	Weld	86,505	10.51	57.44	4.087	5	26.82%	1403	181	73	0	226	34	99.57%	564	149	36	0	111	0
18	Weld	36,500	7.16	28.4	1.5	4	29.28%	1173	98	44	0	154	26	99.71%	296	8	20	0	52	0
19	Weld	16,438	1.88	113	13.7	5	29.20%	0	7	0	0	0	2	29.20%	155	50	13	0	56	60
20	Weld	134,000	0.4465	7.049	1.1029	1	3.50%	38	49	0	2	24	5	29.20%	38	49	0	2	24	5
	Average:	***52,550***	***3.9***	***62.3***	***5.0***	***3.0***	***24.4%***	***791.9***	***50.4***	***15.4***	***0.1***	***102.3***	***21.4***	***78.6%***	***359.4***	***43.5***	***8.7***	***0.8***	***62.6***	***10.8***
											Total Gas Service Components:		***981***					***Total Light Oil Service Components:***		***486***

Composite Model Well Production Facility - VOC Emissions

Each Component TOC Emission Factor[1] [kg/hr]:	*2.00E-04*	*3.90E-04*	*2.00E-03*	*2.40E-03*	*4.50E-03*	*8.80E-03*	*2.10E-04*	*1.10E-04*	*1.40E-03*	*1.30E-02*	*2.50E-03*	*7.50E-03*
Each Component VOC Emission Factor [kg/hr]:	*4.89E-05*	*9.54E-05*	*4.89E-04*	*5.87E-04*	*1.10E-03*	*2.15E-03*	*1.65E-04*	*8.65E-05*	*1.10E-03*	*1.02E-02*	*1.97E-03*	*5.90E-03*
Component Annual VOC Emissions [tons/year]:	***0.37***	***0.05***	***0.07***	***0.00***	***1.09***	***0.44***	***0.57***	***0.04***	***0.09***	***0.08***	***1.19***	***0.62***

Total Annual VOC Emissions [tpy]: 4.6

[1] See Table 2-4 "Oil and Gas Production Operations Average Emission Factors" EPA Protocol for Equipment Leak Emission Estimates, November 1995, EPA-453/R-95-017

Composite Model Well Production Facility - Methane/Ethane Emissions

Each Component C1-C2 Emission Factor [kg/hr]:	*1.51E-04*	*2.95E-04*	*1.51E-03*	*1.81E-03*	*3.40E-03*	*6.65E-03*	*4.49E-05*	*2.35E-05*	*2.99E-04*	*2.78E-03*	*5.35E-04*	*1.60E-03*
Component Annual C1-C2 Emissions [tons/year]:	***1.16***	***0.14***	***0.22***	***0.00***	***3.36***	***1.37***	***0.16***	***0.01***	***0.03***	***0.02***	***0.32***	***0.17***

Total Annual Methane/Ethane Emissions [tpy]: 7.0

Rest of State (Piceance Basin) O&G Well Production Facilities - Fugitive Emissions from Component Leaks

