Initial 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
August 31, 2021
Before the Air Quality Control Commission
Request for Hearing, September 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 GHG Roadmap identifies these 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) CO2e by 2025 and 8 MMT CO2e 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 these goals 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 state GHG Pollution Reduction Roadmap (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 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 proposed on a state-wide and state-only basis.

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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 Initial Economic 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 Initial Economic Analysis, the Division conducts an analysis of the social cost of carbon 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 innovative regulatory programs designed to minimize the loss of natural gas during the production process.

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[1] *See* Highwood Emissions Management, *An Overview of Voluntary Emissions Reduction Initiatives for Responsibly Sourced Oil and Gas,* May 2021. https://highwoodemissions.com/the-highwood-bulletin/2021-voluntary-initiatives-report/
[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

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.

Pursuant to §25-7-110.5(4)(c), C.R.S., the Division, as staff to the Commission, 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.

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;
- 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 Reg. 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]

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

I.A. Monitoring: Reg. 7, Part D, Sec. 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 Reg. 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

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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.

inspected at this frequency, but has not yet received a response. Based on the Reg. 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: Reg. 7, Part D, Sec. 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. The Division assumes 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. 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 has requested that such information be provided by operators. 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 therefore - as staff to the Commission - requests that industry provide information about these costs and the necessity therefore.

I.C. Performance Testing of Enclosed Combustion Devices: Reg. 7, Part D, Sec. 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.

[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 "enviroscreen" 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.

Table 1: ECD Testing Schedule						
Location of Combustion Devices	Compliance Deadlines (on or before December 31)					
	2022	2023	2024	2025	2026	2027[9]
	Number of ECDs that must be tested by each year end					
Inside DI Community	679	679	679	679	-	679
Inside NAA (Not in DI Community)	948	948	948	948	948	948
Outside NAA (Not in DI Community)	205	205	307	307	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 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 Initial 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 2027. The Division calculated that an average of 1,855 ECDs would be required to be tested each year, for the first 5 years. As noted below, in Table 2, the cost per year of testing 1,855 ECDs is estimated at $11,736,757.83.

[9] The estimate of ECDs tested in 2027 also includes those ECDs that were tested in 2022 and are required to complete testing again after 5 years, per the rule proposal, assuming all ECDs tested in 2022 have to be tested again in 2027 (a conservative assumption).
[10] Equipment rental and preparation rates were provided by companies that offer ECD testing services.

Table 2: ECD Performance Improvement Costs				
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	1,855	$11,736,757.83	

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).[11] The Division estimated that its proposal would result in a VOC benefit of 539.59 tpy. Using an assumed methane to VOC ratio of 1.01:1 for storage tanks, the Division estimated a greenhouse gas benefit of 13,843.18 mtCO2e/yr.

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

[11] 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.

reports would be submitted 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 $11,736,757.83, and an annualized cost of flow meters of $3,703,908 per year, the Division estimates a total annual cost of $15,440,666.23. Based on this analysis, the Division has determined that this proposal will result in a cost effectiveness of $28,615.78 per ton VOC and $1,115.40 per mtCO2e.

Table 3: ECD Performance Improvement Cost Effectiveness			
Annual and Total ECD Performance Improvement Costs			
	Cost per test or meter	**Annualized Cost**	**Total Annual Cost**
Total Performance Test	$6,326.60		$11,736,757.83
Flow meter	$2,439.00	$389.68	$3,703,908.40
Total			$15,440,666.23
ECD Performance Improvement Cost Per Ton			
	VOC (tpy)	**Methane (tpy)**	**Methane (mtCO2e/yr)**
Emission Reductions	539.59	544.98	13,843.18
Cost per ton Emission Reduction	$28,615.78		$1,115.40

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

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: Reg. 7, Part D, Sec. II.E[12]

According to the Division's 2020 state-wide LDAR annual reporting, 537,233 inspections were completed at well production facilities (comprised of 510,946 AVO inspections and 26,287 AIMM inspections) and 701 inspections were completed at natural gas compressor stations (all AIMM inspections). From these inspections, 20,966 leaks were discovered at well production facilities (1,822 from AVO and 15,556 from AIMM) 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.

