COST-BENEFIT ANALYSIS

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

DEPARTMENT:	Colorado Department of Public Health & Environment	**AGENCY**:	Air Quality Control Commission
CCR:	5 CCR 1001-9	**DATE:**	November 29, 2019

RULE TITLE OR SUBJECT:

Regulation Number 7
Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions

Per the provisions of 24-1-103(2.5)(a), Colorado Revised Statutes, the Colorado Department of Public Health and Environment, Air Pollution Control Division ("Division") has prepared the following cost-benefit analysis.

1. The reason for the rule or amendment;

The Air Pollution Control Division (Division) has proposed revisions to the Air Quality Control Commission's Regulation Number 7 to address Senate Bill 19-181 (SB 19-181), as well as ozone, streamlining and updating the regulation, and making any necessary typographical, grammatical, and formatting corrections. The Division proposes to include several revisions in Colorado's State Implementation Plan (SIP) as streamlining, clarifications, SIP strengthening, and concerning reasonably available control technology (RACT) provisions for major sources of volatile organic compounds (VOC) and/or nitrogen oxides (NOx).

Two elements of this proposal include recommendations from the Statewide Hydrocarbon Emissions Reduction (SHER) team, formed in response to the Air Quality Control Commission's November 2017 directive to form a stakeholder process to make recommendations on state-wide hydrocarbon emissions reduction strategies for the oil and gas sector. Notably, these SHER team recommendations on addressing emissions from pneumatic controllers and the transmission segment are being made in advance of the January 2020 timeline.

a. Senate Bill 19-181: Minimizing emissions from the oil and gas sector

During the 2019 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes in SB 19-181 (Concerning additional public welfare protections regarding the conduct of oil and gas operations) that include directives for both the Oil and Gas Conservation Commission and the Air Quality Control Commission. This proposed rulemaking focuses on the Air Quality Control Commission directives in § 25-7-109, Colorado Revised Statutes (CRS), which bolster the Air Quality Control Commission's existing authority to "minimize emissions of methane and other hydrocarbons, volatile organic compounds, and oxides of nitrogen" from all the "natural gas supply chain." Further, SB 19-181 identifies specific provisions the Air Quality Control Commission should consider including semi-annual leak detection and repair inspection requirements at well production facilities, transmission pipeline and compressor station inspection requirements, continuous methane emission monitoring requirements, and pneumatic device requirements. This proposed rulemaking addresses many of the specific provisions for consideration, though not continuous methane monitoring, and is expected to be the first of several rulemakings brought before the Air Quality Control Commission to implement SB 19-181.

The Division proposes to increase certain leak detection and repair (LDAR) inspection frequencies, expand inspection requirements for pneumatic controllers, revise the thresholds at which a storage tank is subject to control, expand the well emissions best management practices (BMP) requirements, require new storage tanks to use an automatic tank gauging system, require the control of emissions from storage tank unloading, and establish a performance based emission reduction program for the downstream transmission segment. The Division is also proposing annual emissions inventory and reporting requirements for the oil and gas sector.

b. Ozone reclassification

On May 4, 2016, the U.S. Environmental Protection Agency (EPA) published a final rule that determined that Colorado's Marginal ozone nonattainment area failed to attain the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS) of 75 parts per billion (ppb). EPA, therefore, reclassified the Denver Metro North Front Range (DMNFR) to Moderate and required attainment of the NAAQS no later than July 20, 2018. On August 15, 2019, EPA proposed to reclassify the DMNFR to Serious, after 2015-2017 ozone data failed to show attainment, requiring attainment of the 2008 ozone NAAQS no later than July 20, 2021

Separately, EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb, with an attainment date of August 3, 2021. Colorado must act aggressively to attain both of these standards and submit the necessary revisions to its SIP to address both the Clean Air Act's (CAA) more rigorous Serious ozone nonattainment area requirements, as set forth in CAA §§ 172 and 182(c) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). The emission reduction strategies proposed in response to SB 19-181 will secure ozone emission reductions

A serious SIP revision must include Reasonably Available Control Technology (RACT) requirements for major sources of VOC and/or NOx (i.e., sources that emit or have the potential to emit 50 tons per year (tpy) or more) and for each category of VOC sources covered by a Control Technique Guideline (CTG) for which Colorado has sources in the DMNFR. EPA has established a due date for Colorado's Serious SIP of August 3, 2020 for all elements except RACT (where not tied to attainment), and March 23, 2021 for the remaining RACT SIP element. (See 84 Fed. Reg. 44,238 (Aug. 23, 2019)). Given Colorado's statutory requirement for legislative review of SIP revisions, this timing requires the Division to act now to meet EPA's advanced SIP submittal deadlines.

To address the CAA RACT SIP requirements for Serious nonattainment areas, the Division proposes revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for 50 tpy major sources of VOC and/or NOx including expanding the combustion equipment requirements currently applicable to major sources over 100 tpy VOC and/or NOx, incorporating specific New Source Performance Standards (NSPS) or National Emission Standards for Hazardous Air Pollutant (NESHAP) requirements, a categorical rule concerning general solvent use, and adopting a requirement that specific sources submit RACT analyses to the Division.

The Division also proposes clean-up corrections to the requirements for major source combustion equipment adopted in July 2018.

c. Regulation Number 7 reorganization and SIP streamlining

In an effort to improve the organization and thus usability of Regulation Number 7, the Division is proposing to reorganize Regulation Number 7 into five parts.

As a SIP clean-up effort, the Division proposes revisions to Regulation Number 7, Part B, Sections IV. and VII. and Appendix E to update the gasoline transport truck testing and associated recordkeeping requirements and update and clarify the vapor system requirements.

The Division may also make typographical, grammatical, and formatting corrections throughout Regulation Number 7.

The proposed revisions to Regulation Number 7 are SIP revisions, with the exception of revisions to State Only requirements in Part D, Sections II. and III.

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

The proposed changes to Regulation Number 7 are projected to result in significant reductions of hydrocarbon emissions (including both VOCs and methane/ethane) from the oil and gas industry. For VOCs, the Division projects that based on 2017 emissions, the proposed strategies will reduce VOC emissions from the oil and gas sector by at least approximately 5,766 tons per year and methane/ethane emissions by at least approximately 4,337 tons per year. These numbers are based on the data available to the Division; for some proposals, the Division asked stakeholders for more data about potential emission reductions, but no data was provided (e.g., emissions associated with the opening of thief hatches during the loadout of hydrocarbon liquids; emissions avoided through the storage tank measurement systems, etc.). The Division therefore expects that its proposals will result in more emission reductions than calculated in the Final Economic Impact Analysis submitted to the Commission on November 5, 2019 as updated by the Rebuttal Statement submitted on November 25, 2019 (Final EIA).

These VOC reductions will aid Colorado's efforts to bring the Denver Metro/North Front Range area (DMNFR) into compliance with the 2008 and 2015 ozone NAAQS, as well as serve as a proactive step in addressing future lower ozone standards. Ground level ozone contributes to a number of health conditions, up to and including premature mortality from cardio-respiratory mortality. Attaining the 2008 and 2015 ozone standards will likely result in substantial health benefits. Further, attaining the standards and thereby avoiding further reclassification to higher levels of nonattainment will also have economic benefits (or, more accurately, will avoid the economic dis-benefits of reclassification). If the DMNFR is reclassified to a Severe nonattainment area, the major source threshold will drop to 25 tpy VOC or NOx, which could have negative economic impacts on the sources that become major by the reclassification.

In addition to the benefits associated with reductions of VOCs and methane, the proposed rules will produce additional economic benefits in the form of increased product capture and the creation of new jobs associated with the implementation of the new requirements. The proposed rules are expected to result in the capture of approximately $520,000 worth of natural gas each year that would otherwise be lost to the atmosphere. Additionally, a significant portion of the overall costs associated with the proposed rules is for additional inspections of oil and gas facilities by company employees or contractors. Based on the total calculated inspection time, the proposed requirements will necessitate the hiring of additional employees or contractors to conduct inspections. The remaining costs of the proposal are associated with the purchase, installation and maintenance of equipment along with supervisory oversight and required recordkeeping and reporting. These expenditures will likely result in additional job creation, but the actual number of these jobs has not been calculated.

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

a. Cost Effectiveness Analysis

The Division will oversee the administration and implementation of the proposed revisions to Regulation Number 7. There are no notable direct costs to the Division to administer the rule. The Division is in the process of forming a team focused on climate change and new reporting requirements and will be hiring staff for this initiative as well as additional inspection staff. The Division expects that with this additional staff it will have adequate resources to implement the proposed revisions.

The Division's assessment of the costs and benefits for each of the proposed strategies is set forth below. The Division is attaching its Final EIA submitted to the Commission on November 5, 2019, which offers additional detail and analysis. For each strategy, these assessments identify the cumulative costs for the affected industry, the estimated air pollution reduction, and the projected cost per unit of air pollution reduced. The Division also assessed whether any of the proposed strategies would impose a direct cost on the general public to comply, and determined that based on the available data there will be no direct costs on the general public for any of the proposed requirements.

I. Controls for Hydrocarbon Liquid Storage Tanks

Despite years of ever-more stringent control requirements, storage tanks remain the largest source of VOC in the oil and gas industry. Colorado has adopted numerous control requirements to reduce emissions from storage tanks located at oil and gas exploration and production and other facilities. The Division is proposing several new regulatory provisions aimed at reducing VOC, methane, and other hydrocarbon emissions from this category of sources. For the purposes of this analysis the Division assumes that operators will use enclosed flares to control emissions from storage tanks.

A. General Cost Estimates for Flares

In Table 1, the Division has estimated the annualized cost of an enclosed flare, ancillary equipment, pilot fuel, installation along with operation and maintenance based on identified costs from a 2008 oil and gas cost study[1] adjusted for inflation[2]. Based on this information, the estimated annualized cost of a flare control device with auto-igniter[3] is about $6,488.

Table 1: Flare Control Device with Auto Igniter – Annualized Cost Analysis*

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Flare	$19,245			
Freight/Engineering		$1,745		
Flare Installation		$7,393		
Auto Igniter	$1,745			
Pilot Fuel**			$642	
Maintenance			$2,327	
Subtotal Costs	$20,990	$9,138	$2,969	
Annualized	**$2,909**	**$609**	**$2,969**	**$6,487.7**

[1] See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008. Information from this study was previously submitted to the AQCC as part of the 2008 Ozone Action Plan process.
[2] Inflation adjustment over the period 2008-2018 was estimated at 16.35 % using US Department of Labor CPI-U annual data.
[3] Currently all flares in the state are required to have auto-igniters.

** All the flare control device costs were escalated by 16.35% to reflect CPI-U increases that have occurred since the 2008 rulemaking.*
*** Pilot fuel costs based on $2.85/MMBtu (Henry Hub Spot Price average January - April 2019)*
**** Annualized costs are over a 15 year period assuming a 5% rate of return*

In the Division's Rebuttal Statement filed on November 25, 2019, the Division calculated alternate cost scenarios assuming a higher recurring cost as proposed by the Joint Industry Work Group, which results in a higher annualized cost for the flare. However, the Joint Industry Work Group offered no data or evidence to support their higher cost estimates, so the Division relied on its reliable, well researched flare cost data to determine the cost of the flare for this regulatory revision. Regardless, as set forth in the Division's Rebuttal Statement, even with the higher recurring cost estimates, the Division's proposal remains reasonable and cost-effective. See Rebuttal Statement, p.24, Table 2 and footnotes 108 and 109.

B. Replace the 90% / 70% system-wide condensate storage tank control program in the DMNFR with a discrete threshold-based control requirement for storage tanks > 2 tons per year (tpy) of uncontrolled actual VOC emissions.

Despite significant population growth and increased economic activity, the DMNFR region has seen gradual improvement in ozone levels over the past 20 years, largely from significant reductions in ozone precursor emissions. However, ozone levels remain above the 2008 and 2015 NAAQS and the DMNFR is facing a pending reclassification to a "Serious" nonattainment area for the 2008 standard. Despite significant decreases in emissions since 2004, presently, tanks remain the largest single source of VOC emissions in the DMNFR. Given the region's ozone problems, and the administrative complexity of the current regulatory program, the Division proposes to transition from the current system-wide approach of controlling VOC emissions to a more stringent control program requiring control of all storage tanks with uncontrolled actual emissions of greater than or equal to 2 tpy.