Composite Model based on Nineteen (19) - APCD Form 203 APENs

							Gas Service Count							Light Oil Service Count						
Facility	County	Oil Production (bbl)	Reported Fugitive VOC (tpy)	Uncont. Actuals - Tank Battery VOC (tpy)	VOC Emission Factor (lb/BBL)	Number of Wells	VOC [wt %]	Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other	VOC [wt %]	Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other
1	Routt	11,680	2.3	68.9	11.8	1	36.49%	193	58	0	0	58	23	0.0%	0	0	0	0	0	0
2	Moffat	365	2.3	1.8	10.0	2	12.38%	242	11	0	2	64	23	100.0%	37	2	0	0	35	9
3	Moffat	1,643	3.4	8.2	10.0	2	14.09%	416	12	0	2	103	39	100.0%	60	2	0	0	48	12
4	Moffat	2,081	2.5	10.4	10.0	1	22.36%	242	11	0	0	64	22	98.0%	30	1	0	0	25	9
5	Moffat	1,297	2.2	6.5	10.0	1	0.09%	285	12	0	1	73	28	100.0%	31	1	0	0	27	12
6	Garfield	1,107	9.8	5.5	10.0	1	6.78%	728	143	16	0	180	24	100.0%	503	74	10	12	111	4
7	Moffat	12,593	2.9	54.1	8.6	1	17.84%	324	15	0	1	81	31	100.0%	31	1	0	0	28	13
8	Moffat	36,500	3.9	9.1	10.0	1	63.16%	193	58	0	0	58	23	0.0%	0	0	0	0	0	0
9	Moffat	63,875	9.8	1,287.0	40.3	5	30.89%	891	15	0	5	210	80	100.0%	147	5	0	0	114	16
10	Moffat	2,190	4.3	11.0	10.0	2	24.97%	416	12	0	2	103	39	100.0%	60	2	0	0	48	12
11	Moffat	7,665	5.1	38.3	10.0	3	19.42%	586	15	0	1	141	53	100.0%	89	3	0	0	70	13
12	Moffat	31,000	9.0	155.0	10.0	1	21.91%	690	122	17	0	163	21	100.0%	386	62	5	10	88	2
13	Moffat	14,126	5.9	70.6	10.0	4	17.01%	717	15	0	4	171	64	100.0%	118	4	0	0	91	13
14	Moffat	621	2.1	3.1	10.0	1	12.01%	376	11	0	2	81	27	100.0%	15	1	0	0	19	11
15	Moffat	31,000	9.0	218.6	14.1	1	21.91%	690	122	17	0	163	21	100.0%	386	62	5	10	88	2
16	Rio Blanco	110	4.3	0.5	10.0	1	2.37%	50	500	0	7	300	10	100.0%	30	50	0	6	40	10
17	Moffat	15	2.8	0.1	10.0	1	15.80%	419	11	0	1	90	32	100.0%	30	1	0	0	21	14
18	Moffat	11,315	4.8	56.6	10.0	1	30.57%	501	15	0	2	107	41	100.0%	16	1	0	0	24	18
19	Moffat	2,190	4.3	11.0	10.0	2	24.97%	416	12	0	2	103	39	100.0%	60	2	0	0	48	12
20	Moffat	5,950	2.0	29.7	10.0	1	10.24%	281	14	0	1	72	25	100.0%	30	1	0	0	26	10
	Average:	***11,866***	***4.6***	***102.3***	***11.7***	***1.7***	***20.3%***	***432.8***	***59.2***	***2.5***	***1.7***	***119.3***	***33.3***	***89.9%***	***103.0***	***13.8***	***1.0***	***1.9***	***47.6***	***9.6***
	Accidental Duplicate									***Total Gas Service Components:***			***649***					***Total Light Oil Service Components:***		***177***

Composite Model Well Production Facility - VOC Emissions

	Gas: Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other	Light Oil: Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other
Each Component TOC Emission Factor[1] [kg/hr]:	2.00E-04	3.90E-04	2.00E-03	2.40E-03	4.50E-03	8.80E-03	2.10E-04	1.10E-04	1.40E-03	1.30E-02	2.50E-03	7.50E-03
Each Component VOC Emission Factor [kg/hr]:	4.05E-05	7.90E-05	4.05E-04	4.86E-04	9.12E-04	1.78E-03	1.89E-04	9.89E-05	1.26E-03	1.17E-02	2.25E-03	6.74E-03
Component Annual VOC Emissions [tons/year]:	0.17	0.05	0.01	0.01	1.05	0.57	0.19	0.01	0.01	0.21	1.03	0.63

Total Annual VOC Emissions (when duplicate removed) [tpy]: 3.92 ***Total Annual VOC Emissions [tpy]: 3.94***