The Division uses the same approach to estimate LDAR inspection costs as in the 2014, 2017, and 2019 rulemaking EIAs supporting LDAR requirements.[13] 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 CPI Inflation Calculator. The Division found the current capital cost of an IR camera to be between $100,430 - $163,366.[14] 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[15]. All equipment, including IR cameras, are assumed to have a lifespan of 5 years[16]. Table 4 provides an estimate of the capital and recurring costs required for LDAR inspections.

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[12] The cost analysis of this section is also relevant to the upstream LDAR costs evaluated later in this Initial EIA.
[13] *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.
[14] IR camera capital cost is based on historical Division data as well as current market rates for commercial IR cameras.
[15] Cost is inflated to 2021 dollars from the 2014 value of $7,500/year, using the U.S. Bureau of Labor Statistics CPI Inflation Calculator.
[16] 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[17] 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: Reg. 7, Part D, Sec. 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 Initial 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

[17] This assumes a 40 hour work week, ten holidays, two weeks of vacation, and one week of sick leave.

Control Area with emissions under 12 tpy VOC.[18] That is, 75 compressor stations currently do not have an existing quarterly leak inspection requirement.

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 21.2 hours per IR inspection and 10.6 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%[19], 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[20], as used in

[18] Based on 2020 annual LDAR reporting, 75 compressor stations reported a semi-annual LDAR frequency.
[19] *See* Oil and Gas CTG, Id. at p. 8-7.
[20] *See* "Analysis of Emissions Reduction Techniques for Equipment Leaks," Cindy Hancy, December 21, 2011.

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[21] for all components. Using the estimate for the number of expected leaks per component, the Division estimates that a total of 34.75 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)[22]	Total Annual Value of Recovered Natural Gas
≤ 12 tpy in a DI Community	25	114.084	$222.69	$25,402.90

[21] Based on the hourly repair rate of $66.24 from 2009, used in the Division's 2019 Regulation 7 EIA, adjusted for inflation to 2021 using the U.S. Bureau of Labor Statistics CPI Inflation Calculator.
[22] 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.

Cost Effectiveness

Combining the annual cost of inspections, $63,150.28, with the annual cost of repairs, $71,295.55, yields a total gross annual cost of $134,445.83. 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.

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 (w/o recovered nat gas)**	**Total GHG Emission Reduction (mtCO2e/year)**	**Cost per mtCO2e (w/o recovered nat gas)**
41.00	$3,279.14	2,897.64	$46.40

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.[23] 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: Reg. 7, Part D, Sec. 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 New Source Performance Standard (NSPS) OOOO or NSPS OOOOa. Natural gas processing plants outside the 8-hour Ozone Control Area may also

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

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 initial 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 Control Techniques Guidelines for the Oil and Natural Gas Industry (Oil and Gas CTG)[24] 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)."[25]

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[26]. 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				

[24] Control Techniques Guidelines for the Oil and Natural Gas Industry 2016, EPA. 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)).
[25] Oil and Gas CTG, pp.8-9, 8-10.
[26] Oil and Gas CTG, p. 8-11.

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 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.[27]

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: Reg. 7, Part D, Sec. II.H

II.B.1. Pigging Operations

In Permit Section (PS) Memo 20-04, 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 management 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, Section 6.5 and 6.6.

The Division used gas speciation data collected by the Division, guidance from the EPA[28] and information received from operators and manufacturers to estimate emissions from pigging events.

<u>Cost - Pig Ramps</u>

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[27] *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.

[28] "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.

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.[29] 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-$1300 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.

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."[30] One operator who employed the two best management practices described above (pig ramps and depressurization) and ZEVAC units reported significant reductions in gas vented and emissions as a result.[31] The Division does not have reasonably available information as to the cost of this best management practice nor how widely deployed it is already. The Division as staff to the Commission - requests that information from operators. The Division otherwise assumes this cost to be absorbable.