Presently, Colorado's ozone SIP for the 2008 8-hour ozone standard specifies in Section XII.D.2 of Regulation Number 7 that owners and operators of all condensate tanks emitting ≥ 2 tpy meet a 90% system-wide control requirement on a weekly basis during the summer ozone season May 1st through September 30th. During the remainder of the year, operators must meet a 70% control requirement. The regulation provides exemptions from the system-wide control program to small operators with total company-wide emissions under 30 tpy. Operators are required to submit semi-annual reports to the Division detailing the number of tanks, condensate production, the presence of a control device on the individual tank (or tank battery), and the operational status. While many of the condensate tanks in the DMNFR are already controlled pursuant to the existing system-wide control program, the transition to a 2 tpy tank control threshold will require operators to install additional controls.

1. Condensate Tank Count

All non-exempt operators in the DMNFR are required to submit system-wide control reports to the Division semi-annually. Based on operator reported data for 2017, Table 2 shows there are 5,028 condensate tank batteries[4] in the DMNFR that are subject to Regulation Number 7 system-wide requirements. At the proposed tank control threshold of ≥ 2 tpy, the Division's records show that there are 65 condensate tanks that do not have emission controls. These numbers do not include the additional condensate tanks that currently go uncontrolled by virtue of the 30 tpy exemption described above.

[4] In the DMNFR, owners and operators of condensate tanks with total actual uncontrolled VOC emissions less than 30 tpy are exempt from system-wide control requirements and therefore are excluded from the above listed total. Analysis of these currently exempt tanks is addressed below.

Table 2: DMNFR Condensate Tank Count Based on Reg. 7 System-wide Control Reports			
Tank Battery Size*	Count of NAA Tanks	Count of NAA Tanks w/Controls**	Count of NAA Tanks w/out Controls
≥ 4 tpy	1,812	1,803	9
≥ 3 tpy to < 4 tpy	285	265	20
≥ 2 tpy to < 3 tpy	409	373	36
Subtotal	**2,506**	**2,441**	**65**
≥ 1 tpy to < 2 tpy	703	571	132
≥ 0 tpy to < 1 tpy	1,219	959	260
= 0 tpy	600	-	-
Subtotal	**2,522**	**1,530**	**392**
Grand Total	**5,028**	**3,971**	**457**

** Tank battery size is based on annual reported uncontrolled VOC emissions*
*** Tanks with zero emissions do not report whether facility has flare controls.*

2. Emission Reductions From Controlling DMNFR Condensate Tank ≥ 2 TPY

Using the Regulation Number 7 system-wide reports for 2017, there are a potential 65 condensate storage tanks without emission controls at the proposed ≥ 2 tpy storage tank control threshold in the DMNFR. The Division assumes that 100 percent of the flash gas in the storage tank is captured and routed to a control device through the implementation of Storage Tank Emissions Management (STEM) system requirements.[5] As reflected in Table 3, controlling emissions from these tanks will reduce VOC emissions by 188.93 tpy using an assumed 95 percent control device effectiveness[6].

Table 3: DMNFR Condensate Tank Emission Reductions			
Tank Battery Size	Count of NAA Tanks w/Controls	Count of NAA Tanks w/out Controls	VOC Reduction from Added Controls (tpy)
≥ 4 tpy	1,803	9	40.78
≥ 3 tpy to < 4 tpy	265	20	66.00
≥ 2 tpy to < 3 tpy	373	36	82.15
Total	**2,441**	**65**	**188.93**

[5] See Regulation Number 7, Section XVII.C.2 “Capture and monitoring requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.”
[6] Generally flares can achieve a destruction efficiency of 98 percent, but the Division assumes 95 percent control to account for some downtime.

3. Cost Effectiveness

Table 4 provides the annualized cumulative cost of installing 65 flare control devices is about $421,700 dollars with an average cost effectiveness of about $2,232 per ton of VOC reduced. For the smallest category of tanks (2-3 tpy) the incremental cost of controls on 36 tanks is estimated at $2,843 per ton of VOC reduced.

Table 4: Incremental Control Cost Estimates for Flare Control Devices on Tanks ≥ 2 tpy in the DMNFR

Tank Battery Size	Count of Tanks w/out Controls	Each Flare Annualized Cost[7]	Total Annualized Costs	VOC Reduction (tpy)	Average Control Costs
≥ 4 tpy	9	$6,487.7	$58,389	40.78	$1,432
≥ 3 tpy to < 4	20	$6,487.7	$129,754	66.00	$1,966
≥ 2 tpy to < 3	36	$6,487.7	$233,557	82.15	$2,843
All tanks	65	$6,487.7	$421,700	188.93	$2,232

In order to preserve flexibility in controlling smaller storage tanks that may have very low VOC concentrations that potentially may not be controlled if supplemental firing of natural gas is necessary to control emissions, the Division is proposing to establish in the SIP a control requirement for storage tanks ≥ 4 tpy. At the ≥ 4 tpy threshold, 91.5% control is achieved, thus no SIP backsliding occurs because VOC emission reductions exceed the required 90% system-wide control requirement by 1.5% The control requirement for storage tanks ≥ 2 tpy but < 4 tpy are proposed as “state-only”. The Division considered phasing in control requirements in the nonattainment area first and the remainder of the state across a two-year period (from 2021 to 2022), which could stagger costs over time, but overall cost estimates would remain the same.

C. Remove the Part E, Section I.A.7 exemption (associated with the system-wide control program) for owners or operators of condensate tanks with total actual uncontrolled VOC emissions less than 30 tpy.

Regulation Number 7 provides for an exemption from the system-wide control requirement for small condensate tank operators with total VOC emissions less than 30 tpy. Since these operators are exempt from system-wide reporting and Air Pollutant Emissions Notice (APEN) reporting is infrequent, it is difficult to ascertain how many tanks are using the exemption. Based on 2019 COGCC data, there are 67 operators reporting tank operations in Weld County (both inside and outside the nonattainment area). If the operators reporting to system-wide in Weld County are removed, there are about 46 operators reporting oil production that may have condensate tanks above the proposed 2 tpy VOC emission control threshold that would lose the 30 tpy exemption from control. The 46 operators also include 17 operators that reported zero oil production for the first six months of 2019, but who could presumably produce condensate at some point in the future.

The Division assumes that any condensate tanks previously exempted from control would fall into an uncontrolled VOC tank size range between ≥ 2 to < 6 tpy because all storage tanks state-wide must be controlled if the emissions ≥ 6 tpy. The estimated number of condensate tanks potentially impacted by

[7] See Table 1 for estimated annualized cost of flare controls.

the proposed ≥ 2 tpy threshold control requirement could be as high as 690 tanks assuming all 46 operators were just below the 30 tpy exemption threshold and all had 15 tanks equal to the 2 tpy threshold. A lower number of tanks potentially impacted by the proposed ≥ 2 tpy threshold control requirement is about 230 tanks assuming all 46 operators were just below the 30 tpy exemption threshold and all had 5 tanks just below the 6 tpy threshold. It is more likely that most operators have a few tanks and some will have no tanks above the ≥ 2 tpy threshold. If the Division assumes that all 46 operators have at least three tanks > 2 tpy, the number of tanks subject to control is estimated at 138 tanks. Operators with condensate tanks below the 2 tpy threshold would not incur any additional control costs.

Although the Division is currently unable to establish the exact number of condensate tanks impacted by the proposal to remove the 30 tpy exemption for condensate tanks, the control costs should be similar to the incremental control cost estimates presented in Table 4. The Division has previously requested more information from operators impacted by the removal of the 30 tpy condensate tank exemption but has yet to receive any such information.

D. Require controls on crude oil and produced water tanks in the DMNFR with uncontrolled actual emissions of 2 tpy VOC or greater.

Currently, in Part D, Section I (formerly Section XII) of Regulation Number 7 only condensate tanks ≥ 2 tpy are subject to the system-wide emission control requirement. Other storage tanks (crude oil and produced water) are subject to controls in Part D, Section II (formerly Section XVII) of Regulation Number 7, and then only if the uncontrolled actual VOC emissions ≥ 6 tpy. Consequently, there are a number of crude oil and produced water tanks over the proposed ≥ 2 tpy threshold that are not currently required by Regulation Number 7 to have controls in the DMNFR.

Based on most recently available Regulation Number 7 APEN reported data (for 2018) on crude oil and produced water tanks, Table 5 shows there are 605 crude oil and water tank batteries[8] in the DMNFR with emissions above the 2 tpy threshold. At the proposed storage tank control threshold of ≥ 2 tpy, there are 175 tanks that are reported as not having emission controls that will need to install controls.

Table 5: DMNFR Crude Oil & Produced Water Tank Battery Analysis (2018 APEN Data)

Tank Battery Size*	Count of NAA Tanks	Count of NAA Tanks w/Controls**	Count of NAA Tanks w/out Controls
≥ 4 tpy	417	371	46
≥ 3 tpy to < 4 tpy	58	25	33
≥ 2 tpy to < 3 tpy	130	34	96
Total	**605**	**430**	**175**

** Tank battery size is based on annual reported uncontrolled VOC emissions*
*** Tanks with zero emissions do not report whether facility has flare controls.*

Table 6 shows the estimated 611.4 tpy VOC emission reduction associated with the proposed control requirements on 175 crude oil and produced water tanks ≥ 2 tpy in the DMNFR.

[8] Crude oil and water tanks are determined by screening by respective source classification codes 404003012 and 4040003015.

Table 6: DMNFR Emission Reductions from Crude Oil & Produced Water Tank Controls			
Tank Battery Size	Count of NAA Tanks w/Controls	Count of NAA Tanks w/out Controls	VOC Reduction[9] from Added Controls (tpy)
≥ 4 tpy	371	46	269.8
≥ 3 tpy to < 4 tpy	25	33	108.0
≥ 2 tpy to < 3 tpy	34	96	233.6
Total	**430**	**175**	**611.4**

For crude oil and water tanks in the DMNFR, Table 7 provides the estimated annualized cost of installing 175 flare control devices at about $1.14 million dollars with an average cost effectiveness of about $1,857 per ton of VOC reduced. For the smallest category of tanks (2-3 tons/year) the incremental cost of controls on 96 tanks is estimated at $2,666 per ton of VOC reduced. Produced water tanks generally have lower hydrocarbon concentrations, which could limit flare control effectiveness and may require supplemental fuel to support effective combustion of the hydrocarbon vapors. The Division requested more information about the level of hydrocarbon concentrations triggering the use of supplemental fuel and quantity of supplemental fuel used but has not yet received such information. The Division is also proposing to add to the existing weekly visual inspection requirements inspections of burner trays and audio, visual, and olfactory (AVO) inspections (which AVO inspections were formerly conducted at a different frequency).. As weekly inspection requirements were already in place, there are no additional costs associated with these particular revisions.

Table 7: DMNFR Control Cost Estimates for Crude Oil & Produced Water Tanks ≥ 2 tpy					
Tank Battery Size	Count of Tanks w/out Controls	Each Flare Annualized Cost[10]	Total Annualized Costs	VOC Reduction (tpy)	Average Control Costs ($/ton)
≥ 4 tpy	46	$6,487.7	$298,434	269.8	$1,106
≥ 3 tpy to < 4	33	$6,487.7	$214,094	108.0	$1,982
≥ 2 tpy to < 3	96	$6,487.7	$622,819	233.6	$2,666
All tanks	**175**	**$6,487.7**	**$1,135,348**	**611.4**	**$1,857**

E. Lower the existing statewide control requirement threshold for condensate, oil and produced water storage tanks from ≥ 6 tpy to ≥ 2 tpy of uncontrolled actual VOC emissions and increase the approved instrument monitoring method (AIMM) inspection frequency from annual to semi-annual for storage tanks with VOC emissions > 6 to < 12. The Division has also examined a tank control requirement threshold of > 5 tpy and > 4 tpy for all areas of the state outside the DMNFR nonattainment area.

[9] The VOC emission reduction is calculated assuming the use of enclosed flare control operating at 95% control effectiveness.
[10] See Table 1 for estimated annualized cost of flare controls.

