REGULATORY ANALYSIS

for Proposed Revisions to
Colorado Air Quality Control Commission
Regulation Numbers 3, 6 and 7
(5 CCR 1001-5, 5 CCR 1001-8, and CCR 1001-9)

February 11, 2014

Colorado Department of Public Health and Environment

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1 EXECUTIVE SUMMARY

The Colorado Air Pollution Control Division's ("Division's") proposed revisions to the Air Quality Control Commission's ("Commission's") Regulation Numbers 3, 6, and 7, collectively expand the air emission control requirements on oil and gas facilities in Colorado. They were developed after the Division's extensive, year-long stakeholder process leading up to the Commission's rulemaking hearing, including input from diverse industry, environmental and governmental stakeholders. The proposal has received the support of several industry and environmental leaders, including Anadarko Petroleum, Noble Energy, Encana Oil and Gas, and the Environmental Defense Fund. The proposal affects not only the oil and gas industry and supporting businesses in Colorado, but the Regulation Number 3 revisions broadly affect all businesses in Colorado. Further, the proposal broadly benefits all persons in Colorado, especially those who live and work in the proximity of oil and gas operations, given the anticipated emissions reductions that will be achieved and the reasonable associated cost of implementation. The Division estimates that the proposed strategies will result in substantial reductions of hydrocarbon emissions from the oil and gas industry. More specifically, the Division estimates the proposed strategies will reduce volatile organic compound (VOC) emissions by 93,500 tons per year, and methane/ethane emissions by 64,000 tons per year. The Division conservatively estimates that the annual net costs to industry of the Division's proposal will be $42.4 million per year. This translates to approximately $453 per ton of VOC reduced, which is very reasonable when compared to other air pollution reduction strategies adopted by the Colorado Commission and the U.S. Environmental Protection Agency (EPA). In prehearing submittals to the Commission, the supporters of the proposal have concluded that the Division's costs estimates methodology and cost estimates are reasonable. Some opponents of the proposal have asserted that the costs may be much higher. The Commission will consider the Division's proposal and any alternate proposals at the rulemaking hearing commencing February 19, 2014.

2 INTRODUCTION

On December 13, 2013, interested parties, stakeholders, and state representatives filed eleven separate requests for both a Cost Benefit Analysis and a Regulatory Analysis ("Requests") with the Division, per C.R.S. §24-4-103(2.5), C.R.S. §24-4-103(4.5) and the Commission's Procedural Rules, 5 CCR 1001-1, §V.E.13. This document satisfies the requirements for a Regulatory Analysis, and is separate from the related Cost-Benefit Analysis. Similarly, this Regulatory Analysis is different from, but related to, the required Economic Impact Analysis, C.R.S. §25-7-110.5(4). The Requests were specific to proposed revisions to the Commission's Regulation Numbers 3, Parts A, B, and C ("Regulation 3"); Regulation 6, Part A ("Regulation 6"); and Regulation Number 7 ("Regulation 7").

The Colorado Administrative Procedure Act ("APA")[1] serves as the legal authority for this rulemaking process, and sets forth requirements for both cost-benefit and regulatory analyses. Under the APA, any person may request an agency engaged in a rulemaking to prepare a regulatory analysis.[2] The regulatory analysis must include:

- A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule;
- To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons;
- The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues;
- A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction;
- A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule; and
- A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule.
- To the extent practicable, a quantification of the data used in the analysis; the analysis must take into account both short-term and long-term consequences.[3]

So long as the regulatory analysis is undertaken in good faith, it satisfies the APA.[4]

This Regulatory Analysis evaluates the Division's November 15, 2013 proposed revisions to Regulations 3, 6, and 7, as amended on January 30, 2014, using information gathered through the Division's Cost Benefit Analysis, and Economic Impact Analyses, and other documents associated with the administrative record for the February 19-23, 2014 Commission Hearing.

The Division's proposed revisions to Regulation 3, 6, and 7 are part of an overall effort to fully adopt federal Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 C.F.R. Part 60, Subpart OOOO ("NSPS OOOO"), by incorporating them into Regulation Number 6, Part A, and making the corresponding revisions to the Regulation Number 3 catch-all provisions to address barriers that prevented full adoption of NSPS OOOO. The proposal also revises Regulation Number 7 to address differences and overlaps between NSPS OOOO and Regulation Number 7 oil and gas control requirements, and to further reduce hydrocarbon emissions and leaks from oil and gas facilities. These revisions include:

1. Expanding Colorado's adoption of NSPS OOOO, such that it is adopted in full (Regulation 6);
2. Removing "catch-all" provisions (Regulation 3);

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[1] *See* C.R.S. § 24-4-101 *et. seq*.
[2] *Id. at* § 24-4-103(4.5)
[3] *Id.*
[4] *Id. at* § 24-4-103(2.5)(d) & § 24-4-103(4.5)(d).

3. Removing crude oil storage tank permitting exemptions (Regulation 3);
4. Expanding condensate tank control requirements state-wide, including establishing storage tank emission monitoring ("STEM") requirements (Regulation 7);
5. Expanding dehydration unit ("dehy") control requirements state-wide (Regulation 7);
6. Establishing leak detection and repair ("LDAR") requirements for components at well production facilities and natural gas compressor stations state-wide (Regulation 7);
7. Establishing well maintenance and liquids unloading requirements state-wide (Regulation 7); and
8. Expanding pneumatic controller requirements state-wide (Regulation 7).

In addition to these more prominent revisions, these proposals also correct minor administrative errors, and make typographical, grammatical, and formatting changes in Regulation 3, 6, and 7. This Regulatory Analysis focuses on the more significant revisions and does not address typographical, grammatical, and formatting changes.

This analysis represents information gathered from various stakeholders in an effort to generate the most complete and accurate assessment of the costs and benefits of the proposed strategies. Where data was not reasonably available, the Division utilized assumptions that are set forth in this analysis.

3 ANALYSIS

3.1 Regulation Number 6

3.1.1 Proposed Revisions

The proposed revisions to Regulation 6 fully incorporate by reference the federal NSPS OOOO into Regulation Number 6, Part A, including the provisions not incorporated during the Commission's partial adoption. In late 2012, the Commission partially adopted the Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 C.F.R. Part 60, Subpart OOOO ("NSPS OOOO"), such that Colorado currently administers NSPS OOOO, for all affected facilities under NSPS OOOO including centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels, process unit equipment, and sweetening units, except for natural gas wells (well completion requirements) and equipment that emits less than current reporting and permitting thresholds. At that time, the Commission directed the Division to consider full adoption of NSPS OOOO, as well as other improvements to Colorado's oil and gas emission regulations.

It appears that all parties to the Commission rulemaking support the proposed revisions to Regulation 6.

3.1.2 Class of Persons Affected

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

There is limited impact associated with this proposal, in that NSPS OOOO is already in effect on a federal level and the Commission has already partially adopted NSPS OOOO for Colorado. The classes of persons affected by the proposed full adoption of NSPS OOOO include oil and gas companies operating in Colorado, and businesses that support the oil and gas industry in Colorado. Also, citizens statewide are impacted by the proposal. In all cases, it is simpler and less confusing to no longer have to deal with federal and state agencies administering the same requirements.

Full adoption of NSPS OOOO does not have an additional cost impact on any affected classes of persons because this rule is currently in effect and federally enforceable. Full adoption of NSPS OOOO does not provide additional health or economic benefits to classes of persons affected by the proposal because NSPS OOOO is currently in effect and federally enforceable. However, affected classes of persons will benefit from the proposed full adoption of NSPS OOOO due to having Colorado implement and enforce NSPS OOOO for all sources subject to NSPS OOOO in Colorado.

Further, full adoption of NSPS OOOO benefits the United States Environmental Protection Agency ("EPA") by relieving the agency of the primary responsibility to implement and enforce NSPS OOOO in Colorado.

The Colorado Oil and Gas Conservation Commission ("COGCC") does have well completion requirements that are different but similar to NSPS OOOO requirements. However this proposal to fully adopt NSPS OOOO does not change the fact that there are two different requirements that may apply to natural gas wells. The Division continues to work with the COGCC to address this issue and coordinate implementation of these rules.

3.1.3 Quantitative and Qualitative Impacts

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

There are few if any additional quantitative impacts of the Regulation 6 proposal because these rules are already in effect on a federal level. The qualitative impact of the proposed rule upon affected classes of persons includes Colorado's implementation and enforcement of NSPS OOOO, using Division staff much more familiar with Colorado's oil and gas issues than EPA staff. Full adoption of NSPS OOOO does not provide any other additional costs or benefits beyond those affected by NSPS OOOO.

3.1.4 Probable Agency Costs

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

The probable costs to the Division of implementing and enforcing the NSPS OOOO requirements for affected facilities below current Air Pollutant Emission Notice ("APEN") reporting and minor source permitting thresholds, as well as implementing and enforcing the NSPS OOOO well completion requirements, are unknown at this time. These sources are not currently subject to Colorado's reporting and permitting requirements.

The Division will largely implement the provisions of its proposal through its oil and gas inspection team. This team currently consists of nine full time inspectors and four term limited inspectors. In 2012, in response to the growth in the oil and gas industry in Colorado, the legislature approved increasing the size of the inspection team from six inspectors to nine. In 2013, the legislature appropriated additional funds to hire four term limited inspectors to conduct IR camera inspections at well production facilities in Colorado. The term for these positions runs through June of 2015, but could be extended by the legislature if warranted. The additional inspectors provided during the 2012 and 2013 legislative sessions has significantly expanded the capabilities of the oil and gas inspection team, which will further enable the Division to implement and enforce the proposed requirements if the Commission chooses to adopt the Division's proposal. The total projected annual cost to the Division for the oil and gas inspection team in fiscal year 2013-14 is $1,305,304, which includes salary costs, fringe benefits, operating costs (including vehicles, field equipment, and office equipment), travel training and indirect costs.

There is no anticipated effect on state revenues because the proposal does not assess any additional emissions reporting or permitting fees than those that already apply.

3.1.5 Comparison to Inaction

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

If the Commission does not fully adopt NSPS OOOO, EPA and the Division will continue to share the implementation and enforcement responsibilities for NSPS OOOO. However, regardless of partial or full adoption, NSPS OOOO remains effective and federally enforceable.

Importantly, the Division does not advocate full adoption of NSPS OOOO without removing the catch-all provisions in Regulation Number 3 due to the reporting and permitting impacts on both the regulated community and the Division.

3.1.6 Less Costly Methods/Less Intrusive Methods

"A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule."

There are no less costly or intrusive methods for achieving full adoption of NSPS OOOO. Retaining partial adoption of NSPS OOOO will not resolve the issue of shared implementation responsibilities between EPA and the Division.

3.1.7 Alternative Methods

"A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule."

The Division did not consider any alternative methods for achieving full adoption of NSPS OOOO.

3.1.8 Quantification of Data

"To the extent practicable, a quantification of the data used in the analysis; the analysis must take into account both short-term and long-term consequences."

The short and long term consequences of the full adoption of NSPS OOOO are full implementation and enforcement by Colorado, instead of split implementation and enforcement between EPA and Colorado. The Division did not further quantify the short- or long-term consequences of the Regulation 6 proposal to fully adopt NSPS OOOO beyond what was already performed by EPA.

3.2 Regulation Number 3

3.2.1 Proposed Revisions

The Division is proposing revisions to Regulation 3's reporting and permitting requirements in order to improve the efficiency of Colorado's air quality reporting and permitting system.

The proposed revisions remove the requirement for sources subject to either a federal New Source Performance Standard ("NSPS") or federal National Emission Standards for Hazardous Air Pollutant ("NESHAP")/Maximum Available Control Technology ("MACT") adopted into Regulation Number 6, Part A or Number 8, Parts A, C, D, and E to file an APEN and obtain a minor source permit regardless of whether their emissions exceed the reporting or permitting thresholds ("catch-all provisions"). As a result, sources subject to a NSPS incorporated into Regulation Number 6, Part A or a NESHAP/MACT incorporated into Regulation Number 8, Parts A, C, D, or E are subject to APEN reporting and permitting **only** if their emissions exceed the applicable APEN and permitting thresholds.

In addition, the proposed revisions simplify the Appendix A non-criteria reportable pollutant de minimis determination to 250 pounds per year of any individual non-criteria reportable pollutant. The proposed revisions also remove the crude oil storage tank permitting exemptions.

Finally, the proposed revisions correct an inadvertent error to the minor source permitting exemption for crude oil and condensate truck loading equipment. This revision is administrative in nature, as the Division currently implements the provision as it was originally intended.

It appears that all parties to the Commission rulemaking support the proposed revisions to Regulation 3, and some parties have submitted alternative proposals requesting additional revisions (see Section 3.2.7 in this Regulatory Analysis).

3.2.2 Class of Persons Affected

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

The classes of persons affected by the proposed revisions to Regulation 3 are broad. Revisions to the catch-all provisions affect any stationary source subject to an NSPS adopted into Regulation Number 6 or NESHAP/MACT adopted into Regulation Number 8 that has emissions below the APEN reporting and minor source permitting thresholds. To demonstrate the breadth of impact, some examples of business and industry that are affected include dry cleaners, aggregate mining operations, grain elevators, natural gas compressor stations, surface coating operations, and power plants. Those activities subject to an NSPS or NESHAP/MACT, whose emissions fall below current reporting and permitting thresholds, will no longer have to report emissions and obtain minor source permits.

The proposed revisions to the non-criteria reportable pollutant de minimis threshold will affect stationary sources with emissions of non-criteria reportable pollutants greater than 250 pounds per year. This revision also has a broad impact, as most sources emit some degree of hazardous air pollutants or other non-criteria reportable pollutants.

Further, the revisions to the crude oil storage tank permit exemptions affect owners and operators of crude oil storage tanks with capacities of 40,000 gallons or less. The correction to the minor source permitting exemption for crude oil and condensate truck loading equipment is administrative in nature and affects oil and natural gas operations.

3.2.3 Quantitative and Qualitative Impacts

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

Quantitative and qualitative consequences for each revision are discussed below. Short- and long-term consequences include the continued delay in adopting NSPS OOOO in full, as well as other federal NSPS and NESHAP/MACT that apply to small sources in Colorado. There are minimal if any costs to the regulated community due to these revisions, and in some cases, cost savings are anticipated. Further, the Division anticipates that there will be no significant environmental impact associated with the proposal.

3.2.3.1 Catch-all Provisions

There are no anticipated costs to either the regulated community or the government associated with these proposed revisions. Removal of the catchall provisions will actually reduce reporting, permitting, and associated cost burdens for the regulated community. By reducing reporting and permitting activities, the proposed revision will also reduce costs to the Division associated with these activities.

The Division conducted a permit tracking project from February, 2013 to September, 2013 to understand the impact of this proposal. All pre-construction permits issued were evaluated to determine if they would have required an APEN and permit under this proposal. The Division's permit tracking project indicated that 7% (167 of 2,355) permits processed required permits solely due to the catch-all provision, accounting for approximately 0.03% of the total uncontrolled actual criteria pollutant emissions and 0.003% of statewide uncontrolled actual criteria pollutant emissions. The total hourly permit processing fees for these permits was approximately $50,000.[5] This cost estimate does not include the time saved by the sources by no longer having to complete and submit an APEN or minor source permit application.

The environmental impacts of revising the catch-all provisions are minimal. Further, no emissions increases are anticipated from these sources that would no longer require a permit because these revisions will not exempt them from having to comply with the requirements of an applicable NSPS or NESHAP/MACT.

3.2.3.2 Non-criteria Reportable Pollutants

Some stationary sources affected by the proposed revisions to the non-criteria reportable pollutant thresholds may have new costs related to reporting emissions previously below reporting thresholds, including filing and annual fees. Revision of the threshold for non-criteria reportable pollutants could result in ether cost savings or additional costs to the regulated community depending on the source. Sources that are required to report hazardous air pollutants (a subset of non-criteria reportable pollutants) must pay an emission fee of $152.90 per ton. Currently Regulation Number 3 contains a complex reporting formula involving multiple and different thresholds, some of which are above and some of which are below the proposed 250 pound threshold. Accordingly, changing the threshold will reduce costs for some sources, while increasing costs for other sources. Based on an analysis of reported emissions, the proposed threshold change will reduce industry fees paid to the Division by $47,702 per year. Because the emissions from sources that are not currently reporting is unknown it is not possible to calculate

[5] Permit cost savings were calculated using an average of 4 hours spent per permit, as determined by the time spent on permits processed due to the catch-all provisions in the Division's permit tracking project, multiplied by the Division billing rate of $76.45 an hour.

the additional costs to sources that will be required to report for the first time under the new proposed threshold. Based on the relative prevalence of different emissions, however, the Division believes that there will be a small net savings to the regulated community.

Additionally, beyond the actual emission fees, the current reporting system is very complex resulting in numerous hours being spent by both the regulated community and Division staff in determining whether reporting is required. Simplifying the reporting system will eliminate the costs associated with this analysis.

Some stationary sources affected by the proposed revisions would benefit because they would no longer be required to report their non-criteria reportable pollutant emissions, thus saving filing and possibly annual fees. The revised threshold of 250 pounds per year preserves at least 96% of the Division's current inventory of non-criteria reportable pollutants. Other sources may have new costs related to having to report emissions that were previously below reporting thresholds, including filing and annual fees. This impact is unknown at this time because these sources are not currently subject to Colorado's reporting and permitting requirements. While EPA does not require States to report hazardous air pollutant emissions, EPA utilizes this data to annually populate the National Emissions Inventory. Accordingly, Colorado will continue to provide a robust set of data while also serving an important regulatory streamlining purpose.

3.2.3.3 Crude Oil Storage Tanks

Owners and operators of crude oil storage tanks may have new costs related to obtaining permits for previously permit-exempt equipment. There are minimal direct costs projected for the affected businesses and industrial sector associated with the removal of the crude oil storage tank permitting exemption. Stationary sources with crude oil storage tanks whose uncontrolled actual emissions exceed the minor source or operating permit thresholds would be required to obtain a permit. In 2008, the Commission removed the reporting exemption for crude oil storage tanks to improve the inventory of uncontrolled actual emissions. While the Division believes there are many crude oil storage tanks in Colorado, the Division's APEN inventory only identifies 64 crude oil storage tanks with a design capacity of 40,000 gallons or less in Colorado. Removal of the crude oil storage tank minor source permitting exemption would require these tanks to obtain minor source permits at a cost of approximately $19,500.

3.2.3.4 Minor Source Permitting Correction

No practical impact is anticipated as a result of this revision, as the Division continues to implement the provision as was originally intended.

3.2.4 Probable Agency Costs

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

The Division does not anticipate any negative effect on state revenues. Any potential Full Time Equivalent ("FTE") personnel savings will be redirected to addressing the current permitting backlog. Any loss in permitting fees, will be offset by the processing of backlog permits. In addition, the crude oil storage tank permitting exemption revisions will slightly increase the submission of permitting fees. Similarly, the Division anticipates the reduction in filing and annual fees due to the approximately 4% reduction in current non-criteria reportable pollutant reporting to be offset by the increased reporting and associated fees by stationary sources with non-criteria reportable pollutant emissions greater than 250 pounds per year.

3.2.4.1 Catch-all Provisions

The revisions to the catch-all provisions will reduce the administrative burden on both the Division and the regulated community. The Division estimated through the permit tracking project that the staffing of approximately 0.6 FTE would be saved due to the revisions. However, revising the catch-all provisions does not change the applicability or enforcement of the NSPS or NESHAP/MACT.

3.2.4.2 Non-criteria Reportable Pollutants

The revisions to the non-criteria reportable pollutant threshold establish a simplified, standard reporting threshold of 250 pounds per year for all non-criteria reportable pollutants. This eliminates the complicated matrix system and streamlines the process for sources, and for the Division, both in explaining the process to sources and reviewing reported emissions. The work associated with any increased reporting will be absorbed by existing Division staff or potentially offset by the approximately 4% reduction in current non-criteria reportable pollutant reporting.

3.2.4.3 Crude Oil Storage Tanks

The Division's APEN inventory currently identifies 64 crude oil storage tanks with a design capacity of 40,000 gallons or less. The work associated with permitting and inspecting these, and potentially more, sources will be absorbed by existing Division staff.

3.2.4.4 Minor Source Permitting Correction

There are no additional agency costs incurred as a result of this revision, as the Division continues to implement the provision as was originally intended.

3.2.5 Comparison to Inaction

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

If the Commission does not adopt at least the proposed revisions to the catchall provisions, the Division would not recommend full adoption of NSPS OOOO. Further, absent adoption of the proposed revisions to the catchall provisions, the Division's permitting backlog will be negatively impacted. Finally, the public, regulated community, and other agencies will continue to experience the complexity and confusion of the APEN reporting thresholds and Appendix A de minimis levels applicability determinations. If the Commission does not adopt the proposed crude oil storage tank exemption revisions, a potentially significant source of emissions will continue to be exempt from permitting requirements. If the Commission does not make the minor source permitting correction, the provision will not align with the Commission's intent at the time of adoption nor the Division's current implementation of the provision. The purposes of the proposed revisions to Regulation 3 include allowing full adoption of NSPS OOOO, streamlining and clarifying reporting and permitting, and requiring permits for a potentially significant source of emissions.

3.2.5.1 Catch-all Provisions

The revisions to the catch-all provisions reduce reporting and permitting costs. If the Commission does not adopt the proposed revisions, the regulated community and the Division will retain those reporting and permitting costs. Further, if the Commission adopts NSPS OOOO, and other NSPS and NESHAP/MACT similarly affecting very small sources, in full without removing the catch-all provisions, the increase in APEN reporting and minor source permitting would overwhelm both the Division and the regulated community.

3.2.5.2 Non-criteria Reportable Pollutants

The revisions to the non-criteria reportable pollutant thresholds may reduce costs for some sources and increase costs for other sources. However, all sources will benefit from the increased clarity of the de minimis reporting determination. If the Commission does not adopt the proposed revisions, the public, regulated community, and the Division will continue to deal with a complex and confusing reporting determination.

3.2.5.3 Crude Oil Storage Tanks

The costs of the proposed revisions to the crude oil storage tank permit exemptions include the costs to the regulated community of obtaining permits and the costs to the Division of permitting and inspecting subject tanks. Removing the permitting exemptions also increases the consistency of Colorado's regulations with NSPS OOOO by requiring these sources to also be subject to Colorado's notification, recordkeeping, and control requirements. If the Commission does not adopt the proposed crude oil storage tank exemption revisions, there will not be costs associated with permitting but a potentially significant source of emissions will continue to be exempt from permitting requirements.

3.2.5.4 Minor Source Permitting Correction

No costs are anticipated with the proposed revisions, as the Division will continue to implement the provision as was originally intended.

3.2.6 Less Costly Methods/Less Intrusive Methods

"A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule."

The Division does not believe that there are less costly or less intrusive methods to fully adopt NSPS OOOO than the Division's proposal.

3.2.6.1 Catchall Provisions

The Division believes that the revisions to the catch-all provisions are necessary to adopt NSPS OOOO, and other NSPS and NESHAP/MACT similarly affecting very small sources, due to the anticipated extensive number of APENs and minor source permit applications that would be required. Consider how the current catch-all provisions would apply if the Commission adopts MACT JJJJJJ, which applies to a multitude of small boilers. Under the catch-all provisions, every boiler providing electricity, steam, or hot water in a hotel, restaurant, laundry, medical center, research center, institution of higher education, or manufacturing, processing, mining, or refining facility would be required to file an APEN and obtain a minor source permit, even if the source had emissions less than the reporting and permitting thresholds. Other examples of rules similarly affecting very small sources include NSPS JJJJ, which applies to numerous stationary spark ignition internal combustion engines; MACT M, which applies to all perchloroethylene dry cleaning facilities; MACT HHHHHH, which applies to paint stripping and spray applications of greater than three motor vehicles or mobile equipment; and MACT SSSSSS, which applies to all glass manufacturing facilities. Under the current catch-all provisions, all of these facilities would require APENs and minor source permits, even if emissions are below the reporting and permitting thresholds.

If NSPS OOOO is adopted in full without the corresponding adoption of the proposed revisions to the catch-all provisions, the regulated community will be required to file APENs and obtain minor source permits for every NSPS OOOO affected facility. In turn, the Division's permitting backlog will likely grow and industry's ability to obtain timely permits will be negatively impacted. In comparison, if NSPS OOOO is adopted in full along with the proposed revisions to the catch-all provisions, only NSPS OOOO affected facilities with emissions greater than the reporting and minor source permitting thresholds will be required to report emissions and obtain minor source permits. This is currently how the partial adoption of NSPS OOOO is implemented. Thus, the Division does not believe there are less costly or intrusive methods than the proposed catch-all provisions revisions to reduce the administrative impact of full adoption of NSPS OOOO.

Similarly, the Division does not believe there are less costly or intrusive methods than the proposed catch-all provisions revisions to improve the efficiency of Colorado's reporting and permitting system for NSPS or NESHAP/MACT subject sources with emissions below the reporting and permitting thresholds, especially since these revisions will save costs for both the Division and the regulated community.

3.2.6.2 Appendix A

The purpose of the revisions to the non-criteria reportable pollutant thresholds is to simplify a complex and confusing reporting determination.

The Division cannot quantify the costs of unknown non-criteria reportable pollutants but considers the true cost savings of the proposed revision to the non-criteria reportable pollutant threshold the savings in time and effort of the public and regulated community in determining applicability under the revised Appendix A. While some sources non-criteria reportable pollutant reporting will increase, the Division does not believe there is a less costly or intrusive method to streamline the non-criteria reportable pollutant reporting determination while still maintaining a robust non-criteria reportable pollutant inventory.

3.2.6.3 Crude Oil Tank Permit Exemption

Requiring permits for crude oil storage tanks, a potentially significant source of emissions, cannot be accomplished in any less costly or less intrusive method. Further, some sources will want enforceable permit limits on their crude oil storage tanks so as to be exempt from NSPS OOOO storage vessel requirements.

3.2.6.4 Minor Source Permitting Correction

There are no less costly or no less intrusive methods, as the Division will continue to implement the provision as was originally intended.

3.2.7 Alternative Methods

"A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule."

In addition to the Division's proposal, various parties to the rulemaking have submitted different alternative proposals for the Commission to consider. Some of these proposals request that the Commission adopt additional requirements, increasing APEN reporting and permitting thresholds, as well as change how emissions are reported to the Division.

The Division considered revising the APEN and minor source permitting thresholds to further simplify and clarify APEN reporting and minor source permitting. However, the Division decided not to pursue revising the APEN and minor source permitting thresholds at this time, in order to avoid diverting focus from the important emission reductions associated with the proposed revisions to Regulation Number 7, and provide additional time to work with EPA on the potential development of a sufficient noninterference demonstration for such revisions.

Further, the Division considered alternative thresholds for the proposed revisions to the non-criteria reportable threshold. The Division selected the 250 pound per year threshold due to concerns about higher thresholds and the retention of approximately 96% of the Division's current non-criteria reportable pollutant inventory under the proposed revision.

The Division did not consider any alternatives concerning the proposed revisions to the crude oil storage tank permitting exemptions or the minor source permitting correction.

3.2.8 Quantification of Data

"To the extent practicable, a quantification of the data used in the analysis; the analysis must take into account both short-term and long-term consequences."

The Division quantified the short-term consequences and used them to project long-term consequences of the Regulation 3 proposal.

3.2.8.1 Catch-all Provisions

The Division tracked all pre-construction permits, which includes permits processed for point sources at both major stationary sources and minor sources, between mid-February and September, 2013. The permit tracking project indicates that 7% (167 of 2,355) of those permits processed required permits because of the catch-all provision. In addition, the potentially eliminated emissions in comparison to statewide emissions are all much less than 1%, as illustrated in **Table 1** below.

Table 1: Emissions from Sources Potentially No Longer Requiring Permits due to the Catch-all Revisions (State-wide)

Pollutant	Uncontrolled actual emissions of potentially eliminated permits during tracking project (tpy, % of statewide emissions)	Uncontrolled actual emissions statewide[6] (tpy)
CO	45 (0.05%)	99,929
NOx	110 (0.07%)	165,192
Total PM[7]	32 (0.0004%)	7,385,720
SO2	0.2 (0.0002%)	115,715
VOC	24 (0.005%)	469,396
TOTAL	211.2 (0.003%)	8,235,952

Further, 4% (87 of 2,355) of the permits processed that required permits because of the catch-all provision are in the nonattainment area ("NAA"). The potentially eliminated emissions in comparison to NAA emissions are also much less than 1%, as illustrated in **Table 2** below.

Table 2: Emissions from Sources Potentially No Longer Requiring Permits due to the Catch-all Revisions (8-Hour Ozone NAA)

Pollutant	Uncontrolled actual emissions of potentially eliminated permits during tracking project in the NAA (tpy, % of NAA emissions)	NAA uncontrolled actual emissions[8] (tpy)
CO	19 (0.1%)	19,110
NOx	90 (0.24%)	37,831
Total PM[9]	15 (0.003%)	441,084
SO2	0.1 (0.0004%)	23,994
VOC	5 (0.004%)	140,463
TOTAL	129.1 (0.02%)	662,482

Importantly, these tables represent point source emissions, and do not include mobile source or area source emissions. Therefore, the percentage of emissions potentially eliminated from

[6] January-November, 2013, total emissions.
[7] Includes PM, PM10, and PM2.5.
[8] January-November, 2013, total emissions.
[9] Includes PM, PM10, and PM2.5.

permitting due to the removal of the catch-all provisions is even less, if the total emissions inventory, including point, mobile and area source emissions, were used.

The revisions to the catch-all provisions reduce costs to affected classes of persons, due to fewer sources being required to file APENs and obtain minor source permits. The Division's permit tracking project shows that 7% (167 of 2,355) of the permits processed between mid-February and September, 2013, were permitted due to the catch-all provision. The total hourly permit processing fees for these permits was approximately $50,000[10]. This cost estimate does not include the time saved by the sources by no longer having to complete and submit an APEN or minor source permit application.

The environmental impacts of revising the catch-all provisions are minimal and no emissions increases are anticipated because these revisions will not exempt any source from complying with the requirements of an applicable NSPS or NESHAP/MACT. The Division's permit tracking project shows that the 7% of permits processed between mid-February 14, and September 30, 2013, accounted for approximately 0.03% of the total uncontrolled actual criteria pollutant emissions during the tracking project and 0.003% of statewide uncontrolled actual criteria pollutant emissions.[11]

3.2.8.2 Appendix A

There are potential increased costs to the affected classes of persons associated with the revisions to Appendix A, however the full extent is unknown. This revision may increase the reporting requirements for a currently unknown quantity of Bin B and Bin C non-criteria reportable pollutants because the revised threshold is lower than the current lowest de minimis reporting thresholds of 500 and 1,000 pounds per year, respectively. This revision may also decrease the reporting requirements for some Bin A pollutants because the revised threshold is higher than the current lowest de minimis reporting threshold of 50 pounds per year. Sources will save emission fees of $152.90 per ton of non-criteria reportable pollutant no longer required to report, not including the time saved by the sources due to not collecting the emissions data for and submitting APENs.

The environmental impacts of revising the catch-all provisions are minimal and no emissions increases are anticipated because these revisions will not exempt any source from complying with applicable requirements. In addition, the Division estimates that the proposed reporting thresholds of 250 pounds per year will retain at least 96% of the Division's current non-criteria reportable pollutant tracking for inventory purposes, which will continue to provide data to the EPA for the National Emissions Inventory, as well as to external custormers such as environmental groups and the public. In addition, because the proposed reporting threshold is less than the current thresholds for many of the current scenarios, the revision will result in additional emissions of Bin B and Bin C pollutants being reported.

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[10] Permit cost savings were calculated using an average of 4 hours spent per permit, as determined by the time spent on permits processed due to the catch-all provisions in the Division's permit tracking project, multiplied by the Division billing rate of $76.45 an hour.

[11] See the Division's January 29, 2014, CAA § 110(l) Noninterference Demonstration for a more detailed discussion of noninterference with the NAAQS.

3.2.8.3 Crude Oil Tank Permit Exemption

There are anticipated costs to the affected classes of persons associated with the removal of the crude oil storage tank permitting exemptions. The Division's APEN inventory currently only identifies 64 crude oil storage tanks with a design capacity of 40,000 gallons or less in Colorado. Removal of the crude oil storage tank minor source permitting exemption would requires these tanks to obtain minor source permits at a cost of approximately $19,500.

The emissions from crude oil storage tanks can be significant and permitting exemptions are meant to be limited to emission points with negligible impacts on air quality. The environmental impacts of revising the crude oil storage tank permitting exemptions may be significant, however, due to data limitations that impact is known.

The short term consequences of the proposed catch-all revisions include allowing the Commission to fully adopt NSPS OOOO. The long term consequences of the proposed catch-all revisions include potentially allowing the Commission to adopt other NSPS and NESHAP/MACT similarly affecting very small sources.

The short term consequences of the proposed revisions to the non-criteria reportable pollutant threshold include simplifying the non-criteria reportable pollutant reporting determinations for both the Division and the regulated community and reducing the Division's current non-criteria reportable pollutant inventory by approximately 4%. The long term consequences of the proposed revisions to the non-criteria reportable pollutant threshold are unknown.

The short-term consequences of the proposed crude oil storage tank permit exemptions include requiring existing crude oil storage tanks with a capacity of 40,000 gallons or less to obtain permits. The long term consequences of the proposed crude oil storage tank permit exemptions include requiring new crude oil storage tanks to obtain permits.

3.2.8.4 Minor Source Permitting Correction

Short- and long-term consequences of the proposed correction include aligning the provision with the Commission's original intent. No data was quantified relating to this revision.

3.3 Regulation Number 7

3.3.1 Discussion of Proposed Revisions

The Regulation 7 rulemaking package proposes revisions that expand existing oil and gas control requirements and establish additional monitoring, recordkeeping and reporting requirements. These proposed revisions include the following:

1) Enhancing the existing control program for petroleum storage tanks by:
   a. Lowering the control requirement threshold for condensate storage tanks from 20 to 6 tons per year of uncontrolled actual volatile organic compound (VOC) emissions;

    b. Requiring controls for crude oil and produced water storage tanks with uncontrolled actual VOC emissions that are equal or greater than 6 tons per year; and
    c. Expanding NAA requirements for tank controls during the first 90 days of production to the rest of the state;
2) Establishing requirements to ensure that emissions from controlled storage tanks are captured and routed to the control device;
3) Enhancing the existing control program for dehys by:
    a. Increasing the control requirements from 90% to 95%;
    b. Increasing designed destruction efficiency requirements from 95% to 98%;
    c. Establising more stringent requirements for individual dehys located in proximity to a building unit or designated outside activity area;
4) Establishing LDAR requirements for compressor stations and well production facilities, including requirements to reduce emissions from compressor seals and open ended lines consistent with current federal requirements;
5) Expanding the existing 8-hour ozone NAA requirements for auto-igniters on flare devices to the rest of the state;
6) Expanding the existing NAA requirements for low bleed pneumatic devices to the rest of the state and where feasible requiring no-bleed pneumatic devices; and
7) Requiring that the gas stream at newly constructed well production facilities either be connected to a pipeline or routed to a control device from the date of first production.

If adopted, these proposed revisions will result in substantial reduction of hydrocarbon emissions including volatile organic compounds (VOCs) and methane.

Several industry and environmental parties fully support the Division's proposed revisions to Regulation 7. Conversely, some parties request that the Commission adopt additional requirements that go beyond the Division's proposal, while other alternatives request that the Commission limit aspects of the Division's proposed revisions. See Section 3.3.7 of this Regulatory Analysis for details on the parties' alternative proposals.

3.3.2 Class of Persons Affected

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

The proposal affects the oil and gas industry and supporting businesses in Colorado. Further, the proposal broadly benefits all persons in Colorado, especially those who live and work in the proximity of oil and gas operations. Companies that will bear the costs of this rule change include the oil and gas companies operating, drilling, recompleting or otherwise stimulating wells in the NAA, as well as well production facilities, compressor stations and dehys. Revisions to Regulation 7 may require installation of controls to reduce hydrocarbon emissions from storage tanks, dehys, and separators on newly constructed, hydraulically fractured or recompleted wells. Typically flares are used as control equipment, but vapor recovery units ("VRUs") and other

Division-approved pollution prevention devices may be used. Use of best management practices or controls may also be required for well maintenance and liquids unloading activities. Regulation 7 revisions may also require installation of auto-igniters on combustion devices and installation of low- or no-bleed pneumatic controllers. In addition, compressor stations and well production facilities may be required to monitor components for emissions and repair leaks. Owners and operators of well production facilities or compressor stations that include compressor seals and open-ended lines may have to comply with additional work practice standards.

The proposed Regulation 7 will benefit those companies that manufacture and/or distribute flare control devices, VRUs, auto-igniters or low- and no-bleed pneumatic controllers. Companies that manufacture hydrocarbon monitoring equipment, including infra-red ("IR") cameras, photo-ionization detectors, flame ionization detectors and other Division-approved monitoring methods, as well as those companies that provide or support monitoring services may also benefit from these proposed revisions.

Given that VOCs are precursors to ozone, the citizens in the NAA will benefit from the proposed rule through reduced ozone precursor emissions. State-wide, persons living or working in proximity to storage tanks, dehys, wells, well production facilities or compressor stations will benefit from reduced air emissions. See Section 3.3.3 of this Regulatory Analysis for a more comprehensive review of public health impacts.

Thus, all persons in the State benefit from the proposed revisions.

3.3.3 Quantitative and Qualitative Impacts

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

The proposed changes to Regulation Number 7 are projected to result in substantial reductions of hydrocarbon emissions (including both VOCs and methane/ethane) from the oil and gas industry. The Division estimates approximately 93,500 tons per year VOC, or 257 tons per day, and approximately 64,000 tons per year methane/ethane will be reduced.

Qualitative impacts of this Regulation 7 proposal are closely related to Colorado's air quality and economy. During the past ten years, Colorado has been a leader in developing and implementing requirements to reduce air emissions from the oil and gas sector. As a result of these efforts, Colorado now has in place a series of cost-effective requirements that significantly reduce air emissions from Colorado oil and gas facilities. Despite this success, however, the tremendous growth of oil and gas production in Colorado continues to threaten the air quality gains that we have achieved. Since 2004 gas production in Colorado has increased by 50% while oil production has more than doubled. While this growth has provided important economic benefits for Colorado, increased air emissions can have a negative impact on Colorado's public health and environment.

Specifically, VOC emissions contribute to the formation of ground level ozone. Ozone is photochemical oxidant and known respiratory irritant. Ground level ozone is a secondary pollutant produced through the reaction of VOCs, nitrogen oxides and sunlight. Elevated levels of ground level ozone have been linked to a variety of adverse health effects including decreased lung function, increased respiratory symptoms, serious indicators of respiratory morbidity including emergency visits and hospital admissions, as well as total non-accidental and cardio-respiratory mortality. According to EPA, ground-level ozone also damages vegetation and ecosystems. It leads to reduced agricultural crop and commercial forest yields, reduced growth and survivability of tree seedlings, and increased susceptibility to diseases, pests and other stresses such as harsh weather. In the United States alone, ground-level ozone is responsible for an estimated $500 million in reduced crop production each year. Ground-level ozone also damages the foliage of trees and other plants, affecting the landscape of cities, national parks and forests, and recreation areas.[12]

The U.S. EPA has set the current National Ambient Air Quality Standards ("NAAQS") for ground level ozone at 75 parts per billion (ppb) averaged over an 8-hour period. Based on a review of the then current health literature, the Clean Air Scientific Advisory Committee concluded in 2008 that the 75 ppb standard was not sufficiently protective of public health, and recommended that the standard be set at between 60 ppb and 70 ppb. EPA is in the process of considering whether to lower the ozone standard.

Currently, the Denver Metro/North Front Range area is out of attainment with federal health-based ground level ozone standards. This includes much of the Denver/Julesberg oil field. Other areas of the state have also experienced elevated ozone levels recently, with one monitor in Western Colorado showing concentrations above 75 ppb and a number of other monitors showing levels between 60 ppb and 75 ppb.

Addressing oil and gas emissions is a critical component of Colorado's efforts to lower ozone levels since this sector represents the largest source of VOC emissions in the state. Based on the most recent inventory (2011), 54% of the anthropogenic VOC emissions in the state come from the oil and gas sector, which is roughly triple the amount of emissions from the next largest source. Moreover, because of the ongoing growth in the oil and gas industry and the projected decline in VOC emissions from other sectors, the share of VOC emissions attributable to the oil and gas sector will likely increase over the foreseeable future. The proposed emission reduction strategies will further enhance existing public health and environment protections on both a local and regional scale.

In addition to VOC emissions, oil and gas operations are a large source of methane. Methane is a potent greenhouse gas, which contributes to global climate change. In addition to reducing VOCs that contribute to regional ozone pollution, the Division's proposed strategies will reduce methane, and thereby play a role in Colorado's overall efforts to reduce greenhouse gas emissions. Finally, the proposed strategies will reduce the exposure of people that live and work

[12] See EPA website, "Ozone – Good Up High Bad Nearby." http://www.epa.gov/oar/aqps/gooduphigh/bad.html. February 11, 2014.

near oil and gas production sites to VOC emissions. Methane is also a valuable natural resource (natural gas), and reducing leaks will benefit Colorado's environment and economy.

The Division assesses the direct and indirect costs to the regulated community for each of the proposed strategies in Regulation Number 7 in Section 3.3.8 of this Regulatory Analysis. Equipment costs, labor costs, maintenance costs, supervision costs, travel costs, and costs associated with recordkeeping and reporting are all evaluated. The Division estimates that the total annual costs to the regulated community as a result of the proposed strategies will be approximately $59.2 million. Further, the proposed strategies are expected to result in the capture of additional product worth approximately $16.8 million, for a total net cost of $42.4 per year. In addition to these direct costs, implementation of the proposed strategies could result in the shut-in of certain marginally producing wells, resulting in indirect costs in the form of lost revenues to oil and gas companies, loss of jobs associated with these facilities, lost royalty payments, and lost severance taxes. Based on available information the Division cannot reasonably calculate the amount of additional oil and gas that would be shut-in due to the proposed rules, but believes that the amount is likely to be very small due to the low costs attributable to small, marginally producing facilities.[13] An analysis by an economist hired by certain industry parties has suggested that these indirect costs could be quite large.[14] This information will be considered by the Commission as part of the rulemaking hearing.

The Division recognizes that the oil and gas industry plays an important role in Colorado's economy in the evaluation of qualitative impacts of the Regulation 7 proposal. The industry is a significant employer of highly skilled and well-paid employees. The industry generates large revenues and pays significant taxes in the state. 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 emissions both in the NAA 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 the industry of approximately $42.4 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. In 2012, for example, oil and gas producers in Colorado sold 48,450,717 barrels of oil and 1,661,073,176 MCF of natural gas.

Based on the current price of oil, $96 per barrel, and assuming a price for natural gas of

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[13] See discussion in Section 3.3.8 of this Regulatory Analysis.
[14] See Attached Exhibit A.

$3.5/MCF[15], annual revenue from the sale of oil and gas in Colorado based on 2012 production levels is approximately $10.5 billion. Accordingly, the net cost of the Division's proposal is approximately 0.4% of the annual revenues. Given this small percentage, the Division's proposal is unlikely to have any appreciable impact on the economic competitiveness of the industry as a whole. This conclusion is bolstered by the fact that several of the largest oil and gas companies in the state (Anadarko Petroleum Corp., Noble Energy, Inc., Encana Oil and Gas USA, and DCP Midstream) fully support the Division's proposed revisions. Collectively, the Division estimates that these companies will bear approximately 75% of the total annual cost of the proposed rules.

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's has crafted a tiered proposal that triggers requirements based on emission thresholds that are directly tied to production. Based on this, the truly small facilities are subject to less requirements and less costs; for example, only a one-time instrument-based leak inspection, which the Division estimates will cost approximately $712.

Finally, it does not appear that the costs associated with the Division's proposal will have any meaningful negative 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.

3.3.4 Probable Agency Costs

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

The Division will largely implement the provisions of its proposal through its oil and gas inspection team. This team currently consists of nine full time inspectors and four term limited inspectors. In 2012, in response to the growth in the oil and gas industry in Colorado, the legislature approved increasing the size of the inspection team from six inspectors to nine. In 2013, the legislature appropriated additional funds to hire four term limited inspectors to conduct IR camera inspections at well production facilities in Colorado. The term for these positions runs through June of 2015, but could be extended by the legislature if warranted. The additional inspectors provided during the 2012 and 2013 legislative sessions has significantly expanded the capabilities of the oil and gas inspection team, which will further enable the Division to implement and enforce the proposed requirements if the Commission chooses to adopt the Division's proposal. The total projected annual cost to the Division for the oil and gas inspection

[15] The Division assumed a price per MCF of $3.50 throughout its analysis; however, natural gas prices are currently around $5 per MCF, suggesting that the Division has underestimated the value of gas saved by the proposal.

team in fiscal year 2013-14 is $1,305,304, which includes salary costs, fringe benefits, operating costs (including vehicles, field equipment, and office equipment), travel training and indirect costs.

The Division does not anticipate state revenues to be affected because the proposal does not assess any additional emissions reporting or permitting fees beyond those that already apply. However, state revenues could potentially be affected by implementation of the proposed strategies, in that they could potentially result in the shut-in of a few marginally producing wells, resulting in indirect costs in the form of lost revenues to oil and gas companies, loss of jobs associated with these facilities, lost royalty payments, and lost severance taxes. Based on available information the Division cannot reasonably calculate the amount of oil and gas that could be shut-in due to the proposed rules, but believes that the amount is likely to be very small due to the low costs attributable to small, marginally producing facilities.

3.3.5 Comparison to Inaction

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

The Division estimates the proposed strategies will reduce volatile organic compound (VOC) emissions by 93,500 tons per year, and methane/ethane emissions by 64,000 tons per year. The Division conservatively estimates that the annual net costs to industry of the Division's proposal will be $42.4 million per year. This translates to approximately $453 per ton of VOC reduced. Costs and benefits of the proposed Regulation 7 revisions are detailed in Section 3.3.8.

Conversely, inaction would mean that the above emissions reductions are not realized, that the associated captured methane (natural gas), a valuable natural resource, is lost to the ambient air and that the estimated cost savings in captured product that can be sold at a profit is not realized. Further, emissions from this sector are projected to grow substantially, especially in shale gas/oil development.[16]

The forecast growth in shale gas/oil development will result in increased emissions of VOC and other hydrocarbons including greenhouse gases, unless additional controls are implemented. This could result in increases in ozone formation and the development of additional State Implementation Plan requirements to meet current and future NAAQS requirements. According to EPA, attaining the current ozone standard throughout the nation will result in between $6.9 billion and $18 billion in annual health benefits. For lower standards the health benefits are even greater. For example, EPA projects that achieve a 70 ppb standard will result in between $13 billion and $37 billion in annual health benefits, and for a 65 ppb standard the benefits will increase to between $22 billion and $61 billion per year. EPA does not report these health benefits by state, but since the population of the Denver Metropolitan Area/North Front Range NAA accounts for approximately 2.5% of the total national population living in areas that are in

[16] U. S. Energy Information Administration. "Annual Energy Outlook 2013". April 15-May 2, 2013.

violation of the current NAAQS, the health benefits attributable to Colorado are likely to be substantial.