Cost - ZEVAC unit

In order to comply with the requirement to capture and reduce emissions during pigging operations, the Division assumes operators will use a Zero Emission Vacuum And Compressor (ZEVAC) unit.[32] The Division assumes that a pig launcher and receiver are already on-site.

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. 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

[29] Pipeline Launcher/Receiver Emission Reduction Systems
[30] EPA Enforcement Alert (Sept. 2019). Natural Gas Gathering Operations Clean Air Act Enforcement Alert
[31] See *Methane Reductions in Pigging,* September 2019, Methane Reductions in Pigging
[32] 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

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.[33]

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.

[33] As with elsewhere in this Initial 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[34] 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

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

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 as set forth above.

II.B.2. Blowdowns

The Division's proposal will require midstream owners and operators to reduce hydrocarbon emissions from blowdowns from equipment at compressor stations and gas plants. The Division also proposes requiring best management practices for blowdowns of midstream gathering pipelines.

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

[34] Converted from methane to CO2e.

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[35] 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[36] or other equipment and route the gas to a lower pressure fuel gas line.

Many best management practices are already identified in PS Memo 20-04. The Division - as staff to the Commission - requests additional information from operators on the costs of implementing controls and other practicable best management practices specified in the Division's proposal.

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.

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.

Table12: 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**

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

Not accounting for any reductions from pipeline emissions,[37] 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.

Cost of 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 139 events per day[38] that would be required to be captured or controlled by this rule. Using an annualized portable enclosed combustion device cost of $9,286.78, 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), for a total of 139 units reuqired, the average cost per ton of emission reductions is $3,825.55 per tpy VOC and $39.24 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 13 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 13: 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
Portable Enclosed Combustion Device	$2,591,753.91	1,605.58	156,520.24	$1,614.22	$16.56
Small ZEVAC unit	$2,169,288.84	1,690.08	164,758.15	$1,283.54	$13.17
Medium ZEVAC unit	$3,249,607.52	1,690.08	164,758.15	$1,922.75	$19.72
Large ZEVAC unit	$17,714,882.08	1,690.08	164,758.15	$10,481.68	$107.52
Overall Average Cost Effectiveness				**$3,825.55**	**$39.24**

II.C. Rod Packing Replacement at Natural Gas Processing Plants: Reg. 7, Part D, Sec. 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.[39]

[37] 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.
[38] Operators reported 35,184 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.
[39] 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

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."[40] 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.

II.D. Pneumatic Controller Requirements at Natural Gas Processing Plants: Reg. 7, Part D, Sec. III

The Division's proposal would expand current requirements to use zero-bleed 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 have a bleed rate of zero.

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.[41] 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.[42]

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,

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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.

[40] Oil and Gas CTG, p.5-10.

[41] Id. at p.6-16.

[42] Id. at p.6-17, Table 6-7.

and any pneumatic controllers with a bleed rate greater than zero are required due to safety reasons.[43] 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 natural gas-driven pneumatic controllers with a bleed rate greater than zero 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: Reg. 22, Part B, Sec. 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. 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. 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: Reg. 7, Part D, Sec. 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

[43] Id. at p.6-16.

in a disproportionately impacted 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: Reg. 7, Part D, Sec. II.E.4.f

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 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.

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.[44] 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.

Table 14 below identifies how many additional inspections would be required in each of the first five (5) 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.[45]

[44] 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.

[45] 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.

Table 14: AIMM Inspection Schedule by Area of State			
Proposed AIMM Inspection Schedule in Years 1 - 5			
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 Per Year	**429**	**167**	**40**

The Division took the same approach to estimate inspection time, inspection cost, and repair cost as with the midstream segment leak detection program for compressor stations. Tables 15, 16, and 17, below demonstrate the number of required inspection hours required and the resulting cost in each area. The total cost across locations is found to be $811,877.40 per year.