[1] *See Table 2-4 "Oil and Gas Production Operations Average Emission Factors" EPA Protocol for Equipment Leak Emission Estimates, November 1995, EPA-453/R-95-017*

Composite Model Well Production Facility - Methane/Ethane Emissions

	Gas: Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other	Light Oil: Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other
Each Component C1-C2 Emission Factor [kg/hr]:	1.59E-04	3.11E-04	1.59E-03	1.91E-03	3.59E-03	7.02E-03	2.12E-05	1.11E-05	1.41E-04	1.31E-03	2.53E-04	7.57E-04
Component Annual C1-C2 Emissions [tons/year]:	0.67	0.18	0.04	0.03	4.13	2.25	0.02	0.00	0.00	0.02	0.12	0.07

Total Annual Methane/Ethane Emissions (when duplicate removed) [tpy]: 7.59 ***Total Annual Methane/Ethane Emissions [tpy]: 7.53***

From Final Economic Impact Analysis for the 2014 Regulation Number 7 Hearing (page 24)

Table 32: Compressor Station Leak Inspection Emission Reductions						
Comp. Station Fugitive VOC Tier [tpy]	Number of Comp Stations	LDAR Program Reduction %	Fugitive VOC Emissions for each CS tier [tpy]	Total VOC Reduction [tpy]	Fugitive Methane-Ethane Emissions for each CS tier [tpy]	Total Methane-Ethane Reduction [tpy]
≤ 12	147	40%	10.1	588.0	15.5	911.4
> 12 to ≤ 50	53	60%	16.4	519.4	44.3	1,409.8
> 50		80%				
	200			1,107.4		2,321.1

Compressor Stations with Reported Fugitive Emissions ≤ 12 tpy - Fugitive Emissions from Component Leaks

Composite Model based on Twenty-Two (22) - APCD Form 203 APENs

Facility	County	Uncont. Fugitive VOCs	Total CS Horsepower	Gas Service Count: VOC [wt %]	Gas Service Count: Connectors	Gas Service Count: Flanges	Gas Service Count: Open-Ended Lines	Gas Service Count: Pump Seals	Gas Service Count: Valves	Gas Service Count: Other	Light Oil Service Count: VOC [wt %]	Light Oil Service Count: Connectors	Light Oil Service Count: Flanges	Light Oil Service Count: Open-Ended Lines	Light Oil Service Count: Pump Seals	Light Oil Service Count: Valves	Light Oil Service Count: Other
1	Adams	2.5	180	39.07%	305	141	2	-	75	-	99.79%	101	14	-	-	24	-
2	Rio Blanco	2.9	5,865	5.80%	870	198	-	-	254	42	100.00%	138	34	-	4	46	-
3	Rio Blanco	3.0	5,354	24.11%	-	548	-	12	199	20							
4	Garfield	3.1	9,185	7.20%	870	198	-	24	254	18	100.00%	138	34	-	4	46	-
5	Mesa	4.2	766	5.89%	1,320	214	47	-	284	28	100.00%	214	88	8	2	71	4
6	Delta	5.2	552	33.99%	125	255	293	-	-	14	99.46%	35	68	34	6	-	-
7	Weld	5.3	2,143	29.43%	896	306	8	-	172	-	99.74%	265	25	-	-	89	-
8	Cheyenne	5.3	761	33.61%	599	97	22	-	129	13	100.00%	123	51	4	2	41	2
9	Garfield	5.9	675	10.43%	699	135	20	-	132	21	100.00%	328	37	7	4	65	1
10	Weld	6.6	2,102	25.56%	795	357	8	-	229	-	99.58%	275	33	-	-	123	-
11	Garfield	8.0	8,191	9.44%	1,634	929	-	29	616	32	100.00%	679	74	-	-	121	-
12	Weld	8.0	6,720	24.74%	1,422	213	51	-	306	31	100.00%	217	89	8	2	72	4
13	Weld	8.0	5,040	24.74%	1,422	231	51	-	306	31	100.00%	217	89	8	2	72	4
14	Weld	8.0	6,720	24.74%	1,422	231	51	-	306	31	100.00%	217	89	8	2	72	4
15	Weld	8.0	6,720	24.74%	1,422	231	51	-	306	31	100.00%	217	89	8	2	72	4
16	Adams	8.4	730	15.00%	1,040	193	71	-	402	26	100.00%	474	5	19	1	137	1
17	Arapahoe	8.9	694	100.00%	1,377	182	94	6	212	100							
18	Garfield	10.3	11,760	11.96%	1,042	364	-	32	684	50	100.00%	219	6	-	8	162	-
19	Garfield	11.0	21,904	3.50%	2,106	539	-	-	696	58	29.20%	3,112	481	-	14	941	21
20	Garfield	11.5	11,760	14.12%	2,224	438	-	-	555	87	100.00%	464	142	-	15	136	-
21	Mesa	11.6	5,360	15.00%	2,744	234	-	-	503	74	100.00%	489	-	-	3	123	12
22	Arapahoe	12.0	1,447	100.00%	2,673	367	4	6	294	24							
	Average:	***7.2***	***5,210.4***	***26.5%***	***1227.6***	***300.0***	***35.1***	***5.0***	***314.3***	***33.2***	***96.2%***	***416.9***	***76.2***	***5.5***	***3.7***	***127.0***	***3.0***
									Total Gas Service Components:	***1,915***						***Total Light Oil Service Components:***	***632***