The proposed rules will also produce substantial benefits associated with reducing greenhouse gases. As part of this rulemaking the Environmental Defense Fund has engaged an expert to analyze the benefits of the rulemaking based on the social cost of carbon. Based on this analysis, EDF projects that the total annual benefit from the projected methane reductions is between $104 million and $318 million in 2016 and between $132 million and $404 million in 2025.[17]

In addition to the benefits associated with reductions of VOCs and methane, the proposed rules will produce additional economic benefits in the form increased product capture and the creation of new jobs associated with the implementation of the new requirements.

3.3.6 Less Costly Methods/Less Intrusive Methods

"A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule."

In 2004, 2006 and again in 2008, the Commission established oil and gas industry specific emissions control requirements in an effort to reduce VOC emissions in the 8-hour ozone NAA. The tremendous growth of oil and gas production in Colorado and the associated emissions continue to threaten the air quality gains that have been achieved. Since 2004 gas production in Colorado has increased by 50% while oil production has more than doubled. Since then, the oil and gas industry has grown significantly (more than predicted), and changes in drilling technologies and other advancements have further supported growth in this industry. The oil and gas industry continues to be the largest VOC emitter in Colorado (illustrated in Figure 1, below).

Several industry alternative proposals identify less costly and/or less intrusive methods to reduce emissions (see Section 3.3.7 of this Regulatory Analysis). The Division made several clarifications based on these alternatives, but did not substantially revise the Division's Regulation 7 proposal. The Division believes the Regulation 7 proposal secures more emissions reductions than those alternatives, and those additional emission reductions are cost effective. Moreover, several parties have proposed more costly and/or more intrusive methods to reduce emissions. The Division believes that its proposal strikes a proper balance and achieves substantial emissions reductions in a cost effective manner.

[17] See Attached Exhibit B.

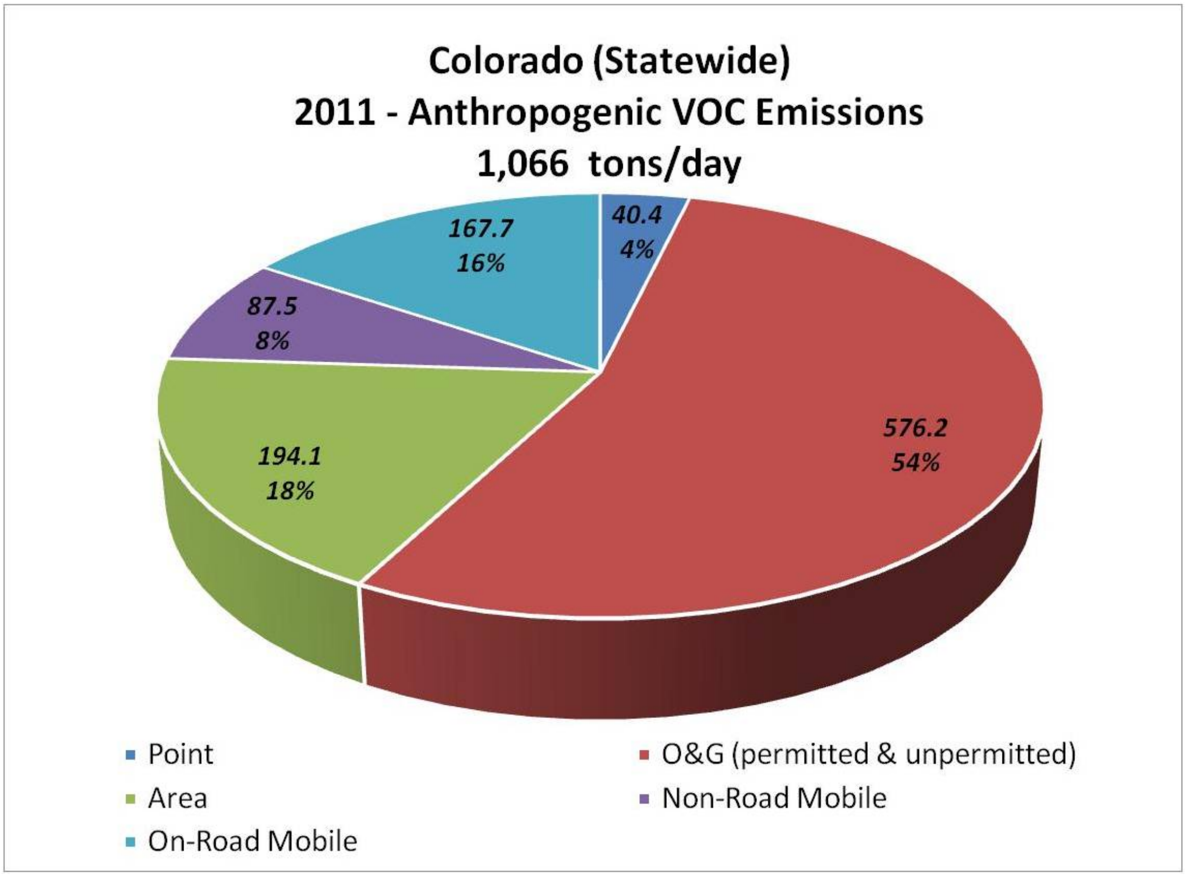

Figure 1 - Colorado Statewide Anthropogenic VOC Emissions (2011)

3.3.7 Alternative Methods

"A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule."

In addition to the Division's proposal, various parties to the rulemaking have submitted 6 different alternative proposals for the Commission to consider. Some of these proposals request that the Commission adopt additional requirements that go beyond the Division's proposal, while other alternatives request that the Commission limit aspects of the Division's proposed revisions. In some cases, the parties submitting the proposals included analyses estimating the costs and benefits associated with their proposals. Copies of each of these proposals along with any economic impact analysis that the parties submitted identifying the projected costs and benefits of their particular proposals are attached to this Regulatory Analysis as exhibits. Upon evaluation of these proposals, and other parties' comments, the Division made several clarifications to but did not substantially revise the Division's Regulation 7 proposal. The Division believes the Regulation 7 proposal strikes an appropriate balance between the various alternatives.

The section below identifies each of the submitted proposals, discusses how the proposals differ from the Division's proposal, and addresses the projected costs and benefits of each proposal.[18]

3.3.7.1 Joint Industry Work Group

A collection of oil and gas companies and industry trade groups have submitted an alternative proposal seeking to limit the requirements set forth in the Division's proposal.[19] Specifically, the Joint Industry Work Group request that the Commission limit the Division's proposal in the following respects: 1) restrict all proposed requirements to the Denver Metropolitan Area/North Front Range 8-hour ozone NAA; 2) reduce the required frequency proposed for leak inspection and repair; 3) eliminate the proposed requirements for dehydrators; 4) limit proposed requirements for compressor seals and open-ended lines to compressor stations; and 5) eliminate proposed requirements related to well maintenance and liquids unloading. In addition to these proposed limitations, the Joint Industry Work Group have proposed a number of additional changes, which could have some minimal additional impacts on the costs and benefits of the proposal.

Since the Joint Industry Group did not submit an economic analysis detailing the projected costs and benefits of their alternative proposal,[20] the Division has conducted an analysis of the Joint Industry Work Group alternative proposal utilizing the same methodologies and assumptions detailed in Section 3.3.8 of this Regulatory Analysis. Based on this analysis, the Division estimates that the Joint Industry Work Group alternative proposal would have a net cost[21] to the regulated community of approximately $32.2 million, and would reduce emissions of VOCs by 56,525 tons per year and methane/ethane by 33,058 tons per year. The decrease in net costs should have some positive impact on the indirect costs associated with potential well shut-ins, but the Division is unable to reasonably calculate this impact. The decrease in costs relative to the Division's proposal includes a decrease in the number of facility inspections, which would result in fewer new inspector jobs attributable to the proposal. Finally, because the Joint Industry Work Group proposal would result in less VOC and methane emission reductions, the economic benefits associated with these reductions discussed in Section 3.3.8 of this Regulatory Analysis would be reduced.

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[18] In instances where a party submitted an analysis of the costs and benefits associated with their proposal such analysis is attached. Where parties submitted proposal without an analysis of their own proposal the Division has endeavored to analyze the costs and benefits of these proposals using the same methodologies used to analyze the costs and benefits of the Division's proposal.

[19] A copy of this alternative proposal is attached to this Regulatory Analysis as Exhibit C.

[20] The group did submit an analysis of the Division's proposal showing substantially higher costs than reflected in the Division's analysis. A copy of this analysis is attached hereto as Exhibit A. It should be noted that while the Joint Industry Work Group predicts much higher costs from the Division's proposals, Anadarko Petroleum Corporation, Noble Energy, Inc. and Encana Oil and Gas USA have submitted information during the rulemaking supporting the reasonableness of the Division's cost and benefit calculations. Submissions from these companies can be found at the following link: ftp://ft.dphe.state.co.us/apc/aqcc/REBUTTAL%20STATEMENTS,%20EXHIBITS%20%26%20ALT%20PROPOSAL%20REVISIONS/

[21] Net cost reflects the cost of implementing the proposed strategy less the value of the additional product captured as a result of the proposed strategies.

3.3.7.2 WPX Energy

WPX is the largest natural gas producer in the state. In the current rulemaking WPX has offered an alternative proposal that would decrease the total number of leak inspections by allowing well production facilities with low leak rates during two consecutive inspections to reduce inspection frequency from monthly to quarterly, or from quarterly to annually depending on the size of the facility.[22] While it is difficult to predict in advance how many facilities would be able to take advantage of this reduced inspection rate, for the purposes of this Regulatory Analysis the Division assumes that one half of the facilities would be able to utilize the reduced frequency. Based on this assumption, adoption of WPX's alternative proposal would reduce the total net annual cost of the proposed revisions from approximately $42.4 million to approximately $36.8 million. This change would also decrease the amount of emission reductions from the Division's proposal by 1,845 tons per year of VOC and 2,757 tons per year of methane/ethane.

The decrease in net costs should have some positive impact on the indirect costs associated with potential well shut-ins, but the Division is unable to reasonably calculate this impact. Given the relatively small difference in net costs between the two proposals, any positive impact should be fairly small. The decrease in costs relative to the Division's proposal includes a decrease in the number of facility inspections, which would result in fewer new inspector jobs attributable to the proposal. Based on the number of inspection hours for each proposal, the number of new inspector jobs would decrease. Finally, because the WPX proposal would result in less VOC and methane emission reductions, the economic benefits associated with these reductions discussed in Section 3.3.8 of this Regulatory Analysis would be reduced.

3.3.7.3 Conservation Groups

As part of the rulemaking a number of conservation groups have submitted an alternative proposal requiring additional leak detection inspections for well production facilities and compressor stations relative to the Division's proposal. In addition, the Conservation Groups' alternative proposal increases the number of pneumatic devices that would need to be retrofitted. A copy of the Conservation Groups' alternative proposal is attached as Exhibit D. Additionally, their analysis of the costs and benefits associated with their alternative proposal is attached as Exhibit E.

3.3.7.4 Local Community Organizations

A group of local community organizations have submitted an alternative proposal aimed at increasing the stringency of the Division's proposal for facilities that are located within 1,320 feet of a building unit or designated outdoor activity area. Specifically, for such facilities the Local Community Organizations' alternative proposal would decrease the threshold for controls from petroleum storage tanks from 6 tons per year (as proposed by the Division) to two tons per year. Additionally, facilities located within 1,320 feet of these designated areas would be subject to a more stringent leak inspection schedule. Copies of the Local Community Organizations'

[22] In addition to this change, WPX has proposed a limited number of additional changes and clarifications that do not impact the cost and benefit calculations conducted for the Division's proposal. A copy of WPX's alternative proposal is attached as Exhibit F.

alternative proposal and their assessment of costs and emission reduction benefits are attached as Exhibits G and H.

3.3.7.5 Local Government Coalition

The Local Government Coalition consists of a number of county and city governments including Adams County, Boulder County, La Plata County, Pitkin County and San Miguel County, Fort Collins, the City of Boulder, and the City and County of Denver. In their alternative proposal, the Local Government Coalition seeks to increase the number of leak detection inspections for compressor stations and well production facilities relative to the Division's proposal. The Local Government Coalition also seeks to require that well production facilities be tied in to a gas gathering line within 90 days after the date of first production, unless the Division approves an extension of this deadline. Copies of the Local Government Coalition's alternative proposal and documents assessing the costs and benefits of that proposal are attached hereto as Exhibits I through M.

3.3.7.6 Worldwide Liquid Solutions, LLC

Worldwide Liquid Solutions (WLS) is a manufacturer of emission reduction technology designed to control VOC emissions from petroleum storage tanks. According to WLS, their emission reduction technology cannot control methane and ethane and therefore cannot meet the control standards for tanks reflected in the Division proposal. To address this, WLS has submitted an alternative proposal that would only require reductions of VOCs from tanks and not methane/ethane. As an alternative to their alternative, WLS has proposed rejecting all of the proposed changes to Regulation No. 7 set forth in the Division's proposal. Copies of WLS' alternative proposal and their assessment of costs and emission reduction benefits are attached as Exhibits N and O.

3.3.8 Quantification of Data

"To the extent practicable, a quantification of the data used in the analysis; the analysis must take into account both short-term and long-term consequences."

As set forth below, the Division has assessed the direct and indirect costs to the regulated community for each of the proposed strategies in Regulation Number 7. The Division estimates revisions to Regulation 7 will reduce VOC emissions by 93,500 tons per year, and methane/ethane emissions by 64,000 tons per year. The Division conservatively estimates that the annual net costs to industry of the Division's proposal will be $42.4 million per year. This translates to approximately $453 per ton of VOC reduced, which is very reasonable when compared to other air pollution reduction strategies adopted by the Colorado Commission and the EPA. The Division estimates that the total annual costs to the regulated community as a result of the proposed strategies will be approximately $59.2 million. Further, the proposed strategies are expected to result in the capture of additional product worth approximately $16.8 million, for a total net cost of $42.4 million per year. In addition to these direct costs, implementation of the proposed strategies could potentially result in the shut-in of certain marginally producing wells, resulting in indirect costs in the form of lost revenues to oil and gas companies, loss of jobs associated with these facilities, lost royalty payments, and lost severance taxes. Based on available information the Division cannot reasonably calculate the amount of oil and gas that could be shut-in due to the proposed rules, but believes that the amount is likely to be very small due to the low costs attributable to small, marginally producing facilities. To mitigate against this possibility, the Division's has crafted a tiered proposal that triggers requirements based on emission thresholds that are directly tied to production. Based on this, the truly small facilities are subject to less requirements and less costs; for example, only a one-time instrument-based leak inspection, which the Division estimates will cost approximately $712. An analysis by an economist hired by certain industry parties has suggested that these indirect costs could be quite large.[23] This information will be considered by the Commission as part of the rulemaking hearing.

The detailed discussions below largely focus on short-term consequences of the proposal. Long term consequences potentially include having to establish greater and potentially more extreme control measures in the future to address the current mass of emissions and anticipated growth in emissions. The oil and gas industry is expected to continue to grow significantly, especially in shale gas/oil development.[24]

This continued growth in shale gas/oil development will result in increased emissions of VOC and other hydrocarbons including methane and ethane, unless additional controls are implemented. This could result in increases in ozone formation and additional State Implementation Plan requirements to meet current and future NAAQS requirements.   According to EPA, attaining the current ozone standard throughout the nation will result in between $6.9 billion and $18 billion in annual health benefits. For lower standards the health benefits are even greater. For example, EPA projects that achieving a 70 ppb standard will result in between $13 billion and $37 billion in annual health benefits, and for a 65 ppb standard the benefits will increase to between $22 billion and $61 billion per year. EPA does not report these health benefits by state, but since the population of the Denver Metropolitan Area/North Front Range NAA accounts for approximately 2.5% of the total national population living in areas that are in violation of the current NAAQS, the health benefits attributable to Colorado are likely to be substantial.

3.3.8.1 Control Requirements for Petroleum Storage Tanks

Commencing in 2004 the Commission has adopted a series of requirements aimed at reducing emissions from petroleum storage tanks at well production facilities, compressor stations and gas processing plants. Currently, condensate tanks with uncontrolled actual emissions of 20 tons per year or greater of VOC must be equipped with a control device that has a control efficiency of at least 95%. Additionally, with certain exceptions, operators in the NAA must achieve a 90% system-wide reduction of VOC emissions from condensate tanks during the period from May 1 through September 30, and 70% during the period from October 1 through April 30. These current requirements only apply to tanks that store condensate, which is defined in the Commission's Common Provisions regulation as "hydrocarbon liquids . . . with an API gravity

[23] See Attached Exhibit A.
[24] U. S. Energy Information Administration. "Annual Energy Outlook 2013". April 15-May 2, 2013.

of 40 degrees or greater." While most of the petroleum liquid produced in Colorado qualifies as condensate, there are heavier hydrocarbon liquids, typically referred to as crude oil, with an API gravity below 40 degrees that are not subject to the current control requirements. Additionally, there are a number of high volume produced water tanks that have VOC emissions above 6 tons per year that are not currently regulated under the existing requirements.

While Colorado has achieved considerable success in controlling emissions from condensate tanks since 2004, petroleum storage tanks at oil and gas production and midstream facilities continue to be the most significant source of VOC emissions from this sector. To address this emission source the Division is proposing the following strategies: 1) reducing the control threshold from 20 tons per year VOC to 6 tons per year; 2) eliminating the distinction between condensate and other liquids and requiring controls strictly based on emission levels; and 3) extending the current requirement that all condensate tanks in the NAA be controlled during the first 90 days of production to storage tanks throughout the state. In order to meet each of these three strategies, the Division assumes that owners and operators will equip tanks with enclosed flares, as is the typical practice under the existing tank control requirements. The estimated costs associated with installing and maintaining an enclosed flare are set forth in subsection 3.3.8.1.1 of this Regulatory Analysis. Utilizing the calculated flare costs, the estimated costs and benefits for each of the three tank control strategies are discussed in subsections 3.3.8.1.2 – 3.3.8.1.4 of this Regulatory Analysis.

3.3.8.1.1 General Cost Estimates for Flares

The estimated cost for a flare control device is based on identified costs from a 2008 oil and gas cost study[25] adjusted for inflation. Based on this data, the estimated annualized cost of a flare control device with auto-igniter[26] is about $6,287.[27]

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[25] 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 Commission as part of the 2008 Ozone Action Plan process. For reference or background purposes, the Division has cited herein certain information that has been submitted to the Commission as part of the rulemaking; however, it is not necessarily included with this Regulatory Analysis as an exhibit.

[26] Currently only flares in the NAA are required to have auto-igniters. Under the current proposal, the auto-igniter requirement would be extended statewide. For the purposes of this cost analysis, it is assumed that auto-igniters will be required statewide. The cost and benefits associated with equipping existing flares outside the non-attainment with auto-igniters are discussed below in Section 3.3.8.1.7.

[27] Certain parties to the rulemaking have asserted that the actual cost per combustion device is higher based on EPA's cost analysis conducted in accordance with NSPS OOOO. Based on a review of EPA's analysis it appears that additional costs were included for surveillance systems that are not applicable to the proposed rule. Additionally, unlike the analysis in NSPS OOOO, the costs that the Division has identified are based on a Colorado specific cost analysis.

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	$18,169			
Freight/Engineering		$1,648		
Flare Installation		$6,980		
Auto Igniter	$1,648			
Pilot Fuel**			$768	
Maintenance			$2,197	
Subtotal Costs	$19,817	$8,628	$2,965	
Annualized Costs***	$2,747	$575	$2,965	$6,287

**Control cost evaluation based on 2008 Ozone Rulemaking cost survey and producer data. Control device costs were developed based on an oil and gas cost study and information submitted by industry in 2008. However, those costs were escalated by 9.85% to reflect CPI-U increases that have occurred since 2008.*[28]
*** Pilot fuel costs $3.41/MMBtu (Henry Hub Spot Price - Aug. 2013)*
**** Annualized over 15 years at 5% ROR*

3.3.8.1.2 Lowering Statewide Condensate Tank Control Threshold (from 20 tpy to 6 tpy)

The Division is proposing to lower the uncontrolled VOC emission control threshold from 20 tpy down to 6 tpy on condensate storage tanks statewide. Based on an analysis of the Air Pollution Emissions Notice (APEN) database, the Division estimates that statewide there are 588 uncontrolled condensate tank batteries with VOC emissions over six tons per year. Of these 588 tanks, 396 are outside the NAA and the remaining 192 are within the current NAA.

Table 2: Condensate Tank Battery Analysis				
Tank Battery Type	Ozone NAA [count]	Outside NAA [count]	Cancelled Tanks [count]	Total Statewide Tanks [count]
Controlled Tanks	4,971	490		5,461
Uncontrolled Tanks	1,451	1,132	36	2,619
All Tanks	6,422	1,622	36	8,080
Uncontrolled Tanks (≥ 6 tpy)	192	396		588

Based on the reported uncontrolled actual VOC emissions for these 588 tanks, and assuming both that 75% of the VOC emissions are captured and sent to the flare,[29] and that the flare has a 95% destruction efficiency, the total VOC emission reduction associated with lowering the condensate tank threshold statewide is 5,162 tons per year.

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[28] It has been suggested that the Division should have used the Producer Price Index to calculate an escalation from 2008 to 2013 costs. From 2008 to 2013, however, the Producer Price Index for the oil and gas field equipment sector grew at a slower rate than the CPI. Accordingly, the Division's analysis may actually overstate the increase in cost from 2008 to 2013.
[29] The costs and benefits associated with improving the capture percentage for controlled storage tanks are discussed below in Section 3.3.8.1.5.

Table 3: Condensate Tank Battery Emissions Analysis for Lowering Statewide Threshold			
Tank Battery Type	Uncontrolled VOC Emissions [tons/year]	Controlled VOC Emissions [tons/year]	VOC Emission Reduction [tons/year]
NAA Uncontrolled Tanks (≥6 tpy)	2,355	677*	1,678
Outside NAA Uncontrolled Tanks (≥6 tpy)	4,890	1,406*	3,484
Totals:	7,245	2,083	5,162

**Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.*

The annualized cost of installing 588 flare control devices is about $3.7 million dollars with an average cost effectiveness of about $716 per ton of VOC reduced. For the smallest individual tank battery subject to controls (6 tons/year), the flare cost effectiveness is estimated at $1,471 per ton of VOC reduced.

Table 4: Tanks over 6 tpy – Control Cost Estimates for Flare Control Devices				
Affected Tanks [count]	Each Flare Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
588	$6,286.8	$3,696,638	5,162	$716

In addition to VOC reductions, this strategy will significantly reduce methane and ethane emissions from currently uncontrolled tanks. To calculate methane and ethane emission reductions, the Division determined the relative proportion of VOCs to methane and ethane based on reported average values from 30 natural gas liquid analyses submitted to the Division. Based on these analyses, methane/ethane emissions from condensate storage tanks are about 38% of the VOC emissions by weight. Accordingly, projected methane/ethane emission reductions from this proposed strategy are 1,963 tons per year or $1,884 per ton of methane/ethane reduced.

3.3.8.1.3 Requiring Controls for Produced Water and Crude Oil Tanks

As discussed above, the Division is proposing to eliminate the distinction between condensate tanks and other storage tanks. If the Commission adopts this proposal, crude oil tanks and produced water tanks with uncontrolled actual VOC emissions of six tons per year or greater will require controls. Because produced water and crude oil tanks are identified separately in the Division's APEN data base, the costs and benefits for these two types of storage tanks are broken out separately.

The Division is proposing that all statewide produced water tanks with uncontrolled VOC emissions over 6 tons/year be required to install emission controls. Some uncontrolled produced water tanks could be co-located at sites with condensate or crude oil tanks that have flare controls, but pressure and flow differences may require the installation of a separate flare control device for the water tank. Consequently, the control costs are based on the assumption that each water tank battery will install a new flare control device. Based on an analysis of the APEN database, the Division estimates that statewide there are 52 uncontrolled produced water tank batteries with VOC emissions over 6 tons/year.

Table 5: Produced Water Tank Battery Analysis	
Tank Battery Type	Total Statewide Water Tanks
Controlled Water Tanks:	338
Uncontrolled Water Tanks:	530
Total:	868
Uncontrolled Tanks (≥6 tpy)	52

Based on the reported uncontrolled actual emissions, the Division estimates that the total VOC emission reduction associated with controlling these produced water tanks statewide is 457 tons per year.

Table 6: Produced Water Tank Battery – Emissions Analysis			
Tank Battery Type	Uncontrolled VOC Emissions [tons/year]	Controlled VOC Emissions [tons/year]	VOC Emission Reduction [tons/year]
Uncontrolled Tanks (≥6tpy)	641.4	184.4*	457

**Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.*

The annualized cost of installing 52 flare control devices is about $327,000, with an average cost effectiveness of about $715 per ton of VOC reduced. For the smallest individual tank battery (6 tons/year), the flare cost effectiveness is estimated at $1,471 per ton of VOC reduced.

Table 7: Produced Water Tanks – Control Cost Estimates for Flare Control Devices					
Tank Size	Affected Tanks [count]	Each Flare Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
≥ 6tpy	52	$6,286.8	$326,914	457	$715

The Division is proposing that all statewide hydrocarbon liquid storage tanks with VOC emissions over six tons/year must install emission controls. Based on a recent analysis of 2013 APEN data, there are 67 reported crude oil tanks batteries statewide. Thirty seven of the tank batteries are already equipped with controls. Of the remaining thirty, eight are over the proposed six tons/year threshold. Given that approximately 5% of the total wells in the state report crude oil production to the Colorado Oil and Gas Conservation Commission (COGCC),[30] it appears

[30] Based on an analysis of 2010 COGCC data.

likely that the Division's APEN database may be undercounting crude oil tanks, either because these tanks have not been reported or because they are being reported as condensate tanks.[31]

Table 8: Crude Oil Tank Battery Analysis	
Tank Battery Type	Total Statewide Crude Oil Tanks
Controlled Crude Oil Tanks	36
Uncontrolled Crude Oil Tanks	29
Total:	65
Uncontrolled Tanks (≥6 tpy)	8

The total VOC emission reduction associated with controlling these 8 crude oil tanks statewide is 118 tons per year.

Table 9: Crude Oil Tank Battery – Emissions Analysis			
Tank Battery Type	Uncontrolled VOC Emissions [tons/year]	Controlled VOC Emissions [tons/year]	VOC Emission Reduction [tons/year]
Uncontrolled Tanks (≥6tpy)	165.2	47.5*	117.7

**Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.*

The annualized cost of installing eight flare control devices is about $50,294 dollars with an average cost effectiveness of about $427 per ton of VOC reduced. For the smallest individual tank battery (6 tons/year), the flare cost effectiveness is estimated at $1,471 per ton of VOC reduced.

Table 10: Crude Oil Tanks – Control Cost Estimates for Flare Control Devices					
Tank Size	Affected Tanks [count]	Each Flare Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
≥ 6tpy	8	$6,286.8	$50,294.4	117.7	$427

3.3.8.1.4 Requiring Controls During the First 90 Days of Production Statewide

Under current requirements owners and operators of new and modified storage tanks outside the NAA have 90 days after the date of first production to determine if emissions from the tank trigger the requirement to install a control. Because production is typically at its highest during this initial period, significant emissions can occur before controls are installed. To address this

[31] Prior to 2008 crude oil storage tanks were exempt from APEN reporting requirements, which may explain in part the small numbers of tanks identified in the system.

issue in the NAA, the Commission mandated in the 2008 Ozone Action Plan that all condensate tanks be controlled during the first 90 days. The Division is now proposing to expand this requirement to storage tanks throughout the state.

To calculate the cost effectiveness of this strategy, the Division first determined the number of new and modified storage tanks outside the NAA based on reported APEN data for the period of 2010-2012. Based on this APEN data, there are on average 141 new and modified tanks each year, with yearly reported uncontrolled actual emissions of 7,370 tons VOC. Assuming that emissions during the first 90 days equal 1/4th of the annual reported emissions,[32] total uncontrolled actual VOC emissions from these tanks during the first 90 days is 1,842.5 tons. Assuming enhanced capture efficiency for these new tanks (see subsection 3.3.8.1.5 of this Regulatory Analysis) the flare control efficiency is 95%, and thus the calculated benefit from expanding the first 90 day control requirement to tanks outside the NAA will be 1,750.4 tons per year.

While the Division estimates that there are 141 new and modified storage tanks outside the NAA each year, the majority of these, 84, will require control devices regardless of this strategy since their uncontrolled actual emissions are over six tpy. For these 84 tanks, the cost of operating a flare during the first 90 days will be approximately 25% of the total annualized cost, or $1,571.70 per tank. For the remaining 57 tanks with emissions less than six tons/year, because controls for these tanks will only need to be in place for 90 days, the Division assumes that each flare can control 3 tanks per year, which means that 19 new flares are required to comply with this proposed strategy. For other applications, the annualized cost of a flare is estimated to be $6,287. Since flares required for this application will be relocated three times a year, the Division assumes an additional $3,000 in annual relocation costs, for a total annualized cost of about $9,287 per flare. Based on the emission reductions calculated above, the total cost effectiveness of this requirement is $176/ton of VOC reduction.

Table 11: Control Cost Estimates for Flare Control Devices Required During the First 90 Days of Production

Storage Tank Threshold [tpy]	Number of New Storage Tanks	Number of New Flares	Annualized Cost Each Flare	Total Flare Cost	Total VOC Reduction [tons/year]	VOC Control Cost [$/ton]
<6	57	19	$9,286.8	$176,449.2	44.7	$3,947
≥6	84	84	$1,571.7	$132,022.8	1,705.7	$77
	141			$308,472	1,750.4	$176

Using the methodology discussed in subsection 3.3.8.1.2 of this Regulatory Analysis, the projected methane/ethane emission reductions from this strategy is 665.5 tons per year or $464 per ton of methane/ethane reduced.

[32] Because reported emissions typically are based on a calculation assuming a standard rate of production decline after the first 90 days, actual emissions during the first 90 days could be much higher.

3.3.8.1.5 Emission Capture Requirements for Controlled Petroleum Storage Tanks

In order for storage tank control requirements to be effective, emissions from the tank must be routed to the control device. Historically the Division has assumed that 100% of a tank's emissions will be captured and routed to the control device, typically a flare, resulting in a 95% reduction of emissions. Field observations using IR cameras and other methodologies indicate that in actuality emissions from controlled storage tanks often escape through the thief hatches and pressure relief valves (PRV) and therefore are not being combusted in the flare. This occurs when the tank cannot adequately contain the flashing emissions that occur when pressurized liquids from the separator are dumped into the atmospheric tank. To address this issue, the Division is proposing new regulatory language clarifying that all emissions from controlled storage tanks must be routed to the control device and that these tanks must be operated without venting emissions from thief hatches, PRVs and other openings, except when venting is reasonably necessary for maintenance, gauging, or safety of personnel and equipment.

To assure compliance with these capture standards, the Division's proposal requires that owners and operators of controlled storage tanks implement a STEM plan. Pursuant to the STEM plan, owners and operators must evaluate and employ appropriate control technologies and/or operational practices designed to meet the proposed capture requirements, and certify that these technologies and/or operational practices are designed to minimize emissions from the tank. The Division's STEM proposal also requires implementation of a two-pronged monitoring strategy involving a weekly[33] auditory, visual, and olfactory (AVO) inspection for all controlled tanks, and a periodic instrument based monitoring for tanks using EPA Reference Method 21, an IR camera or other Division approved monitoring device or method. As proposed, the frequency of this instrument based monitoring will depend on the level of uncontrolled actual emissions from the tank.

Table 12: Proposed Tiering for Instrument Based Tank Inspections

Tank Uncontrolled Actual VOC Emissions	Inspection Frequency
≥ 6 tpy to ≤ 12 tpy	Annually
> 12 tpy to ≤ 50 tpy	Quarterly
> 50 tpy	Monthly

In assessing the cost effectiveness of the proposed requirements, the Division first calculated the costs associated with implementing technological and/or operational changes at controlled tanks. For the purposes of this analysis the Division assumed that all tanks with uncontrolled actual emissions greater than or equal to 6 tons per year would need to be controlled consistent with the Division's proposal discussed in Section 3.3.1 of this Regulatory Analysis. Based on reported data, there are currently 5,310 storage tanks statewide with emissions greater than or equal to 6 tons per year. While the Division's proposal does not specify the type of technology or operational practices that operators will use, for the purposes of this analysis the Division

[33] There is an exception for the weekly inspection requirement where the operator loads out liquids from the storage tank on less than a weekly basis. In these circumstances the operator must conduct the inspection whenever liquids are loaded out, but no less often than every 30 days. Typically liquids are loaded out multiple times in a given week, meaning that for the majority of the tanks AVO inspections will be required weekly.

assumed that buffer bottle technology would be installed on each of the subject tanks.[34] The buffer bottle technology utilizes a small tank that is installed after the separator which allows for a secondary flash of pressurized liquids prior to dumping into the storage tank. The second-stage flash reduces the pressure of the liquids going to the tank and thereby helps to ensure that the tank can adequately handle the flashing emissions that occur when the liquids are brought to atmospheric pressure. Based on industry provided information, the estimated annual cost of a buffer bottle is set forth in Table 13.[35]

Table 13: Annualized Cost Analysis for Buffer Bottle

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Buffer Bottle	$11,500			
Freight/Engr		$600		
Installation		$2,280		
Maintenance			$2,500	
Subtotal Costs	$11,500	$2,880	$2,500	
Annualized Costs*	$1,593.8	$192	$2,500	$4,285.8

** Annualized over 15 years at 5% ROR*

The Division also calculated the costs associated with conducting enhanced inspections. Based on the proposed tiering, operators will need to conduct 24,840 tank inspections per year.[36]

Assuming that each inspection takes two hours and utilizing a $103/hour [37] in-house inspection cost and a $134/hour contractor inspection cost (30% profit added to in-house rate), the total annual cost associated with conducting enhanced inspections under the proposed rule is $5,392,010, which equates to $1,015.4 per year for each tank that will be subject to STEM.

[34] Based on discussions with industry representatives during the stakeholder process there may be other less costly technologies and operational practices that could be used to ensure good emission capture from tanks such as replacing seals, more frequent maintenance, changing the size of piping going to the storage tank, and timing well dumps to avoid overloading the separator. There may also be other options for new facilities that allow for the capture and sale of additional gas such as the installation of high-low pressure separators or utilizing a liquids gathering system that eliminates atmospheric storage tanks at well sites.
[35] For this Regulatory Analysis, the Division increased the capital and maintenance costs for buffer bottles based on input from industry stakeholders.
[36] In practice, many operators are already conducting IR camera inspections at storage tanks, however, the Division does not have information regarding how many inspections are currently occurring.
[37] The hourly inspection cost is discussed below in Table 20.

Table 14: Instrument Based Tank Inspections Based on Proposed Tiering					
Tank Uncontrolled Actual VOC Emissions	Inspection Type/Hourly Rate	Number of Tanks	Inspection Frequency	Number of Inspections	STEM Inspection Costs
>6 tpy to ≤ 12 tpy	In-House/$103	1,085	Annually	1,085	$223,510
>12 tpy to ≤ 50 tpy	In-House/$103	2,595	Quarterly	10,380	$2,138,280
> 50 tpy	In-House/$103	745	Monthly	8,940	$1,841,640
	Subtotal:	***4,425***		***20,405***	***$4,203,430***
>6 tpy to ≤ 12 tpy	Contractor/$134	323	Annually	323	$86,564
>12 tpy to ≤ 50 tpy	Contractor/$134	329	Quarterly	1,316	$352,688
> 50 tpy	Contractor/$134	233	Monthly	2,796	$749,328
	Subtotal:	***885***		***4,435***	***$1,188,580***
	Total:	**5,310**		**24,840**	**$5,392,010**

The Division also considered whether additional costs should be included for conducting periodic AVO inspections. Because these activities are already required for controlled storage tanks under existing regulation, the Division did not include these costs in determining the total cost of the proposed capture requirements. The Division also did not include costs associated with certifying that selected technologies and/or operational practices are designed to minimize emissions, since costs for certifying capture efficiency are already included in the annualized cost of required flares.[38] Accordingly, the total projected annual cost of the proposed capture requirements based on the use of a buffer bottle and enhanced monitoring requirements is $5,301.2 per tank.

To calculate the projected emissions reduction from the proposed capture requirements, the Division assumed a current capture rate of 75% for controlled tanks based on analytical work that the Division, EPA and others have performed. Based on this capture rate, the Division calculated the emissions reduction that would occur if the capture rate were increased to 100% using the following equation:

Emission reduction = [uncontrolled VOC*(1-(0.75*0.95))] – [uncontrolled VOC *(1-0.95)],

Using this equation as applied to the reported uncontrolled actual emissions from the 5,310 storage tanks statewide with emissions greater than or equal to six tons per day, the projected emission reduction from the proposed capture requirements is 53,386 tons per year. Included in the total are 33 existing crude oil tanks with flare controls (>6 tpy) and 8 crude oil tanks that would need flare controls (>6 tpy).

[38] <u>See</u> "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008, at pg. 8.

Table 15: STEM Emission Control Analysis (Statewide)				
Number of Tanks ≥6 tpy	Uncontrolled VOC [tons/year]	Controlled VOC (@ 71.25% Control) [tons/year]	Controlled VOC (@ 95% Control) [tons/year]	VOC Reduction [tons/year]
5,269	221,569	63,701	11,078	52,623
41	3,213	924	161	763
5,310	224,782	64,625	11,239	53,386

Applying this reduction to the costs calculated above, the cost effectiveness of these proposed requirements is $527/ton of VOC.

Table 16: STEM Control Cost Estimates (Statewide)					
Type of Technology	Number of Tanks	Each Device Annualized Costs [$/year]	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
Buffer Bottle	5,310	$5,301.2	$28,149,372	53,386	$527.3

Using the average ratio of VOC to methane/ethane emissions from storage tanks, the projected methane/ethane reduction from this strategy is 20,287 tons per year, which equates to $1,388 per ton of methane/ethane reduced.

During the Division's stakeholder process leading up to the Commission's rulemaking hearing, certain parties have raised questions about the Division's assumption that currently controlled tanks have a 75% capture efficiency. In light of this the Division has also calculated cost effectiveness based on the assumption that current capture efficiency is 50% and 95%. For the 50% case, current controlled emissions would be 118,011 tpy VOC. Accordingly, the emission reduction benefit from increasing capture to 100% would be 106,772 tons per year (118,011-11,239) and the cost effectiveness would be $264/ton VOC[39]. For the 95% capture scenario, current controlled emissions would be 21,916 tons per year VOC and the emission reduction would be 10,677 tons per year (21,916-11,239). Under this scenario, the cost effectiveness would be $2,636/ton VOC[40].

While the buffer bottle technology offers a good alternative in a retrofit situation for reducing pressures to the tank and increasing emission capture, for new facilities, installation of a high-low pressure (HLP) separator to satisfy STEM may prove to be a better performing option. This equipment allows for two stages of separation of the gas and the liquids instead of the single stage separation accomplished in traditional separators. By adding a second stage of separation, the pressure of the liquids sent to the tank is significantly reduced, thereby helping to ensure

[39] This may overestimate the cost effectiveness given that if the current capture rate were only 50% additional costs could be required to increase the capture rate to 100%.
[40] This is a conservative calculation given that if the current capture rate were 95% it is likely that the control costs to increase the capture rate to 100% would be significantly less.

complete capture of flashing emissions instead of venting a portion of the emission stream through the thief hatch or PRV. Additionally, rather than being routed to the flare, as in the case of the buffer bottle technology, gas from the second stage of separation can be sent to a vapor recovery unit (VRU), recompressed and sent to the sales line, resulting in increased product recovery. Based on information provided from industry, the Division has calculated that the annual cost of a HLP separator w/VRU is about $19,341.

Table 17: Annualized Cost Analysis for HLP Separator

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
HLP/VRU	$90,000			
Freight/Engr		$1,648		
HLP/VRU Installation		$11,154		
Maintenance			$9,396	
VRU Recovered NG *			$(3,382)	
Subtotal Costs	$90,000	$12,802	$6,014	
Annualized Costs**	$12,474	$853	$6,014	$19,341

** Recovered NG fuel costs $3.5/MCF (Henry Hub Spot Price - Aug. 2013) and average tank battery size of 63.2 tpy – based on 3-yr average of APEN data on storage tanks ≥6 tpy (uncontrolled VOC).*

*** Annualized over 15 years at 5% ROR*

Unlike the retrofit situation analyzed above where the emission controls are already in place, it is appropriate in new installations to aggregate the cost of the HLP separator w/VRU with the costs of the control unit (flare) to determine the overall cost of controlling emissions from the tank. Based on the $6,286.8 annual cost of a flare and annual instrument based monitoring costs of $1,015.4 per tank, the total annual control costs for a new tank will be $26,643 per year.

Based on an analysis of reported data for new tanks during the past three years, the average uncontrolled actual emissions of a new tank is 63.2 tpy. Assuming a 95% overall control efficiency, equipping a tank with an HLP separator and a flare will reduce the emissions from an average new tank by 60 tpy. This yields a cost effectiveness of $444 per ton VOC reduced. If instead, the highest cost scenario (using a six tpy tank) is assumed, the cost effectiveness is $4,674 per ton VOC. For methane ethane the cost per ton is $1,168 per ton reduced on average.

3.3.8.1.6 LDAR Requirements for Compressor Stations and Well Production Facilities

Commission Regulation Number 7 requires owners and operators of gas processing plants in Colorado to implement LDAR programs to identify and repair fugitive emission leaks from components at these facilities. Under this requirement, owners and operators must conduct periodic inspections using EPA Reference Method 21[41] and repair leaks within a prescribed time frame.

[41] While EPA Reference Method 21 sets performance standards for inspection equipment rather than specifying technology, typically Method 21 inspections utilize photo ionization detectors (PIDs) to assess leak levels.

Although component leaks at compressor stations and well production facilities in Colorado are also a significant source of VOC and methane emissions, Regulation No. 7 does not currently include LDAR requirements for these facilities.[42] To address these emissions, the Division is proposing regulatory changes that would establish LDAR requirements for compressor stations and well production facilities. Pursuant to this proposal, owners and operators of compressor stations and well production facilities will be required to conduct periodic leak inspections, and repair identified leaks. As specified, required inspections may be done either in accordance with EPA Reference Method 21 or utilizing an IR camera. The proposed language also allows the Division to approve other inspection methods as new leak detection technologies are demonstrated to be effective.

The proposed regulation establishes a tiered system to determine inspection frequency. For compressor stations the tiering is based on the uncontrolled actual leak emissions at the facility as follows:

Table 18: Proposed Tiering for Leak Inspections at Compressor Stations

Component Leak Uncontrolled Actual VOC Emissions	Inspection Frequency
≤ 12 tpy	Annually
>12 tpy to ≤ 50 tpy	Quarterly
> 50 tpy	Monthly

For well production facilities the proposed tiering is based on uncontrolled actual emissions from the largest emitting storage tank at the facility as set forth in Table 19. The tiering is based on tank emissions rather than uncontrolled actual leak emissions in order to create an EPA Reference Method 21/IR camera monitoring schedule that is consistent with the monitoring schedule proposed as part of STEM emission capture requirements.[43]

[42] Although leak detection is not currently required at most of these facilities, some operators currently conduct voluntary leak detection and repair programs. Additionally, the Division has issued a limited number of permits that include some leak detection requirements. For the purposes of this analysis, however, the Division assumes that there is no leak detection occurring at well production facilities and compressor stations. Accordingly the actual additional costs that operators may incur may be less than the costs calculated in this analysis.

[43] Because there may be a limited number of instances where well production facilities don't have storage tanks, the proposal also provides that for tank-less facilities, the inspection schedule will be based on the facility's total VOC emissions. This provision is intended to apply to large facilities that utilize a liquids gathering system for transporting petroleum liquids to a centralized facility. These facilities are not included in the facility count used in this Regulatory Analysis, but because the number of these facilities in Colorado is extremely small this exclusion should have a negligible impact on the overall costs and emission reduction benefits of the proposed LDAR requirement. Additionally, because the costs and benefits from the proposed LDAR program increase at roughly the same rate, the cost effectiveness of the program for these facilities should mirror the cost effectiveness of the program as applied to facilities with tanks.

Table 19: Proposed Tiering for Leak Inspections at Well Production Facilities	
Tank Uncontrolled Actual VOC Emissions	Inspection Frequency
< 6 tpy	One Time (and Monthly AVO)
≥ 6 tpy to ≤ 12 tpy	Annually
>12 tpy to ≤ 50 tpy	Quarterly
> 50 tpy	Monthly

The Division utilized a multi-step process to calculate the estimated costs and benefits associated with the proposed LDAR 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.[44] To calculate the total annual cost for each inspector, the Division included salary and fringe benefits for each inspector, annualized equipment and vehicle costs, and add-ons to account for supervision, overhead, travel, record keeping, and reporting. Based on the assumptions set forth in Table 20 below, the total annual cost for each inspector will be $193,629, which equates to an hourly inspection rate of $103.

Table 20: LDAR Inspector – Annualized Cost Analysis			
Item	Capital Costs (one time)	Annual Costs	Annualized Total Costs
FLIR Camera	$122,000		
FLIR Camera Maintenance/Repair		$7,500	
Photo Ionization Detector	$5,000		
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
**over 5 years at 6% ROR*		Annualized Hourly Rate	$103

Initially, the Division assumed that conducting inspections in-house would be the lowest cost option since it would not involve additional profit to be paid to a contractor. For smaller companies that cannot fully utilize an IR camera, however, conducting inspections in-house may not be the most cost effective option. To account for this in this Regulatory Analysis, the Division assumed a 30% profit margin for contractors, which it added to the calculated hourly rate in instances where it appeared that contractors would be used to conduct the inspection ($134 per hour).

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

Second, the Division calculated the average amount of time that it would take to conduct an EPA Reference 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 take 50% of the time required for a Method 21 inspection.[45]

For compressor stations, the Division used reported component counts for compressor stations within each of the tiers identified in Table 18 above. Based on these counts, and the inspection times per component discussed above, the Division calculated that the total inspection time per compressor station facility tier are as follows:

Table 21: Calculated Inspection Time Compressor Station Leak Inspections		
Component Leak Uncontrolled Actual VOC Emissions	Method 21 Inspection	IR Camera/ Hybrid Inspection
≤ 12 tpy	21.2 hours	10.6 hours
>12 tpy to ≤ 50 tpy	56.2 hours	28.1 hours
> 50 tpy*		

* *there are currently no compressor stations in Colorado with calculated leaks at this level*

For well production facilities, the Division has limited 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 NAA and well production facilities outside the NAA. Accordingly, the Division calculated separate inspection times for well production facilities by area as set forth in Table 22.