Based on APEN reports for the most recent complete data year (2018), the Division evaluated the number of condensate, crude oil, and produced water tanks that may need to install controls for areas outside of the DMNFR (referred to herein as the "remainder of the state (ROS)") including the areas north and east of the DMNFR. The Division acknowledges that the APEN reporting system allows flexibility in reporting (up to every 5 years), which may produce inaccurate counts for each tank battery size tier, particularly if well production has declined since the most recently filed APEN report has occurred. Accordingly, the actual number of tanks without controls evaluated in this proposal may differ from the APEN reported data. The Division requested more information about the number of statewide uncontrolled storage tanks that may be impacted by this rulemaking proposal but has yet to receive such information.

Table 8 shows there are about 588 crude oil and produced water tank batteries[11] with emissions > 2 tpy in the ROS. At the proposed storage tank control threshold of ≥ 2 tpy, there are 202 tanks that are reported as not having emission controls.

Table 8: ROS Crude Oil & Produced Water Tank Battery Analysis (2018 APEN Data)

Tank Battery Size*	Count of ROS Tanks	Count of ROS Tanks w/Controls**	Count of ROS Tanks w/out Controls
≥ 5 tpy	341	302	39
≥ 4 tpy to < 5 tpy	51	18	33
≥ 3 tpy to < 4 tpy	83	33	50
≥ 2 tpy to < 3 tpy	113	33	80
Total	**588**	**386**	**202**

** Tank battery size is based on annual reported uncontrolled VOC emissions*
*** Tanks with zero emissions do not report whether the facility has flare controls.*

Table 9 shows the estimated 866.7 tpy VOC emission reduction associated with the proposed control requirements on the 202 crude oil and produced water tanks ≥ 2 tpy in the ROS. A threshold of > 4 tpy would affect 72 tanks and result in an estimated VOC emission reduction of 506.2 tpy. A threshold of > 5 tpy would affect 39 tanks and result in an estimated VOC emission reduction of 366.5 tpy.

Table 9: ROS Emission Reductions from Crude Oil & Produced Water Tank Controls

Tank Battery Size	Count of ROS Tanks w/Controls	VOC Reduction from Existing Controls (tpy)	Count of ROS Tanks w/out Controls	VOC Reduction from Added Controls (tpy)
≥ 5 tpy	302	26,827.1	39	366.5
≥ 4 tpy to < 5 tpy	18	78.2	33	139.8
≥ 3 tpy to < 4 tpy	33	110.5	50	167.4

[11] Crude oil and water tanks are determined by screening by respective source classification codes 404003012 and 4040003015.

Table 9: ROS Emission Reductions from Crude Oil & Produced Water Tank Controls				
Tank Battery Size	Count of ROS Tanks w/Controls	VOC Reduction from Existing Controls (tpy)	Count of ROS Tanks w/out Controls	VOC Reduction from Added Controls (tpy)
≥ 2 tpy to < 3 tpy	33	77.1	80	193.1
Total, ≥ 2 tpy	**386**	**27,092.9**	**202**	**866.7**
Total, ≥ 4 tpy	**320**	**26,905.3**	**72**	**506.2**
Total, ≥ 5 tpy	**302**	**26,827.1**	**39**	**366.5**

For crude oil and water tanks in the ROS, Table 10 provides the estimated annualized cost of installing 202 flare control devices at about $1.31 million dollars with an average cost effectiveness of about $1,512 per ton of VOC reduced. For the smallest category of tanks (2-3 tons/year) the incremental cost of controls on 80 tanks is estimated at $2,688 per ton of VOC reduced. For a > 4 tpy threshold, the estimated annualized cost is $467,114 with an average cost effectiveness of about $923 per ton of VOC reduced. For a > 5 tpy threshold, the estimated annualized cost is $253,020 with an average cost effectiveness of about $691 per ton of VOC reduced.

Produced water tanks generally have lower hydrocarbon concentrations, which could limit flare control effectiveness and may require supplemental fuel to support effective combustion of the hydrocarbon vapors. Generally, the firing of supplemental fuel in a flare control device defeats the fundamental purpose of the control device, which is to reduce emissions and not increase them. Accordingly, the Division is proposing to allow operators to submit a technical demonstration showing that supplemental fuel is necessary for safe and effective combustion of the hydrocarbon vapors in situations where a tank has very low hydrocarbon vapor concentrations. The Division requested more information about the safety associated with combusting very low hydrocarbon vapor streams, the hydrocarbon concentration threshold triggering the use of supplemental fuel and quantity of supplemental fuel necessary for safe and effective combustion but has yet to receive such information.

Table 10: ROS Control Cost Estimates for Crude Oil & Produced Water Tanks ≥ 2 tpy					
Tank Battery Size	Count of Tanks w/out Controls	Each Flare Annualized Cost[12]	Total Annualized Costs	VOC Reduction (tpy)	Average Control Costs ($/ton)
≥ 5 tpy	39	$6,487.7	$253,020	366.5	$691
≥ 4 tpy to < 5 tpy	33	$6,487.7	$214,094	139.8	$1, 532
≥ 3 tpy to < 4 tpy	50	$6,487.7	$324,385	167.4	$1,938
≥ 2 tpy to < 3 tpy	80	$6,487.7	$519,016	193.1	$2,688
All tanks, ≥ 2 tpy	202	$6,487.7	$1,310,515	866.7	$1,512

[12] See Table 1 for estimated annualized cost of flare controls.

Table 10: ROS Control Cost Estimates for Crude Oil & Produced Water Tanks ≥ 2 tpy					
Tank Battery Size	Count of Tanks w/out Controls	Each Flare Annualized Cost[12]	Total Annualized Costs	VOC Reduction (tpy)	Average Control Costs ($/ton)
All tanks, ≥ 4 tpy	72	$6,487.7	$467,114	506.2	$923
All tanks, ≥ 5 tpy	39	$6,487.7	$253,020	366.5	$691

In addition to crude oil and produced water tanks, there are about 874 condensate tank batteries[13] with emissions above the 2 tpy threshold, based on 2018 APEN reported data in the ROS. At the proposed storage tank control threshold of ≥ 2 tpy, Table 11 shows there are about 444 tanks that are reported as not having emission controls.

Table 11: ROS Condensate Tank Battery Analysis (2018 APEN Data)			
Tank Battery Size*	Count of ROS Tanks	Count of ROS Tanks w/Controls**	Count of ROS Tanks w/out Controls
≥ 5 tpy	439	351	88
≥ 4 tpy to < 5 tpy	83	18	65
≥ 3 tpy to < 4 tpy	140	24	116
≥ 2 tpy to < 3 tpy	212	37	175
Subtotal	**874**	**430**	**444**

** Tank battery size is based on annual reported uncontrolled VOC emissions*
*** Tanks with zero emissions do not report whether facility has flare controls.*

Table 12 shows the estimated 1,715.2 tpy VOC emission reduction associated with the proposed control requirements on the 444 condensate tanks ≥ 2 tpy in the ROS. A threshold of > 4 tpy would result in proposed control requirements for 153 condensate tanks and an estimated VOC reduction of 929.9 tpy. There would be an estimated reduction of 656.7 tpy VOC from adding controls to 88 tanks at a threshold of > 5 tpy.

Table 12: ROS Emission Reductions from Condensate Tank Controls			
Tank Battery Size	Count of ROS Tanks w/Controls	Count of ROS Tanks w/out Controls	VOC Reduction from Added Controls (tpy)
≥ 5 tpy	351	88	656.7
≥ 4 tpy to < 5 tpy	18	65	273.1

[13] Condensate tanks are determined by screening by source classification code 404003011.

Table 12: ROS Emission Reductions from Condensate Tank Controls			
Tank Battery Size	Count of ROS Tanks w/Controls	Count of ROS Tanks w/out Controls	VOC Reduction from Added Controls (tpy)
≥ 3 tpy to < 4 tpy	24	116	382.3
≥ 2 tpy to < 3 tpy	37	175	403.1
Total, ≥ 2 tpy	**430**	**444**	**1,715.2**
Total, ≥ 4 tpy	**369**	**153**	**929.9**
Total, ≥ 5 tpy	**351**	**88**	**656.7**

For condensate tanks in the ROS, Table 13 provides the estimated annualized cost of installing 444 flare control devices at about $2.88 million dollars with an average cost effectiveness of about $1,679 per ton of VOC reduced. For the smallest category of tanks (2-3 tons/year) the incremental cost of controls on 175 tanks is estimated at $2,817 per ton of VOC reduced. The estimated annualized cost of installing 153 flare control devices is about $922,618 dollars with an average cost effectiveness of about $1,068 per ton of VOC reduced at a control threshold of > 4 tpy. The estimated annualized cost of installing 88 flare control devices is about $570,918 with an average cost effectiveness of about $879 per ton of VOC reduced at a control threshold of > 5 tpy.

Table 13: ROS Control Cost Estimates for Condensate Tanks ≥ 2 tpy					
Tank Battery Size	Count of Tanks w/out Controls	Each Flare Annualized Cost[14]	Total Annualized Costs	VOC Reduction (tpy)	Average Control Costs ($/ton)
≥ 5 tpy	88	$6,487.7	$570,918	656.7	$869
≥ 4 tpy to < 5 tpy	65	$6,487.7	$421,701	273.1	$1,068
≥ 3 tpy to < 4 tpy	116	$6,487.7	$752,573	382.3	$1,969
≥ 2 tpy to < 3 tpy	175	$6,487.7	$1,135,348	403.1	$2,817
All tanks ≥ 2 tpy	444	$6,487.7	$2,880,539	1,715.2	$1,679
All tanks ≥ 4 tpy	153	$6,487.7	$992,618	929.9	$1,068
All tanks ≥ 5 tpy	88	$6,487.7	$570,918	656.7	$869

Storage tanks with emissions ≥ 2 and less than 6 tpy will have to conduct AVO and visual inspections every 7 to 31 days. The Division is also proposing to add to the existing visual inspection requirements inspections of dump valves and liquid knockout vessels. These proposed requirements are based on the

[14] See Table 1 for estimated annualized cost of flare controls.

storage tank guidelines developed by the Division and industry, and are generally assumed to be conducted by most operators already, thus adding no additional burden or cost.

The Division is also proposing semi-annual AIMM inspections of storage tanks with emissions greater than or equal to 2 and less than 6 and to increase the AIMM inspection frequency from annual to semi-annual for storage tanks with emissions greater than or equal to 6 and less than or equal to 12 tpy, and related recordkeeping. These inspections, and the associated recordkeeping, are intended to align with the leak detection and repair (LDAR) inspections, discussed below.

II. Leak Detection and Repair (LDAR) for well production facilities and natural gas compressor stations

In 2014, the AQCC adopted LDAR requirements for well production facilities and natural gas compressor stations. Recently adopted SB 19-181 requires that the Air Quality Control Commissionreview its rules for oil and gas well production facilities and compressor stations and specifically consider adopting more stringent provisions including increasing the well production facility LDAR inspection frequency to a minimum of semi-annual. In recognition of SB 19-181, the Division is proposing to increase the frequency of AIMM inspections at well production facilities and compressor stations. In addition to proposing semi-annual LDAR inspections (and semi-annual inspections of pneumatic controllers, in Part D, Section III), the Division is proposing to require semi-annual AIMM inspections for storage tanks at these facilities so that the inspection schedules for tanks and components continue to align. Since operators will be conducting LDAR inspections at these facilities (and because storage tank pressure relief devices are included in the components scanned in the LDAR program under the definition of component as revised in 2017), the additional cost of an AIMM inspection on the tanks at that facility should be minimal. Accordingly the Division has not separately assessed the costs of increasing the AIMM inspections for storage tanks.

Consistent with the 2014 Oil and Gas Rulemaking[15] the Division is using a multi-step process to calculate the estimated costs and benefits associated with the proposed leak detection and repair requirements. First, the Division calculated an hourly inspection rate based on the total annual cost for each inspector divided by an assumed 1,880 annual work hours.[16] To calculate the total annual cost for each inspector, the Division included salary and fringe benefits for each inspector, annualized equipment (including an infrared camera) and vehicle costs, and add-ons to account for supervision, overhead, travel, record keeping, and reporting. Based on the assumptions set forth in the Divisions' 2014 Final Economic Impact Analysis, the total annual cost for each inspector is estimated at $193,629, which equates to an hourly inspection rate of $103. The Division adjusted the hourly inspection rate by 5.53% to account for cost increases since 2014. The 2019 "In-house" hourly inspection rate rounded to the nearest dollar is $109.