Composite Model Compressor Station - VOC Emissions

	Gas: Connectors	Gas: Flanges	Gas: Open-Ended Lines	Gas: Pump Seals	Gas: Valves	Gas: Other	Light Oil: Connectors	Light Oil: Flanges	Light Oil: Open-Ended Lines	Light Oil: Pump Seals	Light Oil: Valves	Light Oil: Other
Each Component TOC Emission Factor[1] [kg/hr]:	*2.00E-04*	*3.90E-04*	*2.00E-03*	*2.40E-03*	*4.50E-03*	*8.80E-03*	*2.10E-04*	*1.10E-04*	*1.40E-03*	*1.30E-02*	*2.50E-03*	*7.50E-03*
Each Component VOC Emission Factor [kg/hr]:	*5.30E-05*	*1.03E-04*	*5.30E-04*	*6.36E-04*	*1.19E-03*	*2.33E-03*	*2.02E-04*	*1.06E-04*	*1.35E-03*	*1.25E-02*	*2.40E-03*	*7.21E-03*
Component Annual VOC Emissions [tons/year]:	***0.63***	***0.30***	***0.18***	***0.03***	***3.62***	***0.75***	***0.81***	***0.08***	***0.07***	***0.45***	***2.95***	***0.21***
											Total Annual VOC Emissions [tpy]:	***10.1***

[1] See Table 2-4 "Oil and Gas Production Operations Average Emission Factors" EPA Protocol for Equipment Leak Emission Estimates, November 1995, EPA-453/R-95-017

Composite Model Compressor Station - Methane/Ethane Emissions

	Gas: Connectors	Gas: Flanges	Gas: Open-Ended Lines	Gas: Pump Seals	Gas: Valves	Gas: Other	Light Oil: Connectors	Light Oil: Flanges	Light Oil: Open-Ended Lines	Light Oil: Pump Seals	Light Oil: Valves	Light Oil: Other
Each Component C1-C2 Emission Factor [kg/hr]:	*1.47E-04*	*2.87E-04*	*1.47E-03*	*1.76E-03*	*3.31E-03*	*6.47E-03*	*7.98E-06*	*4.18E-06*	*5.32E-05*	*4.94E-04*	*9.50E-05*	*2.85E-04*
Component Annual C1-C2 Emissions [tons/year]:	***1.74***	***0.83***	***0.50***	***0.08***	***10.04***	***2.08***	***0.03***	***0.00***	***0.00***	***0.02***	***0.12***	***0.01***
											Total Annual Methane/Ethane Emissions [tpy]:	***15.5***