Table 15 -- AIMM - 8-hour Ozone Control Area (not Proximity to Occupied Area)					
# Inspections	**Inspection type**	**Inspection method**	**Result: Inspection hours**	**Cost per hour**	**Result: Total cost**
429	In-house	Method 21	782.15	$105.00	$82,126.04
		FLIR	3519.69	$105.00	$369,567.20
	Contractor	Method 21	127.33	$137.00	$17,443.83
		FLIR	572.97	$137.00	$78,497.22
Totals			**5,002.14**		**$547,634.29**

Table 16 -- AIMM - Outside 8-hour Ozone Control Area (not Proximity to Occupied Area)					
# Inspections	**Inspection type**	**Inspection method**	**Result: Inspection hours**	**Cost per hour**	**Result: Total cost**
40	In-house	Method 21	72.93	$105.00	$7,657.44
		FLIR	328.18	$105.00	$34,458.48
	Contractor	Method 21	11.87	$137.00	$1,626.46
		FLIR	53.42	$137.00	$7,319.09
Totals			**466.40**		**$51,061.47**

Table 17 -- AIMM - Proximity to Occupied Area					
# Inspections	**Inspection type**	**Inspection method**	**Result: Inspection hours**	**Cost per hour**	**Result: Total cost**
167	In-house	Method 21	304.47	$105.00	$31,969.81
		FLIR	1370.13	$105.00	$143,864.15
	Contractor	Method 21	49.57	$137.00	$6,790.49
		FLIR	223.05	$137.00	$30,557.19
Totals			**1,947.22**		**$213,181.65**

Leak Repair

Because the frequency-per-year of inspections changes over time, the Division uses an average scaled leak frequency rate of 1.77%, based on EPA data that suggests an annual leak frequency of 1.18%, a quarterly leak frequency of 1.77% and a monthly leak frequency of 2.36%. Using the previous estimates for component repair time and component repair cost in terms of an hourly rate, the Division estimates that a total of 13.02 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 therefore estimated at $1,485.26 per facility. Multiplying this estimate by the number of total affected facilities in each year yields an industry-wide annual leak repair cost. Total repair hours and costs under each AIMM frequency requirement are demonstrated in Table 18, below. The total repair cost to all affected newly constructed well production facilities is estimated to be $135,149.53 per year.

Table 18: Repair Costs for Well Production Facility Monthly AIMM			
	Facility location		
	AIMM - 8-hour OCA (not Proximity to OA)	AIMM - Proximity to OA	AIMM - ROS (not Proximity to OA)
# of new facilities per year	55	31	5
Repair hours per facility	18.1	18.1	18.1
Total repair hours	995.48	561.08	90.5
Repair cost per hour	$82.06	$82.06	$82.06
Total repair cost	$81,689.22	$46,034.02	$7,426.29
TOTAL	$135,149.53		

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 estimated emission reductions from increasing the frequency of locking the LDAR frequency at monthly for the life of new well production facilities is 126.42 tpy VOC and 4,657.32 mtCO2e/year (methane).

Table 19: LDAR Emission Reductions							
Area of State	Annual Number of New Facilities	Average Emission Reduction per Facility			Total Emission Reduction		
		VOC (tpy)	Methane (tpy)	GHG (mtCO2e/ yr)	VOC (tpy)	Methane (tpy)	GHG (mtCO2e/ yr)
8-hour Ozone Control Area (not Proximity to Occupied Area	55	1.22	1.09	27.80	67.19	60.19	1,528.95
Proximity to Occupied Area	31	0.65	0.95	24.14	20.19	29.46	748.38
ROS (not Proximity to Occupied Area)	40	0.98	2.34	59.50	39.04	93.70	2,379.99
Statewide Total Emission Reduction					**126.42**	**183.35**	**4,657.32**

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		
Total Recovered Methane (tpy)	**Value of Natural Gas ($/ton methane)[46]**	**Total Annual Value of Recovered Natural Gas**
183.35	$274.48	$50,325.65

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.