Table 14: Leak Detection and Repair (LDAR) Inspector – Annualized Cost Analysis

Item	Capital Costs (one time)	Annual Costs	Annualized Total Costs
FLIR Camera	$122,000		
FLIR Camera		$7,500	
Photo Ionization Detector	$5,000		

[15] See the Colorado Department of Public Health and Environment Air Pollution Control Division Final Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7 (5 CCR 1001-9), dated January 30, 2014.
[16] This assumes a 40 hour work week with ten holidays, two weeks of vacation, and one week of sick leave.

Table 14: Leak Detection and Repair (LDAR) Inspector – Annualized Cost Analysis

Item	Capital Costs (one time)	Annual Costs	Annualized Total Costs
Vehicle (4x4 Truck)	$22,000		
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	$149,000	$153,750	
Annualized Costs*	$39,879	$153,750	$193,629

2014 Annualized “In-house” Hourly Rate	$103
2014 Annualized “Contractor” Hourly	$134
2019 Annualized “In-house” Hourly Rate***	$109
2019 Annualized “Contractor” Hourly	**$142**

** Annualized over 5 year period at 6% rate of return*
*** Contractor rate 30% higher than In-house rate*
**** Adjusted by 5.53% to account for inflation since 2014*

In the 2014 Oil and Gas Rulemaking, the Division analyzed both “in-house” and “contractor” options for conducting LDAR inspections. The Division recognizes that in-house inspections would be the lowest cost option for larger operators since it would not involve additional profit to be paid to a contractor. However, for smaller companies that cannot fully utilize an IR camera, conducting inspections in-house may not be the most cost effective option. To account for these differences, the Division assumed a 30% profit margin for contractors, which is added to the calculated hourly rate in instances where it appeared that contractors would be used to conduct the inspection ($142 per hour). Considering the complex mix of large and small oil and gas operations, impacted by this proposal, including some potentially exempted from previous regulatory requirements in the DMNFR, the Division is using the contractor cost option to simplify the analysis. The use of the contractor hourly rate likely overestimates the costs of inspection. Despite using the higher hourly cost ($142), the foregoing analysis shows that the proposed increase in inspection frequency and repair is shown to be cost effective.

Second, the Division calculated the average amount of time that it would take to conduct a Method 21 inspection at compressor stations and well production facilities based on the number of components to be inspected and assuming that a component could be inspected every 30 seconds. The proposed rule also allows owners and operators to use IR cameras either as the sole inspection tool, or as a screening tool to identify potential leaking components followed by a Method 21 inspection. An IR camera inspection or IR Camera/Method 21 hybrid inspection can be conducted more quickly than a Method 21 inspection of each component. While the Division does not currently have actual data regarding how much faster an inspection could be completed using an IR camera, for the purpose of this analysis the Division assumed that an IR camera based inspection would, on average, take 50% of the time required for a Method 21 inspection.[17] However, this figure likely overestimates the time for conducting an IR camera inspection. In its role as staff to the Commission, the Division requested additional information on the time and costs associated with conducting IR camera based inspections, but did not receive any estimates from operators about how long they spend on each inspection.

For compressor stations, the Division used APEN reported component counts for the ≤ 12 tpy inspection tier identified in Table 15. Based on these counts, and the inspection times per component discussed above, the Division calculated the following total inspection time per compressor station facility at the ≤ 12 tpy inspection tier:

Table 15: Calculated Inspection Time Compressor Station Leak Inspections

Component Leak Uncontrolled Actual VOC Emissions	Area	Method 21 Inspection	IR Camera/ Hybrid Inspection
≤ 12 tpy	Rest of State	23.1 hours	11.6 hours

For well production facilities, the Division has limited APEN data on the number of components per facility. Based on this limitation, the Division did not attempt to calculate a separate inspection time for each of the proposed facility tiers, and instead used the overall average component count. Based on the limited available data, however, there does appear to be a distinction between component numbers at well production facilities in the DMNFR and well production facilities in the ROS. Some industry stakeholders have also maintained that ROS well production facilities have fewer components. Accordingly, the Division calculated separate inspection times for well production facilities by area as set forth in Table 16; ROS facilities have a shorter inspection time because of the lower component count assumed.

Table 16: Calculated Inspection Times for Well Production Facility Leak Inspections

Area	Method 21 Inspection	IR Camera/ Hybrid Inspection
DMNFR	12.2 hours	6.1 hours
Remainder of the State	6.8 hours	3.4 hours

[17] Based on the Division's own IR camera inspections, and reports from various parties during the 2014 stakeholder and prehearing process it appears that the Division's assumption may significantly overstate the actual time needed to conduct an IR camera inspection.

In addition to the travel costs that are built into the hourly inspection rate as set forth in Table 16, the Division also assumed an additional three hours in travel time for each well production facility inspection in the ROS. This assumption reflects the fact that certain well sites in basins in the ROS area may be remote, requiring additional travel.

Third, the Division calculated the projected inspection costs for both compressor stations and well production facilities. To make this calculation the Division used industry reported APEN emission data to determine the number of facilities that will be subject to semi-annual inspections to determine the total number of inspections for each tier, and multiplied these inspections by the calculated inspection time and projected hourly inspection rate. For both compressor stations and well production facilities the Division assumed that all inspections would be conducted by 3rd party contractors. Since owners and operators of both compressor stations and well production facilities are already subject to recordkeeping and reporting, the Division believes that any additional recordkeeping and reporting costs will be nominal relative to the overall cost of the LDAR program.

In the assessment of repair costs the Division also estimated product savings from conducting leak detection activities. To calculate repair costs, the Division used EPA information regarding leaking component rates, component repair times, and hourly repair rates. Specifically, the Division assumed a $74.95 hourly rate[18] to repair components, and an average repair time of between 0.17 hours and 16 hours, depending on both the type of component and the complexity of the repair.[19] To calculate the number of leaking components the Division used industry reported component counts and assumed a 1.48% leaking component rate for facilities subject to semi-annual inspections. Some stakeholders offered a lower number of components at facilities in the Piceance Basin. These stakeholders assumed that all sites employ a quad separator (which is not the case) and that each site has only two wells. The Division's data shows that the average number of wells per site in the Piceance Basin is over 5, thus significantly increasing the component counts offered by these industry stakeholders. Given these uncertainties, it is more appropriate to rely on APEN submitted data (which is certified as accurate by operators and which comes accompanied with significant detail).

To calculate the value of the additional product captured, the Division converted the amount of VOC and methane/ethane reduced to thousand cubic feet ("MCF") of natural gas, with a price of $2.92/MCF. With respect to re-monitoring, the Division determined that because of the small number of components that will require repair and the fact that re-monitoring can be undertaken at the same time as repair, any additional costs associated with re-monitoring are negligible. The subsequent LDAR cost analysis is based on the above methodology.

Since Colorado's leak detection and repair program has been in place for a number of years, some industry stakeholders have questioned if a lower leak frequency or leaking component rate should be used in the LDAR technical analysis. Presently, the Regulation Number 7 LDAR inspection reports show the number of facilities inspected and number of leaks found, but no information on the number of components. One important observation from the Regulation Number 7 LDAR inspection reports is that more site visits results in the identification and repair of more leaks. In light of limited data, the Division used EPA data that indicated an annual leak frequency of 1.18%. This data was vetted and approved by the EPA in its promulgation of NSPS OOOOa, though EPA indicated this leak frequency likely underestimates emission benefits from LDAR. Since this Regulation Number 7 proposal involves more inspections (i.e. moving from annual LDAR to semi-annual LDAR), the Division is using a scaled semi-annual leak frequency of 1.48%. In response to questions on whether a lower leak rate should be used, the Division evaluated the effect of a lower leak frequency. If the leak frequency is reduced by

[18] The $66.24 hourly rate adjusted by 13.15% to account for inflation since 2009.

[19] *See* "Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Using Emission and Cost Data From the Uniform Standards," Bradley Nelson and Heather Brown, April 17, 2012; "Analysis of Emissions Reduction Techniques for Equipment Leaks," Cindy Hancy, December 21, 2011.

half (i.e. 0.74%) the total net LDAR cost decreases because the resulting costs of leak detection stay the same but the costs of leak repair go down because fewer leaks are needing to be repaired.

A. Increase the LDAR inspection frequency at well production facilities: from annual to semi-annual for well production facilities in the DMNFR with VOC emissions > 2 tpy to < 6 tpy; from one-time to semi-annual for well production facilities outside the DMNFR with VOC emissions > 2 tpy to < 6 tpy; and from annual to semi-annual for well production facilities outside the DMNFR with actual VOC emissions > 6 tpy to < 12 tpy.

Under Regulation Number 7, LDAR frequency at well production facilities with storage tanks is based on the uncontrolled actual VOC emissions of the largest emitting storage tank at the facility. To calculate the number of facilities that will be subject to additional LDAR inspections at well production facilities the Division used a combination of Regulation Number 7 system-wide operator reported data and 2018 APEN data for storage tanks. Table 17 lists the number of well production facilities throughout the state and the current inspection frequency along with the proposed changes to the inspection frequency for the various facility tiers.

Table 17: Storage Tank Battery Analysis for LDAR at Well Production Facilities

Uncontrolled VOC at Storage Tank Battery Tier	O & G Basin*	Current Inspection Frequency	Proposed Changes to Inspection Frequency	Total Number of Facilities
> 0 to < 1 tpy	DMNFR	One-time		1,294
≥ 1 to < 2 tpy	DMNFR	Annual		915
≥ 2 to ≤ 6 tpy	DMNFR	Annual	Semi-annual	1,384
> 6 to ≤ 12 tpy	DMNFR	Semi-annual		718
			Subtotal:	4,311
> 0 to < 2 tpy	ROS	One-time		466
≥ 2 to < 6 tpy	ROS	One-time	Semi-annual	809
≥ 6 to < 12 tpy	ROS	Annual	Semi-Annual	193
			Subtotal:	1,468
			Total	**5,779**

** ROS = Remainder of State*

In the DMNFR, Regulation Number 7 requires owners and operators of well production facilities with uncontrolled actual VOC emissions >1 tpy to < 6 tpy to conduct an annual LDAR inspection and those > 6 tpy to < 12 tpy to conduct a semi-annual LDAR inspection. For the ROS, owners and operators of well production facilities with emissions > 2 tpy to < 6 tpy must conduct a one-time LDAR inspection and those ≥ 6 tpy to < 12 tpy must conduct an annual LDAR inspection. The LDAR inspection requirement specifies that owners and operators must conduct periodic inspections using EPA Reference Method 21 or IR camera and repair leaks within a prescribed time frame. In Table 18, the Division estimates the increase in inspection frequency at some well production facilities will result in an additional 3,195 inspections at a cost of about $2.8 million dollars. The Division also considered an alternate scenario in which owners and operators of well production facilities in the ROS, with emissions >2 tpy to < 6 tpy, would conduct an annual LDAR inspection and those > 6 tpy to <12 tpy would continue to conduct an annual inspection. An annual inspection frequency would result in an additional 809 inspections in the ROS at a cost of about $735,219 dollars.

Table 18: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid (Used JIWG recommended component counts - 570 in ROS)						
Un controlled VOC at S torage Tank Battery Tier (tpy)	O&G Basin*	Number of Facilities	Change in Annual Inspection Frequency	Total Number of New Inspections	Inspection Time Per Inspection (hours)	Total Annual Inspection Cost
Contractor Inspections at $142/hour						
> 0 to < 1	DMNFR	1,294	0	0	0	0
≥1 to <2 tpy	DMNFR	915	0	0	0	0
≥ 2 to < 6	DMNFR	1,384	1	1,384	6.1	$1,198,821
≥ 6 to < 12	DMNFR	718	0	0	0	0
Subtotal:		4,311		1,384		$1,198,821
Contractor Inspections at $142/hour						
> 0 to < 2	ROS	466	0	0	0	0
≥ 2 to < 6	ROS	809	2	1,618	6.4**	$ 1,470,438
≥ 6 to < 12	ROS	193	1	193	5.4**	$175,398
Subtotal:		1,468		1,811		$1,645836
Total (Contractor Inspections):				**3,195**		**$2,844,657**
Alternative - ROS Annual LDAR Inspection Frequency						
> 0 to < 2	ROS	466	0	0	0	0
≥ 2 to < 6	ROS	809	1	809	6.4**	$735,219
≥ 6 to < 12	ROS	193	0	0	0	0

Table 18: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid (Used JIWG recommended component counts - 570 in ROS)						
Un controlled VOC at S torage Tank Battery Tier (tpy)	O&G Basin*	Number of Facilities	Change in Annual Inspection Frequency	Total Number of New Inspections	Inspection Time Per Inspection (hours)	Total Annual Inspection Cost
ROS Subtotal:		1,468		809		$735,219
Alternative ROS Annual Inspection Frequency Statewide Total:				**2,193**		**$1,934,040**

** ROS = Remainder of State*
*** ROS inspection time includes additional 3 hours for travel time*

Based on the average leak rate, repair time, and hourly repair rate discussed above, the Division calculated that leak repair costs resulting from the proposed new LDAR inspection frequency will total about $920,768 dollars as reflected in Table 19. The Division also considered an alternate scenario in which owners and operators of well production facilities in the ROS, with emissions >2 tpy to < 6 tpy, would conduct an annual LDAR inspection and those > 6 tpy to <12 tpy would continue to conduct an annual inspection. Leak repair costs resulting from a new annual inspection frequency in the ROS would total about $466,886 dollars.