Table 22: Calculated Inspection Times for Well Production Facility Leak Inspections		
Area	Method 21 Inspection	IR Camera/ Hybrid Inspection
NAA	12.2 hours	6.1 hours
Rest of the State	6.8 hours	3.4 hours

45 Based on the Division's own IR camera inspections, and reports from various parties during the 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 20, for the purposes of this Regulatory Analysis the Division also assumed an additional three hours in travel time for each inspection outside the NAA. This assumption reflects the fact that certain well sites in basins outside the NAA may be remote, requiring additional travel.

Next, the Division calculated the projected inspection costs for both compressor stations and well production facilities. To make this calculation the Division used industry reported emission data to determine the number of facilities that will be subject to annual, quarterly and monthly 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 compressor stations the Division assumed that all inspections would be conducted by 3rd party contractors. For well production facilities, the Division assumed that any company with 500 or more inspections per year would conduct inspections in-house, and that companies with less than 500 inspections per year would use contractors.[46] Because the proposed rule also requires owners and operators of well production facilities that are not subject to monthly instrument monitoring to conduct monthly AVO inspections the Division considered whether additional costs should be included for these inspections. Based on information provided during the Division's stakeholder process leading up to the Commission's rulemaking hearing it appears that operators already routinely conduct such inspections and repair leaks identified during these AVO inspections. Additionally, while the proposed rule may impose recordkeeping and reporting requirements associated with these AVO inspections, given the relatively small number of leaks that are expected to be identified, and the fact that any recordkeeping can be readily included in existing inspection and maintenance records the Division believes that any additional recordkeeping and reporting costs will be nominal relative to the overall cost of the LDAR program.

In its Initial EIA, the Division did not include the cost to repair leaking components or re-monitor these components post-repair to verify that the repair was effective, assuming that the cost to repair and re-monitor would be offset by the cost savings from capturing additional product as a result of repairs. Based on information that the Conservation Groups submitted as part of their Pre-Hearing Statement to the Commission, it appears that the Division's assumption in the Initial EIA was reasonable. See Exhibit A to CG-PHS, Testimony of David McCabe at pg. 8. Nevertheless, for this Regulatory Analysis, the Division has included both repair costs and 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 $66.24 hourly rate to repair components, and an average repair time of between 0.17 hours and 16 hours, depending on the both type of component and the complexity of the repair.[47] To calculate the number of leaking components the Division used industry reported component counts and assumed a 1.18% leaking

[46] Based on this assumption, 3,545 inspections per year will be conducted using 3rd party contractors.
[47] 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.

component rate for facilities subject to annual inspections.[48] To account for the projected additional emission reductions from quarterly and monthly inspection schedules the Division used annual leaking component rates of 1.77% for facilities with quarterly inspection schedules and 2.36% for facilities with monthly inspection schedules. To calculate the value of the additional product captured, the Division converted the amount of VOC and methane/ethane reduced to MCF of natural gas, with a price of $3.50/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.

Based on this methodology, the calculated annual inspection costs for compressor stations are set forth in Table 23.

Table 23: Compressor Station Leak Inspection Costs Using IR Camera/Method 21 Hybrid

Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Annual Inspection Frequency	Time per IR Camera Inspection [hours]	Total Annual Inspection Time [hours]	Total Annual Inspection Cost
≤ 12 tpy	147	1	10.6	1,558.2	$208,799
>12 to ≤ 50 tpy	53	4	28.1	5,957.2	$798,265
≥ 50 tpy	0	12			
Total:	200			7,515.4	$1,007,064

Repair costs associated with these inspections are set forth in Table 24 and fuel savings associated with these repairs are set forth in Table 25.

Table 24: Compressor Station Leak Repair Costs

Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Leak Repair Rate [$/hr]	Number of Leaks per Compressor Station	Total Leak Repair Time per CS [hours]	Total Annual Repair Cost
≤ 12 tpy	147	$66.24	30.1	23.0	$223,957.4
>12 to ≤ 50 tpy	53	$66.24	119.4	85.2	$299,113.3
≥ 50 tpy	0	$66.24	-	-	-
Total:	200				$523,071

[48] This leaking component rate is consistent with the rate that the Louis Berger Group used in their Initial Economic Impact Analysis for Industry's Proposed Revisions to Colorado's Air Quality Control Commission Regulation No. 7 (DGS-PHS Ex. C), and is based on the leak rate utilized by Nelson and Brown in their analysis of leak reduction costs and benefits (See footnote 41).

Table 25: Compressor Station Recovered Natural Gas Value from Leak Repairs					
Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Total Recovered Natural Gas per CS [tons/year]	Value of Natural Gas [$/MCF]	Conversion Factor [MCF/ton]	Total Annual Value of Recovered Natural Gas
≤ 12 tpy	147	10.2	$3.5	35.8	$187,875
>12 to ≤ 50 tpy	53	36.4	$3.5	35.8	$241,729
≥ 50 tpy	0		$3.5	35.8	-
Total:	200				$429,604

The total net costs for compressor station LDAR are set forth in Table 26.

Table 26: Compressor Station Net Leak Inspection and Repair Costs					
Compressor Station Fugitive VOC Tier [tpy]	Number of 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	147	$208,799	$223,957.4	$187,875	$244,882
>12 to ≤ 50 tpy	53	$798,265	$299,113.3	$241,729	$855,650
≥ 50 tpy	0		-	-	-
Total:	200	$1,007,064	$523,071	$429,604	$1,100,531

For well production facilities the estimated annual inspection costs are set forth in Table 27.

Table 27: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid						
Uncontrolled VOC at Storage Tank Battery Tier [tpy]	O&G Basin*	Number of Facilities	Annual Inspection Frequency	Total Number of Inspections	Inspection Time Per Inspection [hours]	Total Annual Inspection Cost
In-House Inspections at $103/hour						
> 6 to ≤12	DJ/NAA	945	1	945	6.1	$593,744
> 12 to ≤ 50	DJ/NAA	2,447	4	9,788	6.1	$6,149,800
> 50	DJ/NAA	693	12	8,316	6.1	$5,224,943
	Subtotal:	4,085		19,049		$11,968,487
In-House Inspections at $103/hour						
> 6 to ≤12	ROS	173	1	173	6.4**	$114,042
> 12 to ≤ 50	ROS	176	4	704	6.4	$464,077
> 50	ROS	115	12	1,380	6.4	$909,696
	Subtotal:	464		2,257		$1,487,815
Contract Inspections at $134/hour						
> 6 to ≤12	DJ/NAA	150	1	150	6.1	$122,610
> 12 to ≤ 50	DJ/NAA	153	4	612	6.1	$500,249
> 50	DJ/NAA	118	12	1,416	6.1	$1,157,438
	Subtotal:	421		2,178		$1,780,297
Contractor Inspections at $134/hour						
> 6 to ≤12	ROS	140	1	140	6.4**	$120,064
> 12 to ≤ 50	ROS	148	4	592	6.4	$507,699
> 50	ROS	52	12	624	6.4	$535,142
	Subtotal:	340		1,356		$1,162,905
	Total:	**5,310**		**24,840**		**$16,399,504**

* ROS = Remainder of State

** ROS inspection time includes additional 3 hours for travel time

Repair costs associated with these inspections are set forth in Table 28 and fuel savings associated with these repairs are set forth in Table 29.

Table 28: Well Production Facility Leak Repair Costs					
Uncontrolled VOC at Storage Tank Battery Tier [tpy]	O&G Basin	Number of Facilities	Number of Leaks per Tank	Total Leak Repair Time per Tank [hours]	Total Annual Repair Cost
> 6 to ≤12	DJ/NAA	1,095	17.0	11.8	$855,887
> 12 to ≤ 50	DJ/NAA	2,600	25.5	17.7	$3,048,365
> 50	DJ/NAA	811	34.1	23.6	$1,267,807
	Subtotal:	4,506			$5,172,059
> 6 to ≤12	ROS	313	9.7	7.7	$159,645
> 12 to ≤ 50	ROS	324	14.5	11.6	$248,956
> 50	ROS	167	19.4	15.4	$170,356
	Subtotal:	804			$578,957
	Total:	**5,310**			**$5,751,016**

Table 29: 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 tank [tons/year]	Value of Natural Gas [$/MCF]	Conversion Factor [MCF/ton]	Total Annual Value of Recovered Natural Gas
> 6 to ≤12	DJ/NAA	1,095	4.6	$3.5	35.8	$631,136
> 12 to ≤ 50	DJ/NAA	2,600	7.0	$3.5	35.8	$2,280,460
> 50	DJ/NAA	811	9.3	$3.5	35.8	$945,050
	Subtotal:	4,506				$3,856,646
> 6 to ≤12	ROS	313	4.6	$3.5	35.8	$180,407
> 12 to ≤ 50	ROS	324	6.8	$3.5	35.8	$276,061
> 50	ROS	167	9.1	$3.5	35.8	$190,418
	Subtotal:	804				$646,886
	Total:	**5,310**				**$4,503,532**

The total net costs for well production facility station LDAR are set forth in Table 30.

Table 30: Well Production Facility –Net Leak Inspection and Repair Costs						
Uncont. VOC at Storage Tank Battery Tier [tpy]	O&G Basin	Total Annual Inspection Cost		Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
		In-House	Contractor			
> 6 to ≤12	DJ/NAA	$593,744	$122,610	$855,887	$631,136	$941,105
> 12 to ≤ 50	DJ/NAA	$6,149,800	$500,249	$3,048,365	$2,280,460	$7,417,954
> 50	DJ/NAA	$5,224,943	$1,157,438	$1,267,807	$945,050	$6,705,138
	Subtotal:	$11,968,487	$1,780,297	$5,172,059	$3,856,646	$15,064,197
> 6 to ≤12	ROS	$114,042	$120,064	$159,645	$180,407	$213,344
> 12 to ≤ 50	ROS	$464,077	$507,699	$248,956	$276,061	$944,671
> 50	ROS	$909,696	$535,142	$170,356	$190,418	$1,424,776
	Subtotal:	$1,487,815	$1,162,905	$578,957	$646,886	$2,582,791
	Total:	**$13,456,302**	**$2,943,202**	**$5,751,016**	**$4,503,532**	**$17,646,988**

Additionally, based on information in the Division's APEN reporting system, there are 2,799 well production facilities with uncontrolled actual storage tank emissions less than or equal to 6 tons per year that will be subject to a one-time instrument based inspection. The one-time cost for inspecting these facilities is estimated to be $1,639,239.[49]

Table 31: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid					
Uncontrolled VOC at Storage Tank Battery Tier [tpy]	O&G Basin	Number of Facilities and Inspections	Inspection Time Per Inspection [hours]	Inspection Type/Hourly Rate	Total Annual Inspection Cost
≤ 6	DJ/NAA	1,598	6.1	In-House/$103	$1,004,023
≤ 6	ROS	500	3.4	In-House/$103	$175,100
	Subtotal:	2,098			$1,179,123
≤ 6	DJ/NAA	389	6.1	Contractor/$134	$317,969
≤ 6	ROS	312	3.4	Contractor/$134	$142,147
	Subtotal:	701			$460,116
	Total:	**2,799**			**$1,639,239**

[49] To calculate these costs the Division used the same methodology applicable to periodic inspection costs, except that it did not include additional travel time for facilities outside the NAA based on the assumption that companies could coordinate these one-time inspections with visits to the facilities for other purposes.

The Division recognizes that there are likely additional facilities not included in the APEN database that will be subject to this one-time inspection requirement, thereby increasing the overall cost of the one-time inspection requirement. Roughly speaking the additional cost for one-time inspections will be proportional to the number of additional facilities, so that if there are twice the number of facilities, the overall cost will be approximately double. However, because the expected emission reduction benefit will increase roughly at the same rate as the cost of inspections the overall cost-effectiveness of the one-time inspection requirement should remain approximately the same regardless of the number of facilities.

Finally, the Division calculated the cost effectiveness of the proposed LDAR requirements based on the costs identified above and the projected emission reductions. To determine emission reductions the Division first calculated pre-inspection program VOC and methane emissions based on the reported component counts, standard emission factors for these components, and the average fraction of VOC and non-VOC emissions (methane/ethane). Based on EPA reported information, the Division calculated a 40% reduction for annual inspections, a 60% reduction for quarterly inspections, and an 80% reduction for monthly inspections.

Using this information the Division calculated that the total emission reductions from leaks at compressor stations will be 1,107 tpy VOC and 2,321 tons per year methane/ethane.

Table 32: Compressor Station Leak Inspection Emission Reductions

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

Based on these reductions, the cost effectiveness of conducting leak inspections at compressor stations is estimated to be $994/ton VOC and $474/ton methane/ethane.

Table 33: Compressor Station Leak Inspection Cost Effectiveness using IR Camera/Method 21							
Comp. Station Fugitive VOC Tier [tpy]	Number of Comp Stations	Total Net Annual Inspection & Repair Cost	LDAR Program Reduction %	Total VOC Reduction [tpy]	VOC Control Cost [$/ton]	Total Methane-Ethane Reduction [tpy]	Methane-Ethane Control Cost [$/ton]
≤ 12	147	$244,882	40%	588.0	$416	911.4	$269
> 12 to ≤ 50	53	$855,650	60%	519.4	$1,647	1,409.8	$607
> 50			80%				
	200	$1,100,531		1,107.4	$994	2,321.2	$474

For well production facilities the total emission reductions is estimated to be 14,015 tpy VOC and 21,927 tpy methane/ethane.

Table 34: Well Production Facility Leak Inspection Emission Reductions						
Uncontrolled VOC at Tank Battery Tier [tpy]	Number of Facilities	LDAR Program Reduction %	Fugitive VOC Emissions for each Tank Battery [tpy]	Total VOC Reduction [tpy]	Fugitive Methane-Ethane Emissions for each Tank Battery [tpy]	Total Methane-Ethane Reduction [tpy]
DJ/NAA						
> 6 to ≤ 12	1,095	40%	4.6	1,971.0	7.0	3,066.0
> 12 to ≤ 50	2,600	60%	4.6	7,280.0	7.0	10,920.0
> 50	811	80%	4.6	3,000.7	7.0	4,541.6
Subtotal:	**4,506**			**12,251.7**		**18,527.6**
Remainder of State						
> 6 to ≤ 12	313	40%	3.9	500.8	7.5	939.0
> 12 to ≤ 50	324	60%	3.9	745.2	7.5	1,458.0
> 50	167	80%	3.9	517.7	7.5	1,002.0
Subtotal:	**804**			**1,763.7**		**3,399.0**
Total:	**5,310**			**14,015.4**		**21,926.6**

Based on these reductions, the cost effectiveness of conducting ongoing instrument based inspections at well production facilities is estimated to be $1,259/ton VOC and $805/ton methane/ethane.

Table 35: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21							
Uncont. VOC at Tank Battery Tier [tpy]	Number of Tanks	Total Net Annual Leak Inspection & Repair Cost	LDAR Program Reduction %	Total VOC Reduction [tpy]	VOC Control Cost [$/ton]	Total Methane-Ethane Reduction [tpy]	Methane-Ethane Control Cost [$/ton]
DJ/NAA							
> 6 to ≤ 12	1,095	$941,105	40%	1,971.0	$477	3,066.0	$307
> 12 to ≤ 50	2,600	$7,417,954	60%	7,280.0	$1,019	10,920.0	$679
> 50	811	$6,705,138	80%	3,000.7	$2,235	4,541.6	$1,476
Subtotal:	4,506	$15,064,197		12,251.7	$1,230	18,527.6	$813
ROS							
> 6 to ≤ 12	313	$213,344	40%	500.8	$426	939.0	$227
> 12 to ≤ 50	324	$944,671	60%	745.2	$1,268	1,458.0	$648
> 50	167	$1,424,776	80%	517.7	$2,752	1,002.0	$1,422
Subtotal:	804	$2,582,791		**1,763.7**	$1,464	**3,399.0**	$760
Total:	5,310	$17,646,988		14,015.4	$1,259	21,926.6	$805

Additionally, for the 2,799 well production facilities with uncontrolled actual storage tank emissions equal to or less than 6 tons per year that will be subject to a one-time instrument based inspection, the calculated one-time benefit is 4,876 tons VOC and 8,000 tons methane/ethane, assuming a 40% reduction. Based on these reductions, for the one-time inspections of well production facilities with tanks that are less than six tons per year the cost effectiveness of the proposed rule is calculated to be $409/ton VOC and $249/ton methane/ethane.

In addition to the component LDAR requirements for compressor stations and well production facilities, the Division's proposal includes additional requirements designed to reduce leaks from open ended lines and valves, reciprocating compressors, and wet seal centrifugal compressors. These requirements mirror existing cost-effective requirements set forth in NSPS OOOO and other federal rules.

For open ended valves and lines at well production facilities and compressor stations, the proposal requires that each such valve or line be equipped with a cap, blind flange, plug or second valve commencing January 1, 2015. Alternatively, the Division's proposal allows operators to treat open-ended lines and valves as components and monitor them in accordance with the proposed LDAR requirements. As part of its LDAR cost effectiveness analysis detailed above, the Division included the costs of inspecting and repairing open ended lines and valves in its overall calculation. While the Division has not identified specific information regarding the costs and emission reduction benefits from equipping open ended lines with a cap, blind flange, plug or second valve it notes that the requirement has been included in a multitude of federal air quality rules, including NSPS VV, NSPS VVa, MACT H, MACT CC, MACT TT, MACT YY, MACT GGG, MACT III, and MACT MMM, dating back as far as 1983. Based on this widespread prevalence in federal rules the Division believes that the proposal represents a simple and cost-effective strategy to reduce emissions from open-ended lines and valves. However, to the extent that it is not cost effective in a specific case operators can employ the monitoring option allowed for under the proposed rule.

For centrifugal compressors, the Division's proposal requires that hydrocarbon emissions from wet seal fluid degassing systems be reduced by 95% beginning January 1, 2015. In its updated technical support document for NSPS OOOO, EPA analyzed the cost-effectiveness of this strategy and found that accounting revenues from the capture of additional product, implementation of this strategy would on a per unit basis reduce VOC emissions by 19.5 tpy, methane emissions by 216.2 tpy, and result in a net cost savings of $46,974.[50]

With respect to reciprocating compressors, the Division's proposal requires that commencing January 1, 2015, the rod packing for reciprocating compressors located at compressor stations be replaced every 26,000 hours of operation or every 36 months. As with the requirement for centrifugal compressors, EPA analyzed this proposed strategy as part of the adoption of NSPS OOOO and found that it was a cost-effective way to reduce VOC and methane emissions. Specifically, EPA found that per compressor the strategy reduces VOC emissions by 1.9 tons per year and methane emissions by 6.8 tons per year, at a net cost of $43 per ton of VOC reduced and $12 per ton of methane reduced.[51]

3.3.8.1.7 Auto Igniter Requirements on Existing Flare Control Devices Outside the NAA

Unlike the NAA, flares used to control emissions at condensate tank batteries and glycol dehydration units outside the NAA are not required to have auto-igniters. The Division is proposing that all flares used to control emissions at condensate tank batteries and glycol dehydration units statewide should have auto igniters. Based on an analysis of the APEN database, the Division estimates the statewide number of existing flare control devices without auto-igniters on condensate tank batteries, glycol dehydration, produced water tanks, and crude oil tanks is 796. The reported uncontrolled actual emissions from these units are 53,101.1 tons per year VOC.

The estimated annualized cost for an auto-igniter is $475 based on information that the industry provided to the Division in 2008, adjusted for inflation.[52]

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[50] See APCD-PHS Ex. HHHH pp. 6-1—6-3
[51] See initial technical support document for NSPS OOOO (submitted as DGS-PHS Ex. NN) at pp. 6-12—6-17.
[52] See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008.

Table 36: Auto Igniter Control Device – Retrofit Cost Analysis				
Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Auto Igniter	$1,648			
Freight/Engineering		$200		
Flare Installation		$500		
Maintenance			$200	
Subtotal Costs	$1,648	$700	$200	
Annualized Costs*	$228.4	$46.7	$200	$475

** Annualized over 15 years at 5% ROR*

The Division estimates that a flare without an auto-igniter could experience about 3% pilot light downtime (262.8 hours) over a one year period. During the downtime period, any VOC emissions routed to the flare control device are uncontrolled. Based on the total uncontrolled actual emissions of 53,101.1tons per year VOC from units equipped with flares without auto-igniters, the emissions during this downtime period will be 1,593.1 tons of VOC. The Division assumes that as a result of the installation of an auto-igniter, the amount of downtime can be eliminated, for a total emission reduction of 1,251.7 tons/year. Given that the annualized cost of installing 796 auto-igniters is about $378,100 the estimated cost effectiveness of this strategy is about $302 per ton of VOC reduced.

Table 37: Auto Igniter Emission Reduction Estimates				
Source Type for Existing Flare Controls	Number of Auto Igniters	Uncontrolled VOC [tpy]	Uncontrolled VOC Using 3% Downtime [tpy]	Total VOC Reduction [tpy]
Condensate Tanks	490	31,170.6	935.1	666.3
Dehydrators	131	16,372.0	491.2	466.6
Produced Water Tanks	172	4,842.2	145.3	103.5
Crude Oil Tanks	3	716.3	21.5	15.3
	796	53,101.1	1,593.1	1251.7

** Dehydrator flares assumed to have 100% capture and 95% destruction – thus 95% control. Tank flares are assumed to have 75% capture and 95% destruction – thus 71.25% control.*

Table 38: Auto Igniter Control Cost Estimates (Outside NAA)				
Number	Each Auto-Igniter Annualized Costs	Total Annualized Costs	VOC Reduction* [tons/year]	Control Costs [$/ton]
796	$475	$378,100	1,251.7	$302

3.3.8.2 Expanding Low Bleed Pneumatics Requirements Statewide

As part of the 2008 Ozone Action Plan the Commission adopted regulatory requirements mandating the use of low bleed pneumatic controllers in the NAA. The current proposal would expand this requirement statewide.

To estimate the costs and benefits of this proposed strategy, the Division estimated the number of high-bleed pneumatic devices based on Independent Petroleum Association of the Mountain States (IPAMS) survey data from 2006, which identified the average number of such devices per well. The Division then scaled this number up based on 2012 COGCC well count data. Based on this methodology, there are 9,877 high-bleed pneumatic devices outside the NAA. Assuming a 95% replacement rate, the proposed rule will result in the replacement of 9,384 high bleed devices with low bleed devices. Based on this count, and the average emission reductions per device replaced identified in the IPAMS survey, the projected benefit from the proposed expansion of the current NAA low bleed pneumatic rule will be approximately 14,921 tons per year VOC (40.9 tons per day). Based on this information and assuming an 80/20 ratio of methane/ethane to VOC by volume, the estimated methane/ethane reduction from this strategy is 17,100 tons per year.

The average retrofit cost of a high-bleed pneumatic device is based on costs from the 2008 cost study[53] adjusted for inflation. Utilizing this methodology, the annualized cost for each replaced device is $169. However, because the reduced bleed rate results in more natural gas being sold, operators will receive additional revenue as a result of the installation of a low bleed device. Based on the emission reduction data from the IPAMS survey and August 2013 spot prices for natural gas, the estimated average value of the recovered gas will be $1,268 for each device replaced. As a result, the net annual gain is $1,084 per replaced device. Based on this projected net gain, this strategy will pay for itself in approximately one year and two months.

Table 39: Replace High-Bleed Pneumatics with Low-Bleed Pneumatics – Annualized Cost Analysis*

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Low/No Bleed Device*	$1,033			
Labor		$387		
Value of NG Saved**			$(1,268)	
Maintenance			$16	
Subtotal Costs	$1,033	$387	$(1,253)	
Annualized Costs***	$143	$26	$(1,253)	$(1,084)

** Control device costs were developed based on an Oil and Gas Cost Study and information submitted by industry in 2008. However, those costs were escalated by 9.85% to reflect CPI-U increases that have occurred since 2008.*
*** Recovered NG fuel costs $3.5/MCF (Henry Hub Spot Price - Aug. 2013)*
**** Annualized over 15 years at 5% ROR*

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[53] See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008.

Assuming 9,384 total devices replaced, adoption of this strategy will result in $10,169,441 in annual cost savings.

Table 40: Low Bleed Pneumatic Control Cost Estimates (Outside NAA)				
Number	Each Device Annualized Costs	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
9,384	$(1,084)	$(10,169,441)	14,921	NA

The proposed rule also requires the use of no-bleed pneumatic devices if it is technically and economically feasible and where on-site electrical grid power is being used. Use of no-bleed pneumatic devices will further reduce emissions relative to the use of low bleed devices. Since the Division does not have information indicating the number of no-bleed pneumatic devices that could be required, it is not possible to calculate the cost effectiveness of this particular provision. However, because the proposed requirement expressly provides that use of no-bleed pneumatics is only required where economically feasible the Division assumes that any use of no-bleed pneumatic devices pursuant to the proposed rule will be cost effective.

3.3.8.3 Require Newly Constructed Gas Wells be Connected to a Pipeline or Route Emissions to a Control Device

Currently in Colorado, natural gas produced at oil and gas sites is typically routed to a transmission pipeline. With the advent of new drilling technologies, additional areas of the state without established pipeline infrastructure may experience oil and gas exploration and production. This can lead to instances where produced gas is vented or flared instead of being put into a transmission line. To date the Division has identified 61 instances in Colorado where this is occurring. To address this, the proposed regulation provides that for newly constructed, hydraulically fractured, or recompleted wells, the gas stream must either be connected to a pipeline or routed to a control device achieving 95% control efficiency. Currently all of the sites that are not routed to a pipeline are flaring their gas. Additionally, because venting the gas at such sites would create a safety issue, the Division assumes that in the limited future instances where the gas stream is not routed to a pipeline, operators will route the emissions to a flare or other control device. Accordingly, adoption of this portion of the proposed regulation will likely not result in any additional costs.

3.3.8.4 Control Requirements for Glycol Dehydrators

The Division is proposing to revise the control requirements applicable to glycol natural gas dehydrators statewide. Currently any glycol natural gas dehydrator with uncontrolled actual VOC emissions of 2 tons per year or greater that is located at a facility where the sum of uncontrolled actual emissions from all of the dehydrators at the facility is greater than 15 tons per year, must be equipped with a control device that reduces emissions by at least 90%. Under the Division's proposal, all existing dehydrators with uncontrolled actual emissions of 6 tons per year or greater VOC must be controlled with air pollution control equipment achieving at least 95% reduction. The proposal also provides that existing dehydrators with uncontrolled actual emissions of two tons per year or greater VOC must be controlled if they are located within

1,320 feet of a building unit or designated outside activity area. Finally, the proposal requires that all new dehydrators with uncontrolled actual emissions of two tons per year or greater VOC be controlled. The Division assumes that newly subject glycol dehydrators will be controlled using flares that achieve a 95% destruction efficiency. The annual cost for these units is $6,286.80 per unit.

Based on industry reported APEN data, there are currently 433 uncontrolled dehydrators at sites with total dehydrator uncontrolled actual VOC emissions below 15 tpy. Of these, 217 have uncontrolled actual emissions greater than or equal to two tons per year. The total uncontrolled actual emissions for these 217 dehydrators are 1,827.5 tpy VOC. There are 148 dehydrators with uncontrolled actual VOC emissions greater than or equal to 6 tons per year. The total uncontrolled actual emissions for these 148 dehydrators are 1,549.7 tpy VOC. Currently, the Division does not have information regarding the location of these uncontrolled dehydrators relative to a building unit or designated outside activity area. Assuming, however, that all of the 2 to 6 ton dehydrators are located within 1,320 feet of a building unit or designated outside activity area and thus will require a control, the proposed requirement will reduce 1,736 tpy of VOC at a cost effectiveness of $786/ton VOC. For the smallest dehydrator subject to the proposed rule (2 ton/year) the cost effectiveness is estimated to be $3309 per ton of VOC reduced.

Table 41: Dehydrator Control Cost Estimates (2 TPY Control Threshold)

Number	Each Device Annualized Costs	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
217	$6,286.8	$1,364,236	1,736	$786

Conversely, if it is assumed that none of the 2 to 6 ton existing dehydrators will require controls the proposed requirement will reduce 1,472 tpy of VOC at a cost effectiveness of $632/ton VOC.

Table 42: Dehydrator Control Cost Estimates (6 TPY Control Threshold)

Number	Each Device Annualized Costs	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
148	$6,286.8	$930,446	1,472	$632

3.3.8.5 Control Requirements for Downhole Well Maintenance and Liquids Unloading Events

Historically, Colorado has not regulated air emissions from temporary activities such as well completions and well maintenance at well production sites. Recently, however, EPA, Colorado and other jurisdictions have identified these activities as potentially large sources of emissions from the oil and gas sector. In recognition of this, the Colorado Oil and Gas Conservation Commission and more recently EPA have adopted requirements for green completions to reduce hydrocarbon emissions during well completion activities. The Division is now proposing additional regulatory requirements designed to reduce emissions during well maintenance.

Well maintenance is required when, over time, liquids build up inside the well and reduce gas and oil flow out of the well. To remove these liquids and improve flow, the liquids are blown out of the well under pressure. This process is typically referred to as liquids load-out or well blow-down. Historically emissions from well blow-downs are vented to the atmosphere. EPA has established emission factors for liquid unloading based on fluid equilibrium calculations to calculate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blow-down. Based on its calculations, EPA estimated that in the United States the combined methane emissions for liquid unloading and well completions in 2009, was 217 billion cubic feet, and that liquid unloading may account for 33% of the uncontrolled methane emissions from the natural gas industry.[54] For Colorado, the Division has calculated that emissions from well blow-downs in 2008 were approximately 9,306 tons of VOC per year.

To address these emissions, the Division is proposing a two pronged requirement aimed at reducing the number of required liquids unloading events and reducing the amount of emissions vented to the atmosphere during these events. Under the Division's proposal operators shall use best management practices to minimize the need for venting associated with downhole maintenance and liquids unloading. For example, EPA's Gas Star program advocates the use of a plunger lift system to reduce the need for liquids unloading. According to EPA, use of a plunger lift will on average pay for itself in less than one year through the capture of additional product. The Division's proposal also provides that emissions during well maintenance and liquids unloading shall be captured or controlled using best management practices to limit venting during well blow-downs to the maximum extent practicable. Based on information provided by Environmental Defense Fund, application of these requirements could result in annual VOC reductions of 2,881 tons and methane reductions of 19,207 tons per year. Given the wide variety of practices that this could entail, the Division currently does not have information about the precise cost-effectiveness of this provision. Given the fact that 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.

4 CLOSING SUMMARY

On December 13, 2013, interested parties, stakeholders and state representatives filed requests for a Regulatory Analysis. This Regulatory Analysis is a careful and considerate response to those Requests and is a good faith effort on the part of the Division.

The Division has addressed, to the best of its ability, issues related to the entirety of proposed revisions to Regulation 3, 6, and 7. The Division believes that the proposal before the Commission reflects a balanced approach that includes proven and cost effective strategies to reduce emissions from the oil and gas sector, while enabling the sector to continue to grow in a responsible and protective manner. The Division looks forward to the Commission's consideration of its proposal and alternate proposals of other parties at the February 2014 hearing.

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[54] See EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2009*, April, 2011.

FINAL

ECONOMIC IMPACT ANALYSIS

For Industry's Proposed Revisions to
Colorado Air Quality Control Commission
Regulation Number 3, 6, and 7 (5 CCR 1001-9)

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January 30, 2014

JIWG-REB EX. B

Table of Contents

Executive Summary

This document provides an economic analysis of the proposed revisions to Colorado Air Quality Control Commission (AQCC) Rules. This analysis is focused on specific parts of the regulations, including the costs for flares and auto-igniters, pneumatic controllers, storage tank emission management (STEM), and LDAR for well production facilities and compressor stations. Louis Berger has also estimated the value of the product saved as a result of the LDAR programs for well production facilities and compressor stations. Additionally, Louis Berger analyzed the impacts to marginally producing wells as they become less economically viable and are shut in or plugged as regulatory costs increase, resulting in loss of production, operator revenues, royalties, and severance taxes. Finally, Louis Berger provides estimates on the costs to the state to implement the proposed rules and regulations. This document also provides support for industry's proposed language.

Economic Impact Analysis

Important results of the analysis are summarized in table ES-1 and described in the bullets below.

- Louis Berger estimated pollution control costs using information obtained from industry sources. Total costs to add flares and auto-igniters to tanks between 6 and 20 TPY uncontrolled VOC emissions are estimated to be $5.8 million, $511,680, and $7,872 for condensate, produced water, and crude oil tanks, respectively. Annualized costs of buffer bottles are estimated to be $5,850, with a total annual cost of $31.1 million.
- LDAR programs result in decreased emission reduction benefits after the initial year of program implementation. That is, after initial monitoring, leaks are found and fixed, resulting in reduced leak frequencies and emissions. These decreased leak frequencies in subsequent years affect the cost effectiveness of the regulations. As emissions reductions decline in subsequent years, LDAR annualized costs decrease by a smaller proportion; therefore, costs per ton of VOC reduced in subsequent years are significantly higher in subsequent years compared to the initial year of implementation. Figure ES-1 shows how the emission reductions decline while LDAR costs per ton of VOC increase after the initial year. This figure also demonstrates the disparity in costs for the facilities with differing levels of uncontrolled emissions, with lower emitting tanks having a much higher cost per ton of VOC reduced than the higher emitting tanks.

Table ES-1: Summary of Louis Berger Final EIA Results in Comparison to the Division's Updated EIA Estimates

Item	Louis Berger Estimate			Division Estimate		
	Total Annual Cost	Per Facility/ Tank Costs	Cost Per Ton of VOC Reduced	Total Annual Cost	Per Facility/ Tank Costs	Cost Per Ton of VOC Reduced
Lowering Threshold for Flares and Auto Igniters for Tanks						
Condensate Tanks	$5.8M	$9,840	$988	$3.7M	$6,287	$716
Produced Water Tanks	$511,680	$9,840	$1,121	$326,914	$6,287	$715
Crude Oil Tanks	$78,720	$9,840	$670	$50,294	$6,287	$427
Storage Tank Emission Management Plan (buffer bottle and inspections)						
Buffer Bottle	$31.1M	$5,850	-	$21.0M	$3,949	$391
Initial Year STEM Costs (with buffer bottle)						
6 to 12 TPY	$16.2M	$11,453	$4,800	$5.6M	$4,147	NA
12 to 50 TPY	$39.9M	$13,669	$1,945	$13.8M	$4,741	NA
Greater than 50	$21.0M	$21,433	$555	$6.2M	$6,325	NA
Total	**$77.1M**	**$14,509**	**$1,250**	**$25.6M**	**$4,875**	**$4,800***
Subsequent Year STEM Costs (with buffer bottle)						
6 to 12 TPY	$16.0M	$11,324	$20,172	$5.6M	$4,147	NA
12 to 50 TPY	$38.5M	$13,164	$7,960	$13.8M	$4,741	NA
Greater than 50	$19.5M	$19,903	$2,192	$6.2M	$6,325	NA
Total	**$73.9M**	**$13,915**	**$5,097**	**$25.6M**	**$4,875**	**$4,800***
LDAR for Well Production Facilities						
Initial Year LDAR Costs						
Less than 6 TPY	$19.8M	$6,995	$3,629	$1.3M	$470	NA
6 to 12 TPY	$9.8M	$6,962	$3,611	$663,993	$470	$256
12 to 50 TPY	$56.2M	$19,227	$9,818	$5.5M	$1,881	$682
Greater than 50	$50.9M	$51,999	$25,390	$5.5M	$5,643	$1,533
Total	**$136.7M**	**$16,778**	**$8,590**	**$13.0M**	**$1,598**	**$819**
Subsequent Year LDAR Costs						
Less than 6 TPY	$3.0M	$1,051	$5,454	$1.3M	$470	NA
6 to 12 TPY	$6.3M	$4,452	$9,815	$663,993	$470	$256
12 to 50 TPY	$27.3M	$9,336	$20,261	$5.5M	$1,881	$682
Greater than 50	$21.6M	$22,097	$45,855	$5.5M	$5,643	$1,533
Total	**$58.2M**	**$7,138**	**$19,354**	**$13.0M**	**$1,598**	**$819**
LDAR Costs for Compressor Stations						
Initial Year LDAR Costs						
Less than 12TPY	$3,873,936	$26,353	$3,465	$154,262	$1,049	$260
12 to 50 TPY	$11,532,775	$217,599	$17,344	$589,763	$11,128	$1,131
Greater than 50	-	-	-	-	-	-
Total	**$15,406,710**	**$77,033**	**$8,641**	**$744,025**	**$3,720**	**$667**
Subsequent Year LDAR Costs						
Less than 12TPY	$2,020,457	$13,745	$7,681	$154,262	$1,049	$260
12 to 50 TPY	$4,446,685	$83,900	$28,421	$589,763	$11,128	$1,131
Greater than 50	-	-	-	-	-	-
Total	$6,467,142	$32,336	$15,416	$744,025	$3,720	$667
Value of Product Savings – Initial Year						
Well Production Facilities	$12.4M	$1,532	-	NA	NA	NA
Compressor Station – Initial Year	$1.3M	$6,993	-	NA	NA	NA
Value of Product Savings – Subsequent Years						
Well Production Facilities	$2.3M	$289	-	NA	NA	NA
Compressor Stations	$329,453	$1,647	-	NA	NA	NA
Division Implementation Costs of Proposed Rules						
Hours	12,282			0		
FTE	6.1			0		

*Calculated based on the emission reductions associated with the STEM Control Analysis on page 12 of Division's Updated EIA.

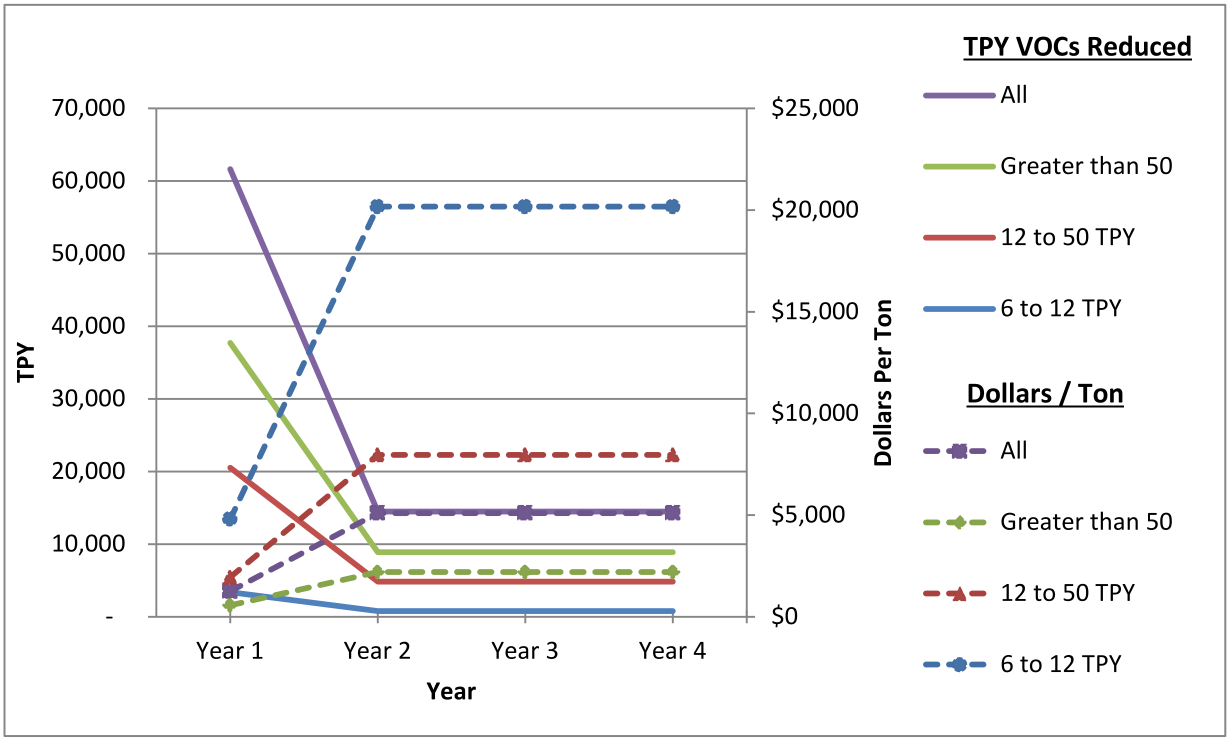

Figure ES-1: STEM Emission Reductions and Cost Per Ton of VOC Reduced

- STEM costs are estimated to be $77.1 million in the initial year and $73.9 million in subsequent years, while the cost per ton of VOC reduced is $1,250 in the initial year and $5,097 in subsequent years, on a recurring annual basis.
- Inspections and LDAR programs are more expensive to implement in the attainment area in comparison to the relatively dense operations in the non-attainment area due to the additional travel time, travel expenses, and fewer inspections possible on an annual basis in the attainment area. The STEM costs show that across all tank levels, the attainment area tanks have $1,000 higher costs per tank per year than in the non-attainment area to implement this program. Similar results occur for well production facilities, with LDAR costs per facility in the initial year higher in the attainment area than non-attainment area for each level of monitoring required.
- LDAR costs for well production facilities are considerable, with initial year costs of $136.7M ($16,778 per facility) and subsequent recurring annual costs of $58.2 million ($7,138 per facility). The cost per ton of VOC reduced is $8,590 in the initial year and $19,354 in the subsequent years on an annual recurring basis.
- LDAR costs for compressor stations are $15.4 million in the initial year ($77,033 per compressor station) and subsequent recurring annual costs of $6.5 million ($32,336 per compressor station). The cost per ton of VOC reduced is $8,641 in the initial year and $15,416 in the subsequent years on an annual recurring basis.
- The total cost to expand the regulatory mandate to modify or retrofit high-bleed pneumatic devices statewide was estimated to be $32 million. This includes the cost to replace an

estimated 9,800 high-bleed devices that are located at facilities outside the nonattainment area. When considering the amount of gas that can be recovered with the low-bleed devices, payback of the costs are expected to occur within 2.8 years. .

- Louis Berger estimated the product savings that can be expected from LDAR requirements for well production facilities and compressor stations. In the initial year, the value of the product captured represents approximately 8.7 percent of the LDAR costs. In subsequent years, the value of the natural gas captured represents 4 and 5 percent of the LDAR costs in subsequent years for well production facilities and compressor stations, respectively. The Economic Impact Analysis requires an assessment of the cost for the Division to implement the proposed rule changes. Oversight of an LDAR program, STEM plans, and annual report review of 5,312 tank batteries, 5,312 well production facilities, and 200 compressor stations with possibly hundreds of thousands of components would require additional Division manpower. Louis Berger reviewed the revised (November 21, 2013) Regulations 3, 6 and 7 to understand the implementation costs to the Division associated with the new rules. The net increase in the number of labor hours at the Division as result of the proposed regulations is anticipated to be approximately 12,282 labor hours annually. Notably, the Division would need 5,600 hours to review and approve initial STEM plans required under Regulation 7, the largest estimated time commitment for the Division. This represents approximately 6.1 FTEs of additional staff for the Division to review, oversee, inspect, manage, and approve various requirements associated with the proposed rules. Therefore, Louis Berger concludes that the Division would incur additional net costs to implement the proposed requirements beyond current expenditures.

In order to gain an understanding of the potential indirect costs to businesses, in particular small businesses if the proposed rules were implemented, Louis Berger evaluated the impacts on small, marginally producing wells within the state. Marginally producing wells with production less than 2 BOPD represent over half (55 percent) of the total producing wells in the state (46,495) as of 2013. Under current economic and regulatory conditions, the economic limit for marginally producing wells was estimated to be 0.43 BOPD, which is the point at which revenues would no longer cover operating expenses and the well would be shut in. Additional operating costs associated with the proposed rules were estimated per well production facility and tank and included in the analysis. Over time, the additional cost burden would result in as much as 128.6 million barrels of oil being left in place and not produced. The calculated present values for these losses include $1.9 billion in lost revenue to producers, $384 million in lost royalties and $96 million in lost severance taxes.

- Support of Industry's Proposed Language

The results of the final economic impact analysis presented here support the industry's key suggested revisions to the Division's proposed rule. Specifically, the proposed revisions will allow similar emission reductions to be achieved in a cost effective, achievable, and reasonable manner. Key points to the analysis include:

- Diminishing marginal benefits associated with LDAR programs implies decreasing cost effectiveness after initial rounds of inspections and repairs. Reducing the monitoring to reflect successful LDAR implementation reduces costs and improves the cost effectiveness of the proposed rule compared to the Division's proposal while maintaining program integrity through realized emission reductions. The "step-down" of monitoring frequency, which rewards companies with four inspections with no leaks, is an example of how the industry changes to the proposed rule would provide incentives for industry to maintain compliance and reduce costs for good behavior.

- Generally, compliance costs of STEM and LDAR for small tanks and well production facilities are more burdensome than for larger facilities on a cost per ton basis. As such, requiring a one-time LDAR inspection and monthly AVO for all facilities (including all well production facilities) with uncontrolled emissions between 2 and 6 TPY would improve the overall cost effectiveness of the proposed rule by limiting the very high costs per ton of VOC reduced incurred by very small facilities with very small VOC fugitive emissions.
- Compliance costs are higher for operations outside of the non-attainment area as the distance among facilities and tanks increases inspection travel time and expenses. Limiting the geographic scope to the non-attainment area will improve the cost effectiveness of the proposed rule.
- Allowing for the use of other established technology, such as the tunable diode laser absorption spectroscopy technology (TDLAS) as an option for inspection monitoring, would reduce costs to industry with faster inspections and reduced camera training requirements, among other factors.

Economic Impact Analysis

This document provides an economic analysis of the proposed revisions to Colorado Air Quality Control Commission (AQCC) Regulation Number 3, 6 and 7. This analysis is focused on the specific parts of the regulation, including the costs for flares and auto-igniters, STEM, LDAR for well production facilities and compressor stations, and pneumatic controllers. Louis Berger has also estimated the value of the product saved as a result of the LDAR programs for well production facilities and compressor stations. Additionally, Louis Berger analyzed the impacts to marginally producing wells as they become less economically viable and are shut in or plugged as compliance costs increase resulting in a loss of production, operator revenues, royalties, and severance taxes. Finally, Louis Berger provided estimates on the costs to the state to implement the proposed rules and regulations.