Cost Effectiveness

As noted before, the total cost of inspections across operators is estimated to be $811,877.40 per year, and the total cost of repairs across operators is estimated to be $135,149.53 per year. This results in a total annual cost of $947,026.93. As outlined in Table 21, the Division estimates an overall cost effectiveness of $7,491.12 per ton VOC and $203.34 per mtCO2e.

Table 21: Upstream LDAR Total Annual Cost			
LDAR Total Annual Cost			
	Inspection	**Repair**	**TOTAL**
Annual Cost	$811,877.40	$135,149.53	$947,026.93
Reporting	--	--	$0.00
Recovered Natural Gas	--	--	-$50,325.65
Net Cost	--	--	**$896,701.28**
Upstream Emissions Reduction and Cost			
Total VOC Emission Reduction (VOC)	**Cost per ton VOC (w/o recovered nat gas)**	**Total GHG Emission Reduction (mtCO2e/year)**	**Cost per mtCO2e (w/o recovered nat gas)**
126.42	$7,491.12	4,657.32	$203.34

III.C. Greenhouse Gas Intensity for Preproduction Emissions and Production Emissions: Reg. 22, Part B, Sec. 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.

[46] 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 24.01 lb/lb-mol of natural gas and 47.08% statewide average of methane by weight.

Based on an analysis of emissions and production data reported to the EPA under the Greenhouse Gas Reporting Rule (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 RCI sector. The Division first used the 2005 baseline emissions for the O&G Sector from the GHG Roadmap, a total of 20,166,407 mtCO2e, 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.[47] 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 RCI 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.

[47] 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).

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 will reduce GHG emissions from the upstream segment of the oil and gas industry in the following amounts:

Table 23: Total Intensity GHG Reductions	
Year	**Total CO2e Reductions from 2020[48] (mtCO2e per year)**
by 2025	5,326,723
by 2027	6,251,946
by 2030	6,922,358

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 Initial 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 - keep Colorado on track to meet its GHG goals.

The costs associated with meeting GHG intensity targets will range widely across the industry. The EPA provides recommendations for technologies to reduce methane emissions[49]. 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. Implementation of methane control technologies can result in realized benefits to operators associated

[48] 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.
[49] Recommended Technologies to Reduce Methane Emissions | US EPA

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.

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

III.D. Emission Reductions From Well Maintenance and Liquids Unloading Activities, Reg. 7, Part D, Sec. II.G

The Division's proposal would augment existing requirements for best management 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.[50] 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 (9,829 in the Piceance and 93 in the remainder of the state).

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.[51] 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 Management 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 management practices.

III.D.2. Well Unloading Emission Reductions

Under the Division's proposal, operators would have to either: (1) install artificial lift, such as plunger lift, to reduce/avoid the need for liquids unloading and/or reduce the volume of gas vented during an unloading event; or (2) use air pollution control equipment to combust the hydrocarbons emitted during liquids unloading.

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[50] This is based upon data received by the Division from COGCC in early July 2021. 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.

[51] 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: Liquids Unloading* (2014), Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings.

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.[52] 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.[53] 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 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 could be entirely avoided - instead of just minimized - through the use of plunger lifts. However, assuming that fifty percent of operators comply through installing plunger lifts, and the use of those plunger lifts avoids the need for unloading fifty (50%) of the time and reduces the volume unloaded by half the other fifty percent of the time, the Division's proposal would result in natural gas avoided of 142,716 MCF. At a gas price of $4 per MCF, that results in a savings of $570,864.

With these same assumptions (i.e. that plunger lifts would completely avoid the emissions from ⅛ of unloading events), 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.

Control Equipment

As a final option, the Division's proposal would require the capture or control of emissions from unloading through the use of control equipment. For purposes of this analysis, the Division assumes 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. If operators conducting multiple unloading events purchased an open flare, costs would be significantly reduced. Based upon information collected by the Division, the Division assumes a cost per well unloading event (including flare rental, delivery fees, installation, engineering, labor, and preparation) of $3,565 per event. Taking the number of events reported to COGCC for the first half of 2021, and extrapolating across the full year, the Division estimates a total of 27,184 well unloading events per year. At a cost of $3,565 per event, the Division estimates an annual cost of $96,910,960 for the use of air pollution control equipment during well unloading events.