Table 19: Well Production Facility Leak Repair Costs (Adjusted repair time to account for incremental change in inspection frequency)				
Uncontrolled VOC at Storage Tank Battery Tier (tpy)	O&G Basin	Number of Tanks (Facilities)	Incremental Leak Repair Time per Facility (hours)	Total Annual Repair Cost
> 0 to < 1	DMNFR	1,294	0	0
≥1 to <2 tpy	DMNFR	915	0	0
≥ 2 to < 6	DMNFR	1,384	3.0	$311,192
≥ 6 to < 12	DMNFR	718	0	0
Subtotal:		4,311		$311,192
> 0 to < 2	ROS	466	0	0
≥ 2 to < 6	ROS	809	9.6	$582,092
≥ 6 to < 12	ROS	193	1.9	$27,484

Subtotal:		1,468		609,576
			Total:	**$920,768**
Alternative - ROS Annual LDAR Inspection Frequency				
> 0 to < 2	ROS	466		
≥ 2 to < 6	ROS	809	7.7	$466,886
≥ 6 to < 12	ROS	193		
ROS Subtotal:		1,468		$466,886
Alternative ROS Annual Inspection Frequency Statewide				**$778,078**

In Table 20, the Division estimates the total value of recovered natural gas from the repair of leaks based on the newly required inspections at about $676,256 dollars. The Division also considered an alternate scenario in which owners and operators of well production facilities in the ROS, with emissions >2 tpy to < 6 tpy, would conduct an annual LDAR inspection and those > 6 tpy to <12 tpy would continue to conduct an annual inspection. An annual inspection frequency would result in a total value of recovered natural gas in the ROS of about $388,175 dollars.

Table 20: Well Production Facility Recovered Natural Gas Value from Leak Repairs

Uncontrolled VOC at Storage Tank Battery Tier (tpy)	O&G Basin	Number of Facilities	Total Recovered Natural Gas per facility (tons/year)	Value of Natural Gas ($/MCF)	Conversion Factor (MCF/ton)	Total Annual Value of Recovered Natural Gas
> 0 to < 1	DMNFR	1,294				
≥1 to <2 tpy	DMNFR	915				
≥ 2 to ≤ 6	DMNFR	1,384	1.16	$2.92	35.8	$167,826
> 6 to ≤ 12	DMNFR	718				
Subtotal:		4,311				$167,826
> 0 to < 2	ROS	466				
≥ 2 to < 6	ROS	809	5.74	$2.92	35.8	$485,430
≥ 6 to < 12	ROS	193	1.14	$2.92	35.8	$23,000

Subtotal:		1,468				$508,430
					Total:	**$676,256**
Alternative - ROS Annual LDAR Inspection Frequency						
> 0 to < 2	ROS	466				
≥ 2 to < 6	ROS	809	4.59	$2.92	35.8	$388,175
≥ 6 to < 12	ROS	193				
ROS Subtotal:		1,468				$388,175
Alternative ROS Annual Inspection Frequency Statewide Total:						**$556,001**

Table 21 summarizes the estimated net costs from increasing the frequency of LDAR at well production facilities. The overall cost is estimated at about $3.1 million dollars. The Division also considered an alternate scenario in which owners and operators of well production facilities in the ROS, with emissions >2 tpy to < 6 tpy, would conduct an annual LDAR inspection and those > 6 tpy to <12 tpy would continue to conduct an annual inspection. The overall net cost in the ROS is estimated at about $813,930 dollars.

Table 21: Well Production Facility -Net Leak Inspection and Repair Costs (Adjusted repair time to account for incremental change in inspections)

Uncontrolled VOC at Storage Tank Battery Tier (tpy)	O&G Basin	Total Annual Inspection Cost (Contractor)	Incremental Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
> 0 to < 1	DMNFR				
≥1 to <2 tpy	DMNFR				
≥ 2 to ≤ 6	DMNFR	$1,198,821	$311,192	$167,826	$1,342,187
> 6 to ≤ 12	DMNFR				
Subtotal:		$1,198,821	$311,192	$167,826	$1,342,187
> 0 to < 2	ROS				
≥ 2 to < 6	ROS	$1,470,438	$582,092	$485,430	$1,567,100
≥ 6 to < 12	ROS	$175,398	$27,484	$23,000	$179,882

Subtotal:		$1,645,836	$609,576	$508,430	$1,746,982
Total:		**$2,844,657**	**$920,768**	**$676,256**	**$3,089,169**
Alternative- ROS LDAR Inspection Frequency					
> 0 to < 2	ROS				
≥ 2 to < 6	ROS	$735,219	$466,886	$388,175	$813,930
≥ 6 to < 12	ROS				
ROS Subtotal:		$735,219	$466,886	$388,175	$813,930
Alternative ROS Annual		**$1,934,040**	**$778,078**	**$556,001**	**$2,156,117**

The estimated emission reductions from increasing the frequency of LDAR at well production facilities is about 2,306 tpy of VOC and 4,164 tpy of methane/ethane. The Division also considered an alternate scenario in which owners and operators of well production facilities in the ROS, with emissions >2 tpy to < 6 tpy, would conduct an annual LDAR inspection and those > 6 tpy to <12 tpy would continue to conduct an annual inspection. The estimated emissions reduction from this scenario in the ROS is about 1,278 tpy of VOC and 2,435 tpy of methane/ethane.

Table 22: Well Production Facility Leak Inspection Emission Reductions

Uncontrolled VOC at Tank Battery Tier (tpy)	Number of Facilities	Incremental LDAR Program Reduction % (one-time or annual to semi-annual)	Fugitive VOC Emissions Reduction for each facility (tpy)	Total VOC Reduction (tpy)	Fugitive Methane-Ethane Emissions for each facility (tpy)	Total Methane-Ethane Reduction (tpy)
DMNFR						
> 0 to < 1	1,294					
≥1 to <2 tpy	915					
≥ 2 to < 6	1,384	10%	0.46	636.6	0.70	968.8
≥ 6 to < 12	717					

Table 22: Well Production Facility Leak Inspection Emission Reductions						
Uncontrolled VOC at Tank Battery Tier (tpy)	Number of Facilities	Incremental LDAR Program Reduction % (one-time or annual to semi-annual)	Fugitive VOC Emissions Reduction for each facility (tpy)	Total VOC Reduction (tpy)	Fugitive Methane-Ethane Emissions for each facility (tpy)	Total Methane-Ethane Reduction (tpy)
Subtotal:	4,311			636.6		968.8
ROS						
> 0 to < 2	466					
≥ 2 to < 6	809	50%	1.97	1,593.7	3.77	3,049.9
≥ 6 to < 12	193	10%	0.39	75.3	0.75	144.8
Subtotal:	1,468			1,669.0		3,194.7
			Total:	**2,305.6**		**4,163.5**
Alternative- ROS LDAR Inspection Frequency						
> 0 to < 2	466					
≥ 2 to < 6	809	50%	1.58	1,278.2	3.01	2,435.1
≥ 6 to < 12	193					
ROS Subtotal:	1,468			1278.2		2,435.1
Alternative ROS Annual Inspection Frequency Statewide Total:				**1,914.8**		**3,403.9**

Based on these reductions, Table 23 summarizes the cost effectiveness of conducting ongoing instrument based inspections at well production facilities to be about $1,340/ton VOC and $742/ton methane/ethane. The Division also considered an alternate scenario in which owners and operators of well production facilities in the ROS, with emissions >2 tpy to < 6 tpy, would conduct an annual LDAR inspection and those > 6 tpy to <12 tpy would continue to conduct an annual inspection. For this scenario, the Division estimates the cost effectiveness of conducting ongoing instrument based inspections at well production facilities in the ROS to be about $1,126/ton VOC and $633/ton methane/ethane. This alternate scenario would result in control of 391 fewer tons of VOC and 760 fewer tons of methane/ethane. The Division's proposal results in a greater emissions reduction and is cost-effective.

Table 23: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21 (adjusted repair time to account for incremental change in inspection frequency)

Uncontrolled VOC at Tank Battery Tier (tpy)	Number of Tanks	Total Net Annual Leak Inspection & Incremental Repair Cost	Incremental LDAR Program Reduction % (one-time or annual to semi-annual)	Total VOC Reduction (tpy)	VOC Control Cost ($/ton)	Total Methane-Ethane Reduction (tpy)	Methane-Ethane Control Cost ($/ton)
DMNFR							
> 0 to < 1	1,294						
≥1 to <2 tpy	915						
≥ 2 to ≤ 6	1,384	$1,342,187	10%	636.6	$2,108	968.8	$1,385
> 6 to ≤ 12	718						
Subtotal:	4,311	$1,342,187		636.6	$2,108	968.8	$1,385
ROS							
> 0 to < 2	466						
≥ 2 to < 6	809	$1,567,100	50%	1,593.7	$983	3,049.9	$514
≥ 6 to < 12	193	$179,882	10%	75.3	$2,389	144.8	$1,242
Subtotal:	1,468	$1,746,982		1,669.0	$1,047	3,194.7	$547
	Total:	**$3,089,169**		**2,305.6**	**$1,340**	**4,163.5**	**$742**
Alternative- ROS LDAR Inspection Frequency							
> 0 to < 2	466						

Table 23: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21 (adjusted repair time to account for incremental change in inspection frequency)

Uncontrolled VOC at Tank Battery Tier (tpy)	Number of Tanks	Total Net Annual Leak Inspection & Incremental Repair Cost	Incremental LDAR Program Reduction % (one-time or annual to semi-annual)	Total VOC Reduction (tpy)	VOC Control Cost ($/ton)	Total Methane-Ethane Reduction (tpy)	Methane-Ethane Control Cost ($/ton)
≥ 2 to < 6	809	$819,930	50%	1,278.2	$637	2,435.1	$334
≥ 6 to < 12	193						
ROS Subtotal:	1,468	$819,930		1,278.2	$637	2,435.1	$334
Alternative ROS Annual Inspection Frequency Statewide Total:		**$2,156,117**		**1,914.8**	**$1,126**	**3,403.9**	**$633**

The Division was also asked to consider a biennial inspection frequency for the ROS. While the Division could estimate biennial costs, there is insufficient documentation to determine the effectiveness of this frequency in reducing emissions of VOCs and methane/ethane.

In early November, the Division received field gas sample data from the Colorado Oil and Gas Association (COGA) suggesting a lower field gas VOC content for a few well production facilities (about 7.9%) and a few compressor stations (about 8.6%) in the Piceance Basin. COGA recommended the Division use this data in the final EIA LDAR analysis for the ROS. In the initial EIA, the Division used producer submitted APEN Form 203 data that showed an average 20.3% VOC content (based on 20 samples) for well production facilities and 14.6% VOC content (based on 12 samples) for compressor stations to estimate the ROS facility fugitive emissions. The Division notes that even if a lower VOC content is used for facilities in the ROS, the result is that the cost-effectiveness of the LDAR program for methane is only improved.

B. Increase the LDAR inspection frequency from annual to semi-annual for compressor stations outside the DMNFR with actual VOC emissions > 0 tpy to < 12 tpy.

For the DMNFR, all compressor stations must conduct quarterly LDAR inspections. Thus, only compressor stations < 12 tpy outside the DMNFR need to increase inspection frequency to semi-annual.