Compressor Stations with Reported Fugitive Emissions > 12 tpy - Fugitive Emissions from Component Leaks

Composite Model based on Eight (8) - APCD Form 203 APENs

				Gas Service Count							Light Oil Service Count						
Facility	County	Uncont. Fugitive VOCs	Total CS Horsepower	VOC [wt %]	Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other	VOC [wt %]	Connectors	Flanges	Open-Ended Lines	Pump Seals	Valves	Other
1	Garfield	13.8	5,865	13.80%	1,924	514	-	-	468	64	100.00%	1,901	123	-	-	203	8
2	Mesa	15.0	5,079	15.00%	2,199	210	-	-	364	41	100.00%	810	72	-	6	262	14
3	Garfield	15.2	26,172	6.28%	2,240	444	58	-	410	69	100.00%	1,086	81	24	8	207	4
4	Garfield	19.0	14,064	8.06%	3,107	780	-	-	843	61	100.00%	1,773	218	-	6	392	12
5	Garfield	20.3	3,945	6.68%	2,366	456	63	-	490	67	100.00%	1,244	97	27	10	258	10
6	Garfield	23.2	7,385	6.82%	3,137	582	81	-	605	99	100.00%	1,549	161	28	22	311	8
7	Mesa	29.3	18,027	11.48%	5,448	1,428	43	-	1,096	481	99.66%	264	65	3	-	56	17
8	Garfield	30.8	23,035	20.00%	7,073	1,232	-	-	1,200	71	100.00%	2,311	85	5	5	397	-
	Average:	***20.8***	***12,947***	***11.0%***	***3,436.8***	***705.8***	***30.6***	***-***	***684.5***	***119.1***	***100.0%***	***1,367.3***	***112.8***	***10.9***	***7.1***	***260.8***	***9.1***
									Total Gas Service Components:	***4,977***						***Total Light Oil Service Components:***	***1,768***

Composite Model Compressor Station - VOC Emissions

Each Component TOC Emission Factor[1] [kg/hr]:	***2.00E-04***	***3.90E-04***	***2.00E-03***	***2.40E-03***	***4.50E-03***	***8.80E-03***	***2.10E-04***	***1.10E-04***	***1.40E-03***	***1.30E-02***	***2.50E-03***	***7.50E-03***
Each Component VOC Emission Factor [kg/hr]:	***2.20E-05***	***4.30E-05***	***2.20E-04***	***2.64E-04***	***4.96E-04***	***9.69E-04***	***2.10E-04***	***1.10E-04***	***1.40E-03***	***1.30E-02***	***2.50E-03***	***7.50E-03***
Component Annual VOC Emissions [tons/year]:	***0.73***	***0.29***	***0.07***	***-***	***3.28***	***1.12***	***2.77***	***0.12***	***0.15***	***0.89***	***6.29***	***0.66***

***Total Annual VOC Emissions [tpy]:* 16.4**

[1] See Table 2-4 "Oil and Gas Production Operations Average Emission Factors" EPA Protocol for Equipment Leak Emission Estimates, November 1995, EPA-453/R-95-017

Composite Model Compressor Station - Methane/Ethane Emissions

Each Component C1-C2 Emission Factor [kg/hr]:	***1.78E-04***	***3.47E-04***	***1.78E-03***	***2.14E-03***	***4.00E-03***	***7.83E-03***	***8.92E-08***	***4.68E-08***	***5.95E-07***	***5.52E-06***	***1.06E-06***	***3.19E-06***
Component Annual C1-C2 Emissions [tons/year]:	***5.91***	***2.37***	***0.53***	***-***	***26.47***	***9.01***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***

***Total Annual Methane/Ethane Emissions [tpy]:* 44.3**