[52] See *Liquids Unloading Options for Natural Gas Wells,* 2012 Natural Gas STAR Annual Implementation Workshop, April 12, 2012. Liquids Unloading Options for Natural Gas Wells (pdf)
[53] Id. See also *Lessons Learned from Natural Gas STAR Partners: Installing Plunger Lift Systems in Gas Wells*, Installing Plunger Lift Systems In Gas Wells.

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 2,958.23 tpy VOC and 136,509.64 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 estimates the cost effectiveness of control as set forth below:

Table 25: Well Unloading Emission Reductions				
Cost of Control	**VOC Reduced (tpy)**	**Cost/Ton VOC**	**GHG Reduced (mtCO2e/year)**	**Cost/mtCO2e**
$96,910,960	2,958.23	$32,760	136,509.64	$710

The cost of control here is estimated assuming operators will need to rent an open flare each time they conduct a well unloading event with venting to atmosphere. The Division believes this to be a very conservative estimate of cost effectiveness because not all operators will use air pollution control equipment to comply, and of those who do, some will purchase open flares, resulting in significant cost savings.

The Division - as staff to the Commission - requests information from stakeholders to inform the costs associated with this proposal.

IV. Annual Emissions Inventory Reporting Updates

The Division's proposal also includes updates to Regulation 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 HB21-1266, 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.[54] 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 over five years. 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.

Table 26: Social Cost of Greenhouse Gases

Year	Social Cost of Carbon ($/mtCO2e)	Emission Reductions (mtCO2e)	Social Benefit	Present Value (2021 $)
2023	$80.34	7,369,038.70	$592,021,200.12	$563,494,301.12
2024	$81.65	7,369,038.70	$601,645,164.66	$558,687,345.49
2025	$82.95	7,369,038.70	$611,269,129.20	$553,779,661.75
2026	$84.26	7,369,038.70	$620,893,093.75	$548,779,023.05
2027	$85.56	7,369,038.70	$630,517,058.29	$543,692,883.30

This analysis assumes that the total estimated annual emission reduction of 7,369,038.70 mtCO2e will be the same in every year. The annual emissions reduction is 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

[54] 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. Technical Support Document: Social Cost of Carbon, Methane,

account for inflation and understand the value of future benefits from today's perspective. As Table 26 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 in every year, 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. Over the first five years that emission reductions would occur (2023-2027), the total net present value is estimated to be $2,215,631,359.09; all a benefit to society.

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	7,369,038.70	$116,086,696.71	$563,494,301.12	$447,407,604.42
2024	7,369,038.70	$113,255,313.86	$558,687,345.49	$445,432,031.62
2025	7,369,038.70	$110,492,989.13	$553,779,661.75	$443,286,672.61
2026	7,369,038.70	$107,798,038.18	$548,779,023.05	$440,980,984.87
2027	7,369,038.70	$105,168,817.74	$543,692,883.30	$438,524,065.56

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 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 Initial 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.

Table 28: Cumulative Cost Effectiveness		
Total Annual Cost	**$121,963,585.73**	
	GHG (mtCO2e)	**VOC (tons)**
Total Emissions Reduced Per Year	7,369,038.70	6,646.86
Total Cost Effectiveness	$16.55	$18,349.05

The Division projects that the proposal will reduce greenhouse gas emissions (In CO2e) by approximately 7,459,343 mtCO2e per year at a cost of approximately $120,729,978.73 per year. The overall cost effectiveness for the entire package is approximately $16.19 per ton of CO2e reduced. The Division also estimates its proposal will reduce at least 6,645 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. The Table 28 cumulative cost-effectiveness analysis does not take into account the social cost of greenhouse gas as discussed in the Section V of this Initial EIA.

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.