The Division determined there are a total of 238 compressor stations[20] in the state based on operator provided LDAR reports, which also include inspection frequency. The estimated number of compressor stations in the ROS is based on subtracting the known number of DMNFR compressors stations[21] that were identified through Pneumatic Controller Task Force. Based on the estimated compressor station

[20] The total number of compressor stations statewide excludes 2 compressor stations in the DMNFR that use compressed air to drive pneumatic devices.
[21] The total number of compressor stations in the DMNFR NAA is 50, but 2 compressor stations that use compressed air to drive pneumatic devices are excluded.

inspection time estimates in Table 17, the Division estimates the total cost of conducting LDAR inspections is about $141,659 dollars.

Table 24: Compressor Station Leak Inspection Costs Using IR Camera/Method 21 Hybrid					
Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Change in Annual Inspection Frequency	Time per IR Camera Inspection (hours)	Total Annual Inspection Time (hours)	Total Annual Inspection Cost
≤ 12 tpy	86	1	11.6	997.6	$141,659
>12 to ≤ 50 tpy	91				
> 50 tpy	11				
Total:	188			997.6	$141,659

The repair costs associated with these inspections are set forth in Table 25 and fuel savings associated with these repairs are set forth in Table 26.

Table 25: Compressor Station Leak Repair Costs (adjusted repair time to account for incremental change in inspections)				
Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Leak Repair Rate ($/hr)	Incremental Leak Repair Time per Compressor Station (hours)	Total Annual Repair Cost
≤ 12 tpy	86	$74.95	6.5	$41,897
>12 to ≤ 50 tpy	91			
> 50 tpy	11			
Total:	188			$41,897

Table 26: Compressor Station Recovered Natural Gas Value from Leak Repairs					
Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Total Recovered Natural Gas per Compressor Station (tons/year)	Value of Natural Gas ($/MCF)	Conversion Factor (MCF/ton)	Total Annual Value of Recovered Natural Gas
≤ 12 tpy	86	2.93	$2.92	35.8	$26,341
>12 to ≤ 50 tpy	91				
> 50 tpy	11				

Total:	188				$26,341

The total net costs for compressor station LDAR are set forth in Table 27.

Table 27: Compressor Station Net Leak Inspection and Repair Costs (adjusted repair time to account for incremental change in inspections)

Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Total Annual Inspection Cost	Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
≤ 12 tpy	86	$141,659	$41,897	$26,341	$157,215
>12 to ≤ 50 tpy	91				
> 50 tpy	11		-	-	-
Total:	188	$141,659	$41,897	$26,341	$157,215

The estimated emission reductions from increasing the frequency of LDAR at compressor stations in the ROS is about 78.3 tpy of VOC and 173.7 tpy of methane/ethane.

Table 28: Compressor Station Leak Inspection Emission Reductions

Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Incremental LDAR Program Reduction % (annual to semi-annual)	Fugitive VOC Emissions Reduction for each CS (tpy)	Total VOC Reduction (tpy)	Fugitive Methane-Ethane Emissions for each CS (tpy)	Total Methane-Ethane Reduction (tpy)
≤ 12 tpy	86	10%	0.91	78.30	2.02	173.70
>12 to ≤ 50	91					
> 50 tpy	11					
			Totals:	**78.30**		**173.70**

Based on these reductions, Table 29 summarizes the cost effectiveness of conducting ongoing instrument based inspections at compressor stations to be about $2,008/ton VOC and $905/ton methane/ethane. If inspection frequency remained at an annual frequency, industry would avoid an additional cost of $157,215 and emissions would not be reduced by 78 tpy of VOCs and 174 tpy of methane/ethane.

Table 29: Compressor Station Leak Cost-Effectiveness Using IR Camera/Method 21							
Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Comp. Stations	Total Net Annual Leak Inspection & Incremental Repair Cost	Incremental LDAR Program Reduction % (annual to semi-annual)	Total VOC Reduction (tpy)	VOC Control Cost ($/ton)	Total Methane-Ethane Reduction (tpy)	Methane-Ethane Control Cost ($/ton)
≤ 12 tpy	86	$157,215	10%	78.3	$2,008	173.7	$905
>12 to ≤ 50	91						
> 50 tpy	11						
	Totals:	**$157,215**		**78.3**	**$2,008**	**173.7**	**$905**

III. Natural gas-driven pneumatic controllers

The Division is proposing to expand the current pneumatic controller inspection and enhanced response program applicable in the DMNFR to owners or operators of natural gas-driven pneumatic controllers at well production facilities and natural gas compressor stations statewide. Under the proposed revisions, owners or operators of natural gas-driven pneumatic controllers at well production facilities and natural gas compressor stations in the ROS must inspect their pneumatic controllers for proper operation during their LDAR approved instrument monitoring method (AIMM) inspections (i.e., with IR camera or EPA Method 21).

The Division estimates there are approximately 2,600 well production facilities and 190 natural gas compressor stations in the ROS that may now have to inspect their pneumatic controllers for proper operation. Based on data collected by the Pneumatic Controller Task Force (PCTF) at two natural gas compressor stations in the DMNFR[22], compressor stations have an average of 11 natural gas-driven pneumatic controllers. The PCTF also collected data on the number of natural gas-driven pneumatic controllers at well production facilities[23] and determined averages based on the barrel per day (bbl/day) production of the facility. Well production facilities producing greater than or equal to 250 bbl/day had an average of 98 natural gas-driven pneumatic controllers per facility. Well production facilities producing greater than or equal to 10 bbl/day but less than 250 bbl/day had an average of 34 natural gas-driven pneumatic controllers per facility. Well production facilities producing greater than or equal to zero bbl/day but less than 10 bbl/day had an average of 9 natural gas-driven pneumatic controllers per facility. Looking at the COGCC's 2018 annual production data, the Division estimates that there are 5 facilities in the counties completely outside of the DMNFR with production greater than or equal to 250 bbl/day, 569 facilities with production greater than or equal to 10 bbl/day but less than 250 bbl/day, and 17,061 facilities with production greater than or equal to zero bbl/day but less than 10 bbl/day, resulting in an estimate of 173,385 natural gas-driven pneumatic controllers at well production facilities in counties wholly outside of the DMNFR. This pneumatic controller estimate is based on average estimates of pneumatic controllers at operations in the DMNFR, and developed

[22] See Division Pneumatic Controller Task Force presentation to the Air Quality Control Commission (February 21, 2019) at https://drive.google.com/drive/folders/13Wy4shXktxtR--UjW6XMbQZm-67bLYGD.
[23] Id.

through the PCTF study. The Division requests that owners or operators of natural gas-driven pneumatic controllers outside of the DMNFR provide data on the number of natural gas-driven pneumatic controllers at their facilities.

The proposed revisions build upon the statewide LDAR program in Regulation Number 7 and the Division assumes that owners or operators will incorporate the pneumatic controller inspections into their well production facility and natural gas compressor station LDAR programs. Therefore, the Division believes that the inspection and recordkeeping costs are likely minimal.

There may also be costs related to activities necessary to return a pneumatic controller to proper operation. In 2017, the Division considered information from pneumatic controller manufacturers about pneumatic controller repair options and potential emission reductions data in EPA's Oil and Gas CTG, NSPS OOOOa TSD, and Natural Gas Star Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry to determine that returning pneumatic controllers to proper operation was cost-effective. The PCTF continues to gather data related to the costs of inspections and repair.[24] Preliminary data indicates that the incremental labor and material costs, costs above those related to the aligned LDAR inspection, are variable and range from insignificant to $600 per facility per year. The Division requested that owners or operators of natural gas-driven pneumatic controllers provide Colorado specific cost information concerning the proposed revisions and has not yet received such data.

IV. Storage Tank Measurement Systems and Truck Loadout

A. Storage Tank Measurement Systems

The Division is proposing to require the owners or operators of new facilities and certain storage tanks use a storage tank measurement system to measure and sample (i.e. determine the quality and quantity)) the liquid in the storage tank, which will reduce emissions resulting from blowing down the tank and opening the thief hatch. Based on the Division's permitting inventory, the Division estimates that from 2016 through 2018 an average of 140 well production facilities per year received permits for this process. It is unknown how many new facilities install these systems either voluntarily or due to permit or other requirements (e.g. compliance orders). Costs related to a storage tank measurement system may include the gauge, temperature and water level sensors, control panels, transmitters, and management software. The American Petroleum Institute (API) has published the Manual of Petroleum Measurement Standards Chapter 18.2 Custody Transfer of Crude Oil from Lease Tanks Using Alternative Measurement Methods (July 2016), which provides standards for sampling, temperature determination, calculating volume, and quality testing during custody transfer of crude oil from tanks to a transport vehicle without requiring direct access to the tank thief hatch.

An operator could also install a lease automatic custody transfer (LACT) unit that provides for the automatic measurement, sampling, and transfer of liquids. LACT units can be used at facilities that unload liquids to a transport truck as well as facilities that transfer liquids directly to a pipeline. In addition to reducing emissions resulting from opening the thief hatch, facilities that use a LACT unit prior to transfer to a pipeline also reduce emissions from vehicle traffic related to storage tank unloading and emissions from decreased flare combustion. For this CBA, the Division has not been able to quantify these co-benefits (i.e. the reduced NOx from vehicle traffic and avoided combustion). The Division requested information from stakeholders, but none was provided.

The Division has received some limited information from operators currently using LACT and/or API Method 18.2 as a result of a compliance order. The Division has reviewed cost and emission estimates from these operators, with data varying based on cost and emission calculation methodologies. Estimates of emissions reduced from using a storage tank measurement system to monitor and sample liquids, thereby eliminating emissions from opening the thief hatch, vary by facility and operation. A

[24] The PCTF will make any recommendations on its findings in a report to the Commission, due May 1, 2020.

tank can be blown-down (i.e., gas is vented) before opening the thief hatch to gauge the tank; alternatively, upon opening of the thief hatch there is a large amount of gas vented to atmosphere, creating a potential safety hazard recognized by the National Institute for Occupational Safety and Health and the Occupational Safety and Health Administration. Assuming VOC emissions of 0.0011 tons per event, which is based on the thief hatch being open for 15 minutes (an estimate reported by one operator, which the Division believes is a low estimate and may vary based on the tank level, pressure, temperature, etc) and 100 blow-down events per year (which again, is a low figure), emission estimates include a 0.28 tpy VOC reduction per tank system by using a storage tank measurement system. A recent Division observation of this procedure revealed that thief hatches can be open upwards of 90 minutes during sampling, gauging, and loadout. Further, the Division is aware that at the larger facilities, which will be subject to this provision, loadout can occur multiple times per day.

In the various compliance orders issued by the Division, operators were required to submit data on the emissions reduced and costs incurred as a result of using LACT and/or API Method 18.2. Estimates range from 0 to 4.91 tons of VOC emissions reduced, based on the amount of production loaded out during sampling and measurement when thief hatches would otherwise have been open. Estimates range from $29,180 to $66,500 per system, reducing emissions by 55.2 tons for all systems installed. Estimates from the use of LACT units ($350,000 initial and $800 monthly) or API Method 18.2 ($17,000 initial and $100 monthly) range $2,120 to $7,094 cost per ton of VOC reduced. One operator indicated that LACT installation costs are as low as $8,300, and that a fee is paid per barrel of production to the operator of the LACT unit. Other estimates provided concerning the use of LACT units reflected an average 2.8 tons of VOC reduced from a system costing on average $1,693,256 and an average 3.46 tons from a system costing an average $1,265,774. As far as the Division is aware, none of these cost estimates took into account the savings from manual gauging errors, which have been estimated to be approximately $150,000 annually per facility. The Best Practices for Custody Transfer Using API MPMS 18.2 document indicates that LACT units pay back over a matter of months. The Division also understands that most operators in the DMNFR utilize LACT units when building new facilities. The Division requested additional information from stakeholders regarding the costs and burdens of this proposal, but none was provided. The Administrative Procedures Act and the Air Pollution Prevention and Control Act require the Division to use only reasonably available data.

Equipment costs will likely be less for owners or operators who already use storage tank measurement systems at other facilities. In addition, storage tank measurement systems offer an increased level of accuracy, which will payback over time.[25] Emission reductions will depend on how frequently the storage tank is gauged or sampled. There may also be costs due to associated recordkeeping requirements, though the Division's proposal is minimal.