Lowering Statewide Tank Control Threshold (from 20 tpy to 6 tpy)

Louis Berger evaluated the costs to industry associated with installing flares and auto-igniters on condensate tanks with uncontrolled emissions between 6 TPY and 20 TPY. The analysis used the state's estimate of 588 condensate tanks that that would be affected by the change in the regulatory threshold, along with updated costs estimated by the EPA and in the industry survey.

Louis Berger developed cost estimates for flares and auto-igniters using data and information obtained from an industry survey conducted in 2013 and data from the EPA. The capital, non-recurring and annual costs were obtained from the EPA.[1] Because the costs were reported in 2008 dollars they were escalated to 2013 dollars using the GDP price index obtained from the U.S. Office of Management and Budget.[2] These costs were annualized for an 11-year life of the equipment based on information obtained from the industry survey at a 5 percent interest rate. The annual cost for the flare is estimated to be $9,840 (Table 1).

Table 1: Estimated Cost for Flares and Auto-Igniters

Item	Estimated Cost (2013$)
Capital and Non-Recurring Cost	$35,070
Annual Costs	$5,823
Annualized Capital Costs	$4,018
Total Annual Costs	**$9,840**

The Division estimated the cost per ton of VOC emission reductions by lowering the statewide tank control threshold from 20 TPY to 6 TPY. According to the Division's analysis, there are 588 condensate tanks that would be affected by this rule change and that by adding flares to these particular tanks, VOC emissions would decline by 5,162 TPY. Louis Berger analyzed the cost of lowering the threshold from 20 tpy to 6 tpy using the flare cost estimate summarized above. The results are summarized in Table 2.

[1] EPA. 2011. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Technical Support Document for Proposed Standards.

[2] Office of Management and Budget. 2013. Fiscal Year 2014. Gross Domestic Product and Deflators Used in Historic Tables. Table 10.1. Available: http://www.whitehouse.gov/sites/default/files/omb/budget/fy2014/assets/hist.pdf

When the costs are separated by uncontrolled emissions, the differences are significant. For tanks with lower uncontrolled emissions (6 to 10 TPY), the control costs are double what they are for the higher emitting tanks (between 10 and 20 TPY). Average cost per ton of VOC reduced is estimated to be $1,121.

Table 2: Estimated Cost Per Ton of VOCs Reduced for Condensate Water Tanks

Uncontrolled Emissions	Number of Tank Batteries Affected	Average Uncontrolled Emissions per tank	Total Uncontrolled Emissions	Emission Reduction with Flare and Auto-Igniter	Total Cost of Flares Per Tank Category	Cost Per Ton of VOC Reduced Per Tank Category
(1)	(2)	(3)	(4) = (3) * (2)	(5) = (4) * 0.7125	(6) = (2) * $9,840	(7) = (6)/(5)
6 to 10	235	7.35	1,729	1,232	$2,314,368	$1,879
10 to 20	353	13.98	4,932	3,514	$3,471,552	$988
Total Affected (State Estimate)	**588**	**12.32**	**7,244**	**5,161**	**$5,785,920**	**$1,121**

Using the same logic and data as described for condensate tanks, the controls for produced water tanks and crude oil tanks yields the following results. According to the Division's analysis, there are 52 produced water tanks and 8 crude oil tanks. Louis Berger believes that there are considerably more crude oil tanks than are reported in the APEN. However, without additional data, Louis Berger used the Division's estimate of 8. Cost per ton of VOC reduced for produced water and crude oil tanks are estimated to be $1,121 and $670, respectively.

Table 3: Estimated Cost Per Ton of VOCs for Produced Water Tanks

Uncontrolled Emissions	Number of Produced Water Tanks Affected	Average Uncontrolled Emissions per tank	Total Uncontrolled Emissions	Emission Reduction with Flare and Auto-Igniter	Total Cost of Flares Per Tank Category	Cost Per Ton of VOC Reduced Per Tank Category
(1)	(2)	(3)	(4) = (3) * (2)	(5) = (4) * 0.7125	(6) = (2) * $9,840	(7) = (6)/(5)
Total Affected (State Estimate)	**52**	**12.32**	**641**	**456**	**$511,680**	**$1,121**

Table 4: Estimated Cost Per Ton of VOCs for Crude Oil Tanks

Uncontrolled Emissions	Number of Oil Tanks Affected	Average Uncontrolled Emissions per tank	Total Uncontrolled Emissions	Emission Reduction with Flare and Auto-Igniter	Total Cost of Flares Per Tank Category	Cost Per Ton of VOC Reduced Per Tank Category
(1)	(2)	(3)	(4) = (3) * (2)	(5) = (4) * 0.7125	(6) = (2) * $9,840	(7) = (6)/(5)
Total Affected (State Estimate)	**8**	**20.62**	**165**	**118**	**$78,720**	**$670**

Emission Capture Requirements for Controlled Petroleum Storage Tanks

This section of the analysis evaluates requirements under the Storage Tank Emissions Management (STEM) plan, including costs of adding a buffer bottle and implementing a LDAR program. With data collected from the industry survey conducted in 2013, Louis Berger estimated an annual cost for buffer bottles of $5,850, as described in Table 5.

Table 5: Estimated Cost for Buffer Bottles

Item	Estimated Cost (2013$)
Capital and Non-Recurring Cost	$25,000
Annual O&M Costs	$2,500
Annualized Capital Costs*	$3,350
Total Annual Costs	**$5,850**

*Capital costs and non-recurring costs were annualized over 9 years, the estimate life of the control technology.

The STEM program would require instrument based monitoring. The monitoring frequency would be based on the uncontrolled emissions of various tanks as reported in the APEN database. Louis Berger estimated the LDAR costs using data and information obtained through an operator survey and follow up interviews. Table 6 summarizes the cost assumptions for the analysis.

Table 6: STEM Cost Assumptions for Tanks (2013$)

	LDAR			AVO		
Item	**Estimated Cost**	**Annualized***	**Unit Cost**	**Estimated Cost**	**Annualized***	**Unit Cost**
Capital and Non-Recurring Costs						
Camera	$122,000	$28,179	$46.96/inspection in NAA $70.45/inspection in the AA			
Vehicle	$30,000	$6,929	$11.54/inspection in the NAA $17.32/inspection in the NAA			
Program set up costs (i.e., Tagging, software, travel, etc.)	$1,000	$231	$231/Tank	$500	$115.49	$115.49/ tank
Inspection, Operations and Maintenance costs						
Assume one camera can inspect 2 tanks a day in the AA, 400 tanks/year; 3 tanks per day in the NAA, 600 tanks/year; 10 weeks for repair and training. Assume weekly inspections for all tanks over 6 TPY.						
Inspection Labor, including travel time Hourly Rate: Inspection and Travel Time (NAA and crude) Inspection and Travel Time (AA)	$150 3 4		$150/hour 4.75 hours 5.75 hours	$100 .5 .5		$100/Hour 0.5 Hours 0.5 Hours
Camera/Inspection training	$7,500		Per 100 Tanks	$7,500		$7,500/100 tanks/year
Camera repair	$12,500		Camera			$12,500/ camera/ year
Travel and per diem costs (NAA Condensate and Crude Oil) Travel and per diem costs (AA Condensate)	$30 $40		Inspection			$30/ inspection $40/ inspection
Supervision	$100 (annual, quarterly) $200 (monthly)		Tank			$100/tank/ year $200/tank/ year
Compiling data, record-keeping and reporting	$1,530 (annual, quarterly) $3,060 (monthly)		Tank			$1,530/ tank/year $3,060/ tank/year

*Camera and set up costs annualized at 5% over 5 year-life of the equipment.

Louis Berger estimated the repair costs using information from a Canadian study and a Trihydro report that provide estimates of the number of components, potential number of leaks, and average leak frequency for production tanks.[3] Louis Berger assumed for this cost estimate that the typical production tank in Colorado has 38 components (Clearstone Engineering 2013) with an initial leak rate of 1.7 percent (Trihydro 2014), which equates to 0.65 components discovered leaking during each inspection. The Trihydro report indicates that subsequent leak frequencies associated with quarterly LDAR drop to 0.4 percent (0.15 leaking components per production tank), which was used to estimate the number of leaks repaired and re-monitored in subsequent years. Costs to repair components were obtained from Nelson and Brown (2012) and include only the labor needed to repair the leak, not materials and equipment costs.[4] Data and cost assumptions for the repair and re-monitoring costs are summarized in table 7. The re-monitoring cost was assumed to apply to the 25 percent of leaks, and the inspection and travel costs were obtained from the operator survey, with a cost estimate of $480 per inspection in the non-attainment area and $640 in the attainment area.

Table 7: Repair and Re-monitoring Cost Assumptions

Percent of Leaks	Type of repair	Repair Time (hours)	Hourly Rate	Re-monitor Cost (per leak)
75%	On-line	1	$75	-
25%	On the ground	4	$75	$480 (NAA) $640 (AA)

The total estimated cost of the proposed STEM program, which includes the costs for the inspections and the buffer bottles, are summarized in the following two tables. Total STEM costs include annualized capital costs, recurring inspection, operations, and maintenance costs, buffer bottle costs, repair costs, and re-monitoring costs. Total costs for all storage tanks are estimated to be $77.1 million, of which the non-attainment area tanks account for $64.1 million. When comparing the costs per condensate tank in the attainment area and non-attainment area over all the different types of tanks, costs per tank in the attainment area are approximately $1,000 higher than tanks in the non-attainment. The higher costs in the attainment area due to longer travel times and per diem costs, as ability to perform fewer inspections on an annual basis. For the greater than 50 TPY tanks, the STEM costs are $23,676 per tank in attainment area compared with the non-attainment area STEM costs of $20,966 per tank. The STEM costs are provided in Tables 8.1 and 8.2.

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[3] Clearstone Engineering, Ltd. 2013. Technical Report: Draft Update of Fugitive Equipment Emissions Factors. Prepared for the Canadian Association of Petroleum Producers. August. See Tables 5 and 12.
Trihydro Corporation. 2014. Colorado Regulation/Litigation Support. Prepared for WPX Energy, Inc. January 6.

[4] Nelson, Bradley and Heather Brown. 2012. Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Use Emission and Cost Data from the Uniform Standards. Memorandum to Greg Nizich and Bruce Moore, EPA. April

Table 8.1: Initial Year STEM Cost Analysis, Part 1

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Number of Storage Tanks and Crude Oil Tanks	Number of inspections/ Year	Capital Costs for Inspections (annualized) (1)	Annual Costs for Inspections, O&M (2)	Number of Cameras Needed
Crude Oil Tanks						
6 to 12 TPY	annually	23	23	$9,314	$114,080	-
12 to 50 TPY	quarterly	5	20	$2,903	$32,000	-
Greater than 50	monthly	14	168	$14,681	$178,680	1
Total	-	**42**	**211**	**$26,898**	**$324,760**	**1**
Attainment Area Condensate Tanks						
6 to 12 TPY	annually	325	325	$141,125	$1,676,500	1
12 to 50 TPY	quarterly	323	1,292	$225,305	$2,323,920	4
Greater than 50	monthly	165	1,980	$230,950	$2,337,850	5
Total	-	**813**	**3,597**	**$597,381**	**$6,338,270**	**10**
Non-Attainment Area Condensate Tanks						
6 to 12 TPY	annually	1,065	1,065	$431,297	$5,307,400	2
12 to 50 TPY	quarterly	2,593	10,372	$1,505,272	$16,820,200	18
Greater than 50	monthly	799	9,588	$837,847	$9,684,130	16
Total	-	**4,457**	**21,025**	**$2,774,416**	**$31,811,730**	**36**
All Tanks						
6 to 12 TPY	annually	1,413	1,413	$581,736	$7,097,980	3
12 to 50 TPY	quarterly	2,921	11,684	$1,733,480	$19,176,120	22
Greater than 50	monthly	978	11,736	$1,083,478	$12,200,660	22
Total	-	**5,312**	**24,833**	**$3,398,695**	**$38,474,760**	**47**

Table 8.2: Initial Year STEM Cost Analysis, Part 2

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Buffer Bottle Costs (3)	Annual Number of Leaks	Leak Repair Costs (4)	Re-monitoring Cost (5)	Total Initial Year STEM Costs for Tanks (1+2+3+4+5)	Per Tank Cost for Initial Year
Crude Oil Tanks							
6 to 12 TPY	annually	$134,545	15	$1,950	$1,783	$261,672	$11,377
12 to 50 TPY	quarterly	$29,248.83	13	$1,696	$1,550	$67,398	$13,480
Greater than 50	monthly	$81,897	109	$14,244	$13,023	$302,525	$21,609
Total	-	**$245,690**	**136**	**$17,890**	**$16,357**	**$631,595**	**$15,038**
Attainment Area Condensate Tanks							
6 to 12 TPY	annually	$1,901,174	210	$27,556	$33,592	$3,779,946	$11,631
12 to 50 TPY	quarterly	$1,889,474	835	$109,545	$133,541	$4,681,786	$14,495
Greater than 50	monthly	$965,211	1,279	$167,879	$204,653	$3,906,544	$23,676
Total	-	**$4,755,859**	**2,324**	**$304,981**	**$371,786**	**$12,368,276**	**$15,213**
Non-Attainment Area Condensate Tanks							
6 to 12 TPY	annually	$6,230,000	688	$90,299	$82,559	$12,141,554	$11,401
12 to 50 TPY	quarterly	$15,168,441	6,700	$879,416	$804,037	$35,177,366	$13,566
Greater than 50	monthly	$4,673,962	6,194	$812,943	$743,262	$16,752,144	$20,966
Total	-	**$26,072,403**	**13,582**	**$1,782,657**	**$1,629,858**	**$64,071,064**	**$14,375**
All Tanks							
6 to 12 TPY	annually	$8,265,719	$913	$119,805	$117,934	$16,183,172	$11,453
12 to 50 TPY	quarterly	$17,087,164	$7,548	$990,657	$939,128	$39,926,550	$13,669
Greater than 50	monthly	$5,721,070	$7,582	$995,066	$960,938	$20,961,213	$21,433
Total	-	**$31,073,952**	**$16,042**	**$2,105,528**	**$2,018,001**	**$77,070,935**	**$14,509**

As a result of initial implementation of a LDAR program, it has been shown that leak frequencies decrease from 1.7 percent to 0.4 percent (Trihydro 2014). Therefore, in subsequent years, the number of leaks was adjusted to reflect the reduced leak frequency. The reduced leak repair and re-monitoring costs with the adjusted number of leaks were estimated and shown in table 9. It is assumed that subsequent LDAR and AVO capital (annualized), recurring annual, and annualized buffer bottle costs would remain as estimated in the initial year (table 8), while the number of repairs and re-monitoring needed would fall as the leak rate frequency also falls in subsequent years (table 9). The total STEM costs for subsequent years, shown in table 9, include the capital, inspection and O&M costs, and buffer bottle costs in table 8, with the adjusted leak repair and re-monitoring costs in table 9.

Table 9: Subsequent Year STEM Cost Analysis

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Number of Storage Tanks and Crude Oil Tanks	Annual Number of Leaks	Leak Repair Costs (4)	Re-monitoring Cost (5)	Total Subsequent Year STEM Costs for Tanks (Annual Cost) (1+2+3+4+5)	Per Tank Cost in Subsequent Years (Annual Cost)
Crude Oil Tanks							
6 to 12 TPY	annually	23	3	$459	$420	$258,817	$11,253
12 to 50 TPY	quarterly	5	3	$399	$365	$64,915	$12,983
Greater than 50	monthly	14	26	$3,352	$3,064	$281,673	$20,120
Total	**-**	**42**	**32**	**$4,209**	**$3,849**	**$605,406**	**$14,414**
Attainment Area Condensate Tanks							
6 to 12 TPY	annually	325	49	$6,484	$7,904	$3,733,186	$11,487
12 to 50 TPY	quarterly	323	196	$25,775	$31,421	$4,495,896	$13,919
Greater than 50	monthly	165	301	$39,501	$48,154	$3,621,666	$21,949
Total	**-**	**813**	**547**	**$71,760**	**$87,479**	**$11,850,749**	**$14,577**
Non-Attainment Area Condensate Tanks							
6 to 12 TPY	annually	1,065	162	$21,247	$19,426	$12,009,369	$11,276
12 to 50 TPY	quarterly	2,593	1,577	$206,921	$189,185	$33,890,019	$13,070
Greater than 50	monthly	799	1,457	$191,281	$174,885	$15,562,105	$19,477
Total	**-**	**4457**	**3,196**	**$419,449**	**$383,496**	**$61,461,493**	**$13,790**
All Tanks							
6 to 12 TPY	annually	1,413	214	28,190	27,750	$16,001,372	$11,324
12 to 50 TPY	quarterly	2,921	1,776	233,095	220,971	$38,450,830	$13,164
Greater than 50	monthly	978	1,784	234,134	226,103	$19,465,444	$19,903
Total	**-**	**5,312**	**3,775**	**495,418**	**474,824**	**$73,917,648**	**$13,915**

To better understand the costs per ton of VOCs reduced across the different levels of uncontrolled emissions, Louis Berger queried data from the APEN database provided by the Division to identify the uncontrolled emissions for the various tanks which is summarized in table 10.[5]

[5] The following Exhibits were analyzed on the state's rulemaking ftp site: APCD-PHS EX TT (produced water tanks), APCD-PHS-EX-LL (condensate tanks), APCD -PHS- EX - MM (crude oil tanks), APCD-PHS EX- (STEM emission control).

Table 10: Uncontrolled Emissions for Tanks

Tank Uncontrolled VOC Emissions	Monitoring frequency	Number of storage tanks and crude oil tanks	Uncontrolled VOC emissions per tank (TPY)	Total uncontrolled VOC emissions (TPY)
Crude Oil Tanks				
6 to 12 TPY	annually	23	8.70	200
12 to 50 TPY	quarterly	5	25.80	129
Greater than 50	monthly	14	268.63	3,760
Total	**-**	**42**	**97.38**	**4,090**
Attainment Area Condensate Tanks				
6 to 12 TPY	annually	325	8.62	2,802
12 to 50 TPY	quarterly	323	22.41	7,237
Greater than 50	monthly	165	156.01	25,742
Total	**-**	**813**	**44.01**	**35,781**
Non-Attainment Area Condensate Tanks				
6 to 12 TPY	annually	1,065	8.77	9,341
12 to 50 TPY	quarterly	2,593	26.15	67,797
Greater than 50	monthly	799	135.99	108,656
Total	**-**	**4,457**	**41.69**	**185,794**

The approach used by Louis Berger for the initial emission reductions (year 1) is very similar to that of the Division's: the uncontrolled emissions less the control for the flares (71.25%) or 0.2876 percent of the uncontrolled emissions, times 95 percent. *Note that the Division's efficiency rate for the flare and auto-igniter of 71.25 percent is not supported by empirical data or industry literature, nor is it consistent with EPA guidance regarding the estimated effectiveness of such control requirements for air quality planning purposes[6]. These sources would suggest that the control efficiency of flares is considerably higher than the estimates by the Division, and the effectiveness of such control requirements is also higher (83% under EPA's noted revised rule effectiveness guidance, not 75%). As such, the emission reductions attributed to STEM in this analysis (as well as in the Division's analysis) are likely overestimated. The cost per ton of VOC reduced associated with STEM are therefore likely to be higher than estimated in this analysis due to the higher efficiency factor of the flare, with fewer fugitive emissions to capture with STEM.*

The initial year results reveal an average of $1,250 per ton of VOC reduced. Emission reductions in subsequent years are much smaller than initial reductions, especially with leak definitions as low as 500 and 2,000 PPM. The Clearstone study has indicated that annual leak detection and monitoring emissions factors result in a net reduction of 75.3 percent compared to what would occur without instrument monitoring.[7] This is consistent with Trihydro's estimated drop in leak rate frequencies after quarterly LDAR from 1.7 percent to 0.4 percent (Trihydro 2014). Louis Berger assumed that the emissions

[6] Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations, Appendix B, Doc.No. EPA-454/R-05-001 (August 2005).
[7] See Clearstone Engineering study previously cited, page 19.

reductions captured in subsequent years would be consistent with this decline in leak frequency. For example, if STEM was assumed to reduce emissions by 100 TPY in the initial year, the subsequent emissions reductions would be 23.5 percent (0.4/1.7) of the initial reduction.

It should be noted that the smaller tanks incur significantly larger costs per ton of VOC reduced. In the initial year, these costs per ton are $4,800 for tanks between 6 and 12 TPY uncontrolled emission, while tanks above 50 TPY, the initial year cost is $555 per ton reduced. Across all tanks, the subsequent year cost per ton of VOC reduced is approximately ***four times as high*** as the initial year cost, with the average cost in the subsequent years of $5,097 per ton of VOC reduced compared to the initial year cost per ton of VOC reduced of $1,250. This is due primarily to the effectiveness of the initial year LDAR in reducing fugitive emissions to a quarter of initial year rate. Despite the relatively higher travel and inspection costs in the attainment area, since the non-attainment area is where the overwhelming majority of tanks are located, there is not a considerable difference in the cost per ton of VOC reduced between these two geographic regions. However, as shown in Table 9, the tank STEM costs are more than $1,000 higher for attainment area tanks when compared to non-attainment tanks (for all tank uncontrolled emissions). Table 11 shows the initial year and subsequent total costs, emission reductions, and costs per ton of VOC reduced.

Figure 1 shows how the emission reductions decline after the initial year while LDAR costs per ton of VOC increase after the initial years. This figure also demonstrates the disparity in costs for facilities with different levels of uncontrolled emissions, with the lower emitting tanks having a much higher cost per ton of VOC reduced than higher emitting tanks. Over time, STEM for the tanks with the smallest uncontrolled emissions control the least amount of VOC emissions with the highest cost per ton of VOC ($20,172), while STEM for the tanks with the highest uncontrolled emissions capture the greatest amount of emissions and have the lowest cost per ton of VOC reduced ($2,192).

Table 11: STEM Costs Per Ton of VOC Reduced

Tank Uncontrolled VOC Emissions	STEM Costs	Emission Reduction from STEM	STEM Cost Per Ton of VOC Reduced	Annual STEM Costs	Emission Reductions	Recurring Annual Cost Per Ton of VOC Reduced
	Initial Year			Subsequent Years		
Crude Oil Tanks						
6 to 12 TPY	$261,672	55	$4,786	$258,817	13	$20,120
12 to 50 TPY	$67,398	35	$1,913	$64,915	8	$7,831
Greater than 50	$302,525	1,027	$295	$281,673	242	$1,165
Total	**$631,595**	**1,117**	**$565**	**$605,406**	**263**	**$2,303**
Attainment Area Condensate Tanks						
6 to 12 TPY	$3,779,946	765	$4,939	$3,733,186	180	$20,732
12 to 50 TPY	$4,681,786	1,977	$2,369	$4,495,896	465	$9,667
Greater than 50	$3,906,544	7,031	$556	$3,621,666	1,654	$2,189
Total	**$12,368,276**	**9,773**	**$1,266**	**$11,850,749**	**2,299**	**$5,154**
Non-Attainment Area Condensate Tanks						
6 to 12 TPY	$12,141,554	2,551	$4,759	$12,009,369	600	$20,006
12 to 50 TPY	$35,177,366	18,517	$1,900	$33,890,019	4,357	$7,778
Greater than 50	$16,752,144	29,677	$564	$15,562,105	6,9823	$2,229
Total	**$64,071,064**	**50,745**	**$1,263**	**$61,461,493**	**11,940**	**$5,148**
Total Tanks						
6 to 12 TPY	$16,183,173	3,371	$4,800	$16,001,372	793	$20,172
12 to 50 TPY	$39,926,549	20,529	$1,945	$38,450,830	4,830	$7,960
Greater than 50	$20,961,213	37,735	$555	$19,465,444	8,879	$2,192
Total	**$77,070,935**	**61,635**	**$1,250**	**$73,917,648**	**14,502**	**$5,097**

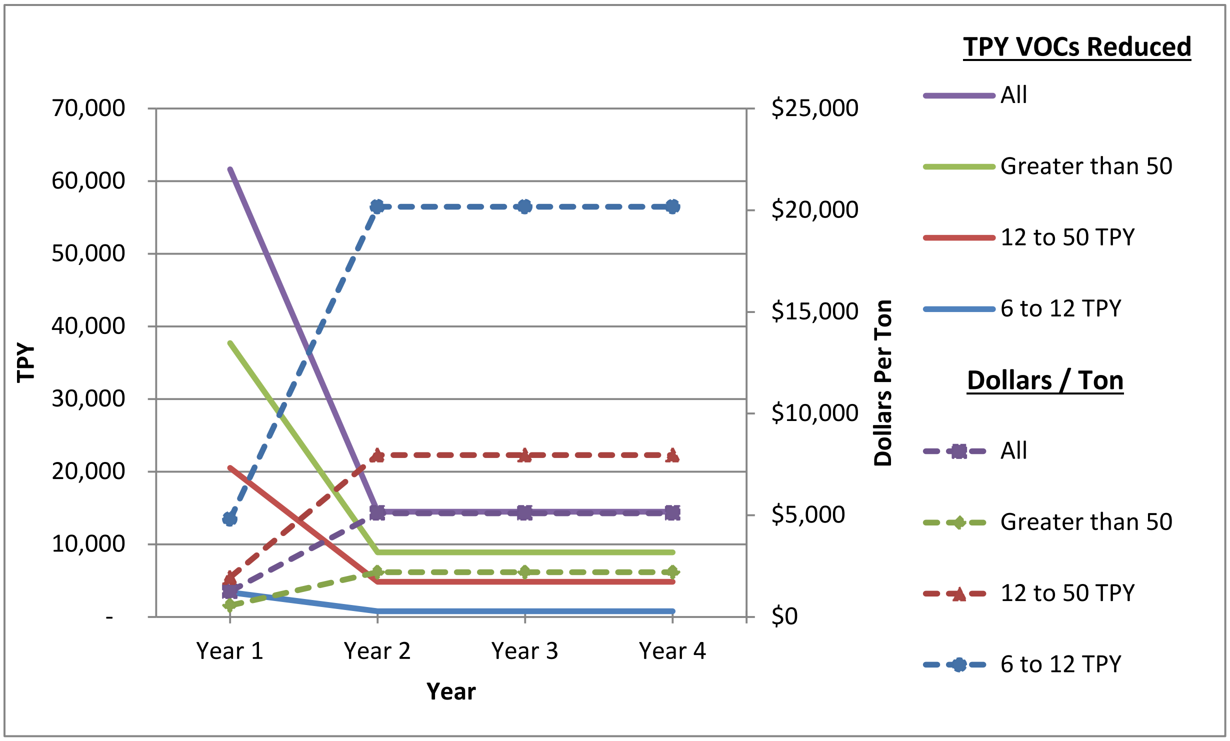

Figure 1: STEM Costs and Emission Reductions Over Time

Leak Detection and Repair Requirements for Well Production Facilities

The Division's proposed regulations include leak detection and repair requirements for well production facilities. The Division has based the LDAR monitoring frequency associated with these facilities on the uncontrolled VOC emissions with associated tanks. However, the Division's well production facility data (Exhibit RR) indicates that the tank VOC uncontrolled emissions do not correlate with fugitive emissions from well production facilities. The correlation coefficient is 0.19 indicating a weak positive correlation among the well production facilities and tank VOC uncontrolled emissions. For example, one tank had uncontrolled VOC emissions of 1,000 TPY, while the well production facilities accompanying the tank had a reported 2.4 TPY of VOC uncontrolled emissions. Regardless, the Division is requiring LDAR monitoring at various frequencies based on tank VOC uncontrolled emissions levels, and this section provides an estimate of the costs of these requirements to industry.

Louis Berger estimated LDAR inspection costs for well production facilities with a similar approach as described above for tanks. The Division has indicated that well production facilities would take on average 4.75 hours to inspect, which is consistent with Louis Berger's estimate of two facilities could be inspected per day in the non-attainment area. However, it is assumed that facilities in the attainment area would require an additional hour for travel time due to more remote operations and greater distance to access operations. Table 12 summarizes these assumptions for well production facilities.

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Table 12: Well Production Facility LDAR Cost Assumptions (2013$)

	LDAR			AVO		
Item	**Estimated Cost**	**Annualized***	**Unit Cost**	**Estimated Cost**	**Annualized***	**Unit Cost**
Capital and Non-Recurring Costs						
Camera	$122,000	$28,179	$70.45/inspection in the AA and NAA			
Vehicle	$30,000	$6,929	$17.32/inspection in the AA and NAA			
Program set up costs (i.e., Tagging, software, travel, etc.)	$1,000	$231	$231/WPF	$500	$115.49	$115.49/WPF
Inspection, Operations and Maintenance costs						
Assume one camera can inspect 2 well production facilities a day in the AA and NAA, 400 WPF/year; 10 weeks for repair and training. Assume monthly inspections for all tanks between 6 and 50 TPY.						
Inspection Labor, including travel time Hourly Rate: Inspection and Travel Time (NAA) Inspection and Travel Time (AA)	 $150 4.75 5.75		 $150/hour 4.75 hours 5.75 hours	 $100 .5 .5		 $100/Hour 0.5 Hours 0.5 Hours
Camera/Inspection training	$7,500		Per 100 WPF	$7,500		$7,500/100 WPF/year
Camera repair	$12,500		Camera			$12,500/ camera/ year
Travel and per diem costs (NAA Condensate and Crude Oil) Travel and per diem costs (AA Condensate)	$30 $40		Inspection			$30/inspection $40/inspection
Supervision	$100 (annual, quarterly) $200 (monthly)		WPF			$100/WPF/year $200/WPF/year
Compiling data, record-keeping and reporting	$1,530 (annual, quarterly) $3,060 (monthly)		WPF			$1,530/ WPF/year $3,060/ WPF/year

*Camera and set up costs annualized at 5% over 5 year-life of the equipment.

Similar to the storage tank analysis, data on costs to repair components for well production facilities were obtained from Nelson and Brown (2012).[8] The initial and subsequent year leak frequency rates were assumed to be 1.7 percent and 0.4 percent, respectively, consistent with the Trihydro report (2014) and Clearstone Engineering (2013) study. The number of components was consistent with the

[8] Nelson, Bradley and Heather Brown. 2012. Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Use Emission and Cost Data from the Uniform Standards. Memorandum to Greg Nizich and Bruce Moore, EPA. April. See attachments 3 and 4.

analysis in the EPA technical memorandum, based on the well pad model plant 2, with an average number of components of 592.[9] As shown in the Division's analysis of its 40 well production facilities (Exhibit RR), the uncontrolled emissions of the tanks do not correlate with the components and uncontrolled emissions of the well production facilities. Additionally, information on 40 well production facilities does not provide a representative sample of well production facilities across the state, accounting for facilities in only five counties. As a result, without further information on the well production facilities, we used a constant number of components and uncontrolled emissions factors for all the well production facilities based on the EPA technical report (2011), consistent with information obtained from communications with industry representatives.

LDAR costs for well production facilities for the first year were estimated by Louis Berger using the approach described above to be $136.7 million, of which 81 percent of the cost is attributed to well production facilities in the non-attainment area. For each of the various tank uncontrolled emissions levels, the costs per well production facility are greater in the attainment area when compared to those in the non-attainment area. However, when averaged across all the facilities, since there are more higher cost tanks (in the 12-50 TPY and over 50 TPY) in the non-attainment area than in the attainment area, the per well production facility cost is actually higher in the non-attainment area. The LDAR costs are summarized in Tables 13.1 and 13.2.

[9] EPA. 2011. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Technical Support Document for Proposed Standards. See Table 8.3.

Table 13.1: Well Production Facility LDAR Cost Analysis for the Initial Year, Part 1

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Number of WPF	Number of inspections/ Year	Capital Costs for Inspections (annualized) (1)	Annual Costs for Inspections (2)	Number of Cameras Needed
Attainment Area WPF						
Less than 6 TPY	One-time and monthly AVO	849	849	$368,662	$2,854,293	2
6 to 12 TPY	annually	328	328	$142,428	$1,105,560	1
12 to 50 TPY	quarterly	324	1,296	$226,003	$1,994,460	3
Greater than 50	monthly	169	2,028	$236,549	$2,456,385	5
Total	-	**1,670**	**4,501**	**$973,641**	**$8,410,698**	**11**
Non-Attainment WPF						
Less than 6 TPY	One-time and monthly AVO	1,986	1986	$862,381	$6,363,085	5
6 to 12 TPY	annually	1,085	1,085	$471,140	$3,479,663	3
12 to 50 TPY	quarterly	2,597	10,388	$1,811,512	$14,348,800	26
Greater than 50	monthly	809	9,708	$1,038,928	$8,900,035	25
Total	-	**6,477**	**23,167**	**$4,183,961**	**$33,091,583**	**59**
All WPF						
Less than 6 TPY	One-time and monthly AVO	2,835	2,835	$1,231,043	$9,217,378	7
6 to 12 TPY	annually	1,413	1,413	$613,568	$4,585,223	4
12 to 50 TPY	quarterly	2,921	11,684	$2,037,515	$16,343,260	29
Greater than 50	monthly	978	11,736	$1,275,477	$11,356,420	30
Total	-	**8,147**	**27,668**	**$5,157,602**	**$41,502,281**	**70**

Table 13.2: Well Production Facility LDAR Cost Analysis, Part 2

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Annual Number of Leaks	Leak Repair Costs (3)	Re-monitoring Cost (4)	Total Initial Year LDAR Costs for WPF (1+2+3+4)	Per WPF Cost for Initial Year
Attainment Area WPF						
Less than 6 TPY	One-time and monthly AVO	8,544	$1,121,444	$1,927,816	$6,272,214	$7,388
6 to 12 TPY	annually	3,301	$433,255	$744,786	$2,426,029	$7,396
12 to 50 TPY	quarterly	13,043	$1,711,886	$2,942,814	$6,875,164	$21,220
Greater than 50	monthly	20,410	$2,678,785	$4,604,959	$9,957,162	$58,918
Total	-	**45,298**	**$5,945,371**	**10,220,376**	**$25,530,568**	**$15,288**
Non-Attainment Area WPF						
Under 6 TPY	One-time and monthly AVO	19,987	$2,623,307	$3,710,106	$13,558,880	$6,827
6 to 12 TPY	annually	10,919	$1,433,177	$2,026,921	$7,410,900	$6,830
12 to 50 TPY	quarterly	104,545	$13,721,509	$19,406,134	$49,287,955	$18,979
Greater than 50	monthly	97,701	$12,823,297	$18,135,806	$40,898,067	$50,554
Total	-	**233,153**	**$30,601,290**	**$43,278,968**	**$111,155,802**	**$17,162**
All WPF						
Under 6 TPY	One-time and monthly AVO	28,531	$3,744,751	$5,637,922	$19,831,094	$6,995
6 to 12 TPY	annually	14,220	$1,866,432	$2,771,707	$9,836,929	$6,962
12 to 50 TPY	quarterly	117,588	$15,433,395	$22,348,948	$56,163,119	$19,227
Greater than 50	monthly	118,111	$15,502,082	$22,740,765	$50,855,229	$51,999
Total	-	**278,451**	**$36,546,661**	**$53,499,344**	**$136,686,370**	**$16,778**

Similar to the storage tank STEM analysis, following the initial implementation of a LDAR program, leak frequencies decrease, and as a result, the number of leaking components also decrease along with repair and re-monitoring costs, when compared to the initial year. Therefore, in subsequent years, the number of leaks was adjusted to reflect the reduced leak frequency (0.4%). As a result, reduced leak repair and re-monitoring costs with the adjusted number of leaks were estimated and shown in table 14. The total LDAR costs for subsequent years include the capital, and inspection and O&M costs in table 13 with the adjusted leak repair and re-monitoring costs in table 14. The exception is for well production facilities with tanks less than 6 TPY, which have been adjusted to include costs for a one-time LDAR inspection and monthly AVO.

Table 14: Subsequent Year LDAR Cost Analysis for Well Production Facilities

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Number of Well Production Facilities	Annual Number of Leaks	Leak Repair Costs (3)	Re-monitoring Cost (4)	Total Subsequent Year LDAR Costs for WPF (Annual Cost) (1+2+3+4)	Per WPF Cost in Subsequent Years (Annual Cost)
Attainment Area Well Production Facilities							
Less than 6 TPY	One-time with monthly AVO	849	4,021	$263,869	$0	$892,542	$1,051
6 to 12 TPY	annually	328	777	$101,942	$175,244	$1,525,174	$4,650
12 to 50 TPY	quarterly	324	3,069	$402,797	$692,427	$3,315,687	$10,234
Greater than 50	monthly	169	4,802	$630,302	$1,083,520	$4,387,239	$25,960
Total	**-**	**1,670**	**12,669**	**$1,662,780**	**$2,858,398**	**$10,120,642**	**$6,060**
Non-Attainment Area Well Production Facilities							
Less than 6 TPY	One-time with monthly AVO	1,986	9,406	$617,249	$0	$2,087,856	$1,051
6 to 12 TPY	Annually	1,085	2,569	$337,218	$476,923	$4,764,943	$4,392
12 to 50 TPY	quarterly	2,597	24,599	$3,228,590	$4,566,149	$23,955,051	$9,224
Greater than 50	monthly	809	22,989	$3,017,246	$4,267,248	$17,223,458	$21,290
Total	**-**	**6,477**	**59,562**	**$6,583,055**	**$11,056,253**	**$48,031,308**	**$7,416**
All Well Production Facilities							
Less than 6 TPY	One-time with monthly AVO	2,835	13,427	$881,118	$0	$2,980,398	$1,051
6 to 12 TPY	Annually	1,413	3,346	$439,160	$652,167	$6,290,117	$4,452
12 to 50 TPY	quarterly	2,921	27,668	$3,631,387	$5,258,576	$27,270,738	$9,336
Greater than 50	monthly	978	27,791	$3,647,549	$5,350,768	$21,610,697	$22,097
Total	**-**	**8,147**	**72,231**	**$8,245,834**	**$13,914,651**	**$58,151,950**	**$7,138**

To better estimate the potential uncontrolled emissions from these facilities, uncontrolled emission factors from the well pad model number 2 were used from the EPA technical document.[10] As described above, the tank uncontrolled emissions factors do not correlate with uncontrolled emissions associated with the well production facilities.[11] Additionally, the Division has utilized a very small sample of the well production facilities in the state for its analysis. As a result, Louis Berger used the VOC uncontrolled emissions per well production facility of 2.56 TPY associated with well pad model number 2 (592 components), which we believe more accurately reflects the types of facilities operating in Colorado based on communication with industry representatives. Table 15 summarizes the uncontrolled emissions for well production facilities.

[10] See EPA (2011) previously cited, tables 8-2, 8-3, and 8-10.
[11] See Division's analysis of 40 well production facilities in Exhibit RR in the rulemaking documents.

Table 15: Uncontrolled Emissions for Well Production Facilities

Uncontrolled VOC Emissions for Well Production Facilities	Monitoring Frequency	Number of Well Production Facilities	Uncontrolled VOC Emissions per Well Production Facility (TPY)	Total Uncontrolled VOC Emissions (TPY)
WPF in the Attainment Areas				
Less than 6 TPY	One time and AVO	849	2.560	2,173
6 to 12 TPY	annually	328	2.560	840
12 to 50 TPY	quarterly	324	2.560	829
Greater than 50	monthly	169	2.560	433
Total	-	**1,670**	-	**4,275**
WPF in the Non-Attainment Area				
Less than 6 TPY	One time and AVO	1,986	2.560	5,084
6 to 12 TPY	annually	1,085	2.560	2,778
12 to 50 TPY	quarterly	2,597	2.560	6,648
Greater than 50	monthly	809	2.560	2,071
Total	-	**6,477**	-	**16,581**
All WPFs				
Less than 6 TPY	One time and AVO	2,835	2.560	7,257
6 to 12 TPY	annually	1,413	2.560	3,618
12 to 50 TPY	quarterly	2,921	2.560	7,477
Greater than 50	monthly	978	2.560	2,504
Total	-	**8,147**	-	**20,856**

Louis Berger again uses an approach which utilizes a Canadian study, described above, and assumes an across the board reduction of 75.3 percent of uncontrolled emissions in the initial year with a one-time and annual LDAR program. The quarterly LDAR program is assumed to reduce emissions in the initial year by 76.5, consistent with the report by Trihydro (2013), and monthly LDAR is assumed to be even more effective, reducing emissions by 80 percent in the initial year. The average initial year cost per ton of VOC reduced across all well production facilities was estimated to be $8,590 per ton.

As with the STEM program, subsequent emission reductions in future years are expected to be much lower than in the initial year. The emission reductions in subsequent years are assumed to decline by the same proportion as the decline in leak frequency (0.4/1.7). The emission reductions were then divided by total annual costs in subsequent years to estimate the cost per ton of VOC reduced. In subsequent years, the average cost is $19,354 per ton of VOC reduced, approximately twice the initial year cost. Since uncontrolled emissions per well production facility are assumed constant across all of the tank uncontrolled emissions levels, the costs per tons of VOC reduced increase significantly with the higher tank VOC uncontrolled emissions levels (greater than 50 TPY) as more monitoring is required of these facilities. The cost per ton of VOC reduced for well production facilities is $45,855 in subsequent years for the greater than 50 TPY, while 12 to 20 TPY facilities incur a cost of $20,261 per ton of VOC reduced in subsequent years.

When comparing across the geographies, the costs per ton reduced are approximately $1,000 more in the attainment area when compared to costs in the non-attainment area. Table 16 and Figure 2 shows the initial and subsequent year total costs, emission reductions, and cost per ton of VOC reduced.

Table 16: Well Production Facility LDAR Cost per Ton of VOC Reduced

Tank Uncontrolled VOC Emissions	LDAR Costs	Emission Reduction from LDAR	LDAR Cost Per Ton of VOC Reduced	Annual LDAR Costs	Emission Reductions with LDAR	Recurring LDAR Annual Cost Per Ton of VOC Reduced
	Initial Year			Subsequent Years		
Attainment Area WPF						
Less than 6 TPY	$6,272,214	1,637	$3,832	$892,542	164	$5,454
6 to 12 TPY	$2,426,029	632	$3,837	$1,525,174	149	$10,252
12 to 50 TPY	$6,875,164	635	$10,835	$3,315,687	149	$22,208
Greater than 50	$9,957,162	346	$28,769	$4,387,239	81	$53,872
Total	**$25,530,568**	**3,250**	**$7,857**	**$10,120,642**	**543**	**$18,633**
Non-Attainment Area WPF						
Less than 6 TPY	$13,558,880	3,828	$3,542	$2,087,856	383	$5,454
6 to 12 TPY	$7,410,900	2,092	$3,543	$4,764,943	492	$9,682
12 to 50 TPY	$49,287,955	5,086	$9,691	$23,955,051	1,197	$20,018
Greater than 50	$40,898,067	1,657	$24,684	$17,223,458	390	$44,181
Total	**$111,155,802**	**12,663**	**$8,778**	**$48,031,308**	**2,462**	**$19,513**
Total WPF						
Less than 6 TPY	$19,831,094	5,465	$3,629	$2,980,398	547	$5,454
6 to 12 TPY	$9,836,929	2,724	$3,611	$6,290,117	641	$9,815
12 to 50 TPY	$56,163,119	5,720	$9,818	$27,270,738	1,346	$20,261
Greater than 50	$50,855,229	2,003	$25,390	$21,610,697	471	$45,855
Total	**$136,686,370**	**15,913**	**$8,590**	**$58,151,950**	**3,005**	**$19,354**

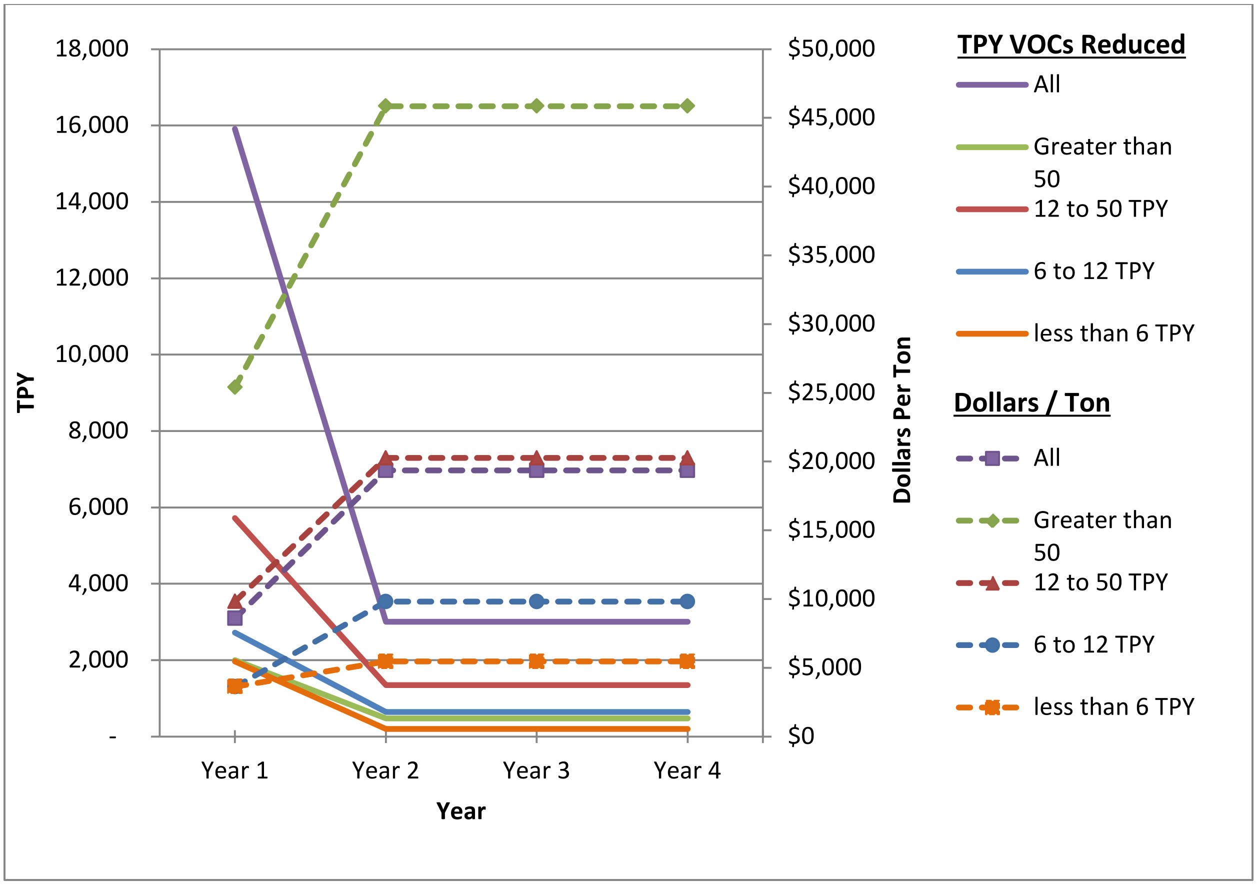

Figure 2: Well Production Facilities LDAR Costs and Emission Reductions Over Time

LDAR Costs for Compressor Stations

Louis Berger estimated LDAR costs for compressor stations with a similar approach as described above using the Division's estimates of the number of compressor stations affected by the proposed regulations. Louis Berger assumed two and four days per inspection for small and large compressor stations, respectively. Table 17 summarizes these assumptions.