Further, the Division has provided operators with sufficient additional time to address contracting issues. No stakeholder provided any information regarding the cost of renegotiating contracts or other indirect costs from the Division's proposal.

B. Truck Loadout of Hydrocarbon Liquids

The Division is proposing to require owners or operators of hydrocarbon liquid storage tanks with annual throughput of 5,000 bbl (on a rolling 12 month basis) control emissions from the loadout of hydrocarbon liquids from the storage tank into a transport vehicle. Owners or operators must use submerged fill and may use either a vapor collection and return system, air pollution control equipment, or both to control emissions. The Division estimates there are fewer than 3,600 storage tanks with production at this level. The Division also estimates an average of 140 new well production facilities per year, and assumes that all storage tanks will have throughput over 5,000 barrels. Weld County provided data showing that 6,341 wells reported production of 5,000 BOE or greater in 2018,

[25] See Best Practices for Custody Transfer Using API MPMS 18.2 (October 2017), https://www.emerson.com/documents/automation/white-paper-best-practices-for-custody-transfer-rosemount-en-1730756.pdf.

out of 17,829 total wells (thus, under these numbers, only 36% of wells in Weld County would be subject to loadout controls). See WeldCo_REB_Ex-001, Figure 9. As production is generally lower outside the nonattainment area, there are fewer facilities that will be subject to control requirements. Based on COGCC's 2018 annual production data (355,697,624 barrels of oil produced) and assuming that all production was loaded to a transport vehicle instead of to a pipeline, the Division estimates that loadout emissions range from 18,496 to 41,972 tpy (0.104 lb VOC/bbl crude oil loaded and 0.236 lb VOC/bbl condensate loaded[26]). This is an overestimate as some facilities direct some, if not most, of the product to a pipeline instead of a transport vehicle (although even at those facilities, for example, LACT units can be out of service and operators will need to loadout by truck). In the 2017 oil and gas area source inventory, the Division estimated that emissions from truck loadout of condensate liquid in the DMNFR was 7.5 tons per day (tpd) (2,737 tpy). This estimate is low as it does not include crude oil loadout, nor does it address emissions associated with the opening of the thief hatch.

Loadout emissions calculations vary based on the hydrocarbon liquid being loaded into the transport vehicle. Using the Division's default emission factor for condensate loadout, the estimated emission reductions anticipated per tank from a 95% loadout control requirement are listed in Table 30 below. Table 30 uses throughput to estimate potential emission reductions. Further, the Division acknowledges that the default emission factors were developed for gasoline transport trucks loading from dedicated loading racks at refineries. Thus, these emissions estimates do not include emission sources such as the blow-down of the tank or from the opening of the thief hatch, and as a result, the loadout emissions may actually be higher.

Table 30: Estimated loadout uncontrolled emissions and potential emission reductions, per tank battery

Storage tank throughput (bbl/yr)	Loadout uncontrolled emissions (tpy)	Loadout emissions controlled at 95% (tpy)	Estimated VOC reduction from loadout control (tpy)
5,000	0.59	0.03	0.56
10,000	1.18	0.06	1.12
20,000	2.36	0.12	2.24
30,000	3.54	0.18	3.36
40,000	4.72	0.24	4.48
50,000	5.90	0.30	5.61

Costs will also vary, depending on facility configuration and control system installed. EPA estimates the cost of purchasing additional connections to route a transport vehicle vent to a useful outlet at $1,000 (estimated implementation cost) and additional operating costs to connect the lines at $200 (incremental operating cost).[27] EPA also estimates that recovering these vapors can payback in two years depending on the frequency of loading, load volumes, and the value of the gas.[28] The Division's proposal is to limit this requirement to controlled storage tanks; therefore, the additional costs to

[26] See APCD PS Memo 14-02: Oil and Gas Industry Hydrocarbon Liquid Loadout General Permit GP-07 Regulatory Definitions and Permitting Guidance.
[27] EPA Natural Gas Star – Recover Gas During Condensate Loading (2011) at https://www.epa.gov/sites/production/files/2016-06/documents/recyclelinerecovers.pdf.
[28] Id.

control the transport vehicle emissions may only be related to the installation of vapor return lines to the storage tank such that transport vehicle emissions are then routed to the existing control device. Under the proposed storage tank revisions described above, all storage tanks statewide with uncontrolled actual emissions equal to or greater than two tpy must control emissions. However, some operators may choose to install an air pollution control system dedicated to controlling the loadout process, which would have increased costs, though this scenario is not likely for new facilities. Lastly, there may be costs associated with the equipment inspection and recordkeeping requirements, though the Division's proposals are minimal.

Similar to the storage tank measurement system requirements described above, the Division has reviewed cost and emission estimates from several operators, with data varying based on the costs of systems and equipment installed and emission calculations. Estimates provided by operators range from 0.48 to 21.94 tons of VOC emissions reduced, based on the production after the truck loading controls were implemented. Other estimates range from 0.8 to 2.47 tons of VOC emissions reduced, with a loadout system costing $11,250. Estimates for dedicated air pollution control equipment range from $48,500 to $45,000 per loadout control system, with commensurate reduction in loadout emissions of 195 tpy (95% control). Yet other cost estimates range from $12,200 to $14,000 per system, with emission reductions of 25.95 tons VOC. And, other estimates from tank loadout controls ($15,000 each system) range $7,333 to $8,420 cost per ton of VOC reduced.

The Division requested that owners or operators of potentially impacted operations provide Colorado specific cost information concerning the proposed revisions. The Division has received some such information from industry, which numbers are generally consistent with the information described above.

Industry provided cost information based on three potential loadout control scenarios: (1) the addition of a vapor line to existing infrastructure without requiring vapor control system upgrades or updates; (2) the addition of a vapor line to existing infrastructure and requiring vapor control system upgrades or updates; and (3) the addition of a dedicated loadout control system. Industry provided a range of costs for each scenario, as listed in the table below. Additionally, industry identified the likely percentage of facilities that would fall under each scenario.

Table 31: Industry provided loadout control system cost estimates

Scenario	Capital cost	Annual maintenance cost	Percentage of facilities
1	$2,000-$25,000	$1,000-$5,000	41%
2	$10,000-$30,000	$2,000-$3,600	14%
3	$20,000-$79,000	$1,500-$8,600	45%

Using the average of the estimated capital and annual costs, amortized over five years, the cost per ton of VOC reduced is listed in the table below. Some stakeholders asked the Division to consider a decline factor. However, the Division disagrees with the use of a decline factor to determine the cost effectiveness for loadout. There is not a decline for midstream facilities, and thus use of a decline factor is inappropriate. For well production facilities, initial throughput from newly fractured or drilled wells often exceeds 200,000 – 1,000,000 bbl/year with the decline occurring from such high initial throughput. By the time the well production facility has an annual throughput of 40,000 bbl/year or less, the decline has disappeared and the emissions are largely consistent year to year. Therefore, the Division did not use a decline factor in its cost analysis.

Using the industry cost estimates, the Division believes that controlling loadout emissions is generally cost-effective.

Table 32: Estimated cost per ton to control loadout emissions							
Annual throughput (bbl/yr)		5,000	10,000	20,000	30,000	40,000	50,000
Annual VOC emission reduction (tpy)		0.56	1.12	2.24	3.36	4.48	5.61
Scenario	Average annual cost	Cost of emission control per ton of VOC reduced per annual throughput category ($/tpy VOC)					
		5,000	10,000	20,000	30,000	40,000	50,000
1	$3,514	$6,269	$3,134	$1,567	$1,045	$784	$627
2	$6,086	$10,858	$5,429	$2,714	$1,810	$1,357	$1,086
3	$11,095	$19,794	$9,897	$4,949	$3,299	$2,474	$1,979

Using the cost information provided by operators in this rulemaking and assuming no decline factor as described above, the Division determined that the cost of requiring controls on loadout operations at facilities with tank throughput of 5,000 bbl/year ranges from $6,269 (for Scenario 1) to $19,794 (for Scenario 3) per ton VOC. Across the three scenarios identified by operators, the weighted average cost per ton VOC would be $12,998. This does not account for the additional methane reductions to be realized from the requirement, nor does it recognize the additional reductions from avoiding the opening of the thief hatch during loadout.

V. Well Emissions

The Division is proposing to expand the current requirement for owners or operators to use best management practices (BMPs) to minimize emissions associated with well maintenance and liquids unloading to also require operators use BMPs to minimize emissions associated with well plugging activities. During the plugging of a well, emissions may be released from the well to the atmosphere.

According to COGCC data, from 2016 through 2018, an average of 1,854 wells per year were plugged and abandoned. Due to the variability of BMPs that could be employed to minimize emissions, the specific costs and quantity of emissions that will be reduced by the proposed revision are unknown. Because the proposal only requires use of best management practices, which takes into account the cost of the practices in a given situation, the Division assumes that the proposed strategy will be cost effective.

The Division is also proposing additional recordkeeping and reporting requirements. There is uncertainty around the emissions from these activities as well as when and which BMPs may be used to minimize emissions. There may be additional costs in maintaining records and submitting reports to the Division. The additional records and report will address some of these uncertainties and inform potential, future emission reduction strategies.

The Division requested that owners or operators of potentially impacted oil and gas wells provide Colorado specific cost information concerning the proposed revisions but did not receive such cost information.

VI. Downstream Transmission

The Division is proposing a new performance based program for the downstream transmission segment, as a result of a recommendation from the SHER team. The downstream transmission segment includes pipelines, compressor stations, aboveground and underground storage facilities, and other equipment transporting or storing natural gas downstream of the natural gas processing plant and prior to the natural gas distribution segment. In Colorado, this segment consists of six owners or operators operating 56 facilities and miles of pipelines. Under the proposed program, a Steering Committee will be established to develop a methane emissions intensity target and evaluate progress against this target. Additionally, downstream transmission owners or operators will begin implementing company specific best management practices (BMP) plans in 2021; begin gathering emissions data in 2021, which will be used to establish the segment methane emissions intensity target; and achieve the segment methane emissions intensity target by 2025. Due to the variability of BMPs that could be employed to reduce emissions from these operations, the specific costs and quantity of emissions that will be reduced by the proposed revision are unknown. There will be additional costs associated with participating on the Steering Committee and compiling data through a third party contractor selected and funded by the transmission segment. There will also be costs related to data collection and associated recordkeeping and reporting requirements.

The Division requested that owners or operators of downstream transmission facilities and other SHER team participants provide cost information concerning the proposed revisions but did not receive such cost information. The Division, however, continued to work with the SHER team participants to finalize the proposed regulatory and statement of basis language and was able to achieve consensus.

VII. Oil and Gas Sector – Annual Emissions Inventory

The Division is proposing an annual emissions inventory program for the oil and gas sector. Under the proposed inventory program, owners or operators of oil and gas operations and equipment will collect VOC, NOx, carbon monoxide (CO), methane, and ethane emissions data and submit an annual report to the Division. These reports may be partially duplicative of current air pollutant emissions notice (APEN) requirements. However, these reports may partially offset future information requests made by the Division to inform emission inventory development for ozone and other modeling efforts and measuring progress against new greenhouse gas reporting requirements of associated with Senate Bill 19-096 and House Bill 19-1261. The Division intends to consider in future rulemakings how to streamline these related reporting regimes. There will be costs related to data collection and associated recordkeeping and reporting requirements.

The Division requested that owners or operators of engines, drilling operations, well production facilities, natural gas compressor stations, and downstream transmission operations provide cost information concerning the proposed revisions but did not receive such cost information. After multiple discussions with stakeholders, the Division proposed to delay the recordkeeping associated with the inventory to July 2020 to allow for a stakeholder process to better define both the emission source categories and calculation methods.

VIII. Serious Area RACT Requirements for Major Sources

The Division expects that EPA will reclassify the DMNFR as a Serious ozone nonattainment area in late 2019. As a Serious nonattainment area, Colorado must revise its ozone SIP to include, among other things, provisions that provide for the implementation of RACT for each category of VOC sources covered by a CTG, for which Colorado has sources, and all other major stationary sources of VOC or NOx located in the DMNFR area. Under a Serious nonattainment area classification, major sources are sources that emit or have the potential to emit greater than or equal to 50 tons per year of NOx and/or VOC.