Table 17: Compressor Station LDAR Cost Assumptions (2013$)

Item	Estimated Cost	Annualized*	Unit Cost
Capital and Non-Recurring Costs			
Camera	$122,000	$28,179	$282 per inspection for small CS and $564 for large CS
Vehicle	$30,000	$6,929	$69 per inspection for small CS and $139 for large CS
Program set up costs (i.e., Tagging, software, travel, etc.)	$13,688 for small compressor stations, and $27,272 for large CS	$1,319 for small CS and $2,627 for large CS	$1,319/small CS and $2,627/large CS
Assume inspections would take 2 days to inspect for smaller facilities, 100 inspections with one camera per year; inspections would take 4 days for larger facilities, 50 inspections with one camera per year.			
Inspection, Operations and Maintenance costs			
Small CS with Annual LDAR	$6,468		$6,468/year/CS
Large CS with Quarterly LDAR	$32,683		$32,683/year/CS
Travel and per diem costs	$32		$32/Inspection
Supervision	$200		$200/CS
Camera Repair	$12,500		$12,500/year/camera
Camera Training	$7,500		$7,500 per 100 CS
Record-keeping and reporting of comments	$1,530 for small CS $3,060 for large CS		$1,540/small CS $3,060/large CS

*Camera and vehicle costs annualized at 5% over 5 year-life of the equipment. Program set up costs are annualized over 15 years at 5%.

Similar to the previous analysis, data on costs to repair components were obtained from Nelson and Brown (2012).[12] The initial year leak frequency rate was assumed to be 1.17 percent, consistent with the Trihydro study (2014). The number of components was assumed to be 2,544 for small compressor stations and 6,744 for large compressor stations. Cost assumptions for repairs and re-monitoring are similar to those described above.

Tables 18.1 and 18.2 summarize the LDAR costs for compressor stations. LDAR costs for 200 compressor stations were estimated to be $15.4 million. Small compressor stations are estimated to incur $26,353 per facility in the initial year, while larger compressor stations would incur $217,599 per facility in the initial year.

[12] Nelson, Bradley and Heather Brown. 2012. Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Use Emission and Cost Data from the Uniform Standards. Memorandum to Greg Nizich and Bruce Moore, EPA. April. See attachments 3 and 4.

Table 18.1: Compressor Stations LDAR Cost Analysis for the Initial Year, Part 1

Compressor Station Uncontrolled VOC Emissions	Monitoring Frequency	Number of Compressor Stations	Number of Inspections/ Year	Capital Costs for Inspections (annualized) (1)	O&M Annual Costs for Inspections (2)	Number of Cameras Needed
Less than 12TPY	annual	147	147	$204,321	$1,245,835	2
12 to 50 TPY	quarterly	53	212	$288,112	$1,978,238	5
Greater than 50	monthly	-	-	-	-	-
Total	**-**	**200**	**359**	**$492,433**	**$3,224,073**	**7**

Table 18.2: Compressor Station LDAR Cost Analysis for the Initial Year, Part 2

Compressor Station Uncontrolled VOC Emissions	Monitoring Frequency	Number of Components	Annual Number of Leaks	Leak Repair Costs (3)	Re-monitor Costs (4)	Total Annual LDAR Costs for Compressor Stations (1+2+3+4)	Per Compressor Station Cost, Initial Year
Less than 12	annual	2,544	6,357	$834,416	$1,589,364	$3,873,936	$26,353
12 to 50 TPY	quarterly	6,744	24,305	$3,190,081	$6,076,344	$11,532,775	$217,599
Greater than 50	monthly	-	-	$0	$0	$0	-
Total	**-**	**9,288**	**30,663**	**$4,024,497**	**$7,665,708**	**$15,406,710**	**$77,033**

Similar to the storage tank STEM analysis, following the initial implementation of a LDAR program, leak frequencies decrease, and as a result, the number of leaking components also decrease along with repair and re-monitoring costs, when compared to the initial year. Therefore, in subsequent years, the number of leaks was adjusted to reflect the reduced leak frequency (0.4%). As a result, reduced leak repair and re-monitoring costs with the adjusted number of leaks were estimated and shown in table 19. The total LDAR costs for subsequent years include the capital, and inspection and O&M costs in table 18 with the adjusted leak repair and re-monitoring costs in table 19.

Table 19: Compressor Station LDAR Cost Analysis for Subsequent Years

Compressor Stations Uncontrolled VOC Emissions	Monitoring Frequency	Number of Components	Annual Number of Leaks	Leak Repair Costs (3)	Re-monitor Costs (4)	LDAR Costs for Compressor Stations in Subsequent Years (Annual Cost) (1+2+3+4)	Per Compressor Station Cost, Subsequent Years
Less than 12	annual	2,544	1,496	$196,333	$373,968	$2,020,457	$13,745
12 to 50 TPY	quarterly	6,744	5,719	$750,607	$1,429,728	$4,446,685	$83,900
Greater than 50	monthly	-	-	-	-	-	-
Total	**-**	**9,288**	**7,215**	**$946,940**	**$1,803,696**	**$6,467,142**	**$32,336**

The Division has identified an average uncontrolled emission rate for compressor stations of 10.1 TPY of VOCs for small compressor stations and 16.4 for large compressor stations, respectively. Louis Berger used these assumptions for uncontrolled emissions for the analysis as summarized in Table 20.

Table 20: Uncontrolled Emissions for Compressor Stations

Compressor Stations Uncontrolled VOC Emissions	Monitoring Frequency	Number of Compressor Stations	Uncontrolled VOC Emissions per Compressor Station (TPY)	Total Uncontrolled VOC Emissions (TPY)
Less than 12 TPY	annual	147	10.1	1,485
12 to 50 TPY	quarterly	53	16.4	869
Greater than 50	monthly	-	-	-
Total	**-**	**200**	**-**	**2,354**

Similar to the analyses on storage tanks and well production facilities, Louis Berger again uses the emission reductions associated with annual LDAR from the Clearstone Engineering, Ltd. study, described above, which estimates 75.3 percent emissions reductions associated with the annual LDAR program. Quarterly LDAR monitoring is assumed to be slightly more effective, reducing emissions by 76.5 percent, consistent with declining leak frequencies documented in the Trihydro report (2014).

As with tanks and well production facilities, Louis Berger accounts for subsequent year emission reductions with LDAR for compressor stations. The emission reductions in subsequent years are assumed to decrease by the proportion based on the reduction in leak frequency (0.4/1.7). The subsequent year costs were then divided by emission reductions in subsequent years to estimate the cost per ton of VOC reduced. Initial year cost per ton of VOC reduced is $8,641, while in subsequent years, the cost per ton of VOC reduced increases to $15,416. Table 21 shows the initial year and subsequent year total costs, emission reductions, and cost per ton of VOC reduced.

Table 21: Compressor Station LDAR Cost per Ton of VOC Reduced in Initial and Subsequent Years

Compressor Stations VOC Uncontrolled Emissions	LDAR Costs	Emissions Reductions	Cost Per Ton of VOC Reduced	Annual LDAR Costs	Emission Reductions	Annual Cost Per Ton of VOC Reduced
	Initial Year			Subsequent Years		
Less than 12 TPY	$3,873,936	1,118	$3,465	$2,020,457	263	$7,681
12 to 50 TPY	$11,532,775	665	$17,344	$4,446,685	156	$28,421
Greater than 50	-	-	-	-	-	-
Total	**$15,406,710**	**1,783**	**$8,641**	**$6,467,142**	**420**	**$15,416**

Expanding Low Bleed Pneumatics Requirements Statewide

The Division is proposing to expand statewide the regulatory requirements mandating the use of low bleed pneumatic controls that were adopted for the nonattainment area in 2008. This section estimates the cost of the requirement to industry.

Under the proposed rules, high-bleed pneumatic controllers shall be replaced or retrofitted with low-bleed pneumatic devices by May 1, 2015. It is assumed that the Division would define a low-bleed pneumatic device as one that emits less than or equal to 6 standard cubic feet per hour (scfh), while high-bleed devices bleed at a rate greater than 6 scfh. The Division has estimated that 9,877 high-bleed pneumatic devices are being utilized outside the nonattainment area. Louis Berger utilizes this estimate of the number of devices that will need to be replaced to comply with the proposed rule.

The EPA through their Natural Gas Star Program, has evaluated the effectiveness of reducing methane emissions through the replacement of high-bleed pneumatic devices with low-bleed pneumatics. In the document titled, "Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry", EPA provides estimates of costs, service life, benefits and decision process for determining the feasibility of replacing high-bleed pneumatics.[13] The costs of several models of pneumatic devices are summarized in Appendix B and range from $380 to $3,500 in 2006 dollars. In addition, EPA reported the average cost of a low-bleed pneumatic device of $2,553 in 2008 dollars. Based on this information, Louis Berger assumes the cost of low-bleed pneumatic devices averages $2,775 adjusted to 2013 dollars. In addition, the analysis assumes a service life of 5 years[14] and cost are annualized at a 5 percent interest rate.

Replacement of pneumatic devices would require an initial assessment of the devices used at various facilities. The EPA suggests that a system-wide or facility-specific pneumatic survey would need to record for each device "location, function, make and model, condition, age, estimated remaining useful

[13] U.S. EPA, "Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry", October, 2006.
[14] U.S. EPA, "Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry", October, 2006.

life, and bleed rate characteristics (volume and whether intermittent or continuous)."[i] Louis Berger has estimated the cost of conducting a pneumatic survey in the cost of the regulatory mandate as summarized in Table 22. Total cost of the mandate is estimated to be $32 million.

Table 22: Estimated Cost of Low-Bleed Pneumatic Devices

Item	Estimated Cost	Annualized*
Capital and Non-Recurring Costs		
Low-Bleed Pneumatic Devices	$2,775	$641
Pneumatic Survey	$500	$115
Total Cost	**$3,275**	**$756**

*Annualized at 5% over a five year service life.

Replacing high-bleed pneumatics with low-bleed devices will likely result in gas savings and the value of these savings per device are estimated in Table 23. Payback period is estimated to be 2.8 years.

Table 23: Gas Savings Associated with Low-Bleed Pneumatic Devices

Estimated Annual Bleed Emission Reductions (Methane) (Tons)[ii]	Gas Volume (Mcf)	Gas Price ($/Mcf)	Value of Gas Recovered
(1)	(2) = (1)*40.49 Mcf/ton	(3)	(4) = (3) * (2)
6.65	269	$4.34	$1,168

Recovered Product Estimates Attributable to proposed STEM and LDAR Requirements

In their analysis of cost effectiveness of LDAR requirements, the Division "…assumes that the costs savings from additional product capture will be equal or greater than the cost of repair and re-inspection."[15] In order to test the validity of this assumption, Louis Berger estimated the product savings that can be expected from LDAR requirements for well production facilities and compressor stations.

Gas Savings Attributed to LDAR – Well Production Facilities

Product savings attributable to the LDAR program as it relates to well production facilities in the initial year are estimated as shown in Table 24. Column 1 shows that 15,913 tons of VOCs are estimated to be detected and captured by the LDAR program for all well production facilities in the initial year of the program (see Table 16). Louis Berger used a Gas/VOC ratio (22.4%) reported by the Division in their analysis of LDAR costs of well production facilities to estimate the amount of gas that would be captured by the controls. In this case, 71,040 tons of gas is expected to be captured by the LDAR program at well production facilities in the initial year. The gas mass was then converted to a volume metric using a

[15]Colorado Air Quality Control Commission 2014. Updated Economic Impact Analysis for Proposed Revisions to AQCC Regulations Number 7. Submitted with Pre-Hearing Statement on January 6, 2014. Page 17.

natural gas density factor and results in 2,876,121Mcf of gas recovered. The value of the recovered gas was estimated at $12.4 million for the initial year using a recent natural gas price of$4.34 Mcf. The value of the product savings equates to 8.8 percent of the total LDAR costs ($136 million) for the initial year of implementation.

Table 24: Product Savings Attributable to the LDAR Program for Well Production Facilities for the Initial Year

Tons of VOCs Captured by LDAR Program at WPF	Average Gas/VOC Ratio[1]	Tons of Methane Captured by LDAR Program for WPF (Tons)	Natural Gas Volume Recovered (MCF)[2]	Natural Gas Price ($/Mcf)[3]	Value of Recovered Gas
(1)	(2)	(3) = (1) / (2)	(4) = (3)/0.0247 ton/mcf	(5)	(6) = (4) * (5)
15,913	22.4%	71,040	2,876,121	$4.34	$12,482,363

[1] Taken from the Division's calculation on LDAR costs for well production facilities. Spreadsheet titled "APCD-PHS EX-RR.xlsx"; sheet: statewide wells model FAC.

[2] Natural gas volumes calculated by assuming a gas density of 0.791 kg/m3 and converted to English units.

[3] Henry Hub Natural Gas Spot Price for December, 2013. Obtain from the Energy Information Agency at http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

For subsequent years, the LDAR program at well production facilities is expected to realize product savings though they are expect to decline from the initial year. An estimate of the amount and value of the product saved is estimated as shown in Table 25. Using the same approach as used for the initial year, the amount of natural gas expected to be recovered in subsequent years is estimated to be 543,125 Mcf and is valued at $2.3 million which is less than four percent of the total annual LDAR costs in subsequent years.

Table 25: Product Savings Attributable to the LDAR Program for Well Production Facilities for Subsequent Years

Tons of VOCs Captured by LDAR Program at WPF	Average Gas/VOC Ratio[1]	Tons of Methane Captured by LDAR Program for WPF (Tons)	Natural Gas Volume Recovered (MCF)[2]	Natural Gas Price ($/Mcf)[3]	Value of Recovered Gas
(1)	(2)	(3) = (1) / (2)	(4) = (3)/0.0247 ton/mcf	(5)	(6) = (4) * (5)
3,005	22.4%	13,415	543,125	$4.34	$2,357,161

[1] Taken from the Division's calculation on LDAR costs for well production facilities. Spreadsheet titled "APCD-PHS EX-RR.xlsx"; sheet: statewide wells model FAC.

[2] Natural gas volumes calculated by assuming a gas density of 0.791 kg/m3 and converted to English units.

[3] Henry Hub Natural Gas Spot Price for December, 2013. Obtain from the Energy Information Agency at http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

The Division's assertion that product captured and sold would offset costs of repair and re-monitoring is not supported by this analysis. Well production facility LDAR repair and re-monitoring costs in the initial year are estimated to be $90.0 million (see table 13), while the value of the recovered gas is estimated to be $12.4 million in the initial year, or 13.8 percent of the repair and re-monitoring cost. In subsequent years, the value of the gas recovered would offset 10.9 percent of the repair and re-monitoring costs.

Gas Savings Attributed to LDAR – Compression Stations

Gas savings attributable to the LDAR program as it relates to compressor stations in the initial year are estimated as shown in Table 26. The amount of gas that is expected to be detected and captured by a successful LDAR program at compressor stations during the initial year is 322,260 Mcf and is valued at $1.3 million. This value represents 8.6 percent of the total cost of the LDAR program during the initial year. It is worth noting that Louis Berger believes the estimated product savings for compressor stations may be conservatively high. This opinion is based on the likelihood that the gas/VOC ratio is not as high for compressor stations as it is for well production facilities.

Table 26: Product Savings Attributable to the LDAR Program for Compressor Stations for the Initial Year

Tons of VOCs Captured by LDAR Program for Compressor Stations	Average Gas/VOC Ratio[1]	Tons of Methane Captured by LDAR Program for Compressor Stations (Tons)	Natural Gas Volume Recovered (MCF)[2]	Natural Gas Price ($/Mcf)[3]	Value of Recovered Gas
(1)	(2)	(3) = (1) / (2)	(4) = (3)/0.0247 ton/mcf	(5)	(6) = (4) * (5)
1,783	22.4%	7,960	322,260	$4.34	$1,398,608

[1] Taken from the Division's calculation on LDAR costs for well production facilities. Spreadsheet titled "APCD-PHS EX-RR.xlsx"; sheet: statewide wells model FAC.

[2] Natural gas volumes calculated by assuming a gas density of 0.791 kg/m3 and converted to English units.

[3] Henry Hub Natural Gas Spot Price for December, 2013. Obtain from the Energy Information Agency at http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

For subsequent years, the LDAR program at compressor stations is also expected to generate gas savings though these savings are expected to decline from the initial year. An estimate of the amount and value of the project saved is shown in Table 27. The amount of natural gas expected to be recovered in subsequent years is estimated to be 1,875Mcf and is valued at $329,453 which represents 5 percent of total annual costs of the program in subsequent years.

Table 27: Product Savings Attributable to the LDAR Program for Compressor Stations for Subsequent Years

Tons of VOCs Captured by LDAR Program for Compressor Stations	Average Gas/VOC Ratio[1]	Tons of Methane Captured by LDAR Program for Compressor Stations (Tons)	Natural Gas Volume Recovered (MCF)[2]	Natural Gas Price ($/Mcf)[3]	Value of Recovered Gas
(1)	(2)	(3) = (1) / (2)	(4) = (3)/0.0247 ton/mcf	(5)	(6) = (4) * (5)
420	22.4%	1,875	75,911	$4.34	$329,453

[1] Taken from the Division's calculation on LDAR costs for well production facilities. Spreadsheet titled "APCD-PHS EX-RR.xlsx"; sheet: statewide wells model FAC.

[2] Natural gas volumes calculated by assuming a gas density of 0.791 kg/m3 and converted to English units.

[3] Henry Hub Natural Gas Spot Price for December, 2013. Obtain from the Energy Information Agency at http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

The Division's assertion that product captured and sold would offset costs of repair and re-monitoring is not supported by this analysis. Compressor station LDAR repair and re-monitoring costs in the initial year are estimated to be $11.7 million (see table 13), while the value of the recovered gas is estimated to be $1.4 million in the initial year, or 12.0 percent of the repair and re-monitoring cost. In subsequent years, the value of the gas recovered would also offset only 12.0 percent of the repair and re-monitoring costs.

Indirect Costs of Regulations on Small Operators and Marginally Producing Wells

In order to gain an understanding of the potential indirect costs to businesses, in particular small businesses, if the proposed rules were implemented, Louis Berger evaluated the impacts on small operators and marginally producing wells within the state. Evaluation of historical production and well count data maintained by the Colorado Oil and Gas Conservation Commission (COGCC) indicates that 25,463 conventionally completed wells produce approximately 1.57 million barrels of oil per month (BOPM) or on average two barrels of oil per day as of mid-year 2013. These marginally producing wells represent over half (55 percent) of the total producing wells in the state (46,495) as of 2013. Given the likelihood that smaller operations would be negatively impacted by the increased costs of the proposed rules and regulations as well as the large percentage of these wells that occur within the state, small and marginally producing operations are the focus of this analysis.

Louis Berger first evaluated the economic limit (in barrels per day) that marginally producing wells would realize under current economic and regulatory conditions. The economic limit is defined as the point that production levels are no longer economic given a number of factors (price of oil, lease costs, tax rates, etc.). Relevant assumptions for this analysis are as follows:

- Current Rate of Production – 2 BOPD
- Oil Price - $90 ($/BO)
- Severance Tax Rate – 5%

- Net Return on Investment (NRI) (well income minus royalties) – 80%
- Lease Operating Expense ($/well/month) (includes ad valorem taxes) - $900
- Number of Tanks per lease – 2
- Number of Wells per lease – 4
- Production Decline Rate – 2.5%

The economic limit in barrels of oil per day (BOPD) was calculated for wells using the following equation.

$$\textbf{\textit{Economic Limit (BOPD)}} = \frac{\textbf{Lease Operating Expense (LOE)}}{\textbf{\textit{(Oil Price) * (30.4 days) * (NRI * (1- severance tax))}}}$$

Implementation of the new air quality rules would have an impact on lease operating expenses for each well. The increase costs would change the economic limit for each well as shown in Figure 3. Under current economic and regulatory conditions, the economic limit for marginally producing wells was estimated to be 0.43 BOPD. In other words, when production falls below 0.43 BOPD, the well is no longer economic and will be shut it or plugged. If lease operating costs increase, the economic limit increases, causing wells to be shut in earlier than planned. This leads to oil left in place as shown in Figure 3.

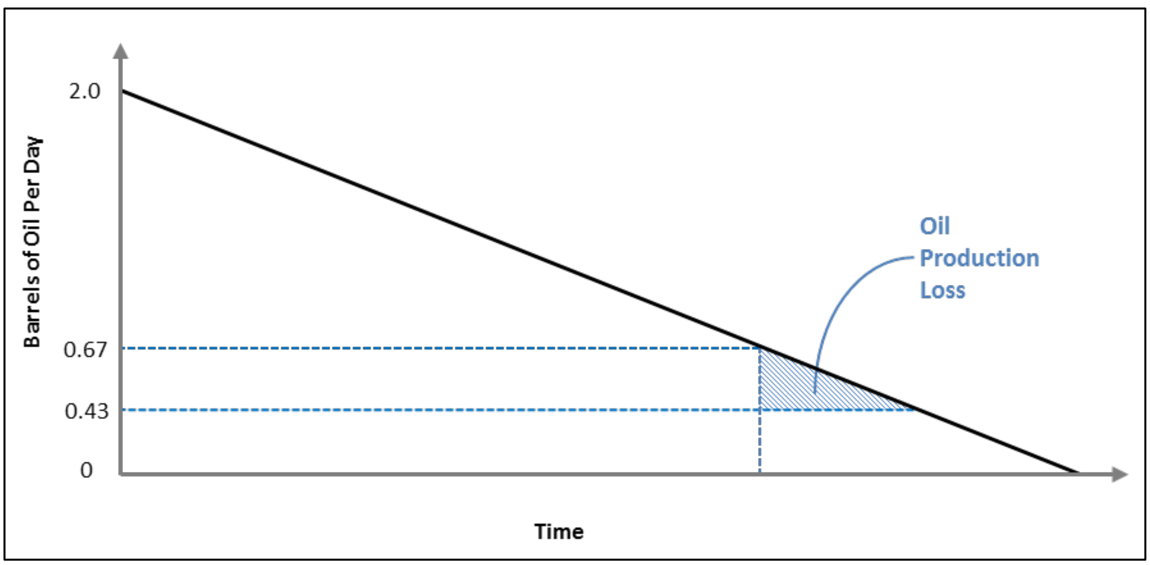

Figure 3: Oil Production Loss with an Increase in the Economic Limit

The amount of production that would result under different economic limits was calculated as follows.

$$\textbf{\textit{Remaining Oil}} = \frac{(Q_i - Q_f) * 365}{Limit\ (1 - Decline\ Rate)}$$

Where:

Q_i = *Current Production Rate = 2 BOPD*
Q_f = *Calculated Economic Limit*

Louis Berger estimated the economic limit for marginally producing wells if the air regulations relevant to oil and gas operations were implemented as proposed by the Division. The STEM costs for tanks and the LDAR costs for well production facilities were included as additional monthly unit costs in the lease operating expenses, increasing these costs for operators. The results are summarized in Table 19. Changes in lease operating costs due to the regulations were estimated for different sizes of facilities. Costs are expected to increase from $22 to $1,290 per month with an average of $729 for all facilities. The increase costs are expected to increase the economic limit from 0.44 to 1.05 BOPD, depending on the size of facilities.

The additional cost burden would result in as much as 128.6 million barrels of oil being left in place and not produced over time. Assuming a price per barrel of oil is $90, this would equate in $11.6 billion in lost revenue to producers, $2.3 billion in lost royalties and $579 million in lost severance taxes. Present values for these losses are $1.9 billion in lost revenue, $384 million in lost royalties and $96 million in lost severance taxes.[16]

[16] Present value analysis assumed a 10 percent discount rate over 60 years.

Table 28: Evaluation of Impacts of Air Regulation Costs on Marginally Producing Wells

Item	Oil and Gas Leases					
	Base Case	WITH WPF & TANK less than 6	WITH WPF & TANK s>=6 to <=12	WITH WPF & TANK s>12 to <= 50	WITH WPF & TANK >50	WITH WPF & TANK TOTAL
LOE ($/well/month)	$900	$900	$900	$900	$900	$900
Additional LOE with new rules ($/well/month)	$0	$22	$565	$743	$1,290	$729
Total LOE ($/wee/month)	$900	$922	$1,465	$1,643	$2,190	$1,629
Economic Limit (BOPD)	0.43	0.44	0.70	0.79	1.05	0.78
Remaining Oil (BO)	22,594	22,442	18,679	17,442	13,652	17,543
Estimated Oil Shut In (BO)	-	152	3,914	5,151	8,942	5,051
Facility Allocation	-	0.35	0.17	0.35	0.12	1
Production Lost (BO)	-	1,353,302	16,944,548	45,908,655	27,321,315	128,611,449
Lost Royalties ($)	-	$24,359,432	$305,001,869	$826,355,781	$491,783,676	$2,315,006,074
Lost Severance Taxes ($)	-	$6,089,858	$76,250,467	$206,588,945	$122,945,919	$578,751,519

*Values in the table have not been discounted and reflect revenues and costs over the life of the well.

Costs to Division to Implement Proposed Rules

The Economic Impact Analysis requires an assessment of the cost for the Division to implement the proposed rule changes. Oversight of an LDAR program, STEM plans, and annual report review of 5,312 tank batteries, 5,312 well production facilities, and 200 compressor stations with possibly hundreds of thousands of components would require additional Division manpower. Louis Berger reviewed the revised (November 21, 2013) Regulations 3, 6 and 7 to understand the implementation costs to the Division associated with the new rules. A summary of potential cost implications for the Division, as result of the rule changes, is provided in Table 29. The rationale for the estimated additional costs or cost savings is provided after the table.

Table 29: Summary of Potential Implementation Costs to the Division with Proposed Changes in Regulation 3, 6, and 7

Regulation Subpart	Description	Cost Impact	Estimated Savings/Cost
Regulation 3			
Minor Source Permits	Facilities with emissions less than the APEN no longer have to file for a minor source permit.	Cost Savings	An estimated 882 hours per year in labor would be saved from not having to review and approve minor source permits.
Standardization of de minimis Reporting Threshold	The de minimis reporting threshold would be set to a standard of 250 pounds per year. This increases the clarity of reporting requirements.	Cost Savings	An undetermined amount of savings would be realized by the Division.
Crude Oil Storage Tank Permitting	Additional permits would now be required for crude oil tanks as the tank permitting exemptions are removed.	Cost Increase	An estimated 128 hours per year in additional labor would be required to review and approve permits.
Regulation 6			
Adoption of NSPS OOOO	This regulation adopts NSPS OOOO. No additional impacts beyond the minimum required by federal law would occur.	No Impact	No Impact
Regulation 7			
Evaluation of Operation and Maintenance of Air Pollution Control Equipment	The Division would be required to make determinations on the acceptableness of operating and maintenance procedures used to control Air Pollution Control Equipment.	Cost Increase	An estimated 1,062 hours per year in additional labor would be required to review and monitor o&m procedures.
Approval of STEM Plans	The Division would be required to review and approve STEM plans for compliance with regulatory requirements.	Cost Increase	An estimated 5,600 hours in additional labor would be required for review and approval of STEM plans.

Ongoing Management of STEM Program	The Division would incur labor costs for review of records that would be retained by each operator or owner as part of their STEM plan compliance.	Cost Increase	An estimated 1,062 hours per year in additional labor would be required.to manage the STEM program
Division Approval of Monitoring Devices or Methods	When the Division is required to approve monitoring devices or methods not mentioned in these regulations it is anticipated that additional labor costs to the Division would occur.	Cost Increase	An undetermined additional cost would be incurred by the Division.
Recordkeeping Requirements	The owner or operator of each facility is required to keep records of various tests and repairs. It anticipated that the Division would review a percentage of these records annually.	Cost Increase	An estimated 1,062 hours per year in additional labor would be required.
Reporting Requirements	Each owner or operator is required to submit an annual report summarizing the inspection and maintenance activities of all facilities during the previous year. It is anticipated that the Division would review a percentage of these annual reports.	Cost Increase	An estimated 2,125 hours per year in additional labor would be required to review annual reports.
Venting Recordkeeping Requirements	Each owner or operator is required to record venting statistics and make them available to the Division upon request. Additionally, the Division may be called upon to make a determination on the visibility of venting. It is anticipated that the Division would commit a certain amount of time annually to reviewing these venting records and making visibility determinations on venting events.	Cost Increase	An estimated 2,125 hours per year in additional labor would be required for review and monitoring.

The following section provides an explanation of the implementation cost analysis summarized in Table 29 for each proposed rule change.

Regulation 3

Minor Source Permits

Under Regulation 3, the Division is proposing that NSPS OOOO affected facilities with uncontrolled actual emissions that are less than the APEN and minor source permit thresholds no longer automatically have to file APENs and obtain minor source permits. As such, it expected that the Division would realize an implementation cost savings with this proposed rule change. As a result of this revision, up to 441 facilities would be exempt from submitting an APEN. If it is assumed that it requires two hours to process each APEN application, then this rule change could save the Division up to 882 hours of processing time. This would allow the Division to reallocate permitting resources to more complicated sources with greater impact to Colorado air quality, as well as develop and maintain other guidance and compliance assistance tools.

Standardization of de minimis Reporting Threshold

The Division is proposing to revise method (Part A, Appendix A) for determining non-criteria reportable pollutant de minimis levels in order to standardize the de minimis reporting threshold and set a 250 pounds per year threshold for all non-criteria reportable pollutants, regardless of the pollutant, height of release point or distance to property boundary. This revision increases regulatory clarity and reduces the administrative reporting burdens on both sources and the Division by simplifying the process. This revision is therefore anticipated to reduce costs to the Division though it is uncertain what the cost savings would be for this rule change.

Crude Oil Storage Tank Permitting

The Division is proposing to remove the crude oil storage tank permitting exemptions in Part B, Section II.D.1.n. and Part C, Section II.E.3.ddd. It is estimated that up to 64 additional crude oil tanks would be required to obtain a permit under this revision. If it is assumed that it takes approximately two hours to review and issue each permit, it is anticipated that this would result in up to 128 hours of additional labor for the Division each year to implement this rule.

Regulation 6

This regulation adopts NSPS OOOO; therefore, this rule makes NSPS OOOO enforceable under Colorado law and is not anticipated to impose additional requirements beyond the minimum required by federal law. The revised changes to this regulation are not anticipated to impact regulation implementation costs to the Division.

Regulation 7

It is anticipated that several new provisions of the revised Regulation 7 would require owners or operators of facilities to prepare reports and documentation or perform tasks that would require review, approval and inspection by the Division. These additional tasks are expected to result in an increase in the implementation costs to the Division.

Evaluation of Operation and Maintenance of Air Pollution Control Equipment

The revised regulations would require that air pollution control equipment be maintained and operated in a manner consistent with good air pollution practices. A determination on whether or not acceptable operating and maintenance procedures are being used at a facility would be based on information provided to the Division by the owner or operator of the facility. This information could include, but would not be limited to: monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. The requirement for the Division to make a determination on the acceptability of operating and maintenance procedures is expected to take 2 hours per facility per year. The Division has reported that there are 5,312 facilities that would be affected by this rule. If it is assumed that the Division would review approximately 10 percent of these records annually, then the rule change would require an additional 1,062 labor hours per year for implementation.

Approval of STEM Plans

Owners or operators of storage tanks would be required to develop, certify and implement a Storage Tank Emission Management System (STEM) plan to identify appropriate strategies to minimize emissions from venting at thief hatches (or other access points to a storage tank) and pressure relief devices during normal operation under the revised Regulation 7. It has been estimated that approximately 5,312 storage tanks under the revised regulations would have to meet the STEM requirements. Assuming that a STEM plan could be developed for sites with multiple tanks (2), at most, 2,800 STEM plans would be developed and require review by the Division. Assuming the Division would review and approve each plan and it would require 2 hours per review would result in an additional 5,600 hours to initially review and approve the individual STEM plans, resulting in additional implementation costs as a result of the revised regulation.

Ongoing Management of STEM Program

As each owner or operator of a storage tank subject to section XII.D or XVII.C under the revised regulation must maintain records of STEM, including the plan, any updates, and the certification; and as these records should be made available to the Division upon request, it is anticipated that the Division would incur additional implementation costs as a result of this requirement. Further document retention requirements under the revised regulation would include retention of the AIRS ID for the storage tank; the date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions; the date and duration of any period where the air pollution control equipment is not operating, or where a flare or other combustion device is being used; the date and result of any Method 22 test, as well as the timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions. While the Division is not required to review this information, the requirement for the retention of this information would allow it to be reviewed. It is anticipated that the Division would review approximately 10 percent of these records annually. As there would be at most 5,312 facilities under the revised regulations subject to these requirements and each would take an assumed 2 hours of review per set of records, this would require, at most, 1,062 hours per year, resulting in additional implementation costs as a result of the revised regulation.

Division Approval of Monitoring Devices or Methods

Under section XVII.F.6, the Division may be required to approve monitoring devices or methods not mentioned in these regulations, resulting in additional time and funding costs to the Division.

Recordkeeping Requirements

As a result of recordkeeping requirements under the proposed regulation, the owner or operator of each facility subject to inspection and maintenance requirements under Section XVII.F is required to maintain documentation of the pre-start-up pressure tests for new well production facilities; date and site information for each inspection; a list of leaking components and monitoring method used to determine the presence of the leak; the date of the first attempt to repair the leak and additional attempts; the date the leak was repaired; the delayed repair list; the date the leak was re-monitored to verify effectiveness of the repair and the results of re-monitoring effort; and a list of identification numbers for the components designated as unsafe or inaccessible to monitor, as well as an explanation for each component stating why the component was so designated and the plan for monitoring such components for a period of two years and make them available to the Division upon request. It is anticipated that the Division would review approximately 10 percent of these records annually. As there would be at most 5,312 facilities under the revised regulations subject to these requirements and it is assumed to take approximately 2 hours of review per set of records, this would require, at most, 1,062 hours per year in additional labor. This would result in increased implementation costs of Regulation 7.

Reporting Requirements

In addition to recordkeeping, the owner or operator of each facility subject to the inspection and maintenance requirements in Section XVII.F would be required to submit a single annual report each year summarizing the inspection and maintenance activities at all of their subject facilities during the previous year. This report would contain at least the number of facilities inspected as well as the total number of inspections, leaks identified, categorized by component type and the number of leaks repaired. It would also require the identification of the number of leaks on the delayed repair list at the end of the calendar year. Additionally, each of these reports would be required to be accompanied by a self-certification form certifying the accuracy of the information in the report. It is anticipated that review of one annual report by the Division would require 4 hours. As there would be at most 5,312 annual reports, depending on the ownership of individual facilities in the state of Colorado, this new requirement is anticipated to add an additional amount of 2,125 hours, at most, of labor to the Division each year. This would result in increased implementation costs of Regulation 7.

Venting Recordkeeping Requirements

Records of the cause, date, time, and duration of venting events under Section XVII.H would be required to be kept and made available to the Division upon request under the revised regulation. Regarding visible emissions, the Commission expects that both Division inspectors and the regulated community will, if any smoke is observed, determine whether the emissions are considered visible emissions for purposes of Regulation Number 7. When the venting event records are reviewed by the Division or if the Division makes a determination on the visibility of emissions this would result in additional implementation costs as a result of the revised regulation. It is anticipated that the average time required to determine the visibility of emissions or review the records of a facility would be four hours per facility. As there would be, at most, 5,312 facilities that may require review by an inspector annually and assuming 10 percent of these facilities require monitoring per year it is anticipated that up to 2,125 labor hours would be required. This would result in increased implementation costs of Regulation 7.

Conclusions

The net increase in the number of labor hours at the Division as result of the proposed regulations is anticipated to be approximately 12,282 labor hours annually. Notably, the Division would need 5,600 hours to review and approve initial STEM plans required under Regulation 7, the largest estimated time commitment for the Division. This represents approximately 6.1 FTEs of additional staff for the Division to review, oversee, inspect, manage, and approve various requirements associated with the proposed rules. Therefore, Louis Berger concludes that the Division would incur significant additional net costs to implement the proposed requirements beyond current expenditures, contrary to the Division's assertions to date.

Support of Industry's Proposed Language

The results of the initial economic impact analysis presented here support the industry's key suggested revisions to the Division's proposed rule. Specifically, the proposed revisions will allow similar emission reductions to be achieved in a much more cost effective manner than the regulatory approach proposed by the Division. Key points to the analysis include:

- Diminishing marginal benefits associated with LDAR programs implies increasing costs per ton of VOC reduced after initial rounds of inspections and repairs. Reducing the monitoring to reflect successful LDAR implementation reduces costs and improves the cost effectiveness of the proposed rule compared to the Division's proposal while maintaining program integrity through realized emission reductions. The "step-down" of monitoring frequency, which rewards companies with four inspections with no leaks, is an example of how the industry changes to the proposed rule would provide incentives for industry to maintain compliance and reduce costs for good performance.
- Generally, compliance costs of STEM and LDAR for small tanks and well production facilities are more burdensome than for larger facilities on a cost per ton basis. As such, requiring a one-time LDAR inspection and monthly AVO for all facilities (including all well production facilities) with uncontrolled emissions between 2 and 6 TPY would improve the overall cost effectiveness of the proposed rule by limiting the very high costs per ton of VOC reduced incurred by very small facilities with very small VOC fugitive emissions.
- Compliance costs are higher for operations outside of the non-attainment area as the distance among facilities and tanks increases inspection travel time and expenses. Limiting the geographic scope to the non-attainment area will improve the cost effectiveness of the proposed rule.
- Allowing for the use of other established technology, such as the tunable diode laser absorption technology (TDLAS), as an option for inspection monitoring, would reduce costs to industry with faster inspections, reduced camera training requirements, among other factors.

Expert Rebuttal Report and Rebuttal Written Testimony of Gernot Wagner, Ph.D.

Characterizing the Economic Benefits of Anticipated Methane Reductions for the Proposed Amendment to Colorado's Proposed Oil and Gas Regulation with Respect to Climate Change

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Expert Introduction: Dr. Gernot Wagner

My name is Gernot Wagner, Ph.D., and I am a senior economist at EDF, where I co-lead the office of economic policy and analysis to advocate for market-based solutions to a wide range of environmental problems. I teach energy economics as adjunct faculty at Columbia's School of International and Public Affairs, and I am the author of *But Will the Planet Notice?* (Hill & Wang/Farrar, Strauss & Giroux, 2011) and, joint author with Harvard University's Martin Weitzman, of the forthcoming *Climate Shock* (Princeton University Press). I am a research associate at the Harvard Kennedy School and a term member of the Council on Foreign Relations. Prior to EDF, I worked for the Boston Consulting Group and served on the editorial board of the *Financial Times*. I hold a Ph.D. and M.A. in Political Economy and Government as well as an A.B. in Environmental Science and Public Policy, and Economics (*magna cum laude* with highest honors in the field) from Harvard University, and an M.A. in Economics from Stanford University. A copy of my cv is attached as Exhibit A to this expert report and testimony.

The following is my written testimony on the topics covered in this report, based on my education, research, and expertise on the topic of the Social Cost of Carbon and related issues.

Summary of Written Testimony and Expert Opinion

Calculating the social costs of greenhouse gas pollutants has a long tradition in the academic literature. In 2010, the United States' Interagency Working Group ("IWG") calculated the Social Cost of Carbon ("SCC") in a transparent, well-reviewed inter-agency process involving a dozen federal agencies and entities. A routine update in 2013, reflecting the latest changes in the peer-reviewed literature resulted in a central estimate for the SCC of $37 per ton of carbon dioxide emitted in 2015. Converting the value into one reflecting the social cost of methane – and making conservative assumptions every step along the way – results in a central value of the social benefit of methane reductions for the proposed oil and gas rule in Colorado per year: over $104,000,000 when fully implemented in 2016 and increasing to $132,000,000 in 2025. The upper range of the central estimate reaches over $318,000,000 per year in 2016 and over $404,000,000 per year in 2025.

Social Cost of Carbon

The SCC is a monetary measure of the incremental damage to the climate resulting from carbon dioxide emissions. The SCC assigns a net present value to the marginal impact of one additional ton of carbon dioxide emissions released at a specific point in time. The SCC is based on a large and growing body of research regarding the quantitative economic damages that would result from unmitigated climate change. These economic estimates are typically based on the results of integrated assessment models, in which a scientific model of the predicted physical impacts of climate change is paired with a socio-economic model that evaluates the economic impact of these effects.

The most comprehensive effort to calculate the SCC is the work published by the IWG. The IWG is a group of numerous federal agencies/departments, including the Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and the Department of the Treasury. The IWG developed the SCC through an open and transparent process, involving extensive meetings, public comment and peer review. The SCC developed by the IWG is widely used in regulatory rulemakings in the United States.[1]

[1] The SCC has been used in numerous notice-and-comment rulemakings by various agencies since it was published in 2010, and each of these occasions has provided opportunity for public comment on the SCC. *See, e.g.*, Energy Conservation Program: Energy Conservation Standards for Residential Clothes Washers, 77 Fed. Reg. 32,381 (May 31, 2012); Energy Conservation Program: Energy Conservation Standards for Residential Dishwashers, 77 Fed. Reg. 31,964 (May 30, 2012); Energy Conservation Program: Energy Conservation for Battery Chargers and External Power Supplies, 77 Fed. Reg. 18,478 (Mar. 27, 2012); Energy Conservation Program: Energy Conservation Standards for Standby Mode and Off Mode for Microwave Ovens, 77 Fed. Reg. 8526 (Feb. 14, 2012); Energy Conservation Program: Energy Conservation Standards for Distribution Transformers, 77 Fed. Reg. 7282 (Feb. 10, 2012); Energy Conservation Program for Certain Industrial Equipment: Energy Conservation Standards and Test Procedures for Commercial-Heating, Air-Conditioning, and Water-Heating Equipment, 77 Fed. Reg. 2356 (Jan. 17, 2012); 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards, 76 Fed. Reg. 74,854 (Dec. 1, 2011); Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 Fed. Reg. 52,738 (Aug. 23, 2011); Energy Conservation Program: Energy Conservation Standards for Residential Furnaces and Residential Central Air Conditioners and Heat Pumps, 76 Fed. Reg. 37,549 (June 27, 2011); Energy Conservation Program: Energy Conservation Standards for Residential Clothes Dryers and Room Air Conditioners, 76 Fed. Reg. 22,324 (Apr. 21, 2011); Energy Conservation Program: Energy Conservation Standards for Fluorescent Lamp Ballasts, 76 Fed. Reg. 20,090 (Apr. 11, 2011); National Emission Standards for Hazardous Air Pollutants: Mercury Emissions from Mercury Cell Chlor-Alkali Plants, 76 Fed. Reg. 13,852 (Mar. 14, 2011); Greenhouse Gas Emissions Standards

The IWG's most recent value for the social cost of carbon is $37/ton (central value for a ton released in 2015, assuming a 3% discount rate).[2] The SCC is derived from running three state-of-the-art, peer-reviewed Integrated Assessment Models ("IAMs") that quantify the costs of climate change to the economy. They project future economic output with and without climate change using five reference scenarios and three constant discount rates of 2.5, 3, and 5 percent. The use of three models, three discount rates, and five scenarios produces a number of distributions for the SCC. The final $37 number is the average of the monetized effect found by all three models under the central model run, assuming a 3% discount rate. SCC values rise over time, reflecting the increased costs of unmitigated climate change over time. A ton emitted in 2020 is calculated to come with a social cost of $43; a ton emitted in 2025 will cost $47 (Table 1).

This central value is conservative because it does not reflect a declining discount rate, fully value impacts associated with catastrophic events, or include non-monetized benefits. The latter may be the most significant omission, since quantifying the full cost of climate damages is difficult. The IWG also presents a value for the 95th-percentile of the SCC distribution as a conservative proxy for including the value of extreme events (Table 1). This estimate can only be seen as a proxy and is likely a large underestimate of the actual damages in extreme situations.[3]

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and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles, 75 Fed. Reg. 74,152 (Nov. 30, 2010); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, 75 Fed. Reg. 63,260 (Oct. 14, 2010); Energy Conservation Program: Energy Conservation Standards for Residential Refrigerators, Refrigerator-Freezers, and Freezers, 75 Fed. Reg. 59,470 (Sept. 27, 2010); Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 75 Fed. Reg. 45,210 (Aug. 2, 2010).

[2] EDF-REB-GW-EX B. "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866" (November 1, 2013)

[3] E.g.: Pindyck, Robert S. 2012. "Uncertain outcomes and climate change policy." Journal of Environmental Economics and Management 63, no. 3: 289-303. (EDF-REB-GW-EX C) Weitzman, Martin. "GHG Targets as Insurance Against Catastrophic Climate Damages." Journal of Public Economic Theory. 2012;14(2):221-244. (EDF-REB-GW-EX D) Pindyck, Robert S. 2013. "The Climate Policy Dilemma." Review of Environmental Economics and Policy vol. 7(2):219-237. (EDF-REB-GW-EX E) Wagner, Gernot and Richard J. Zeckhauser. "Expecting a Black Swan and Getting a Dragon: Confronting Deep Uncertainty in Climate Change." ASSA Conference presentation (January 3, 2014). (EDF-REB-GW-EX F)

Table 1—Social cost of carbon dioxide, 2010-2050 (in 2007 dollars per metric ton of CO_2)

	5.0%	3.0%	2.5%	3.0%
Year	Avg	Avg	Avg	95th
2010	11	32	51	89
2015	11	37	57	109
2020	12	43	64	128
2025	14	47	69	143
2030	16	52	75	159
2035	19	56	80	175
2040	21	61	86	191
2045	24	66	92	206
2050	26	71	97	220

Using the Social Cost of Carbon to Calculate Damage associated with Methane Emissions

Each greenhouse gas has its own potential to force changes to the climate, and those impacts can also differ over time. To evaluate the SCC of a non CO2 greenhouse gas, such as methane, it is necessary to convert those emissions to the same units as the SCC, using the Global Warming Potential ("GWP") of the gas at issue. GWP is a measure of the climate forcing potential of a gas (such as methane) relative to CO2.

The most recent Intergovernmental Panel on Climate Change ("IPCC") establishes the 100-year GWP for methane at a figure of at least 28, which means that methane is 28 times more potent than CO2 over a 100-year period.[4] However, because methane causes greater climate damage over shorter time frames than over longer time frames, choosing a 100-year GWP will undervalue the short-term impacts of methane. Accordingly, the benefits of methane reductions should also be valued using the most-recent 20-year GWP for methane, which is at least 84.

These GWP values for methane (28 long term and 84 short term) are conservative because they do not include climate-carbon ("cc") feedbacks (which are feedbacks between climate change and the carbon cycle). The latest IPCC report concludes that, when cc is considered, methane has an even higher GWP on both 100- and 20-year timeframes of 34 and 86, respectively.[5] Other scientific analyses have likewise determined that methane is an even more potent climate forcer.[6]

Table 2 below shows the GWP of methane in the short and long term from the most recent IPCC report, both with and without climate-carbon feedback.

Table 2—Global Warming Potential (GWP) of methane relative to one metric ton of CO_2

	Global Warming Potential (GWP) relative to CO_2
100-year GWP without cc feedbacks	28
100-year GWP with cc feedbacks	34
20-year GWP without cc feedbacks	84
20-year GWP with cc feedbacks	86

[4] CLIMATE CHANGE 2013: THE PHYSICAL SCIENCE BASIS, CONTRIBUTION OF WORKING GROUP I TO THE FIFTH ASSESSMENT REPORT OF THE INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE at Table 8.A.1 (Joussaume, S., J. Penner & F. Tangang eds. 2013), *available at* http://www.climatechange2013.org/images/uploads/WGIAR5_WGI-12Doc2b_FinalDraft_All.pdf.
[5] *Id.* at Table 8.7.
[6] EDF-REB-GW-EX G. D.T. Shindell, G. Faluvegi, D.M. Koch, G.A. Schmidt, N. Unger, S.E. Bauer (2009) "Improved Attribution of Climate Forcing to Emissions," *Science* **326** 716-718.

This conversion yields a conservative estimate—undervaluing the benefits of methane reductions by up to 36%.[7]

Calculating the Benefits of Anticipated Methane Reductions from Proposed Changes to Air Pollution Control Regulations in Colorado

An expert retained by EDF, WZI Inc., estimates that the proposed rule will reduce methane emissions by around 112,000 short tons per year once fully implemented (EDF-PHS-WZI Expert Report, Table 7-1). Table 3, below, calculates the value of avoided methane emissions in 2007 dollars for 2015, 2020, and 2025 by using central values for the social cost of carbon (at the central 3% discount rate). This table results from the IWG values for SCC, the IPCC values for GWP of methane, and the WZI estimate of methane reductions. Benefits are calculated using both 100- and 20-year GWPs for methane, and GWPs with and without climate-carbon feedbacks. The calculations are performed by multiplying the SCC (shown in the top row) by the GWP of methane (shown in the column on the left) times the tons of methane reduced (112,000 short tons based on current oil and gas production activity in Colorado, equal to 102,000 metric tons).

In 2015, the central value for calculated benefits is $104,000,000, going as high as $318,000,000. In 2025, the central value for calculated benefits is $132,000,000, going as high as $404,000,000 (Table 3).

The values below almost certainly understate the actual SCC associated with these emissions. Among other things:

- The values are stated in 2007 dollars, so the values are understated in terms of current dollars.

[7] EDF-REB-GW-EX H. Marten, Alex L., and Stephen C. Newbold. "Estimating the social cost of non-CO2 GHG emissions: Methane and nitrous oxide." *Energy policy* 51 (2012): 957-972, at 964;Marten, A. L., and Newbold, S. C. (2011), "Estimating the Social Cost of Non-CO2 GHG Emissions: Methane and Nitrous Oxide," EPA NCEE Working Paper # 11-01, at 16, available at http://www.sciencedirect.com/science/article/pii/S0301421512008555.

- The 2025 reductions only account for the existing rates of production. Production is projected to increase, so the actual reductions compared to the business as usual case would be greater than indicated below.
- This estimate does not include the monetary impact of extreme climate events. IWG prepared an SCC that includes these factors (shown as the "95th percentile" value in Table 1 above). The estimate for these factors would increase the values below by approximately a factor of three.
- The conversion of the SCC to the social cost of methane using GWP is likely conservative, resulting in a further underestimate.[8]

Table 3—Benefits of Methane reductions from Proposed Oil and Gas Rule (in 2007 dollars)

	2015	2020	2025
	3.0% Average (SCC: $37)	3.0% Average (SCC: $43)	3.0% Average (SCC: $47)
100-year GWP without cc feedbacks (GWP: 28)	$104 million	$120 million	$132 million
100-year GWP with cc feedbacks (GWP: 34)	$126 million	$146 million	$160 million
20-year GWP without cc feedbacks (GWP: 84)	$311 million	$361 million	$395 million
20-year GWP with cc feedbacks (GWP: 86)	$318 million	$370 million	$404 million

[8] See footnote 7 above.

I, Gernot Wagner, of proper age, state that the above-testimony has been prepared by me, or under my supervision and control, and that it is true and correct to the best of my knowledge, and belief, and would be the same if given orally under oath.

Dr. Gernot Wagner

Date: January 30, 2014

EXHIBIT A
TO THE JOINT INDUSTRY WORK GROUP REBUTTAL STATEMENT

REVISED COLLECTIVE PROPOSED REVISIONS

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 3

STATIONARY SOURCE PERMITTING AND AIR POLLUTANT EMISSION NOTICE REQUIREMENTS

5 CCR 1001-5

>>>>>>>>

PART A CONCERNING GENERAL PROVISIONS APPLICABLE TO REPORTING AND PERMITTING

>>>>>>>>

II. Air Pollutant Emission Notice (APEN) Requirements

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II.B.3. APEN Applicability

For the purposes of Air Pollutant Emission Notice applicability, a source will be considered to be an individual emission point, or group of points pursuant to Section II.B.4. of this Part A.

II.B.3.a. Criteria Pollutants

For criteria pollutants, Air Pollution Emission Notices are required for: ~~each individual emission point in a nonattainment area with uncontrolled action emissions of one ton per year or more of any criteria pollutant (pollutants are not summed) for which the area is nonattainment;~~ each individual emission point ~~in an attainment or attainment/maintenance area~~ with uncontrolled actual emissions of two tons per year or more of any individual criteria pollutant (pollutants are not summed)~~;~~ and each individual emission point with uncontrolled actual emissions of lead greater than one hundred pounds per year, regardless of where of where the source is located.

II.B.3.b. Non-criteria Reportable Pollutants

For non-criteria reportable pollutants, Air Pollutant Emission Notices are required for each individual emission point with uncontrolled actual emissions equal to or greater than 250 pounds per year or more of any individual non-criteria reportable pollutant (pollutants are not summed) ~~that exceed the de minimis levels as determined following the procedures set forth in Appendix A.~~

>>>>>>>>

II.D. Exemptions from Air Pollutant Emission Notice Requirements

II.D.1. ~~Notwithstanding the exemptions contained in Section II.D.1., Air Pollutant Emission Notices must be filed for all emission units specifically identified in the applicability section of any subpart of Part A of Regulation Number 6 (New Source Performance Standards) and/or Regulation Number 8 (Hazardous Air Pollutants), Parts A,C,D, and E. However, Air Pollutant Emission Notices need not be filed for wet screening operations subject to Subpart OOO of the New Source Performance Standards if the exemption in Section II.D.1.cccc. is applicable.~~

Stationary sources having emission units that are exempt from the requirement to file an Air Pollutant Emission Notice must nevertheless comply with all requirements that are otherwise applicable specifically to the exempted emission units, including, but not limited to: Title V, Prevention of Significant Deterioration, nonattainment New Source Review, opacity limitations, odor limitations, particulate matter limitations, and volatile organic compounds controls.

An applicant may not omit any information regarding APEN exempt emission units in any permit application if such information is needed to determine the applicability of Title V (Part C of this Regulation Number 3), Prevention of Significant Deterioration (Section VI., Part D of this Regulation Number 3), or nonattainment New Source Review (Section V., Part D of this Regulation Number 3).

The following sources are exempt from the requirement to file Air Pollutant Emission Notices because by themselves, or cumulatively as a category, they are deemed to have a negligible impact on air quality.

II.D.1.a. Individual emission points ~~in nonattainment areas having uncontrolled actual emissions of any criteria pollutant of less than one ton per year, and individual emission points in attainment or attainment/maintenance areas~~ having uncontrolled actual emissions of any criteria pollutant of less than two tons per year~~,~~ and each individual emission point with uncontrolled actual emissions of lead less than one hundred pounds per year~~, regardless of where the sources is located~~.

II.D.1.b. Individual emission points ~~of non criteria reportable pollutants~~ having uncontrolled actual emissions of any individual non-criteria reportable pollutant less than ~~the de minimis levels as determined following the procedures set forth in Appendix A~~ 250 pounds per year.

>>>>>>>>

APPENDIX A
APPENDIX A
~~Method For Determining~~ De Minimis Levels For Non-Criteria Reportable Pollutants

An Air Pollutant Emission Notice must be filed for each emission point (individual or grouped) that has uncontrolled actual emissions equal to or greater than 250 pounds per year of any non-criteria reportable pollutant listed in Appendix B.

If a non-criteria pollutant is not listed in Appendix B, it does not have to be reported unless it is included in a chemical compound group.

~~**The following procedures must be followed in order to determine the appropriate de minimis (minimum) reporting level for each pollutant that is emitted from each emission point at a contiguous site. If you do not wish to use the three-scenario approach at your facility, you may elect to use Scenario 1 for all emission points.**~~

Definitions

~~Release Point - the lowest height above ground level from which the pollutants are emitted to the atmosphere.~~

~~Property Boundary - the distance from the base of the release point to the nearest property boundary.~~

Point - an individual emission point or a group of individual emission points reported on one Air Pollutant Emission Notice as provided for in Part A, Section II.B.4.

~~**Methodology**~~

~~To determine the de minimis level for a single pollutant being emitted from a point (single or grouped).~~

~~**STEP 1:**~~

~~Determine which of the three scenarios below applies to the emission point. If different scenarios can be applied to the same emission point, use the highest numbered scenario that applies. In the case of grouped emission points, use the lowest scenario number (for the entire group) that applies to any of the single emission points within the group.~~

~~Scenario 1: Release point less than 10 meters or property boundary less than 100 meters;~~

~~Scenario 2: Release point equal to or greater than 10 meters, but less than 50 meters, or property boundary equal to or greater than 100 meters, but less than 500 meters; or~~

~~Scenario 3: Release point equal to or greater than 50 meters, or property boundary equal to or greater than 500 meters.~~

~~**STEP 2:**~~

~~Use Appendix B to identify which of the three bins (Bin A, B, or C) the chemical is listed under.~~

~~If the pollutant is not listed, it does not have to be reported unless it is included in a chemical compound group.~~

~~**STEP 3:**~~

~~Use the table below to determine the de minimis level.~~

~~All values are in pounds per year.~~

	~~**Scenario 1**~~	~~**Scenario 2**~~	~~**Scenario 3**~~
~~Chemical Bin~~	~~De Minimis~~	~~De Minimis~~	~~De Minimis~~
~~Bin A~~	~~50~~	~~125~~	~~250~~

~~Bin B~~	~~500~~	~~1250~~	~~2500~~
~~Bin C~~	~~1000~~	~~2500~~	~~5000~~

~~**STEP 4:**~~

~~Repeat the above steps for each pollutant emitted from each emission point (single or grouped). One Air Pollutant Emission Notice must be filed for each emission point that emits one or more chemicals above the de minimis level.~~

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PART B CONCERNING CONSTRUCTION PERMITS

>>>>>>>>

II. General Requirements For Construction Permits

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II.A.5. Construction permits are required for hazardous air pollutants if:

II.A.5.a. The source is subject to Colorado Maximum Achievable Control Technology or Generally Available Control Technology~~; or~~

~~II.A.5.b. The source is subject to Federal National Emission Standards for Hazardous Air Pollutants; or~~

~~II.A.5.c. The source is subject to Federal Maximum Achievable Control Technology or Generally Available Control Technology standards; or~~

~~II.A.5.d. The source is subject to Regulation Number 8, Part E, where the more specific requirements of Regulation Number 8, Part E, take precedence over requirements in this regulation.~~

>>>>>>>>

II.D. Exemption from Construction Permit Requirements

~~None of the exemptions listed below in Sections II.D.1. through II.D.4. shall apply if a source is subject to Part A of Regulation Number 6 (New Source Performance Standards) and/or Regulation Number 8 (Hazardous Air Pollutants), Parts A,C, D, and E.~~ Permit exemptions taken under this section do not affect the applicability of ~~the~~ any State or Federal regulations that are otherwise applicable to the source.

An applicant may not omit any information regarding APEN or permit exempt emission units in any application if such information is needed to determine the applicability of Title V (Part C of this Regulation Number 3), Prevention of Significant Deterioration (Section VI. of Part D of this Regulation Number 3), or Nonattainment New Source Review (Section V. of Part D of this Regulation Number 3).

II.D.1. The following sources are exempt because by themselves, or cumulatively as a category, they are deemed to have a negligible impact on air quality:

>>>>>>>>

II.D.1.l. Crude oil truck loading equipment at exploration and production sites where the loading rate does not exceed 10,000 gallons of crude oil per day averaged on an annual basis. Condensate truck loading equipment at exploration and production sites that splash fill less than 6750 barrels of condensate per year or that submerge fill less than 16308 barrels of condensate per year. ~~Crude oil or condensate loading truck equipment at crude oil production sites where the loading rate does not exceed 10,000 gallons per day averaged over any thirty-day period.~~

>>>>>>>>

II.D.1.n. Exemption Repealed ~~Crude oil storage tanks with a capacity of 40,000 gallons or less.~~

II.D.2. ~~Facilities located in a nonattainment area for any criteria pollutant for which the area is nonattainment; with t~~Total facility-wide uncontrolled actual emissions ~~(potential emissions at actual operating hours)~~ that are less than the following amounts:

II.D.2.a. ~~Two~~ Twenty five tons per year of volatile organic compounds.

II.D.2.b. ~~One ton per year PM10~~Twenty five tons per year of any other criteria pollutant, except for lead.

~~II.D.2.c. One ton per year PM2.5.~~

~~II.D.2.d. Five tons per year total suspended particulate.~~

~~II.D.2.e. Five tons per year carbon monoxide.~~

~~II.D.2.f. Five tons per year sulfur dioxide.~~

~~II.D.2.g. Facilities located in attainment or attainment/maintenance areas for all criteria pollutants with total facility uncontrolled actual emissions less (potential emissions at actual operating hours) than the following amounts:~~

~~II.D.3. Facilities located in attainment or attainment/maintenance areas for all criteria pollutants with total facility uncontrolled actual emissions less (potential emissions at actual operating hours) than the following amounts:~~

~~II.D.3.a. Five tons per year volatile organic compounds.~~

~~II.D.3.b. Five tons per year PM10.~~

~~II.D.3.c. Five tons per year PM2.5.~~

~~II.D.3.d. Ten tons per year total suspended particulate.~~

~~II.D.3.e. Ten tons per year carbon monoxide.~~

~~II.D.3.f. Ten tons per year sulfur dioxide.~~

~~II.D.3.g. Ten tons per year nitrogen oxides.~~

~~II.D.3.h. Two hundred pounds per year lead.~~

II.D.3~~4~~. Facilities that emit any other criteria pollutant that is not listed in Section~~s~~ II.D.2.~~ and II.D.3.~~, above (flourides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, reduced sulfur compounds, and municipal waste combustor engines), with total facility uncontrolled actual emissions of such pollutants that are less than ~~two ~~twenty five tons per year.

II.D.5~~5~~. When a facility that was previously exempt from permit requirements exceeds one of the permit de minimis levels stated in Section~~s~~ II.D.2.~~ through II.D.4., above~~, due to the addition of new emission points or an increase in uncontrolled actual emissions, the Division will issue either a facility-wide permit for all non-grandfathered emission units ~~above ~~that require Air Pollutant Emission Notices~~ de minimis levels~~=, or individual emission permits for those emission units that are not otherwise permit exempt.

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PART C CONCERNING OPERATING PERMITS

>>>>>>>>

II.E. Insignificant Activities and Exemptions from Operating Permit Requirements

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The following sources are exempt from the requirement to obtain an operating permit pursuant to this Part C:

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II.E.3.ddd. Exemption Repealed ~~*Crude oil storage tanks with a capacity of 40,000 gallons or less.~~

>>>>>>>>

PART D CONCERNING MAJOR STATIONARY SOURCE NEW SOURCE REVIEW AND PREVENTION OF SIGNIFICANT DETERIORATION

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XV. Actuals PALs

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XV.F. Contents of the PAL permit.

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XV.F.5. A requirement that, once the PAL expires, the major stationary source is subject to the requirements of Section XV.H.

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 6

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

5 CCR 1001-8

PART A

Federal Register Regulations Adopted by Reference

>>>>>>>>

The Air Quality Control Commission adopts in full Subpart OOOO, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution,~~.~~ 40 CFR Part 60, Subpart OOOO (July 1, 2012), as amended by 78 Fed. Reg. 58416 (September 23, 2013) only ~~.~~if the Environmental Protection Agency (EPA), approves the Air Quality Control Commission's Revisions to Regulation Number 3 adopted on [insert date]. If the EPA disapproves of the Air Quality Control Commission's Revisions to Regulation Number 3 adopted on [insert date], full adoption of Subpart OOOO, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, 40 CFR Part 60, Subpart OOOO (July 1, 2012), as amended by 78 Fed. Reg. 58416 (September 23, 2013) by the Air Quality Control Commission herein will be immediately and automatically withdrawn.~~, August 16, 2012, (77 FR 49490) where both uncontrolled actual emissions from the affected facility are equal to or greater than the Air Pollution Emission Notice (APEN) thresholds found at Regulation Number 3, Part A, Sections II.B.3.a. or II.B.3.b. and total facility uncontrolled actual emissions are equal to or greater than the permitting thresholds found at Regulation Number 3, Part B, Sections II.D.2., II.D.3., or II.D.4. for the following affected facilities: storage vessels at well sites beginning ninety days after the first day of production; storage vessels at any site other than well sites in the oil and natural gas production segment, the natural gas processing segment, and the natural gas transmission and storage segment; centrifugal compressors with wet seals; reciprocating compressors; pneumatic controllers; the group of all equipment (equipment leaks or leaking components) at on-shore natural gas processing plants; and sweetening units at on-shore natural gas processing plants~~.

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE VIA OZONE PRECURSORS ~~AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS~~

(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

5 CCR 1001-9

[The Joint Industry Work Group proposes that all Division Proposed Rules as well as any changes made in this Revised Collective Proposed Revisions document apply only in the ozone nonattainment area]

>>>>>>>>

II. General Provisions

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II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation.

~~(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Sections XVII. and XVIII.~~

>>>>>>>>

XVII. (State Only, except Section XVII.E.3.a. which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines

XVII.A. (State Only) Definitions

XVII.A.1 "Air Pollution Control Equipment," as used in this Section XVII, means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section XVII.B.2.e.

XVII.A.2. ""Approved Instrument ~~Based~~ Monitoring Method" or "AIMM"~~," as used in this Section XVII."~~ means an infra-red camera with cooled InSb focal plane array with non-dispersive infra-red filter, tunable diode laser absorption spectroscopy ("TDLAS"), flame ionization detector, optical methane detector, infra-red controlled interference polarization spectrometer, cavity ring-down spectroscopy, mid-infra-red laser-based differential absorption light detection and ranging ("LIDAR"), pulsed infra-red laser, three-channel non-dispersive gas correlation infra-red spectrometer, EPA Method 21, or other Division approved instrument ~~based~~ monitoring, device or method. If an owner~~/~~ or operator elects to use ~~a~~ Division approved ~~Continuous Emission Monitoring program~~continuous emission monitoring, the Division may approve a streamlined inspection and reporting program for such operations. ~~Any instrument based monitoring method approved by the Division under this definition must be at least as effective as Method 21 or an infra-red camera.~~

XVII.A.~~2.~~ ~~"Atmospheric", when used to modify the term "condensate storage tank", means a type of condensate storage tank that vents, or is designed to vent, to the atmosphere.~~3. ""Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust ~~volatile organic compound~~ VOC emissions.

XVII.A.4. "Centrifugal Compressor" means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

XVII.A.5. "Component" means each pump seal, ~~compressor seal~~, flange, pressure relief device, connector, ~~open ended line~~, and valve that contains or contacts a process stream with ~~hydrocarbons~~at least 10 percent VOCs by weight. For the purpose of Section IXVII., ~~P~~process stream~~s~~ does not include those streams consisting of glycol, amine, produced water, or methanol ~~are not components for purposes of this Section XVII~~.

XVII.A.~~5~~6. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Jointed fittings welded completely around the circumference of the interface are not considered connectors.

XVII.A.~~3~~6. "~~Condensate Storage Tank" means any production tank or series~~Date of First Production" means the date reported to the COGCC as the "~~first~~ date of first production ~~tanks that are manifolded together that store condensate~~."

XVII.A.~~7~~8. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

XVII.A.9 "Intermediate Hydrocarbon Liquid" means any naturally occurring, unrefined petroleum liquid, as defined in 40 CFR Part 60, Subpart OOOO.

~~XVII.A.89. "Multi-Well Site" means a common well pad from which multiple wells may be drilled to various bottomhole locations.~~

XVII.A.~~9~~10. "Natural Gas Compressor Station" means a facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure ~~and recompress~~ prior to the inlet of a natural gas ~~prior to~~ processing plant.

XVII.A.~~10~~11. "Normal Operation" means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. ~~For storage tanks at well production facilities, normal operation includes, but is not limited to, liquid dumps from the separator.~~

~~XVII.A.11~~XVII.A.12. "Open-Ended Valve or Line" means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

XVII.A.13. "Reciprocating Compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the driveshaft.

XVII.A.14. "Stabilized" when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited to those commonly referred to within the industry as working, breathing, and standing losses.

XVII.A.~~12~~15. "Storage Tank" means any permanent fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage vessel is as defined in 40 CFR Part 60, Subpart OOOO. Storage tanks may be located at a well production facility or other location.

~~XVII.A.1316. "Unsafe to Monitor" means a component is unsafe to inspect because inspecting personnel would be exposed to an imminent or potentialimmediate danger as a consequence of such monitoring.~~

XVII.A.16. "Uncontrolled Release" means emissions from thief hatches (or other access points to the storage tank) and pressure relief devices at a storage tank that result from inadequate design, operation, or maintenance, except for those emissions that are necessary for the safety of personnel and equipment. Emissions during routine maintenance, tank gauging, and loadout operations shall not be considered Uncontrolled Releases.

XVII.A.~~14~~17. "Visible Emissions" means observations of smoke for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation pursuant to EPA Method 22. Visible emissions do not include radiant energy or water vapor. This definition also applies to Visible Emissions as referred to in XII of this Regulation Number 7.

XVII.A.~~15~~18. "Well Production Facility" means all permanent equipment co-located at a single stationary source directly associated with one or more oil ~~wells~~ or gas production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline located at the inlet to the separator through the point of Custody Transfer. Oil and gas production wells located on the same surface disturbance as the single stationary source are included in the Well Production Facility. "Custody Transfer" means the transfer of produced crude oil and/or condensate, after processing and/or treating in the producing operations, from Storage Tanks or automatic transfer facilities to sales pipelines or any other forms of post-sales transportation or the point at which natural gas passes from Well Production Facilities to natural gas gathering lines through which gathered natural gas is conveyed to Compressor Stations.

XVII.B. (State Only) General Provisions

These Regulations shall not apply to any lands within the exterior boundaries of the Southern Ute Indian Reservation, as agreed in, and defined by, that Intergovernmental Agreement between the Southern Ute Indian Tribe and the State of Colorado Concerning Air Quality Control on the Southern Ute Indian

Reservation, codified at Colorado Revised Statutes Section 24-62-101 (2013); (see also C.R.S. § 25-7-1301 (2013)); and approved by the United States Environmental Protection Agency on March 2, 2012 at 77 Fed. Reg. 15267 (March 14, 2012).

XVII.B.1. General requirements for prevention of emissions and good air pollution control ~~equipment, prevention of leakage, and flares and combustion devices.~~practices for all ~~oil and gas exploration and production operations,~~ well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.B.1.a. All intermediate hydrocarbon liquids collection, storage, processing, and handling operations, regardless of size, shall be designed, operated, and maintained so as to minimize leakage of ~~volatile organic compounds~~VOCs and other hydrocarbons to the atmosphere to the extent reasonably practicable.

XVII.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment ~~shall~~must be maintained and operated in a manner consistent with good air pollution control practices for minimizing VOC emissions. Determination of whether or not acceptable ~~operating~~operation and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of ~~operating~~operation and maintenance procedures, and inspection of the source.

XVII.B.2. General requirements for air pollution control equipment~~, flares, and combustion devices used~~ required to comply with Section XVII.

XVII.B.~~1~~2.a. All air pollution control equipment ~~required by this Section XVII~~ shall be operated and maintained pursuant to ~~manufacturer~~the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates ~~required by this Section XVII~~ and to handle reasonably foreseeable fluctuations in emissions of ~~volatile organic compounds~~VOCs ~~and other hydrocarbons~~ during normal operations. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

~~XVII.B.1.b. All condensate collection, storage, processing and handling operations, regardless of size, shall be designed, operated and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the extent reasonably practicable.~~

XVII.B.~~1~~2.~~c~~b. If a ~~flare or other~~ combustion device is used to control emissions of ~~volatile organic compounds to comply with Section XVII~~VOCs ~~and other hydrocarbons~~ from storage tanks subject to Section XVII.C. and glycol natural gas dehydrators subject to Section XVII.D., it shall be enclosed except as described below in Section XVII.B.2.f., have no visible emissions during normal ~~operations~~operation, and be designed so ~~than~~that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other ~~convenient~~ means approved by the Division, determine whether it is operating properly. An owner or operator that installed a combustion device prior to [insert date of promulgation] with Division approval, either express or implied, is not required to replace or retrofit the control device unless the combustion device is modified after [insert date of promulgation].

XVII.B.~~1~~2.~~d~~c. Any of the effective dates for installation of controls on ~~condensate~~storage tanks, glycol natural gas dehydrators, and/or internal combustion engines may be extended at the ~~air pollution control~~ Division's discretion for good cause shown.

XVII.B.2.d. Auto-igniters: All combustion devices used to control emissions of ~~hydrocarbons~~ VOCs from storage tanks subject to Section XVII.C. and glycol natural gas dehydrators subject to Section XVII.D. ~~shall~~must be equipped with and operate an auto-igniter as follows:

XVII.B.2.d.(i) All such combustion devices installed on or after ~~May~~ January 1, 2015~~4~~, ~~will~~must be equipped with an operational auto-igniter upon installation of the combustion device~~.~~; and

XVII.B.2.d.(ii) All such combustion devices installed before ~~May~~ January 1, 2015~~4~~, ~~will~~must be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

XVII.B.2.e. Alternative emissions control equipment shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section XVII, if the Division approves the equipment, device or process. ~~As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section XVII.~~

XVII.B.2.f. An owner or operator may install a non-enclosed flare that otherwise meets the requirements of XVII.B.2.b. to control volatile organic compounds as follows:

XVII.B.2.f.(i) If the flare will control emissions at a Well Production Facility, Compressor Station, or natural gas processing plant and the required design capacity exceeds the reasonably available capacity for an enclosed combustor;

XVII.B.2.f.(ii) If the flare will serve as a backup to the primary means of control;

XVII.B.2.f. (iv) If the flare is located more than 1,320 feet from a Residential Area. For purposes of this Section XVII.B.2.f., Residential Area means an area where six (6) or more occupied residential homes are within a 1,320 foot radius of the Well Production Facility, Compressor Station, or natural gas processing plant at which the flare is located. The presence of a Residential Area shall be determined at the time the non-enclosed flare is installed. Owners and operators shall not be required to replace or retrofit the non-enclosed flare in the event that a Residential Area is later established within 1,320 feet of the Well Production Facility, Compressor Station, or natural gas processing plant.

(v) An owner or operator that installed a flare subject to one of the exceptions at XVII.B.2.f.(i). through (iv). or with prior division approval, either express or implied, is not required to retrofit or replace the flare unless modified, pursuant to Regulation 3, and a cost-benefit analysis reasonably justifies retrofit or replacement.

XVII.B.2.g. In the event that a control device is inoperable or malfunctioning, the owner or operator may choose to shut-in operations to the source or site as an air pollution control alternative, in lieu of, emergency recordkeeping and reporting requirements. Only records of the shut-in and control device maintenance must be maintained.

XVII.B.3. Requirements for compressor seals and open-ended valves or lines at natural gas compressor stations only.

XVII.B.3.a. Beginning January 1, 2015, each open-ended valve or line at ~~well production facilities and~~ natural gas compressor stations must be equipped with a cap, blind flange, plug, or a second valve that seals the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirement to seal the open end of the valve or line.

XVII.B.3.b. Beginning January 1, 2015, uncontrolled actual ~~hydrocarbon~~ VOC emissions from wet seal fluid degassing systems on wet seal centrifugal compressors at natural gas compressor stations must be reduced by at least 95%, unless the centrifugal compressor is subject to 40 C.F.R. Part 60, Subpart OOOO on that date or thereafter.

XVII.B.3.c. Beginning January 1, 2015, at natural gas compressor stations, the rod packing on any reciprocating compressor installed must be replaced every 26,000 hours of operation or every thirty six (36) months, unless the reciprocating compressor is subject to 40 C.F.R. Part 60, Subpart OOOO on that date or thereafter or if the vent gas from the rod packing is being captured, controlled or put to other beneficial use. The measurement of accumulated hours of operation (26,000) or months elapsed (36) begins on January 1, 2015.

X.V.II.B.4. Oil refineries are not subject to ~~this section of the rule~~Section XVII.

XVII.B.~~4~~5. ~~Condensate tanks,~~Glycol natural gas dehydrators and internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard ("NSPS") under 40 CFR Part 60 are not subject to ~~this~~ Section XVII.

XVII.C. (State Only) Emission reduction from ~~condensate~~ storage tanks at ~~oil and gas exploration and production operations, natural gas compressor stations~~well production facilities, natural gas ~~drip~~compressor stations, and natural gas processing plants.

XVII.C.1. Control and monitoring requirements for storage tanks

XVII.C.1.a. Beginning May 1, 2008, owners or operators of all ~~atmospheric condensate~~ storage tanks storing condensate with uncontrolled actual emissions of ~~volatile organic compounds~~VOCs equal to or greater than twenty (20) tons per year based on a rolling twelve-month total ~~shall~~must operate air pollution control equipment that has an average control efficiency of at least 95% for VOCs ~~on such tanks~~.

XVII.C.~~2~~1.b. ~~For condensate~~Owners or operators of all storage tanks with ~~past,~~ uncontrolled actual emissions of ~~volatile organic compounds~~VOCs ~~of less~~equal to or greater than ~~20~~six (6) tons per year based on a rolling twelve-month total ~~that may become subject to Section XVII.C.1. by virtue of the addition of a newly drilled well or the recompletion or stimulation of an existing well, owners or operators of such tanks shall have until 90 days after the date of 1st production of the newly drilled, recompleted or stimulated well to install and~~must operate ~~any required~~ air pollution control equipment~~. If the owner or operator determines that emissions of volatile organic compounds will be below the 20 ton per year threshold, the owner or operator shall notify the Division of this determination in writing and include an explanation of the methodology used to make this determination.~~ that achieves an average ~~hydrocarbon~~ VOC control efficiency of 95%. If a combustion device is used, it ~~shall~~must have a design destruction efficiency of at least 98% for ~~hydrocarbons~~VOCs.

XVII.C.1.b.(i) Control requirements of Section XVII.C.1.b. must be achieved in accordance with the following schedule:

XVII.C.1.b.(i)(a) A storage tank constructed on or after ~~May~~ January 1, 201~~4~~5, must be in compliance ~~by~~within ninety (90) days from the date that the storage tank commences operation.

XVII.C.1.b.~~(ii)~~(i)(b) A storage tank ~~constructed~~ that began operating before ~~May~~ January 1, 201~~5~~4, must be in compliance by May 1, 201~~6~~5.

XVII.C.1.b.~~(iii)~~(i)(d~~c~~) A storage tank not otherwise subject to Sections XVII.C.1.b.(i)(a) or XVII.C.1.b.(i)(b)~~(ii), above~~, that increases uncontrolled actual emissions to six (6) tons per year VOC or more ~~per year~~ on a rolling twelve month basis after ~~May~~ January 1, 201~~4~~5, must be in compliance within sixty ~~days~~ (60) days of discovery of the emissions increase.

XVII.C.1.c. Control requirements within ninety (90) days of the date of first production.

XVII.C.1.c.(i) Beginning ~~May~~ January 1, 201~~4~~5, owners or operators of storage tanks at well production facilities ~~shall~~must collect and control emissions by routing emissions to operating air pollution control equipment during the first ninety (90) calendar days after the date of first production. The air pollution control equipment ~~shall~~must achieve an average ~~hydrocarbon~~ VOC control efficiency of 95%. If a combustion device is used, it ~~shall~~must have a design destruction efficiency of at least 98% for ~~hydrocarbons~~VOCs. ~~Except that this~~This control requirement does not apply to storage tanks that are reasonably projected to have emissions less than 1.5 tons of VOC during the first ninety (90) days after the date of first production.

XVII.C.1.c.(ii) The air pollution control equipment and any associated monitoring equipment required pursuant to Section XVII.C.1.c~~., above~~(i), may be removed at any time after the first 90 calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank are reasonably expected to be below the threshold in Section XVII.C.1.b~~., above~~.

~~XVII.C.2. Capture requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or~~ XVII.C.1.

~~XVII.C.2.a.~~ Beginning ~~on~~January~~May~~ 1, 20154, or the applicable compliance date ~~specified~~ in Section XVII.C.1.b.~~,~~(i), whichever comes later, owners ~~and~~or operators of storage tanks ~~shall route all hydrocarbon emissions~~subject to ~~air pollution control equipment, and shall operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment.~~

~~XVII.C.2.b. Beginning on the applicable compliance date specified in section XVII.C.1.b., owners and operators of storage tanks shall develop, certify, and implement a document Storage Tank Emission Management System (STEM) plan to identify appropriate strategies to minimize emissions from venting at thief hatches (or other access points to a storage tank) and pressure relief devices during normal operation. As part of STEM, owners and operators shall evaluate and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section XVII.C.2.a., above, and will update the STEM plan as necessary to achieve or maintain compliance. Owners and operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed below.~~

XVII.C.2.1.~~b.(i) STEM~~ must~~ include a monitoring strategy that incorporates the minimum monitoring frequency set forth in Section XVII.F.5.e., procedures for evaluating ongoing storage tank emission capture performance, and, if applicable, the selected strategies.~~

~~XVII.C.2.b.(ii) STEM must include a certification by the owner or operator that the selected STEM strategy or strategies are designed to minimize emissions from storage tanks and associated equipment components at the facility or facilities, including thief hatches and pressure relief devices.~~

~~XVII.C.3. Monitoring: The monitoring strategy of each STEM plan must include monitoring in accordance with Approved Instrument Based Monitoring Methods, as specified in Section XVII.F.5.~~

~~XVII.C.3.a. In addition to any applicable Approved Instrument Based Monitoring Methods,~~ conduct audio, visual, olfactory ("AVO") ~~inspection~~ and additional visual inspections of the storage tank and any associated equipment (~~i.~~e. separator, air pollution control equipment, or other pressure reducing equipment~~), must be completed~~) ~~as often~~at the same frequency as liquids are loaded out from the storage tank. ~~However, AVO inspection is~~These inspections are required no more frequently than every seven (7) days or less frequently than every thirty-one (31~~0~~) days. AVO monitoring is not required for ~~components and~~ storage tanks or associated equipment that are unsafe, difficult, or inaccessible to monitor~~. AVO inspection~~, as defined in Section XVII.C.1.e. The ~~additional visual~~AVO inspections must include, at a minimum:

XVII.C.~~3.a.~~1.d.(i) Visual inspection of any storage tank thief hatch, pressure relief valve, or other access point to ensure that they are enclosed and properly sealed;

XVII.C.~~3.a.~~1.d.(ii) Visual inspection or monitoring of the storage tank air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment;

XVII.C.~~3.a.~~1.d.(iii) If a ~~flare or other~~ combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light, to ensure they are functioning properly;

XVII.C.~~3.a.~~1.d.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open; and

XVII.C.~~3.~~1.d.(v) ~~Monitoring: The owner or operator of any condensate storage tank that is required to control volatile organic compound emissions pursuant to this Section XVII.C. shall visually inspect or monitor the Air Pollution Control Equipment to ensure that it is operating at least as often as condensate is loaded out from the tank, unless a more frequent inspection or monitoring schedule is followed. In addition, if~~a.(v) If a ~~flare or~~ other combustion device is used, ~~the owner or operator shall visually inspect~~inspection of the device for the presence ~~of~~ or absence of smoke. If smoke is observed, either the equipment ~~will~~must be immediately shut-in to investigate ~~that~~the potential cause for smoke and perform repairs, as necessary, or EPA Method 22 ~~shall~~must be conducted to determine whether visible emissions are present for a period of at least ~~as often as condensate is loaded out from the tank~~one (1) minute in fifteen (15) minutes.

XVII.C.1.e. If equipment associated with the storage tank is unsafe, difficult, or inaccessible to monitor, the owner or operator ~~is~~ shall not be required to monitor such equipment ~~until it becomes feasible to do so~~.

XVII.C.1.e.(i) Difficult to monitor equipment are those that ~~means it~~ cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or is unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

XVII.C.1.e.(ii) Unsafe to monitor means ~~it~~ equipment is unsafe to monitor because ~~cannot be monitored without exposing~~ monitoring personnel would be exposed to ~~an~~ imminent and potential ~~immediate~~ danger as a consequence of completing the monitoring.

XVII.C.1.e.(iii) Inaccessible to monitor equipment means equipment that is buried, insulated, or obstructed by equipment or piping that prevents access to the equipment by monitoring personnel.

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.

XVII.C.2.a. Owners or operators of storage tanks must ~~route all hydrocarbon emissions to air pollution control equipment, and must~~ operate ~~without~~ to minimize ~~venting hydrocarbon emissions~~ uncontrolled releases to the maximum extent practicable from the thief hatches (or other access point to the tank) or pressure relief device ~~during normal operation, unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment. Compliance must be achieved~~ in accordance with the schedule in Section XVII.C.2.b.(ii).

XVII.C.2.b. Beginning on January 1, 2015, or the applicable compliance date in Section XVII.C.1.b.(i), whichever comes later, ~~O~~owners or operators of storage tanks subject to control requirements of Sections XII.D.2., XVII.C.1.a. or XVII.C.1.b. must develop, certify, and implement a documented Storage Tank Emission Management System (STEM) plan to identify, evaluate, and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section XVII.C.2.a. An owner or operator may develop a STEM plan applicable to multiple Storage Tanks across some or all of the owner or operators' assets and operations within Colorado. ~~-~~Owners or operators must update the STEM plan as necessary to achieve or maintain compliance. Owners or operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed below.

XVII.C.2.b.(i) The STEM plan must include selected control technologies, monitoring practices, operational practices, and/or other strategies; procedures for evaluating ongoing storage tank emission capture performance; and monitoring in accordance with ~~approved instrument based monitoring methods~~AIMM following the applicable monitoring frequency in Table 1.

XVII.C.2.b.(ii) Owners or operators must achieve the requirements of Sections XVII.C.2.a. ~~and XVII.C.2.b.~~ and begin implementing the required ~~approved instrument based monitoring~~AIMM method in accordance with the following schedule:

XVII.C.2.b.(ii)(a) A storage tank constructed on or after ~~May~~ January 1, 2015~~4~~, must comply with the requirements of Sections XVII.C.2.a. ~~and XVII.C.2.b.~~ by the date that the storage tank commences operation. Approved instrument based monitoring method inspections must begin within ninety (90) days after the tank commences operation.

XVII.C.2.b.(ii)(b) A storage tank constructed before ~~May~~ January 1, 2015~~4~~, must comply with the requirements of Sections XVII.C.2.a. and XVII.C.2.b. by May 1, 201~~5~~6. Approved instrument based monitoring method inspections must begin within ninety (90) days of the Phase-In Schedule in Table 1, or within thirty (30) days for storage tanks with uncontrolled actual VOC emissions > 50 tons per year.

XVII.C.2.b.(ii)(c) A storage tank not otherwise subject to Sections XVII.C.2.b.(ii)(a) or XVII.C.2.b.(ii)(b) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve month basis after ~~May~~ January 1, 2015~~4~~, must be in compliance with Sections XVII.C.2.a. and XVII.C.2.b. and implement the required ~~approved instrument based monitoring~~AIMM method within sixty (60) days of discovery of the emissions increase.

XVII.C.2.b.(ii)(d) Following the first approved instrument based monitoring method inspection, owners or operators must continue conducting ~~approved instrument based monitoring~~AIMM method inspections in accordance with the Inspection Frequency in Table 1.

Table 1 – Storage Tank Inspections		
Threshold: Storage Tank Uncontrolled Actual VOC Emissions (tpy)	Approved Instrument Based Monitoring Method Inspection Frequency	Phase-In Schedule
> 6 and ≤~~<~~ 12	Annually	January 1, 2016
> 12 and ≤~~<~~ 50	Quarterly	July 1, 2015
> 50	Monthly	January 1, 2015

XVII.C.2.b.(iii) Owners or operators are not required to monitor storage tanks and associated equipment that are unsafe, difficult, or inaccessible to monitor, as defined in Section XVII.C.1.e.

XVII.C.2.b.(iv) STEM must include a certification by the owner or operator that the selected STEM strategy or strategies are designed to minimize emissions from storage tanks and associated equipment at the facility or facilities, including thief hatches and pressure relief devices.

XVII.C.3. Recordkeeping: The owner or operator of each condensate storage tank ~~shall~~subject to Sections XII.D. or XVII.C.1.b. must maintain ~~the following~~ records of STEM ~~as~~if applicable, including the plan, any updates, and the certification, ~~to be made~~and make them available to the Division upon request. In addition, for a period of ~~five~~two years, the owner or operator must maintain records of any required monitoring and make them available to the Division upon request, including:

XVII.C.~~4~~3.a. ~~Monthly condensate production from the~~The AIRS ID for the storage tank.

XVII.C.~~4~~3.b. The date and duration of any period where uncontrolled releases are discovered at the storage tank thief hatch, pressure relief device, or other access point ~~are found to be venting hydrocarbon emissions~~.

XVII.C.~~4.~~3~~b~~c. ~~For any condensate storage tank required to be controlled pursuant to this Section XVII.C., the~~The date~~, time~~ and duration of any period where the air pollution control equipment is not operating. ~~The duration of a period of non-operation shall be from the time that the air pollution control equipment was last observed to be operating until the time the equipment recommences operation.~~

XVII.C.~~4~~3.~~c~~d. ~~For tanks where~~Where a ~~flare or other~~ combustion device is being used, the date and ~~time of any instances where visible emissions are observed from the device~~result of any EPA Method 22 test or investigation pursuant to Section XVII.C.4.1.d.(v).

XVII.C.3.e. The timing of and efforts made to eliminate ~~venting~~an uncontrolled release, restore operation of air pollution control equipment, and to mitigate visible emissions.

XVII.C.3.f. A list of equipment that ~~identification numbers for components that are~~is designated as unsafe, difficult, or inaccessible to monitor, as described in Section

XVII.C.1.e., an explanation stating why the equipment~~component~~ is so designated, and the plan for monitoring such equipment~~component(s)~~.

XVII.D. (State Only) Emission reductions from glycol natural gas dehydrators

XVII.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at ~~an oil and gas exploration and production operation~~a well production facility, natural gas compressor station, ~~drip station or~~ or natural gas gas-processing plant subject to control requirements pursuant to Section XVII.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of ~~a condenser or~~ air pollution control equipment.

XVII.D.2. The control requirement in Section XVII.D.1. shall apply where:

XVII.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and

XVII.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.

~~XVII.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, and drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons, except where:~~

~~XVII.D.3.a. The combustion device has been authorized by permit prior to May 1, 2014; and~~

~~XVII.D.3.b. A building unit or designated outside activity area is not located within 1,320 feet of the facility at which the natural gas glycol dehydrator is located.~~

~~XVII.D.4. The control requirement in Section XVII.D.3. shall apply where:~~

~~XVII.D.4.a. Actual uncontrolled emissions Owners or operators of volatile organic compounds from a single newa glycol natural gas dehydrator are constructed on or after May 1, 2015, with uncontrolled actual emissions of VOCs equal to or greater than two (2) tons per year must be in compliance with Section XVII.D.3. by the date that the glycol natural gas dehydrator commences operation; or~~

~~XVII.D.4.b. Actual uncontrolled Uncontrolled actual emissions of volatile organic compoundsVOCs from a single existing glycol natural gas dehydrator constructed before May 1, 2015, are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.~~

~~XVII.D.4.c. For purposes of SectionSections XVII.D.3. and XVII.D.4.:~~

~~XVII.D.4.c.(i) Building Unit shall mean a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.~~

~~XVII.D.4.c.(ii) A designated outside activity areaDesignated Outside Activity Area shall mean an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a Designated Outside Activitydesignated outside activity area by the COGCC Area; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.~~

XVII.E. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

XVII.E.1. (State Only) The requirements of this Section XVII.E. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.2. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.2.a. Except as provided in Section XVII.E.2.b. below, the owner or operator ~~on~~of any natural gas fired reciprocating internal combustion engine that is either constructed or relocated to the state of Colorado from another state, on or after the date listed in the table below shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section XVII.E.2.b. Table ~~1~~2 below.

XVII.E.2.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table ~~1~~2 below as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE ~~1~~2				
Maximum Engine Hp	Construction or Relocation Date	Emission Standards is G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥100 Hp	On or after January 1, 2008	2.0	4.0	1.0

and < 500 Hp	On or after January 1, 2011	1.0	2.0	0.7
≥500 Hp	On or after July 1, 2007 On or after July 1, 2010	2.0 1.0	4.0 2.0	1.0 0.7

XVII.E.3. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.3.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

XVII.E.3.a.(i) Except as provided in Sections XVII.3.1.(i)(b) and (c) and XVII.E.3.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

XVII.E.3.a.(i)(a) All control equipment required by this Section XVII.E.3.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

XVII.E.3.a.(i)(b) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology (“MACT”) standard under 40 CFR Part 63, a Best Available Control Technology (“BACT”) limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to this Section XVII.E.3.a.

XVII.E.3.a.(i)(c) The requirements of this Section XVII.E.3.a. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.3.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1,2009.

XVII.E.3.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

XVII.E.3.b.(i) Except as provided in Section XVII.E.3.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

XVII.E.3.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.F. (State Only) Leak detection and repair program for components at well production facilities~~,~~ ~~storage tanks,~~ and natural gas compressor stations, excluding storage tank thief hatches, pressure relief devices, and access points subject to STEM. Natural gas processing plants, including Components, Storage Tanks and Compressor Stations at natural gas processing plants, are not subject to this Section XVII.F.