The Division analyzed 31 major sources (> 50 tpy VOC or NOx) in the DMNFR. The Division did not analyze oil and gas sources with emissions between 50 and 100 tpy as these sources are subject to the requirements adopted in 2017 that correspond to EPA's Oil and Gas CTG and engine and other combustion equipment requirements in Regulation Number 7. The 31 sources analyzed by the Division are subject to various and numerous Regulation Number 7 RACT, RACT/beyond RACT/BACT, or NSPS or NESHAP requirements. Although these requirements are included in federally enforceable permits, some of the requirements are not currently included in Colorado's SIP, as is required for a Serious nonattainment area.

Therefore, the Division is proposing to revise Regulation Number 7 to include requirements for general solvent use, to expand the combustion equipment requirements, to incorporate by reference specific NSPS or NESHAP requirements, and to require specific sources to submit a RACT analysis concerning the facility or specific point(s) to the Division.

A. Solvents

The Division is proposing to define RACT on a categorical basis for general solvent use operations. The proposed revisions would broadly apply to sources with a potential to emit 50 tons per year of VOC and whose solvent use emissions trigger permitting thresholds (i.e., 2 tons per year VOC on an uncontrolled actual basis in the ozone nonattainment area, or 5 tons per year in the rest of the state). At these thresholds, new work practice standards apply requiring that containers be covered, proper disposal of solvent waste, and use good air pollution practices (e.g., the use of low/no VOC solvent if possible, using only amounts needed, submerged fill pipes, closed loop systems, maintaining operations to be leak free). Additionally, in the DMNFR, if an applicable source's solvent use operations have 25 tons per year VOC emissions on an uncontrolled actual basis, emissions must be reduced by 90% and additional control requirements, monitoring, performance testing, and recordkeeping requirements for general solvent use operations apply. The Division has identified at least two facilities in the DMNFR that may be subject to this proposal and believes there are likely other sources that may be subject, including marijuana and hemp solvent extraction facilities. Although there may be potential costs related to these requirements , the Division requested that owners or operators of equipment or activities that may be subject to these provisions provide cost information concerning the proposed revisions but did not receive such cost information.

B. Combustion Equipment

The Division is proposing to expand the combustion equipment requirements for boilers; turbines; engines; and ceramic kilns, dryers, and furnaces that the AQCC adopted in 2018 for sources with emissions greater than or equal to 100 tpy of NOx to sources with emissions greater than or equal to 50 tpy of NOx.

1. Boilers

The categorical RACT requirements for boilers include an emission limit of 0.2 lb/MMBtu, associated monitoring and recordkeeping, and combustion process adjustment (tuning). The Division is proposing to lower the MMBtu/hr applicability for these boilers from 100 MMBtu/hr to 50 MMBtu/hr. The Division is also proposing to require only initial and periodic performance testing for these boilers instead of continuous emission monitoring systems (CEMS).

There are 24 boilers that may be subject to this categorical RACT standard. There are 10 boilers below the heat input applicability threshold of 50 MMBtu/hr that are subject to the combustion process adjustment requirements but not the numerical standard.

There are 14 boilers with a design heat input rating greater than or equal to 50 MMBtu/hr that are potentially subject to the categorical RACT standard. The Division is not proposing to revise the low utilization capacity factor exemption and an owner could maintain the operation of a boiler below the capacity factor, which would exempt the boiler from the numerical standard. Such boilers would then only be subject to minimal recordkeeping requirements. For boilers subject to the numerical limit, the Division is proposing a periodic performance test requirement to ensure compliance with the limit. In developing the monitoring requirements for boilers at sources with NOx emissions greater than or equal to 100 tpy, the Division estimated that the cost for the installation, operation, and maintenance of a CEMS device range from approximately $150,000 to $200,000 (capital cost) and $26,000 to $49,000 (annual cost).[29] In contrast, for boilers at sources with NOx emissions greater than or equal to 50 tpy, the Division estimates the cost of a performance test at approximately $4,000 to $8,000 per test, depending on the contractor fee schedules and location with response to the source. These tests will be required every two years. Additional costs include costs related to the associated recordkeeping requirements. In addition, these boilers will be subject to period combustion process adjustment requirements.

2. Turbines

The categorical RACT requirements for turbines include compliance with NSPS GG for turbines constructed on or before February 18, 2005, and compliance with NSPS KKKK for turbines constructed after February 18, 2005, as well as associated monitoring and recordkeeping requirements.

There are 8 turbines that may be subject to this categorical RACT standard. The Division believes the direct economic impact to owners or operators of affected turbines to be negligible since these turbines are already required to meet the limits and monitoring requirements of the applicable NSPS provisions.

3. Engines

The categorical RACT requirements for engines include an emission limit of 9.0 g/bhp-hr for compression ignition engines with a maximum design power output greater than or equal to 500 hp. Engines that operate at less than 10% of the capacity factor are exempt from the numerical emission limit.

There are 17 engines that may be subject to this categorical RACT standard. As most of these engines are backup or emergency generators, the Division anticipates that the economic impact of the proposal on owners and operators will be negligible since the engines are likely to operator under the capacity factor exemption and therefore be subject to minimal recordkeeping requirements. However, the engines may continue to be subject to the combustion process adjustment requirements, applicable to engines with uncontrolled actual emissions greater than or equal to 5 tpy.

4. Kilns, dryers, furnaces

The categorical RACT requirements for kilns, dryers, and furnaces currently apply to lightweight aggregate kilns and process heaters. Therefore, the Division is proposing to expand the combustion process adjustment requirements to ceramic kilns, dryers, and furnaces.

There are five facilities that may be subject to this proposed requirement, with kilns ranging from 0.9 MMBtu/hr to 10 MMBtu/hr, dryers ranging from 3 MMBtu/hr to 44.1 MMBtu/hr, and furnaces ranging from 17 MMBtu/hr to 32 MMBtu/hr. There may be costs where the owner is not currently conducting a

[29] See July 19, 2018, AQCC rulemaking hearing establishing RACT for combustion equipment.

regulatory, voluntary, or manufacturer specified tuning or combustion adjustment due to the time to conduct the adjustment and potential costs of any necessary replacement equipment components.

The Division requested that owners or operators or equipment or activities that may be subject to these provisions provide cost information concerning the proposed revisions but did not receive such cost information. The Division has, however, worked with stakeholders to refine the combustion equipment requirements for ceramic kilns and was able to reach consensus.

C. Incorporation By Reference of NSPS/NESHAP

The Division proposes to include RACT requirements through incorporating by reference certain NSPS and/or NESHAP requirements for specific sources. There may be costs for sources associated with including these RACT requirements in the SIP due to the process and timeframe for a source seeking to amend an EPA approved SIP provision. However, incorporating NSPS or NESHAP requirements for these specific sources does not add additional implementation costs because these requirements are already federally enforceable.

D. Requirements for RACT Analysis Submittal

The Division proposes to require owners or operators of some major sources or specific points at major sources to submit a RACT analysis concerning the facility or specific point(s) to the Division. The proposed revisions may involve costs related to developing the RACT analyses and potential costs related to resulting emission reduction controls or measures.

IX. Gasoline transport trucks, testing facilities, terminals, and service stations

The Division is proposing to update and streamline the requirements for gasoline transport truck testing and vapor systems.

The Division processes 2,500 to 3,000 gasoline transport truck vapor integrity certifications per year. These gasoline transport trucks must be vacuum-pressure tested annually. There are seven testing facilities that conduct vacuum-pressure testing. The Division is proposing to update the vacuum-pressure test in Regulation 7 with the more current EPA Method 27 test method. EPA Method 27 is the required test method in EPA's NSPS and NESHAP for bulk terminals and gasoline dispensing facilities. Under the proposed revisions, the owners or operators of gasoline transport trucks must conduct this annual test using EPA's Method 27 and maintain records associated with the EPA Method 27 test.

There are approximately 40 bulk terminals in the DMNFR, six of which are large volume bulk terminals. Under the proposed revisions, the terminal operators must ensure that the gasoline transport trucks filled at the terminal have been tested annually according to EPA Method 27.

There are approximately 2,200 service stations in the DMNFR. The Division is proposing to clarify that the service stations must ensure that petroleum liquids are transferred using a properly maintained, functioning, and leak-tight vapor system.

The Division's proposed revisions clarify the vapor systems standards and update the test requirements and associated records to align with the current federal standards. Therefore, the Division believes that the cost impacts will be minimal or even reduced due to the removal of the requirement for the Division to provide and gasoline transport truck owners or operators to apply the certification sticker. Further, there may be cost savings in streamlining conflicting requirements in the SIP and associated with EPA's Method 27 and federal rules.

The Division requested that owners or operators of gasoline transport trucks, bulk terminals, or service stations provide Colorado specific cost information concerning the proposed revisions but did not receive such cost information.

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

The oil and gas industry plays an important role in Colorado's economy. The industry is a significant employer of highly skilled and well-paid employees. It produces valuable domestic resources that help keep prices low while adding to national stability and security. At the same time, emissions from the oil and gas industry represent a significant portion of the total VOC and methane emissions both in the nonattainment area and throughout the rest of the state. The Division's proposal is intended to achieve significant reductions in air emissions without imposing unreasonable costs that could stifle economic activity.

As discussed above, the Division's proposal is projected to result in a net annual cost to industry of approximately $8.9 million. As with any increase in costs, the costs associated with the Division's proposal could have some adverse impact on economic activity associated with the oil and gas industry in Colorado. However, over the past decade Colorado's oil and gas industry has experienced unprecedented growth, even as Colorado has enacted regulatory measures to ensure that development continues in a protective and responsible manner. Moreover, given the relative size of the costs of the current proposal to the overall size of the industry, the total impact of these costs will likely be minimal. The Division's proposal is unlikely to have any appreciable impact on the economic competitiveness of the industry as a whole.

While it is unlikely that the costs associated with the proposed revisions will have any meaningfully adverse impacts on the competitiveness of the industry as a whole in Colorado, the costs could incrementally add to the current costs associated with operating marginally producing wells. This could potentially lead to some wells being shut in and the resultant economic consequences of these shut-ins including lost production revenue, lost royalties, lost severance taxes and potentially lost jobs. To mitigate against this possibility, the Division has crafted a proposal that triggers requirements based on emission thresholds that are directly tied to production. Emission controls are not required for tanks emitting less than a threshold amount of VOCs. The truly small facilities are not subject to additional tank control requirements or additional leak inspection frequency. The Division reviewed COGCC data regarding shut-ins of wells over the past several years, and this data shows that there has not been a significant increase in the shutting in of wells since the Commission adopted its sweeping 2014 rule revisions. (See APCD_REB_EX-008). The exception to that is Weld County, where there were significant shut-ins in 2017 and 2018, though shut-ins again appear to be on the decline. The Division believes that the large number of shut-ins in Weld County in these years was likely due to circumstances other than the Commission's regulations- such as COGCC requirements and safety concerns following the issue of abandoned flow lines that came up beginning in 2016. Further, production in Weld County has only continued to expand, more than offsetting the shut-in of wells.

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

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

The Division throughout this rulemaking process considered a number of alternate proposals, as reflected in the proposed revisions of the Joint Industry Work Group, the Local Community Organizations, and the Clean Air Climate and Health Coalition. The Division reperformed its own cost analysis based on some of the suggestions of these groups, and determined its proposals remained cost effective. The Division also indicated that it will consider some of these alternate proposals in later rulemakings (e.g. the LCO proposal for proximity-based LDAR and the CACHC proposal to regulate pre-production emissions).

The Division has considered two alternate emission thresholds, > 4 tpy and > 5 tpy VOCs, for the requirement for controls for condensate, crude, and produced water tanks. In addition, the Division considered requiring annual leak inspections for tanks outside the DMNFR non-attainment area with uncontrolled emissions > 2 to < 6 tpy VOCs. These alternate scenarios are discussed above.

The Colorado Petroleum Council (CPC) and the Colorado Oil and Gas Association (COGA) requested that the Division consider the "cumulative costs" of the Proposed Rules. CPC and COGA suggest that the Division consider the costs of all rulemakings undertaken by the Commission since 2014. As required by statute, the Division considered the cumulative cost of the proposed revisions, not existing control requirements (which, by definition, are not "proposed").

The Grand Valley Citizens Alliance, League of Oil and Gas Impacted Coloradans, and Western Colorado Alliance (Local Community Organizations) have submitted an alternative proposal concerning more frequent inspections of tanks and facilities within 1,000 feet of a building unit. This proposal will be before the Commission to be considered during the December 2019 rulemaking.

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