XVII.F.1. Beginning ~~January 1, 2015~~the date the well production facility or natural gas compressor station becomes subject to this Section XVII.F., owners ~~and~~or operators of components at well production facilities ~~and~~or natural gas compressor stations ~~will~~must identify and repair leaks from such components ~~at these facilities~~ in accordance with the requirements of this ~~this~~ Section XVII.F. The ~~following~~ provisions of Section XVII.F. shall apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

XVII.F.2. Owners ~~and~~or operators of components at well production facilities or natural gas compressor stations that monitor components as part of ~~this~~ Section XVII.F. may ~~opt to~~ estimate uncontrolled actual emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

~~XVII.F.3. Owners andor operators of well production facilities or natural gas compressor stations shall utilizemust implement the Approved Instrument Based Monitoring Method approved instrument based monitoring method and AVO programinspections as outlined in Section XVII.F. AVO monitoringMonitoring is not required offor components and tanks that are unsafe to monitor, difficult, or inaccessible to monitor, pursuant toas defined in Section XVII.F.5.g6.~~

XVII.F.3. If upon the completion of four consecutive semi-annual AIMM inspection events, no leaks requiring repair are detected, AIMM inspection shall be conducted annually for that well production facility or natural gas compressor station. If upon the completion of four consecutive quarterly AIMM inspection events, no leaks requiring repair are detected, AIMM inspection shall be conducted semi-annually for that well production facility or natural gas compressor station. If two or more leaks requiring repair are detected during subsequent AIMM inspection events, then the inspection frequency shall revert back to the original frequency for that well production facility or natural gas compressor station until the terms of this provision are again met.

XVII.F.3.a. An owner or operator may skip the next AIMM inspection event where the owner or operator demonstrates in the previous AIMM inspection event that less than or equal to 2 percent of components required repair for all well production facilities or natural gas compressor stations in a basin belonging to the same threshold class as set forth in Tables 2 and 3. An owner or operator may estimate a facility's component count using the Default Average Component Counts in 40 CFR Part 98, Subpart W, Tables W-1B and W-1C for equipment located at natural gas production facilities and oil production facilities, respectively.

XVII.F.4. ~~Inspection schedules for natural gas compressor stations: Beginning January 1, 2015, owners and~~ Leak detection for components at natural gas compressor stations.

XVII.F.4.a. Beginning January 1, 2016, within 180 days of startup of a new natural gas compressor station, ~~O~~owners or operators of natural gas compressor stations ~~shall~~must inspect components for leaks using an ~~Approved Instrument Based Monitoring Method~~ ~~approved instrument based monitoring~~AIMM ~~method~~, in accordance with ~~the following~~ Table ~~2~~3, except under the conditions described in XVII.F.6. ~~for components subject to~~~~that are unsafe, difficult, or inaccessible to monitor, as defined in Section XVII.F.5.g6.~~

XVII.F.4.b. Owners or operators of existing natural gas compressor stations shall inspect components for leaks as set forth in Table 3, except under the conditions described in Section XVII.F.6.

XVII.F.4.c. –For purposes of ~~this~~ Section XVII.F.4., fugitive VOC emissions ~~shall~~must be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), ~~of~~for other Division approved method.

~~Table 2~~Table 3
~~—~~Compressor Station Component Inspections

Fugitive VOC Emissions (tpy)	AIMM Inspection Frequency (calendar basis)	Beginning of Phase-In Schedule for Existing Compressor Stations[1]
> 2 and < 6	One time, within five years of applicable phase-in or implementation date	July 1, 2016
>6~~0~~ and < 20~~12~~	Annually	January 1, 2016
> ~~12~~ 20 and < 50	~~Quarterly~~Semi-annually	July 1, 2015
> 50	~~Monthly~~Quarterly	January 1, 2015

[1] As set forth in XVII.F.4.a., owners and operators of new Compressor Stations shall initiate compliance with this Table 2 within 180 days after the commenced construction date (i.e., the implementation date).

XVII.F.5. ~~Requirements~~ Leak detection for components at ~~for~~ well production facilities ~~and/or storage tanks~~

~~XVII.F.5.a. Beginning August 1, 2014, all newAll well production facilities shallconstructed on or after August 1, 2014, must have a documented pressure test performed on all equipment and piping prior to start up. Documentation of this 90 day testing and monitoring shallinitial pressure test must be provided in the first annual report to the Division, as required by Section XVII.F.910.~~

XVII.F.5.a~~b~~. ~~Beginning January 1, 2015, within 90 days of startup of all new~~Owners or operators of well production facilities ~~and/or storage tanks, owners and/or operators shall~~ constructed on or after January 1, 201~~5~~6, must ~~identify~~ inspect components for leaks using as set forth in Table 4 no later than 180 days after the date of first production, except under the conditions described in Section XVII.F.6.~~and repair leaks from components using an Approved Instrument Based Monitoring Method. Such action shall qualify as an inspection pursuant to approved instrument based monitoring method within ninety (90) days after the inspection frequencyfacility commences operation and in accordance with the Inspection Frequency schedule in Table 3.~~ To the extent that pursuant to Table 4 an AIMM inspection and an AVO monitoring would occur simultaneously, then the AIMM inspection satisfies the requirement to conduct AVO for that inspection.

4. XVII.F.5.c. ~~Consistent with the provisions of XVII.F.5.f., owners and~~ Owners or operators of ~~existing~~ well production facilities ~~and/or storage tanks shall identify and repair leaks using an Approved Instrument Based Monitoring Method, in accordance with the implementation schedule in XVII.F.5.e. Inspection frequency shall be determined according to Table 3.~~

~~XVII.F.5.d. Consistent with the provisions of XVII.F.5.f., owners and operators of new well production facilities and/or storage tanks shall identify and repair~~ constructed before January 1, 2016~~5~~, must ~~identify~~ inspect components for leaks as set forth in Table 4, except under the conditions described in Section XVII.F.6.~~from components using an Approved Instrument Based Monitoring Method beginning on January 1, 2015. approved instrument based monitoring method within ninety (90) days of the Phase-In Schedule in Table 4, within thirty (30) days for > 50 tons per year, or by July 1, 2016, for > 0 and < 6 tons per year tanks. Thereafter, approved instrument based monitoring method and AVO inspections must be conducted in accordance with the Inspection frequency shall be determined according to Frequency in Table 3~~4. To the extent that pursuant to Table 4 an AIMM inspection and an AVO monitoring would occur simultaneously, then the AIMM inspection satisfies the requirement to conduct AVO for that inspection.

XVII.F.5.~~e~~d. For purposes of this Section XVII.F.5., ~~T~~the VOC thresholds shall be calculated using the estimated uncontrolled actual emissions from the largest single storage tank~~s~~ as set forth in Table 4. ~~determine the frequency at which inspections must be performed.~~ If no storage tanks storing oil or condensate are located at the well production facility ~~or multi-well site~~, ~~owners or operators willmust rely on~~ VOC thresholds shall be calculated using the potential to emit of VOC for all of the emissions sources, including emissions from components located at the. ~~facility.~~

XVII.F.5.e. ~~All components at a~~ Inspection of components at a well production facility ~~or storage tank must be inspected~~ shall be conducted as set forth in Table 4:

~~Table 3~~Table 4 —Well Production Facility Component Inspections

VOC Threshold (per XVII.F.5.ed.) ~~VOC Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks~~)	AIMM Inspection Frequency (calendar basis)	AVO Monitoring Frequency (calendar basis)	Beginning of Phase-In Schedule For Existing Well Production Facilities[2]
> 2 and < 6	One time, within five years of phase-in or implementation date ~~using Approved Instrument Based Monitoring Method~~~~approved instrument based monitoring methods and thereafter using monthly AVO~~	Annual	July 1, 2016
> 6 and < ~~12~~20	Annually ~~with monthly AVO~~	Semi-annual	January 1, 2016
> ~~12~~ 20 and < 50	~~Quarterly with monthly AVO~~Semi-annually	Quarterly	July 1, 2015
> 50	~~Monthly~~Quarterly	Monthly	January 1, 2015
~~Multi~~Well production facilities ~~or multi-well sites~~ without storage tanks ~~after April 15, 2014,~~storing oil or condensate that have a ~~PTE~~potential to emit > 20 tpy VOC	~~Monthly~~Quarterly	Monthly	January 1, 2015

~~XVII.F.~~5.f. ~~Phase-in of Approved Instrument Based Monitoring Methods: Owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method, in accordance with the following schedule:~~

~~XVII.F.5.f.(i) Beginning January 1, 2015, facilities with uncontrolled actual VOC emissions greater than 50 tpy or multi-well sites.~~

~~XVII.F.5.f.(ii) Beginning July 1, 2015, facilities with uncontrolled actual VOC emissions greater than 20 tpy but less than or equal to 50 tpy.~~

~~XVII.F.5.f.(iii) Beginning January 1, 2016, facilities with uncontrolled actual VOC emissions greater than 6 tpy but less than or equal to 20 tpy.~~

~~XVII.F.5.g.(iv) By July 1, 2016, facilities with uncontrolled actual VOC emissions less than or equal to 6 tpy.~~

~~XVII.F.5.g.~~XVII.F.6. If a component is unsafe, difficult~~, unsafe,~~, or inaccessible to monitor, the owner or operator ~~shall~~is not ~~be~~ required to monitor the component or equipment~~until it becomes feasible to do so~~.

[2] As set forth in XVII.F.6.a., owners and operators of new Well Production Facilities installed after January 1, 2016 shall comply with this Table 3 within 180 days after the Date of First Production (i.e., the implementation date).

XVII.F.~~5.g.(i)~~6.a. Difficult to monitor components or equipment are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

XVII.F.~~5.g.(ii)~~6.b. Unsafe to monitor means a component or equipment that is unsafe because inspectings ~~are those that cannot be monitored without exposing monitoring~~ personnel would be exposed to ~~an~~ immediate danger as a consequence of completing the monitoring, which includes weather conditions preventing access to the site, or that endanger monitoring personnel or equipment, or prevent use of AIMM (such as reflection due to precipitation).

XVII.F.~~5.g.(iii)~~6.c. Inaccessible to monitor components or equipment are those that are buried, insulated ~~in a manner that prevents access to the components by a monitor probe~~, or obstructed by equipment or piping that prevents AIMM inspection or AVO monitoring access to the components by ~~a monitor probe~~monitoring personnel.

XVII.F.~~6~~7 Leaks ~~detection~~ requiring repair: Leaks at components that are not otherwise designed to leak ~~shall~~must be identified utilizing the methods listed in ~~this~~ Section XVII.F.~~6.a. through XVII.F.6.d~~7. Only leaks detected pursuant to ~~this~~ Section ~~XVIII~~XVII.F.~~6. shall~~ 7, require repair under Section XVII.F.8.

XVII.F.~~6~~7.a. For EPA Method 21 or other quantitative AIMMs, monitoring at ~~existing~~ well production facilities and natural gas compressor stations constructed before ~~May~~ January 1, 201~~5~~4, a leak is any concentration of VOC above 10,000ppm ~~hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where a leak is defined as any concentration of hydrocarbon above 500 ppm~~.

~~XVII.F.67.b. For EPA Method 21 monitoring at facilities constructed on or after May 1, 2014, a leak is any concentration of hydrocarbon above 500 ppm.~~

XVII.F.~~6~~7.c. For ~~infra-red camera and~~ AVO monitoring or other non-quantitative AIMMs such as Infra-red camera, a leak is any detectable VOC emissions except as described in XVII.F.7.d ~~emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation~~.

~~XVII.F.67.d. For other Division approved monitoring devices or methods, leak identification requiring repair will be established as set forth in the Division's approval.~~

XVII.F.7.d For leaks identified using AVO, or other non-quantitative AIMM, owners and operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.8. or conducting follow-up monitoring using EPA Method 21 within fifteen (15) working days of the day the leak was detected. If the follow-up EPA Method 21 monitoring shows that the leak concentration is less than or equal to 10,000 ppm volatile organic compound for well production facilities or natural gas compressor stations, then the emissions shall not be considered a leak for purposes of this Section and shall not require repair.

XVII.F.7.e. If a leak is identified using AIMM or AVO and the leak is immediately repaired (within the same working day), any such leak does not constitute a leak under this Section XVII.F.7. and is not subject to the Repair and Re-monitoring or Recordkeeping and Reporting requirements at Sections XVII.F.8. through XVII.F.10.

XVII.F.~~7~~8. Repair and remonitoring

XVII.F.~~7~~8.a. First attempt to repair a leak that requires repair pursuant to XVII.F.7. ~~shall~~must be made no later than ~~five~~ fifteen (15) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists. If parts are unavailable, they ~~shall~~must be ordered promptly and the repair ~~shall~~must be made within ~~fifteen~~ thirty (~~15~~30) working days of receipt of the parts. If shutdown is required, the leak ~~shall~~must be repaired during the next scheduled shutdown. If delay is attributable to other good cause, repairs ~~shall~~must be completed within ~~fifteen~~ thirty (30~~15~~) working days after the owner or operator has reason to believe the cause of delay ceases to exist.

XVII.F.~~7~~8.b. Within ~~fifteen~~ thirty (30~~15~~) working days of completion of a repair, the ~~leaks shall~~leak that is repaired according to Section XVII.F.7. must be remonitored to verify the repair was effective utilizing AIMM.

XVII.F.~~7~~8.c. Leaks discovered pursuant to the leak detection methods of Section XVII.F.7. shall not be a violation of the Air Quality Control Commission's Rules or subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section XVII.F.~~7~~8.

~~XVII.F.7.d. For leaks identified using an Approved Instrument Based Monitoring Methodapproved instrument based monitoring method, owners andor operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.78. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detecteddetection. If the follow-up EPA Method 21 monitoring shows that the leak concentration is less than or equal to 2,000 ppm hydrocarbon for existing facilities (other than existing well production facilities), or 500 ppm for new facilities or existing well production facilities, then the emission shall not be consideredis a leak for purposes of thisas defined in Section XVII.F.7., the leak must be repaired and remonitored in accordance with Section XVII.F.8.~~

XVII.F.~~8~~9. Recordkeeping: The owner or operator of each well production facility or natural gas compressor station subject to the ~~inspection~~leak detection and ~~maintenance~~repair requirements in ~~this~~ Section XVII.F. ~~shall~~must maintain the following records for a period of two (2) years and make them available to the Division upon request.

~~XVII.F.89.a. Documentation of the pre-start-up pressure tests for new well production facilities;~~

XVII.F.~~8~~9.a~~b~~. The date and site information for each inspection;

XVII.F.~~8~~9.~~c~~b. A list of the leaking components and the monitoring method used to determine the presence of the leak;

XVII.F.~~8~~9.c~~d~~. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

XVII.F.~~8~~9.d~~e~~. The date the leak was ~~repair~~repaired;

XVII.F.~~8~~9.d~~f~~. The delayed repair list including the basis for placing leaks on the list;

XVII.F.~~8~~9.f~~g~~. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and

XVII.F.~~8~~9.g~~h~~. A list of ~~identification numbers for~~ components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section XVII.F.~~5.g~~6., and an explanation ~~for each component~~ stating why the component is so designated~~, and the plan for monitoring such component(s)~~.

XVII.F.~~9~~10. Reporting: The owner or operator of each well production facility and natural gas compressor station subject to the ~~inspection~~leak detection and ~~maintenance~~repair requirements in this Section XVII.F. ~~shall~~must submit a single annual report on or before ~~April 30th~~May 31st of each year ~~summarizing~~ that includes the following information regarding inspection and maintenance ~~inspection~~~~leak detection and~~ ~~maintenance~~repair activities at all of their subject facilities during the previous calendar year~~. This report shallmust contain, at a minimum, the following information~~:

XVII.F.~~9~~10.a. The number of facilities inspected;

XVII.F.~~9~~10.b. The total number of inspections;

XVII.F.~~9~~10.c. The total number of leaks identified that require repair, broken out by component type;

XVII.F.~~9~~10.d. The total number of leaks repaired;

XVII.F.~~9~~10.e. The number of leaks on the delayed repair list as of December 31st; and

XVII.F.~~9~~10.f. Each report shall be accompanied by a self-certification form. The form shall contain a certification by an authorized representative ~~responsible official~~ of the truth, accuracy, and completeness of such form, report, or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

XVII.G. (State Only) Control of emissions from well production facilities

~~XVII.G.1. Well Operation and Maintenance:~~ On or after August 1, 2014, ~~during normal operation~~ gas coming off a separator, produced during normal operation from any newly constructed, hydraulically fractured, or recompleted oil and gas well must either be routed to a gas gathering line or controlled from the date of first production by air pollution control equipment that achieves an average ~~hydrocarbon~~ VOC control efficiency of 95~~% from the date of first production.~~%. If a combustion device is used, it ~~shall~~must have a design destruction efficiency ~~of~~for at least 98% of ~~hydrocarbons~~VOCs.

~~XVII.H. (State Only) Venting during downhole well maintenance and unloading events~~

~~XVII.H.1. Well Maintenance: Beginning May 1, 2014, hydrocarbon emissions from flowing wells must be captured or controlled during downhole well maintenance or servicing activities, unless venting is necessary for safety.~~

~~XVII.H.1.a. Operators shallOwners or operators must use best management practices to minimize the need for well venting associated with downhole well~~

~~maintenance and liquids unloading. During liquids unloading events, any means of creating differential pressure willmust first be used to attempt to unload the liquids from the well without venting. If these methods are not successful in unloading the liquids from the well, the well may be vented to the atmosphere to create the necessary differential pressure to bring the liquids to the surface.~~

~~XVII.H.1.b. Venting willmust be minimized to the extent possible, using best management practices during the well maintenance and liquids unloading events in XVII.H.1.a. The owner and/or operator shallmust be present on-site during any planned well maintenance and liquids unloading event in XVII.H.1.a. and shallmust ensure that any venting to the atmosphere is limited to the maximum extent practicable.~~

~~XVII.H.1.c. Records of the cause, date, time, and duration of venting events under this Section XVII.H. willmust be kept and made available to the Division upon request.~~

XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations ~~in the 8-Hour Ozone Control Area or Any Ozone Nonattainment or Attainment/Maintenance Area~~

XVIII.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: ~~oil and gas exploration and production operations~~well production facilities~~,~~ and natural gas compressor ~~stations, and/or natural gas drip~~ stations) ~~in the 8-Hour Ozone Control Area or any Ozone Nonattainment or Attainment/Maintenance Area~~.

XVIII.B. Definitions

XVIII.B.1. "Affected Operations" shall mean pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: ~~oil and gas exploration and production operations~~well production facilities~~,~~ and natural gas compressor ~~stations, and/or natural gas drip~~ stations).

XVIII.B.2. "Enhanced Maintenance" is specific to high-bleed devices and shall include but is not limited to cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

XVIII.B.3. "High-Bleed Pneumatic Controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

XVIII.B.4. "Low-Bleed Pneumatic controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

XVIII.B.5. "Natural Gas Processing Plant" shall mean any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

XVIII.B.6. "No-~~bleed~~Bleed Pneumatic Controller" shall mean any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas.

XVIII.B.~~6~~7. “Pneumatic Controller” shall mean a~~n~~ continuous bleed instrument that is actuated using ~~natural~~pressurized gas ~~pressure~~ and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature.

XVIII.C. Emission Reduction Requirements

The owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

XVIII.C.1. In the 8-Hour Ozone Control Area:

XVIII.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, shall emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.~~3~~1.c.

XVIII.C.~~2~~1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section XVIII.C.~~3~~1.c.

XVIII.C.~~3~~1.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.~~3~~1.~~a~~c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.~~3~~1.~~b~~c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.~~XVIII.D. Monitoring~~

XVIII.C.2. Statewide:

XVIII.C.2.a. All continuous bleed pneumatic controllers placed in service on or after May 1, 2014, shall:

XVIII.C.2.~~c~~a.(i) Emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.; or

XVIII.C.2.~~c~~a.(ii) Where the operator is using on-site electrical grid power and where use of ~~Utilize~~ no-bleed pneumatic controllers ~~where on-site electrical grid power is being used and~~ is technically and economically feasible, operators shall employ no-bleed pneumatic controllers. Nothing in this provision shall require an operator to bring electrical grid power to the location in order to meet this requirement or replace or retrofit low-bleed pneumatic controllers upon availability of electrical grid power to the location.

XVIII.C.2.b. All high-bleed pneumatic controllers in service prior to May 1, 2014, shall be replaced or retrofitted by May 1, 2015, such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.

XVIII.C.2.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.2.c.(i) ~~AllFor~~ high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.D. Monitoring

This section applies only to high-bleed pneumatic controllers identified in ~~Section~~Sections XVIII.C.~~3~~1.c. and XVIII.C.2.c.

XVIII.D.1. In the 8-Hour Ozone Control Area

XVIII.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.~~2~~1.b. Effective May 1, 2009, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2~~.~~,., and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.D.2. Statewide:

XVIII.D.2.a. Effective May 1, 2015, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.2.b. Effective May 1, 2015, each high-bleed pneumatic controller shall be inspected on a monthly basis, ~~perform~~undergo necessary enhanced maintenance as defined in Section XVIII.B.2 , and ~~maintain the device~~be maintained according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.E. Recordkeeping

This section applies only to high-bleed pneumatic controllers identified in ~~Section~~Sections XVIII.C.~~3~~1.c. and XVIII.C.2.c.

XVIII.E.1. The owner or operator of affected operations shall maintain a log of the total number of high-bleed pneumatic controllers and their associated controller numbers per facility, the total number of high-bleed pneumatic controllers per company and the associated justification that the high-bleed pneumatic controllers must be used pursuant to ~~Section~~Sections XVIII.C.~~3~~1.c. and XVIII.C.2.c. The log shall be updated on a monthly basis.

XVIII.E.2. The owner or operator shall maintain a log of enhanced maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, high-bleed pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

XVIII.E.3. Records of enhanced maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the ~~division~~Division upon request.

>>>>>>>>

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT
Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS

(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

5 CCR 1001-9

>>>>>>>>

II. General Provisions

>>>>>>>>

II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation.

(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Sections XVII. and XVIII.

>>>>>>>>

XVII. (State Only, except Section XVII.E.3.a. which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines

XVII.A. (State Only) Definitions

XVII.A.1 "Air Pollution Control Equipment," as used in this Section XVII, means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section XVII.B.2.e.

XVII.A.2. "Approved Instrument Based Monitoring Method," as used in this Section XVII. means an infra-red camera, Method 21, or other Division approved instrument based monitoring device or method. If an owner/operator elects to use a Division approved

Continuous Emission Monitoring program, the Division may approve a streamlined inspection and reporting program for such operations. Any instrument based monitoring method approved by the Division under this definition must be at least as effective as Method 21 or an infra-red camera.

XVII.A.3. "Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.

XVII.A.4. "Component" means each pump seal, compressor seal, flange, pressure relief device, connector, open ended line, and valve that contains or contacts a process stream with hydrocarbons. Process streams consisting of glycol, amine, produced water, or methanol are not components for purposes of this Section XVII.

XVII.A.5. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Jointed fittings welded completely around the circumference of the interface are not considered connectors.

XVII.A.6. "Date of First Production" means the date reported to the COGCC as the "first date of production."

XVII.A.7. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

XVII.A.8. "Multi-Well Site" means a common well pad from which multiple wells may be drilled to various bottomhole locations.

XVII.A.9. "Natural Gas Compressor Station" means a facility which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure and recompress natural gas prior to processing, as well as well as compressors located downstream of processing plants.

XVII.A.10. "Normal Operation" means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes but is not limited to liquid dumps from the separator.

XVII.A.11. "Stabilized" when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited to those commonly referred to within the industry as working, breathing, and standing losses.

XVII.A.12. "Storage Tank" means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage vessel is as defined in 40 CFR Part 60, Subpart OOOO. Storage tanks may be located at a well production facility or other location.

XVII.A.13. "Unsafe to Monitor" means a component is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of such monitoring.

XVII.A.14. "Visible Emissions" means observations of smoke for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation. Visible emissions do not include radiant energy or water vapor.

XVII.A.15. "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or gas wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

XVII.B. (State Only) General Provisions

XVII.B.1. General requirements for prevention of emissions and good air pollution control practices for all oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.B.1.a. All intermediate hydrocarbon liquids collection, storage, processing, and handling operations, regardless of size, shall be designed, operated, and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the extent reasonably practicable.

XVII.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment shall be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

XVII.B.2. General requirements for air pollution control equipment, flares, and combustion devices used to comply with Section XVII.

XVII.B.2.a. All air pollution control equipment shall be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates and to handle reasonably foreseeable fluctuations in emissions of volatile organic compounds and hydrocarbons during normal operations. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

XVII.B.2.b. If a flare or other combustion device is used to control emissions of hydrocarbons, it shall be enclosed, have no visible emissions during normal operations, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other means approved by the Division, determine whether it is operating properly.

XVII.B.2.c. Any of the effective dates for installation of controls on storage tanks, dehydrators, and/or internal combustion engines may be extended at the Division's discretion for good cause shown.

XVII.B.2.d. Auto-igniters: All combustion devices used to control emissions of hydrocarbons shall be equipped with and operate an auto-igniter as follows:

XVII.B.2.d.(i) All combustion devices installed on or after May 1, 2014, will be equipped with an operational auto-igniter upon installation of the combustion device.

XVII.B.2.d.(ii) All combustion devices installed before May 1, 2014, will be equipped with an operational auto-igniter by or before May 1, 2015~~6~~, or after the next combustion device planned shutdown, whichever comes first.

XVII.B.2.e. Alternative emissions control equipment shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section XVII, if the Division approves the equipment, device or process. As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section XVII.

XVII.B.3. Oil refineries are not subject to Section XVII.

XVII.B.4. Glycol natural gas dehydrators and internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard ("NSPS") under 40 CFR Part 60 are not subject to this Section XVII.

XVII.C. (State Only) Emission reduction from storage tanks at oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.C.1. Control requirements for storage tanks

XVII.C.1.a. Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of volatile organic compounds equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must operate air pollution control equipment that has an average control efficiency of at least 95% for VOCs.

XVII.C.1.b. Owners or operators of all storage tanks with uncontrolled actual emissions of volatile organic compounds equal to or greater than six (6) tons per year based on a rolling twelve-month total must operate air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.C.1.b.(i) A storage tank constructed on or after May 1, 2014, must be in compliance by the date that the storage tank commences operation.

XVII.C.1.b.(ii) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

XVII.C.1.b.(iii) A storage tank not otherwise subject to Sections XVII.C.1.b.(i) or XVII.C.1.b.(ii), above, that increases uncontrolled actual emissions to six tons VOC or more per year on a rolling twelve month basis after May 1, 2014, must be in compliance within sixty days of discovery of the emissions increase.

XVII.C.1.c. Control requirements within 90 days of the date of first production.

XVII.C.1.c.(i) Beginning May 1, 2014, owners or operators of storage tanks at well production facilities shall collect and control emissions by routing emissions to operating air pollution control equipment during the first 90 calendar days after the date of first production. The air pollution control equipment shall achieve an average hydrocarbon control efficiency of 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons. Except that this requirement does not apply where the Division has approved a demonstration that the~~se~~ storage tanks ~~that are projected to~~ will have emissions less than 1.5 tons of VOC during the first 90 days after the date of first production.

XVII.C.1.c.(ii) The air pollution control equipment and any associated monitoring equipment required pursuant to Section XVII.C.1.c., above, may be removed at any time after the first 90 calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank are below the threshold in Section XVII.C.1.b., above.

XVII.C.2. Capture requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.

XVII.C.2.a. Beginning on the applicable compliance date specified in Section XVII.C.1.b., owners and operators of storage tanks shall route all hydrocarbon emissions to air pollution control equipment, and shall operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment.

XVII.C.2.b. Beginning on the applicable compliance date specified in section XVII.C.1.b., owners and operators of storage tanks shall develop, certify, and implement a document Storage Tank Emission Management System (STEM) plan to identify appropriate strategies designed to meet the requirements of XVII.C.2.a. ~~minimize emissions from venting at thief hatches (or other access points to a storage tank) and pressure relief devices during normal operation~~. As part of STEM, owners and operators shall evaluate and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies ~~designed to meet the requirements set forth in Section XVII.C.2.a., above,~~ and will update the STEM plan as necessary to achieve or maintain compliance. Owners and operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed below.

XVII.C.2.b.(i) STEM must include a monitoring strategy that incorporates the minimum monitoring frequency set forth in Section XVII.F.5.e., procedures for evaluating ongoing storage tank emission capture performance, and, if applicable, the selected strategies.

XVII.C.2.b.(ii) STEM must include a certification by the owner or operator that the selected STEM strategy or strategies are designed to meet the requirements of XVII.C.2.a. ~~minimize emissions from storage tanks and~~

~~associated equipment components at the facility or facilities, including thief hatches and pressure relief devices.~~

XVII.C.3. Monitoring: The monitoring strategy of each STEM plan must include monitoring in accordance with Approved Instrument Based Monitoring Methods, as specified in Section XVII.F.5.

XVII.C.3.a. In addition to any applicable Approved Instrument Based Monitoring Methods, audio, visual, olfactory ("AVO") inspection of the storage tank and any associated equipment (i.e. separator, air pollution control equipment, or other pressure reducing equipment), must be completed as often as liquids are loaded out from the storage tank. However, AVO inspection is required no more frequently than every seven (7) days or less frequently than every thirty (30) days. AVO monitoring is not required for components and tanks that are unsafe to monitor. AVO inspection must include, at a minimum:

XVII.C.3.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are enclosed and properly sealed;

XVII.C.3.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment;

XVII.C.3.a.(iii) If a flare or other combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light, to ensure they are functioning properly;

XVII.C.3.a.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open; and

XVII.C.3.a.(v) If a flare or other combustion device is used, inspection of the device for the presence of absence of smoke. If smoke is observed, either the equipment will be immediately shut-in to investigate that potential cause for smoke and perform repairs, as necessary, or Method 22 shall be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

XVII.C.4. Recordkeeping and Reporting: The owner or operator of each storage tank subject to XII.D. or XVII.C. must maintain records of STEM as applicable, including the plan, any updates, and the certification, and submit them to the Division by the applicable compliance date specified in section XVII.C.1.b.~~to be made available to the Division upon request~~. In addition, for a period of five~~two~~ years, the owner or operator must maintain records of any required monitoring and make them available to the Division upon request, including:

XVII.C.4.a. The AIRS ID for the storage tank.

XVII.C.4.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions.

XVII.C.4.c. The date and duration of any period where the air pollution control equipment is not operating.

XVII.C.4.d. Where a flare or other combustion device is being used, the date and result of any Method 22 test.

XVII.C.4.e. The timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions.

XVII.D. (State Only) Emission reductions from glycol natural gas dehydrators

XVII.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of a condenser or air pollution control equipment.

XVII.D.2. The control requirement in Section XVII.D.1. shall apply where:

XVII.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and

XVII.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.

XVII.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, and drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.D.4. The control requirement in Section XVII.D.3. shall apply where:

XVII.D.4.a. Actual uncontrolled emissions of volatile organic compounds from a single new glycol natural gas dehydrator are equal to or greater than two tons per year; or

XVII.D.4.b. Actual uncontrolled emissions of volatile organic compounds from a single existing glycol natural gas dehydrator are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.

XVII.D.4.c. For purposes of Section XVII.D.4.:

XVII.D.4.c.(i) Building Unit shall mean a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.

XVII.D.4.c.(ii) A designated outside activity area shall mean an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a Designated Outside Activity Area; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

XVII.E. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

XVII.E.1. (State Only) The requirements of this Section XVII.E. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.2. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.2.a. Except as provided in Section XVII.E.2.b. below, the owner or operator on any natural gas fired reciprocating internal combustion engine that is either constructed or relocated to the state of Colorado from another state, on or after the date listed in the table below shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section XVII.E.2.b. Table 1 below.

XVII.E.2.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table 1 below as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE 1				
Maximum Engine Hp	Construction or Relocation Date	Emission Standards is G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥100 Hp and < 500 Hp	On or after January 1, 2008 On or after January 1, 2011	2.0 1.0	4.0 2.0	1.0 0.7
≥500 Hp	On or after July 1, 2007 On or after July 1, 2010	2.0 1.0	4.0 2.0	1.0 0.7

XVII.E.3. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.3.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

XVII.E.3.a.(i) Except as provided in Sections XVII.3.1.(i)(b) and (c) and XVII.E.3.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

XVII.E.3.a.(i)(a) All control equipment required by this Section XVII.E.3.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

XVII.E.3.a.(i)(b) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to this Section XVII.E.3.a.

XVII.E.3.a.(i)(c) The requirements of this Section XVII.E.3.a. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.3.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1,2009.

XVII.E.3.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

XVII.E.3.b.(i) Except as provided in Section XVII.E.3.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

XVII.E.3.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.F. (State Only) Leak detection and repair program for well production facilities, storage tanks, and compressor stations

XVII.F.1. Beginning January 1, 2015, owners and operators of well production facilities and compressor stations will identify and repair leaks from components at these facilities in accordance with the requirements of this Section XVII.F. The following shall apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

XVII.F.2. Owners and operators of well production facilities or natural gas compressor stations that monitor components as part of this Section XVII.F. may opt to estimate emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

XVII.F.3. Owners and operators of well production facilities or natural gas compressor stations shall utilize the Approved Instrument Based Monitoring Method and AVO program as outlined in Section XVII.F. AVO monitoring is not required of components and tanks that are unsafe to monitor or inaccessible to monitor, pursuant to XVII.F.5.g.

XVII.F.4. Inspection schedules for natural gas compressor stations: Beginning January 1, 2015, owners and operators of natural gas compressor stations shall inspect components for leaks using an Approved Instrument Based Monitoring Method, in accordance with the following Table 2, except for components subject to XVII.F.5.g. ~~For purposes of this Section XVII.F.4., fugitive emissions shall be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), orf other Division approved method.~~

Table 2	
~~Fugitive VOC Emissions (tpy)~~ VOC Emissions – PTE (tpy)	Inspection Frequency
>0 and ≤ 12	Annually with monthly AVO
> 12 and ≤ 50	Quarterly with monthly AVO
> 50	Monthly

XVII.F.5. Requirements for well production facilities and/or storage tanks

XVII.F.5.a. Beginning August 1, 2014, all new well production facilities shall have a documented pressure test performed on all equipment and piping prior to start up. Documentation of this 90 day testing and monitoring shall be provided in the first annual report to the Division, as required by Section XVII.F.9.

XVII.F.5.b. Beginning January 1, 2015, within 90 days of startup of all new well production facilities and/or storage tanks, owners and/or operators shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method. Such action shall qualify as an inspection pursuant to the inspection frequency schedule in Table 3.

XVII.F.5.c. ~~Consistent with the provisions of XVII.F.5.f.~~Beginning January 1, 2015, owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks using an Approved Instrument Based Monitoring Method, in accordance with the ~~implementation~~ schedule in XVII.F.5.e. Inspection frequency shall be determined according to Table 3.

XVII.F.5.d. Consistent with the provisions of XVII.F.5.f., owners and operators of new well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method beginning on January 1, 2015. Inspection frequency shall be determined according to Table 3.

XVII.F.5.e. The estimated uncontrolled actual emissions from storage tanks determine the frequency at which inspections must be performed. If no storage tanks are located at the well production facility or multi-well site, operators will rely on the potential to emit of VOC for all of the emissions sources, including emissions from components located at the facility. All components at a well production facility or storage tank must be inspected:

Table 3	
Threshold (per XVII.F.5.e.) VOC Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks)	Inspection Frequency
> 0 and ≤ 12~~6~~	Annually with monthly AVO~~One time using Approved Instrument Based Monitoring Method and thereafter using monthly AVO~~
~~> 6 and ≤ 12~~	~~Annually with monthly AVO~~
> 12 and ≤ 50	Quarterly with monthly AVO
> 50	Monthly
Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 20 tpy VOC	Monthly

~~XVII.F.5.f. Phase-in of Approved Instrument Based Monitoring Methods: Owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method, in accordance with the following schedule:~~

~~XVII.F.5.f.(i) Beginning January 1, 2015, facilities with uncontrolled actual VOC emissions greater than 50 tpy or multi-well sites.~~

~~XVII.F.5.f.(ii) Beginning July 1, 2015, facilities with uncontrolled actual VOC emissions greater than 20 tpy but less than or equal to 50 tpy.~~

~~XVII.F.5.f.(iii) Beginning January 1, 2016, facilities with uncontrolled actual VOC emissions greater than 6 tpy but less than or equal to 20 tpy.~~

~~XVII.F.5.g.(iv) By July 1, 2016, facilities with uncontrolled actual VOC emissions less than or equal to 6 tpy.~~

XVII.F.5.g. If a component is difficult, unsafe, or inaccessible to monitor, the owner or operator shall not be required to monitor the component until it becomes feasible to do so.

XVII.F.5.g.(i) Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

XVII.F.5.g.(ii) Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

XVII.F.5.g.(iii) Inaccessible to monitor components are those that are buried, insulated in a manner that prevents access to the components by a monitor probe, or obstructed by equipment or piping that prevents access to the components by a monitor probe.

XVII.F.6 Leak detection requiring repair: Leaks shall be identified utilizing the methods listed in this Section XVII.F.6.a. through XVII.F.6.d. Only leaks detected pursuant to this Section XVIII.F.6. shall require repair under Section XVII.F.

XVII.F.6.a. For Method 21 monitoring at existing facilities, a leak is any concentration of hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where leak is defined as any concentration of hydrocarbon above 500 ppm.

XVII.F.6.b. For Method 21 monitoring at facilities constructed after May 1, 2014, a leak is any concentration of hydrocarbon above 500 ppm.

XVII.F.6.c. For infra-red camera and AVO monitoring, a leak is any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

XVII.F.6.d. For other Division approved monitoring devices or methods, leak identification requiring repair will be established as set forth in the Division's approval.

XVII.F.7. Repair and remonitoring

XVII.F.7.a. First attempt to repair a leak shall be made no later than five (5) working days after discovery, unless parts are unavailable or~~,~~ the equipment requires shutdown to complete repair~~, or other good cause exists~~. If parts are unavailable, they shall be ordered promptly and the repair shall be made within five (5)~~fifteen (15)~~ working days of receipt of the parts. If shutdown is required, the leak shall be repaired during the next scheduled shutdown. ~~If delay is attributable to other good cause,~~

~~repairs shall be completed within fifteen (15) working days after the cause of delay ceases to exist.~~

XVII.F.7.b. Within fifteen (15) working days of completion of a repair, the leaks shall be remonitored to verify the repair was effective.

XVII.F.7.c. Leaks discovered pursuant to the leak detection methods of Section XVII.F. shall not be subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section XVII.F.7.

XVII.F.7.d. For leaks identified using an Approved Instrument Based Monitoring Method, owners and operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.7. or conducting follow-up monitoring using Method 21 within five (5) working days of the leak detected. If the follow-up Method 21 monitoring shows that the leak concentration is less than or equal to 2,000 ppm hydrocarbon for existing facilities (other than existing well production facilities), or 500 ppm for new facilities or existing well production facilities, then the emission shall not be considered a leak for purposes of this Section.

XVII.F.8. Recordkeeping: The owner or operator of each facility subject to the inspection and maintenance requirements in this Section XVII.F. shall maintain the following for a period of five (5) ~~two (2)~~ years and make them available to the Division upon request.

XVII.F.8.a. Documentation of the pre-start-up pressure tests for new well production facilities;

XVII.F.8.b. The date and site information for each inspection;

XVII.F.8.c. A list of the leaking components and the monitoring method used to determine the presence of the leak;

XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

XVII.F.8.e. The date the leak was repair;

XVII.F.8.f. The delayed repair list including the basis for placing leaks on the list;

XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and

XVII.F.8.h. A list of identification numbers for components that are designated as unsafe or inaccessible to monitor, as described in Section XVII.F.5.g., an explanation for each component stating why the component is so designated, and the plan for monitoring such component(s).

XVII.F.9. Reporting: The owner or operator of each facility subject to the inspection and maintenance requirements in Section XVII.F. shall submit a single annual report on or before April 30th of each year summarizing inspection and maintenance activities at all of their subject facilities during the previous calendar year. This report shall contain at a minimum the following information:

XVII.F.9.a. The number of facilities inspected;

XVII.F.9.b. The total number of inspections;

XVII.F.9.c. The total number of leaks identified, broken out by component type;

XVII.F.9.d. The total number of leaks repaired;

XVII.F.9.e. The number of leaks on the delayed repair list as of December 31st; and

XVII.F.9.f. Each report shall be accompanied by a self-certification form. The form shall contain a certification by a responsible official of the truth, accuracy, and completeness of such form, report, or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

XVII.G. (State Only) Control of emissions from well production facilities

XVII.G.1. Well Operation and Maintenance: On or after August 1, 2014, during normal operation gas coming off a separator produced from any newly constructed, hydraulically fractured, or recompleted oil and gas well must either be routed to a gas gathering line or controlled by air pollution control equipment that achieves an average hydrocarbon control efficiency of 95% from the date of first production. If a combustion device is used, it shall have a design destruction efficiency of at least 98% of hydrocarbons.

XVII.H. (State Only) Venting during downhole well maintenance and unloading events

XVII.H.1. Well Maintenance: Beginning May 1, 2014, hydrocarbon emissions from flowing wells must be captured or controlled during downhole well maintenance or servicing activities, unless venting is necessary for safety.

XVII.H.1.a. Operators shall use best management practices to minimize the need for well venting associated with downhole well maintenance and liquids unloading. During liquids unloading events, any means of creating differential pressure will first be used to attempt to unload the liquids from the well without venting. If these methods are not successful in unloading the liquids from the well, the well may be vented to the atmosphere to create the necessary differential pressure to bring the liquids to the surface.

XVII.H.1.b. Venting will be minimized to the extent possible, using best management practices during the well maintenance and liquids unloading events in XVII.H.1.a. The owner and/or operator shall be present on-site during any planned well maintenance and liquids unloading event in XVII.H.1.a. and shall ensure that any venting to the atmosphere is limited to the maximum extent practicable.

XVII.H.1.c. Records of the best management practices employed under this Section XVII.H., and the cause, date, time, and duration of venting events ~~under this Section XVII.H.~~, will be kept and submitted annually ~~made available~~ to the Division ~~upon request~~.

XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

XVIII.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B. Definitions

XVIII.B.1. "Affected Operations" shall mean pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B.2. "Enhanced Maintenance" is specific to high-bleed devices and shall include but is not limited to cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

XVIII.B.3. "High-Bleed Pneumatic Controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

XVIII.B.4. "Low-Bleed Pneumatic controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

XVIII.B.5. "Natural Gas Processing Plant" shall mean any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

XVIII.B.6. "No-bleed Pneumatic Controller" shall mean any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas.

XVIII.B.7. "Pneumatic Controller" shall mean an instrument that is actuated using natural gas pressure and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature.

XVIII.C. Emission Reduction Requirements

The owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

XVIII.C.1. In the 8-Hour Ozone Control Area:

XVIII.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, shall emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.1.c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.1.c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2. Statewide:

XVIII.C.2.a. All pneumatic controllers placed in service on or after May 1, 2014, shall:

XVIII.C.2.c.(i) Emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.; or

XVIII.C.2.c.(ii) Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and is technically and economically feasible.

XVIII.C.2.b. All ~~high-bleed~~ pneumatic controllers in service prior to May 1, 2014 with VOC emissions greater than a low-bleed pneumatic controller~~,~~ shall be replaced or retrofitted by May 1, 2015, such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.

XVIII.C.2.c. All ~~high-bleed~~ controllers with VOC emissions greater than a low-bleed pneumatic controller that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.2.c.(i) A~~For~~ll ~~high-bleed~~ pneumatic controllers in service prior to May 1, 2014, the owner/operator shall submit justification for ~~high-bleed~~ all pneumatic controllers with VOC emissions greater than a low-bleed pneumatic controller to remain in service due to safety and/or process purposes by March 1, 2015. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2.c.(ii) For ~~high-bleed~~ pneumatic controllers placed in service on or after May 1, 2014, the owner/operator shall submit justification for ~~high-bleed~~ all pneumatic controllers with VOC emissions greater than a low-bleed pneumatic controller to be installed due to safety and/or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.D. Monitoring

This section applies only to high-bleed pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.D.1. In the 8-Hour Ozone Control Area

XVIII.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.1.b. Effective May 1, 2009, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2 , and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.D.2. Statewide:

XVIII.D.2.a. Effective May 1, 2015, each ~~high-bleed~~ pneumatic controller with VOC emissions greater than a low-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique ~~high-bleed~~ pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.2.b. Effective May 1, 2015, each ~~high-bleed~~ pneumatic controller with VOC emissions greater than a low-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2 , and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.E. Recordkeeping

This section applies only to ~~high-bleed~~ pneumatic controllers with VOC emissions greater than a low-bleed pneumatic controller identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.E.1. The owner or operator of affected operations shall maintain a log of the total number of ~~high-bleed~~ pneumatic controllers with VOC emissions greater than a low-bleed pneumatic controller and their associated controller numbers per facility, the total number of ~~high-bleed~~ such pneumatic controllers per company and the associated justification that those ~~high-bleed~~ pneumatic controllers must be used pursuant to Sections XVIII.C.1.c. and XVIII.C.2.c. The log shall be updated on a monthly basis.

XVIII.E.2. The owner or operator shall maintain a log of enhanced maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, ~~high-bleed~~ pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

XVIII.E.3. Records of enhanced maintenance of pneumatic controllers shall be maintained for a minimum of five (5) ~~three~~ years and readily made available to the Division upon request.

XVIII.C.1.a. Effective May 1, 2008, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.C.1.b. Effective May 1, 2008, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2., and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.C.2. Statewide

XVIII.C.2.a. Effective May 1, 2013, each high-bleed pneumatic controller with VOC emissions greater than a low-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.C.2.b. Effective May 1, 2013, each high-bleed pneumatic controller with VOC emissions greater than a low-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2., and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.D. Recordkeeping

This section applies only to high-bleed pneumatic controllers with VOC emissions greater than a low-bleed pneumatic controller identified in Sections XVIII.C.1. and XVIII.C.2.

XVIII.D.1. The owner or operator of affected operations shall maintain a log of the total number of high-bleed pneumatic controllers with VOC emissions greater than a low-bleed pneumatic controller, and their associated controller numbers per facility, the total number of high-bleed pneumatic controllers per company and the associated justification that these high-bleed pneumatic controllers must be used pursuant to Sections XVIII.C.1. and XVIII.C.2. The log shall be updated on a monthly basis.

XVIII.D.2. The owner or operator shall maintain a log of enhanced maintenance, which shall include, at a minimum, inspection dates, the date of the maintenance activity, high-bleed pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

XVIII.D.3. Records of enhanced maintenance of pneumatic controllers shall be maintained for a minimum of five (5) years and readily made available to the Division upon request.

FINAL
ECONOMIC IMPACT ANALYSIS
PER § 25-7-110.5(4), C.R.S.

For Conservation Groups' Alternate Proposal modifying proposed revisions to
Colorado Air Quality Control Commission
Regulation Number 7 (5 CCR 1001-9)

I. INTRODUCTION

This economic analysis addresses the impact of the Conservation Groups' alternate proposal on the Division-proposed revisions to Regulation 7. The alternate proposal includes the following changes covered in this analysis:[1]

1. Leak detection requirements for compressors should be expanded in two ways:

   a. The definition of "Natural Gas Compressor Station" in Rule XVII.A.10 should be expanded so that it is not limited to those compressors upstream of processing facilities.

   b. The inspection frequencies for compressor stations in Rule XVII.F should be calculated based on <u>total</u> VOC emissions (potential to emit), similar to the approach for well production facilities, rather than based only on <u>fugitive</u> VOC emissions.

2. For well production facilities and tanks with uncontrolled actual emissions of less than 6 tpy, the leak detection schedule in Rule XVII.F should require an instrument-based inspection on an annual basis – not just a single time.

3. Under Rule XVIII.C, the requirement to retrofit existing high-bleed pneumatic controllers should be clarified to ensure that it requires retrofitting <u>all</u> pneumatics emitting VOCs at a rate higher than a low-bleed pneumatic. This would include retrofitting <u>intermittent-bleed</u> pneumatics.

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[1] The alternate proposal includes several other proposed changes, such as shortening excessively long phase-in periods and requiring that records be kept for a longer time period. These proposed requirements are not separately analyzed in the discussion below because they are not expected to involve any material costs to companies. This is consistent with the approach taken by the Division in its initial economic analysis, which does not alter its analysis of a requirement's cost-effectiveness based on when the requirement takes effect, or how long records must be retained, for example.

The discussion below uses the relevant sections from the Division's initial economic analysis, with modifications reflecting the limited changes proposed by the Conservation Groups.

II. COST/BENEFIT ANALYSIS:

A. Leak Detection and Repair Requirements for Compressor Stations and Well Production Facilities

AQCC Regulation Number 7 requires owners and operators of gas processing plants in Colorado to implement leak detection and repair programs to identify and repair fugitive emission leaks from components at these facilities. Under this requirement, owners and operators must conduct periodic inspections using EPA Reference Method 21[2] and repair leaks within a prescribed time frame.

Although component leaks at compressor stations and well production facilities in Colorado are also a significant source of VOC and methane emissions, Regulation No. 7 does not currently include leak detection and repair requirements for these facilities.[3] To address these emissions, the Division is proposing regulatory changes that would establish leak detection and repair requirements for compressor stations and well production facilities. Pursuant to this proposal, owners and operators of compressor stations and well production facilities will be required to conduct periodic leak inspections, and repair identified leaks. As specified, required inspections may be done either in accordance with Method 21 or utilizing an IR camera. The proposed language also allows the Division to approve other inspection methods as new leak detection technologies are demonstrated to be effective.

The Division's Proposal would establish a tiered system to determine inspection frequency. For well production facilities, the tiering is based on the uncontrolled actual emissions from the largest storage tank at the facility.[4] This approach creates a Method 21/IR camera monitoring schedule that is consistent with the monitoring schedule proposed as part of the STEM emission capture requirements. The Conservation Groups would use the same approach, but require that facilities with emissions under 6 tpy conduct annual instrument-based inspections (instead of just a one-time inspection as proposed by the Division). For compressor stations, the Division proposes tiers based on the station's fugitive emissions. The Conservation Groups tiering is based instead on the facility's potential to emit (PTE) VOCs.

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[2] While Method 21 sets performance standards for inspection equipment rather than specifying technology, typically Method 21 inspections utilize photo ionization detectors (PIDs) to assess leak levels.

[3] Although leak detection is not currently required at most of these facilities, some operators currently conduct voluntary leak detection and repair programs. Additionally, the Division has issued a limited number of permits that include some leak detection requirements. For the purposes of this analysis, however, the Division assumes that there is no leak detection occurring at well production facilities and compressor stations. Accordingly the actual additional costs that operators may incur may be less than the costs calculated in this analysis.

[4] Because there may be instances where facilities do not have storage tanks, the proposal also provides that for tank-less facilities, the inspection schedule will be based on the facility's potential to emit (PTE) VOC.

For compressor stations and well production facilities, the frequencies proposed by the Conservation Groups are described as follows in Tables 1-2:

Table 1: Conservation Groups' Proposed Tiering for Leak Inspections at Compressor Stations	
PTE VOCs	Inspection Frequency
≤ 12 tpy	Annually, with monthly AVO
>12 tpy to ≤ 50 tpy	Quarterly, with monthly AVO
> 50 tpy	Monthly

Table 2: Conservtion Groups' Proposed Tiering for Leak Inspections at Well Production Facilities	
Tank Uncontrolled Actual VOC Emissions or PTE	Inspection Frequency
≤ 12 tpy	Annually (and monthly AVO)
>12 tpy to ≤ 50 tpy	Quarterly (and monthly AVO)
> 50 tpy	Monthly

1. Well production facilities

To evaluate the cost-effectiveness of the alternate proposal with regard to well production facilities, the Conservation Groups followed the approach used by the Division in its initial economic analysis. The Division utilized 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.[5] To calculate the total annual cost for each inspector, the Division included salary and fringe benefits for each inspector, annualized equipment and vehicle costs, and add-ons to account for supervision, overhead, travel, record keeping, and reporting. Based on the assumptions set forth in the Division's EIA Table 20 (reproduced below), the total annual cost for each inspector will be $186,129, which equates to an hourly inspection rate of $99.

Leak Detection and Repair (LDAR) Inspector – Annualized Cost Analysis (Division EIA Table 20)			
Item	Capital Costs (one time)	Annual Costs	Annualized Total Costs
FLIR Camera	$122,000		
Photo Ionization Detector	$5,000		
Vehicle (4x4 Truck)	$22,000		
Inspection Staff		$75,000	
Supervision (@ 20%)		$15,000	
Overhead (@10%)		$7,500	
Travel (@15%)		$11,250	

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

Recordkeeping (@10%)		$7,500	
Reporting (@10%)		$7,500	
Fringe (@30%)		$22,500	
Subtotal Costs	$149,000	$146,250	
Annualized Costs*	$39,879	$146,250	$186,129
over 5 years at 6% ROR		Annualized Hourly Rate	$99

Second, the Division calculated the average amount of time that it would take to conduct a Method 21 inspection at 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 its analysis the Division assumed that an IR camera based inspection would take 50% of the time required for a Method 21 inspection. Discussions with multiple private contractors that perform these inspections at well production and oil and gas processing facilities indicates that, on average, the value of 30 seconds per component for camera-based inspections errs on the side of over-estimation of time. One contractor with extensive experience with camera-based inpsections stated that inspections can be conducted for 300 to 400 components per hour, when components are generally accessible.

For well production facilities, the Division has limited 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 this overall average component count each Method 21 inspection will take 9.5 hours and each IR camera based inspection will take 4.75 hours.

Next, the Division calculated the projected inspection costs for well production facilities. To make this calculation the Division used industry reported emission data to determine the number of facilities that will be subject to annual, quarterly and monthly 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. The calculated inspection costs for well production facilities do not include the cost to repair leaking components or re-monitor these components post-repair to verify that the repair was effective. Conversely, the calculated costs also do not account for the cost savings from capturing additional product as a result of repairs. For the purposes of its initial cost analysis the Division assumes that the cost savings from additional product capture will be equal to or greater than the cost of repair and re-inspection. The Division's estimated annual inspection costs for well production facilities are set forth in its EIA Table 23.[6]

[6] The Division's proposal also requires monthly AVO inspections at facilities. Based on information provided during the stakeholder process, the Division reports that AVO inspections are part of current standard operational practice. Accordingly, the regulatory provisions should not result in additional costs.

Taking the same approach, the Conservation Groups' estimated annual inspection costs for well production facilities are set forth in Table 3.

Table 3: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid					
Uncontrolled Tank Battery VOCs/PTE Tier [tpy]	Number of Facilities	Annual Inspection Frequency	Inspection Time Per Inspection [hours]	Total Inspection Time [hours]	Total Annual Inspection Cost
≤12	4,200	1	4.75	19,950	$1,975,050
> 12 to ≤ 50	2,916	4	4.75	55,404.0	$5,484,996
> 50	964	12	4.75	54,498.0	$5,439,852
Total:	8,080			129,852	$12,899,898

Finally, the Division calculated the cost effectiveness of the proposed leak detection and repair requirements based on the costs identified above and the projected emission reductions. To determine emission reductions the Division first calculated pre-inspection program VOC and methane emissions based on the reported component counts, standard emission factors for these components, and the average fraction of VOC and non-VOC emissions (methane/ethane). Based on EPA reported information, the Division calculated a 40% reduction for annual inspections, a 60% reduction for quarterly inspections, and an 80% reduction for monthly inspections. The Division estimated total emissions reductions at well production facilities from its proposal would be 14,153 tpy VOC and 22,461 tpy methane/ethane. This resulted in a Division estimate that its proposal would cost $818/ton VOC controlled, and $516/ton methane/ethane controlled, at well production facilities. These were calculated in Tables 26-27 of the Division's EIA.

The Conservation Groups have used a similar approach. The total emissions reductions and cost-effectiveness at well production facilities from the alternate proposal are set forth in Tables 4-5. Under the alternate proposal, the cost effectiveness of conducting ongoing instrument based inspections at well production facilities is estimated to be $668/ton VOC and $421/ton methane/ethane. Thus, the Conservation Groups' alternate proposal for well production facilities is <u>more</u> cost-effective than the Division proposal.

Table 4: Well Production Facility Leak Inspection Emission Reductions						
Uncontrolled Tank Battery VOCs/PTE Tier [tpy]	Number of Facilities	LDAR Program Reduction %	Fugitive VOC Emissions for each Tank Battery [tpy]	Total VOC Reduction [tpy]	Fugitive Methane-Ethane Emissions for each Tank Battery [tpy]	Total Methane-Ethane Reduction [tpy]
≤ 12	4,200	40%	4.6	7,728	7.3	12,264
> 12 to ≤ 50	2,916	60%	4.6	8,048.2	7.3	12,772.1
> 50	964	80%	4.6	3,547.5	7.3	5,629.8
Total:	8,080			19,323.7		30,665.9

Table 5: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21							
Uncont. Tank Battery VOCs/PTE Tier [tpy]	Number of Tanks	Total Annual Inspection Cost	LDAR Program Reduction %	Total VOC Reduction [tpy]	VOC Control Cost [$/ton]	Total Methane-Ethane Reduction [tpy]	Methane-Ethane Control Cost [$/ton]
≤ 12	4,200	$1,975,050	40%	7,728	$256	12,264	$161
> 12 to ≤ 50	2,919	$5,484,996	60%	8,048.2	$682	12,772.1	$429
> 50	964	$5,439,852	80%	3,547.5	$1533	5,629.8	$966
Total:	8,080	$12,899,898		19,323	$668	30,665.9	$421

Finally, it should be noted that the Division's methodology for calculating the cost-effectiveness of LDAR at well production facilities is conservative in several respects. An analysis by the Clean Air Task Force of data from actual inspections found that costs are lower than those estimated by the Division. Testimony of David McCabe at 7-8.

2. Compressor stations

The Division's analysis of cost-effectiveness for compressor stations was similar to its analysis for well production facilities. It concluded that VOCs would be controlled at a cost of $667/ton, and methane/ethane controlled for $321/ton. These estimates are summarized in Table 25 of the Division's initial EIA.

Division Proposal - Compressor Station Leak Inspection Cost Effectiveness using IR Camera/Method 21 (Division EIA Table 25)							
Comp. Station Fugitive VOC Tier	Number of Comp Stations	Total Annual Inspection Cost	LDAR Program Reduction %	Total VOC Reduction [tpy]	VOC Control Cost [$/ton]	Total Methane-Ethane Reduction	Methane-Ethane Control Cost [$/ton]

[tpy]						[tpy]	
≤ 12	147	$154,262	40%	593.9	$260	911.4	$169
> 12 to ≤ 50	53	$589,763	60%	521.5	$1,131	1,408.7	$419
> 50			80%				
	200	$744,025		1,115.4	$667	2,320.1	$321

For compressor stations, the Conservation Groups do not have data that allows for a comparable calculation of the cost-effectiveness of their alternate proposal. Testimony of Maureen Barrett at 3-4. As a result, the Conservation Groups cannot provide numeric estimates of: (a) how many additional facilities would be affected if the LDAR provisions cover compressor stations downstream of processing plants; (b) how many compressor stations would fall into each inspection tier based on total VOCs (instead of fugitive VOCs); and (c) the potential to emit of each compressor station.

With regard to the estimated 200 compressor stations upstream of processing plants, the Conservation Groups expect that their alternate proposal will be cost-effective. For these compressors, the alternate proposal is expected to require more frequent inpections because total facility VOC emissions are typically much greater than the fugitive emissions counted by the Division Proposal. Barrett testimony at 2-3. While the increased inspections will result in greater costs, that expense will be offset by greater reductions of VOCs and methane/ethane at compressors than would result from the Division Proposal. An analysis by Clean Air Task Force estimates that quarterly instrument-based inspections of compressor stations controls VOC emissions at a cost of $800/metric ton, and the cost for monthly insepctions is under $3,500/metric ton. See McCabe testimony at 8. The control costs for methane are only about $10/metric ton with quarterly inspections, and just over $50/metric ton for monthly inspections. Id. at 4.

With regard to compressor stations downstream of processing plants, the cost of controlling methane/ethane reductions is likely to be even lower than for their upstream counterparts. The CATF figures indicate that methane control costs at transmission compressor stations are somewhat lower than those for gathering stations. McCabe testimony at 8-9.[7]

The cost per ton of VOC reductions for transmission compressor stations, however, likely would be greater than for compressors upstream of processing plants. Limited data is available, but the Title V permits for two such compressor stations, Kerr McGee's Fort Lupton station and DCP Midstream's Enterprise station, include limits for VOC fugitive emissions that allow for a conservative estimate of cost-effectiveness. The Kerr-McGee permit has a limit of 30.8 tpy fugitive VOCs, Supp. Testimony of Maureen Barrett at 2, and the DCP permit has a limit of 18.22 tpy fugitive VOCs. The Conservation Groups' alternate proposal would subject these two facilities to monthly instrument-based inspections. Assuming that such inspections reduce

[7] If the value of gas conserved by LDAR programs is not considered in the analysis of abatement costs for transmission compressor stations (because the facility owners may not own the gas), the methane abatement cost for those facilities is slightly higher than for gathering compressor stations, but still very reasonable (under $3/ metric ton CO_2e). McCabe testimony at 9 n. 5.

WPX REB EX A

BEFORE THE COLORADO AIR QUALITY CONTROL COMMISSION
COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

WPX ENERGY ROCKY MOUNTAIN, LLC'S AND WPX ENERGY PRODUCTION, LLC'S PROPOSED REGULATION TEXT – WPX REB EX A

IN THE MATTER OF OIL & GAS RULEMAKING EFFORTS REGARDING PROPOSED REVISIONS TO:
REGULATION NUMBER 3, PARTS A, B, AND C;
REGULATION NUMBER 6, PART A;
REGULATION NUMBER 7

WPX ENERGY ROCKY MOUNTAIN, LLC and WPX ENERGY PRODUCTION, LLC (collectively "WPX") respectfully submit to the Colorado Air Quality Control Commission ("Commission") WPX's final proposed regulation text to accompany WPX's alternate proposal[1] pursuant to Procedural Rule § V.C.3.c.

Based on the revised language of the Proposed Regulation Text circulated by the Division on January 24, 2014, please see the attached revised alternate proposal by WPX indicated by the redlined attachment. *See* attached WPX ALT EX D REVISED. For clarity, WPX has only included here the sections for which it proposes changes, and has indicated such changes in the attached redline.

[1] Note that WPX does not believe that the minor changes it proposed on January 6, 2014, rise to the level of an alternate proposal. However, out of an abundance of caution, WPX filed its proposed revisions to the Division rules as an alternate proposal with the documents described in 5 CCR 1001-1 ("Procedural Rules") Section V.C.3.a through k.

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS

XVII.C.1.e.(ii)
(new section) Unsafe to monitor means it cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring, which includes weather conditions preventing access to the site, or that endanger monitoring personnel or equipment, or prevent use of Approved Instrument Based Monitoring Methods (such as reflection due to precipitation).

XVII.F.5.c. Owners or operators of well production facilities constructed before January 1, 2015, must identify leaks from components using an approved instrument based monitoring method within ninety (90) days of the Phase-In Schedule in Table 4, within thirty (30) days for > 50 tons per year, or by July 1, 2016, for > 0 and < 6 tons per year tanks. Thereafter, approved instrument based monitoring method and AVO inspections must be conducted in accordance with the Inspection Frequency in Table ~~4.~~4 or when a reduced LDAR demonstration is made, the frequency may be determined by Alternative Table 4A pursuant to Section XVII.F.5.d.

XVII.F.5.~~e~~d. The largest estimated uncontrolled actual emissions from a single storage ~~tanks determine~~tank batterys determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility or multi-well site, owners or operators must rely on the potential to emit of VOC for all of the emissions sources, including emissions from components located at the well production facility~~.~~ in accordance with Table 4 of Alternative Table 4A.

Table 4 – Well Production Facility Component Inspections

Threshold (per XVII.F.5.d.) VOC Emissions (tpy)	Inspection Frequency	Phase-In Schedule
> 0 and < 6	One time using approved Instrument based monitoring method and thereafter using monthly AVO	July 1, 2016
> 6 and < 12	Annually with monthly AVO	January 1, 2016
> 12 and < 50	Quarterly with monthly AVO	July 1, 2015
> 50	Monthly	January 1, 2015
Well production facilities or multi-well sites without storage tanks storing oil or condensate that have a potential to emit > 20 tpy VOC	Monthly	January 1, 2015

An alternative inspection frequency schedule pursuant to Alternative Table 4A may be implemented once a reduced LDAR demonstration is made. A reduced LDAR demonstration requires that an owner or operator identify fewer than either (1) the specified number of leaking components listed in "Demonstration of Reduced LDAR – Monitoring History" in Alternative Table 4A or (2) two percent of the total components for that facility during a single monitoring event, for at least two consecutive monitoring events.

Once the reduced LDAR demonstration is made pursuant to this Section, the alternative inspection frequency pursuant to Alternative Table 4A may remain in place until, during any monitoring event under the alternative inspection frequency, more leaks are indentified than allowed under Alternative Table 4A's "Demonstration of Reduced LDAR – Monitoring History." Using the alternative inspection frequency identified in Alternative Table 4A, during any monitoring event, if more leaks are identified than listed in the "Demonstration of Reduced LDAR – Monitoring History," then the original monitoring frequency identified in Table 4 shall become applicable until or if the operator can make another reduced LDAR demonstration for that facility.

Alternative Table 4A		
Threshold (per XVII.F.5.e.) VOC Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks)	Demonstration of Reduced LDAR - Monitoring History	Alternative Inspection Frequency
> 0 and < 6		One time using Approved Instrument Based Monitoring Method and thereafter using monthly AVO
> 6 and < 12		Annually with monthly AVO
> 12 and < 50	5 or less component leaks (or 2% of total components) identified in each of two consecutive monitoring events.	Annually with monthly AVO
> 50	10 or less component leaks (or 2% of total components) identified in each of two consecutive monitoring events.	Quarterly with monthly AVO
Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 20 tpy VOC	10 or less component leaks (or 2% of total components) identified in each of two consecutive monitoring events.	Quarterly with monthly AVO

XVII.F.~~5.g.(ii)~~6.b. Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring, which includes weather conditions preventing access to the site, or that endanger monitoring personnel or equipment, or prevent use of Approved Instrument Based Monitoring Methods (such as reflection due to precipitation).

XVII.F.~~6.~~7.a. For EPA Method 21 monitoring at facilities constructed before May 1, 2014, a leak is any concentration of hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where a leak is defined as any concentration of hydrocarbon above 500 ppm~~.~~ after January 1, 2016.

XVII.F.~~6.~~7.b. For EPA Method 21 monitoring at facilities constructed on or after ~~May~~January 1, ~~2014,~~2016, a leak is any concentration of hydrocarbon above 500 ppm.

EXHIBIT 9.C

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS

(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

5 CCR 1001-9

>>>>>>>>

II. General Provisions

>>>>>>>>

II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation.

(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Sections XVII. and XVIII.

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XVII. (State Only, except Section XVII.E.3.a. which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines

XVII.A. (State Only) Definitions

XVII.A.1 "Air Pollution Control Equipment," as used in this Section XVII, means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section XVII.B.2.e.

XVII.A.2. "Approved Instrument Based Monitoring Method," as used in this Section XVII. means an infra-red camera, Method 21, or other Division approved instrument based monitoring device or method. If an owner/operator elects to use a Division approved Continuous Emission Monitoring program, the Division may approve a streamlined inspection and reporting program for such operations. Any instrument based monitoring method approved by the Division under this definition must be at least as effective as Method 21 or an infra-red camera.

XVII.A.3. "Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.

XVII.A.4. "Building Unit" shall mean a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.

XVII.A.5~~4~~. "Component" means each pump seal, compressor seal, flange, pressure relief device, connector, open ended line, and valve that contains or contacts a process stream with hydrocarbons. Process streams consisting of glycol, amine, produced water, or methanol are not components for purposes of this Section XVII.

XVII.A.6~~5~~. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Jointed fittings welded completely around the circumference of the interface are not considered connectors.

XVII.A.7~~6~~. "Date of First Production" means the date reported to the COGCC as the "first date of production."

XVII.A.8. "Designated Outside Activity Area" shall mean an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a Designated Outside Activity Area; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

XVII.A.9~~7~~. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

XVII.A.10. "Major Gas Leak" shall mean any leak greater than 10,000 ppm hydrocarbon concentration above background as determined through an approved instrument based monitoring method,

XVII.A.11~~8~~. "Multi-Well Site" means a common well pad from which multiple wells may be drilled to various bottomhole locations.

XVII.A.12~~9~~. "Natural Gas Compressor Station" means a facility which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure and recompress natural gas prior to processing.

XVII.A.13~~0~~. "Normal Operation" means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes but is not limited to liquid dumps from the separator.

XVII.A.14~~1~~. "Stabilized" when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited to those commonly referred to within the industry as working, breathing, and standing losses.

XVII.A.15~~2~~. "Storage Tank" means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage vessel is as defined in 40 CFR Part 60, Subpart OOOO. Storage tanks may be located at a well production facility or other location.

XVII.A.16~~3~~. "Unsafe to Monitor" means a component is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of such monitoring.

XVII.A.17~~4~~. "Visible Emissions" means observations of smoke and/or hydrocarbon vapors for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation. Visible emissions do not include radiant energy~~ or water vapor~~.

XVII.A.18~~5~~. "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or gas wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

XVII.B. (State Only) General Provisions

XVII.B.1. General requirements for prevention of emissions and good air pollution control practices for all oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.B.1.a. All intermediate hydrocarbon liquids collection, storage, processing, and handling operations, regardless of size, shall be designed, operated, and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the extent reasonably practicable.

XVII.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment shall be maintained and operated in a manner consistent with ~~good air pollution control~~best management practices for minimizing emissions. Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

XVII.B.2. General requirements for air pollution control equipment, flares, and combustion devices used to comply with Section XVII.

XVII.B.2.a. All air pollution control equipment shall be operated and maintained pursuant to the manufacturing specifications or equivalent.~~ to the extent practicable,~~ and consistent with technological limitations and ~~good ~~best engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates and to handle reasonably foreseeable fluctuations in emissions of volatile organic compounds and hydrocarbons during normal operations.

Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

XVII.B.2.b. If a flare or other combustion device is used to control emissions of hydrocarbons, it shall be enclosed, have no visible emissions during normal operations, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other means approved by the Division, determine whether it is operating properly.

XVII.B.2.c. Any of the effective dates for installation of controls on storage tanks, dehydrators, and/or internal combustion engines may be extended at the Division's discretion for good cause shown.

XVII.B.2.d. Auto-igniters: All combustion devices used to control emissions of hydrocarbons shall be equipped with and operate an auto-igniter as follows:

XVII.B.2.d.(i) All combustion devices installed on or after May 1, 2014, will be equipped with an operational auto-igniter upon installation of the combustion device.

XVII.B.2.d.(ii) All combustion devices installed before May 1, 2014, will be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

XVII.B.2.e. Alternative emissions control equipment shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section XVII, if the Division approves the equipment, device or process. As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section XVII.

XVII.B.3. Oil refineries are not subject to Section XVII.

XVII.B.4. Glycol natural gas dehydrators and internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard ("NSPS") under 40 CFR Part 60 are not subject to this Section XVII.

XVII.C. (State Only) Emission reduction from storage tanks at oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.C.1. Control requirements for storage tanks

XVII.C.1.a. Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of volatile organic compounds equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must operate air pollution control equipment that has an average control efficiency of at least 95% for VOCs.

XVII.C.1.b. Owners or operators of all storage tanks with uncontrolled actual emissions of volatile organic compounds, based on a rolling twelve-month total, equal to or greater than six (6) tons per year~~, based on a rolling twelve-month total~~ or two (2) tons per year if the storage tanks is located within 1,320 feet of a building unit or designated outside activity area, must operate air pollution control equipment that achieves an average hydrocarbon control efficiency of no less than 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.C.1.b.(i) A storage tank constructed on or after May 1, 2014, must be in compliance by the date that the storage tank commences operation.

XVII.C.1.b.(ii) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

XVII.C.1.b.(iii) A storage tank not otherwise subject to Sections XVII.C.1.b.(i) or XVII.C.1.b.(ii), above, that increases uncontrolled actual emissions to six (6) tons VOC or more per year on a rolling twelve month basis after May 1, 2014, or two tons VOC or more per year if located within 1,320 feet of a building unit or designated outside activity area, must be in compliance within sixty days of discovery of the emissions increase.

XVII.C.1.c. Control requirements within 90 days of the date of first production.

XVII.C.1.c.(i) Beginning May 1, 2014, owners or operators of storage tanks at well production facilities shall collect and control emissions by routing emissions to operating air pollution control equipment during the first 90 calendar days after the date of first production. The air pollution control equipment shall achieve an average hydrocarbon control efficiency of 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons. Except that this requirement does not apply to storage tanks that are projected to have emissions less than 1.5 tons of VOC during the first 90 days after the date of first production, or 0.5 tons of VOC emissions during the first 90 days after the date of first production if located 1,320 feet from a building unit or designated outdoor activity area.

XVII.C.1.c.(ii) The air pollution control equipment and any associated monitoring equipment required pursuant to Section XVII.C.1.c., above, may be removed at any time after the first 90 calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank are below the thresholds in Section XVII.C.1.b., above.

XVII.C.2. Capture requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.

XVII.C.2.a. Beginning on the applicable compliance date specified in Section XVII.C.1.b., owners and operators of storage tanks shall route all hydrocarbon emissions to air pollution control equipment, and shall operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment.

XVII.C.2.b. Beginning on the applicable compliance date specified in section XVII.C.1.b., owners and operators of storage tanks shall develop, certify, and implement a document Storage Tank Emission Management System (STEM) plan to identify appropriate strategies to minimize emissions from venting at thief hatches (or other access points to a storage tank) and pressure relief devices during normal operation. As part of STEM, owners and operators shall evaluate and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section XVII.C.2.a., above, and will update the STEM plan as necessary to achieve or maintain compliance. Owners and operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed below.

XVII.C.2.b.(i) STEM must include a monitoring strategy that incorporates the minimum monitoring frequency set forth in Section XVII.F.5.e., procedures for evaluating ongoing storage tank emission capture performance, and, if applicable, the selected strategies.

XVII.C.2.b.(ii) STEM must include a certification by the owner or operator that the selected STEM strategy or strategies are designed to minimize emissions from storage tanks and associated equipment components at the facility or facilities, including thief hatches and pressure relief devices.

XVII.C.3. Monitoring: The monitoring strategy of each STEM plan must include monitoring in accordance with Approved Instrument Based Monitoring Methods, as specified in Section XVII.F.5.

XVII.C.3.a. In addition to any applicable Approved Instrument Based Monitoring Methods, audio, visual, olfactory ("AVO") inspection of the storage tank and any associated equipment (i.e. separator, air pollution control equipment, or other pressure reducing equipment), must be completed as often as liquids are loaded out from the storage tank. However, AVO inspection is required no more frequently than every seven (7) days or less frequently than every thirty (30) days. AVO monitoring is not required for components and tanks that are unsafe to monitor. AVO inspection must include, at a minimum:

XVII.C.3.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are enclosed and properly sealed;

XVII.C.3.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment;

XVII.C.3.a.(iii) If a flare or other combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light, to ensure they are functioning properly;

XVII.C.3.a.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open; and

XVII.C.3.a.(v) If a flare or other combustion device is used, inspection of the device for the presence ~~of~~ or absence of smoke or vapors. If smoke or vapors are ~~is~~ observed, either the equipment will be immediately shut-in to investigate that potential cause for smoke and perform repairs, as necessary, or Method 22 shall be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

XVII.C.4. Recordkeeping: The owner or operator of each storage tank subject to XII.D. or XVII.C. must maintain records of STEM as applicable, including the plan, any updates, and the certification, to be made available to the Division upon request. In addition, for a period of two years, the owner or operator must maintain records of any required monitoring and make them available to the Division upon request, including:

XVII.C.4.a. The AIRS ID for the storage tank.

XVII.C.4.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions.

XVII.C.4.c. The date and duration of any period where the air pollution control equipment is not operating.

XVII.C.4.d. Where a flare or other combustion device is being used, the date and result of any Method 22 test.

XVII.C.4.e. The timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions.

XVII.D. (State Only) Emission reductions from glycol natural gas dehydrators

XVII.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of a condenser or air pollution control equipment.

XVII.D.2. The control requirement in Section XVII.D.1. shall apply where:

XVII.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and

XVII.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.

XVII.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, and drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.D.4. The control requirement in Section XVII.D.3. shall apply where:

XVII.D.4.a. Actual uncontrolled emissions of volatile organic compounds from a single new glycol natural gas dehydrator are equal to or greater than two (2) tons per year; or

XVII.D.4.b. Actual uncontrolled emissions of volatile organic compounds from a single existing glycol natural gas dehydrator are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.

~~XVII.D.4.c. For purposes of Section XVII.D.4.:~~

~~XVII.D.4.c.(i) Building Unit shall mean a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.~~

~~XVII.D.4.c.(ii) A designated outside activity area shall mean an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a Designated Outside Activity Area; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.~~

XVII.E. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

XVII.E.1. (State Only) The requirements of this Section XVII.E. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.2. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.2.a. Except as provided in Section XVII.E.2.b. below, the owner or operator on any natural gas fired reciprocating internal combustion engine that is either constructed in or relocated to the state of Colorado from another state, on or after the date listed in the table below shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section XVII.E.2.b. Table 1 below.

XVII.E.2.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table 1 below as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE 1

Maximum Engine Hp	Construction or Relocation Date	Emission Standards is G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥100 Hp and < 500 Hp	On or after January 1, 2008	2.0	4.0	1.0
	On or after January 1, 2011	1.0	2.0	0.7
≥500 Hp	On or after July 1, 2007	2.0	4.0	1.0
	On or after July 1, 2010	1.0	2.0	0.7

XVII.E.3. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.3.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

XVII.E.3.a.(i) Except as provided in Sections XVII.3.1.(i)(b) and (c) and XVII.E.3.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

XVII.E.3.a.(i)(a) All control equipment required by this Section XVII.E.3.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent practicable, and consistent with technological limitations and best~~good~~ engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

XVII.E.3.a.(i)(b) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology (“MACT”) standard under 40 CFR Part 63, a Best Available Control Technology (“BACT”) limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to this Section XVII.E.3.a.

XVII.E.3.a.(i)(c) The requirements of this Section XVII.E.3.a. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.3.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1,2009.

XVII.E.3.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

XVII.E.3.b.(i) Except as provided in Section XVII.E.3.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

XVII.E.3.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.F. (State Only) Leak detection and repair program for well production facilities, storage tanks, and compressor stations

XVII.F.1. Beginning January 1, 2015, owners and operators of well production facilities and compressor stations will identify and repair leaks from components at these facilities in accordance with the requirements of this Section XVII.F. The following shall apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

XVII.F.2. Owners and operators of well production facilities or natural gas compressor stations that monitor components as part of this Section XVII.F. may opt to estimate emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

XVII.F.3. Owners and operators of well production facilities or natural gas compressor stations shall utilize the Approved Instrument Based Monitoring Method and AVO program as outlined in Section XVII.F. AVO monitoring is not required of components and tanks that are unsafe to monitor or inaccessible to monitor, pursuant to XVII.F.5.g.

XVII.F.4. Inspection schedules for natural gas compressor stations: Beginning January 1, 2015, owners and operators of natural gas compressor stations shall inspect components for leaks using an Approved Instrument Based Monitoring Method, in accordance with the following Table 2, except for components subject to XVII.F.5.g. For purposes of this

Section XVII.F.4., fugitive emissions shall be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), of other Division approved method.

Table 2	
Fugitive VOC Emissions (tpy)	Inspection Frequency
>0 and $\leq$ 12	Annually
> 12 and $\leq$ 50	Quarterly
> 50	Monthly

XVII.F.5. Requirements for well production facilities and/or storage tanks

XVII.F.5.a. Beginning August 1, 2014, all new well production facilities shall have a documented pressure test performed on all equipment and piping prior to start up. Documentation of this 90 day testing and monitoring shall be provided in the first annual report to the Division, as required by Section XVII.F.9.

XVII.F.5.b. Beginning January 1, 2015, within 90 days of startup of all new well production facilities and/or storage tanks, owners and/or operators shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method. Such action shall qualify as an inspection pursuant to the inspection frequency schedule in Table 3.

XVII.F.5.c. Consistent with the provisions of XVII.F.5.f., owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks using an Approved Instrument Based Monitoring Method, in accordance with the implementation schedule in XVII.F.5.e. Inspection frequency shall be determined according to Table 3.

XVII.F.5.d. Consistent with the provisions of XVII.F.5.f., owners and operators of new well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method beginning on January 1, 2015. Inspection frequency shall be determined according to Table 3.

XVII.F.5.e. The estimated uncontrolled actual emissions from storage tanks determine the frequency at which inspections must be performed. If no storage tanks are located at the well production facility or multi-well site, operators will rely on the potential to emit of VOC for all of the emissions sources, including emissions from components located at the facility. All components at a well production facility or storage tank must be inspected:

Table 3		
Threshold (per XVII.F.5.e.) VOC	Threshold within 1,320 feet of a building	Inspection Frequency

Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks)	unit or designated outside activity area (per XVII.F.5.e.) VOC Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks)	
> 0 and < 6		One time using Approved Instrument Based Monitoring Method and thereafter using monthly AVO
> 6 and < 12	> 0 and < 6	Annually with monthly AVO
> 12 and < 50	> 6 and < 12	Quarterly with monthly AVO
> 50	> 12	Monthly
Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 20 tpy VOC	Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 12 tpy VOC	Monthly

XVII.F.5.f. Phase-in of Approved Instrument Based Monitoring Methods: Owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method, in accordance with the following schedule:

XVII.F.5.f.(i) Beginning January 1, 2015, facilities with uncontrolled actual VOC emissions greater than 50 tpy or multi-well sites.

XVII.F.5.f.(ii) Beginning July 1, 2015, facilities with uncontrolled actual VOC emissions greater than 20 tpy but less than or equal to 50 tpy.

XVII.F.5.f.(iii) Beginning January 1, 2016, facilities with uncontrolled actual VOC emissions greater than 6 tpy but less than or equal to 20 tpy.

XVII.F.5.g.(iv) By July 1, 2016, facilities with uncontrolled actual VOC emissions less than or equal to 6 tpy.

XVII.F.5.g. If a component is difficult, unsafe, or inaccessible to monitor, the owner or operator shall not be required to monitor the component until it becomes feasible to do so.

XVII.F.5.g.(i) Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

XVII.F.5.g.(ii) Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

XVII.F.5.g.(iii) Inaccessible to monitor components are those that are buried, insulated in a manner that prevents access to the components by a monitor probe, or obstructed by equipment or piping that prevents access to the components by a monitor probe.

XVII.F.6 Leak detection requiring repair: Leaks shall be identified utilizing the methods listed in this Section XVII.F.6.a. through XVII.F.6.d. Only leaks detected pursuant to this Section XVIII.F.6. shall require repair under Section XVII.F.

XVII.F.6.a. For Method 21 monitoring at existing facilities, a leak is any concentration of hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where leak is defined as any concentration of hydrocarbon above 500 ppm.

XVII.F.6.b. For Method 21 monitoring at facilities constructed after May 1, 2014, a leak is any concentration of hydrocarbon above 500 ppm.

XVII.F.6.c. For infra-red camera and AVO monitoring, a leak is any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

XVII.F.6.d. For other Division approved monitoring devices or methods, leak identification requiring repair will be established as set forth in the Division's approval.

XVII.F.7. Repair and remonitoring

XVII.F.7.a. Except as provided in Section XVII.F.7.b. below, the f~~F~~irst attempt to repair a leak shall be made no later than five (5) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists. If parts are unavailable, they shall be ordered promptly and the repair shall be made within fifteen (15) working days of receipt of the parts. If shutdown is required, the leak shall be repaired during the next scheduled shutdown. If delay is attributable to other good cause, repairs shall be completed within fifteen (15) working days after the cause of delay ceases to exist.

XVII.F.7.b. Repairs to major gas leaks that are discovered within 1,320 feet of a building unit or designated outside activity area shall be made no later than 24 hours after discovery. If a repair is not possible with 24 hours, the well shall be shut down until a repair can be made. If shutting down the well will not stop the leak, demonstrable efforts should be made to minimize the leak within the first 24 hours.

XVII.F.7.c~~b~~. Within fifteen (15) working days of completion of a repair, the leaks shall be remonitored to verify the repair was effective.

XVII.F.7.d~~c~~. Leaks discovered pursuant to the leak detection methods of Section XVII.F. shall not be subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section XVII.F.7.

XVII.F.7.e~~d~~. For leaks identified using an Approved Instrument Based Monitoring Method, owners and operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.7. or conducting follow-up monitoring using Method 21 within five (5) working days of the leak detected. If the follow-up Method 21 monitoring shows that the leak concentration is less than or equal to 2,000 ppm hydrocarbon for existing facilities (other than existing well production facilities), or 500 ppm for new facilities or existing well production facilities, then the emission shall not be considered a leak for purposes of this Section.

XVII.F.8. Recordkeeping: The owner or operator of each facility subject to the inspection and maintenance requirements in this Section XVII.F. shall maintain the following for a period of two (2) years and make them available to the Division upon request.

XVII.F.8.a. Documentation of the pre-start-up pressure tests for new well production facilities;

XVII.F.8.b. The date and site information for each inspection;

XVII.F.8.c. A list of the leaking components and the monitoring method used to determine the presence of the leak;

XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

XVII.F.8.e. The date the leak was repaired;

XVII.F.8.f. The delayed repair list including the basis for placing leaks on the list;

XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and

XVII.F.8.h. A list of identification numbers for components that are designated as unsafe or inaccessible to monitor, as described in Section XVII.F.5.g., an explanation for each component stating why the component is so designated, and the plan for monitoring such component(s).

XVII.F.9. Reporting: The owner or operator of each facility subject to the inspection and maintenance requirements in Section XVII.F. shall submit a single annual report on or before April 30th of each year summarizing inspection and maintenance activities at all of their subject facilities during the previous calendar year. Reports will be made publicly available on the APCD Website and searchable by API well number, APEN permit number, operator, date, and geographic area. In addition to this information, ~~This~~ the report shall also contain ~~at a minimum~~ the following information:

XVII.F.9.a. The number of facilities inspected;

XVII.F.9.b. The total number of inspections;

XVII.F.9.c. The total number of leaks identified, broken out by component type;

XVII.F.9.d. The total number of leaks repaired;

XVII.F.9.e. Each major gas leak discovered and how quickly it was repaired;

XVII.F.9.f~~e~~. The number of leaks on the delayed repair list as of December 31st; and

XVII.F.9.g~~f~~. Each report shall be accompanied by a self-certification form. The form shall contain a certification by a responsible official of the truth, accuracy, and completeness of such form, report, or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

XVII.G. (State Only) Control of emissions from well production facilities

XVII.G.1. Well Operation and Maintenance: On or after August 1, 2014, during normal operation gas coming off a separator produced from any newly constructed, hydraulically fractured, or recompleted oil and gas well must either be routed to a gas gathering line or controlled by air pollution control equipment that achieves an average hydrocarbon control efficiency of 95% from the date of first production. If a combustion device is used, it shall have a design destruction efficiency of at least 98% of hydrocarbons.

XVII.H. (State Only) Venting during downhole well maintenance and unloading events

XVII.H.1. Well Maintenance: Beginning May 1, 2014, hydrocarbon emissions from flowing wells must be captured or controlled during downhole well maintenance or servicing activities, unless venting is necessary for safety.

XVII.H.1.a. Operators shall use best management practices to minimize the need for well venting associated with downhole well maintenance and liquids unloading. During liquids unloading events, any means of creating differential pressure will first be used to attempt to unload the liquids from the well without venting. If these methods are not successful in unloading the liquids from the well, the well may be vented to the atmosphere to create the necessary differential pressure to bring the liquids to the surface.

XVII.H.1.b. Venting will be minimized to the extent possible, using best management practices during the well maintenance and liquids unloading events in XVII.H.1.a. The owner and/or operator shall be present on-site during any planned well maintenance and liquids unloading event in XVII.H.1.a. and shall ensure that any venting to the atmosphere is limited to the maximum extent practicable.

XVII.H.1.c. Records of the cause, date, time, and duration of venting events under this Section XVII.H. will be kept and made available to the Division upon request.

XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

XVIII.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B. Definitions

XVIII.B.1. “Affected Operations” shall mean pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B.2. “Enhanced Maintenance” is specific to high-bleed devices and shall include but is not limited to cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

XVIII.B.3. “High-Bleed Pneumatic Controller” shall mean a pneumatic controller that is designed to have a constant bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

XVIII.B.4. “Low-Bleed Pneumatic controller” shall mean a pneumatic controller that is designed to have a constant bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

XVIII.B.5. “Natural Gas Processing Plant” shall mean any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

XVIII.B.6. “No-bleed Pneumatic Controller” shall mean any pneumatic controller that is not using hydrocarbon gas as the valve’s actuating gas.

XVIII.B.7. “Pneumatic Controller” shall mean an instrument that is actuated using natural gas pressure and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature.

XVIII.C. Emission Reduction Requirements

The owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

XVIII.C.1. In the 8-Hour Ozone Control Area:

XVIII.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, shall emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.1.c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.1.c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2. Statewide:

XVIII.C.2.a. All pneumatic controllers placed in service on or after May 1, 2014, shall:

XVIII.C.2.c.(i) Emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.; or

XVIII.C.2.c.(ii) Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and is technically and economically feasible.

XVIII.C.2.b. All high-bleed pneumatic controllers in service prior to May 1, 2014, shall be replaced or retrofitted by May 1, 2015, such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.

XVIII.C.2.c. All high-bleed controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.2.c.(i) All high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.D. Monitoring

This section applies only to high-bleed pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.D.1. In the 8-Hour Ozone Control Area

XVIII.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.1.b. Effective May 1, 2009, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2 , and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.D.2. Statewide:

XVIII.D.2.a. Effective May 1, 2015, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.2.b. Effective May 1, 2015, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2 , and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.E. Recordkeeping

This section applies only to high-bleed pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.E.1. The owner or operator of affected operations shall maintain a log of the total number of high-bleed pneumatic controllers and their associated controller numbers per facility, the total number of high-bleed pneumatic controllers per company and the associated justification that the high-bleed pneumatic controllers must be used pursuant to Sections XVIII.C.1.c. and XVIII.C.2.c. The log shall be updated on a monthly basis.

XVIII.E.2. The owner or operator shall maintain a log of enhanced maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, high-bleed pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

XVIII.E.3. Records of enhanced maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the Division upon request.

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XIX. Statements of Basis, Specific Statutory Authority and Purpose

The Local Community Organizations adopt the Statement of Basis and Purpose proposed by the APCD.

<u>EXHIBIT I.</u>

LOCAL COMMUNITY ORGANIZATIONS' FINAL ECONOMIC IMPACT ANALYSIS PER § 25-7-110.5(4), C.R.S.

For proposed revisions to
Colorado Air Quality Control Commission
Regulation Number 7 (5 CCR 1001-9)

I. INTRODUCTION

This final economic impact analysis will cover only the changes the Local Community Organizations have made to the Air Quality Control Division's (APCD) proposal. The Local Community Organizations appreciate the assistance from the APCD in the creation of this final economic impact analysis.

II. OVERVIEW OF PROPOSED REGULATORY CHANGES

The Local Community Organizations are proposing revisions to the APCD's proposed AQCC Regulation Number 7. This Regulation Number 7 rulemaking package adopts nearly all of the changes proposed by the Colorado Air Pollution Control Division but amends specific sections to accomplish the following:

1) Reduce nearby residents' exposure to air toxics by requiring operators of facilities within 1,320 feet of a building unit or outdoor activity area to

    a. control VOCs down to 2 TPY,
    b. conduct more frequent inspections, and
    c. repair "major leaks" within 24 hours.

2) Increase transparency by requiring annual inspection reports to be posted online and accessible by the public.

III. COST/BENEFIT ANALYSIS:

<u>A. Control Requirements for Petroleum Storage Tanks</u>

The Local Community Organizations have proposed changes to require that tanks within 1,320 feet (1/4 mile) of a building unit or designated outdoor activity area must utilize air pollution control equipment if the tanks have uncontrolled actual emissions of equal or greater than two (2) tons per year.

The proposed APCD regulations would require operators with tanks that have uncontrolled emissions of at least **six (6) tons** per year to use emission control devices capable of achieving 95% control efficiency of volatile organic compounds (VOCs). Currently, the Colorado Oil and Gas Conservation Commission (COGCC) requires all tanks with uncontrolled emissions of VOCs

<u>of five (5) tons</u> per year or greater that are located within 1,320 feet of a Building Unit, or a Designated Outside Activity Area to use an emission control device capable of achieving 95% control efficiency of VOCs. (COGCC Rule 805.b.(2)). Therefore, this change only will affect those tanks that emit from 2-5 tons of VOCs per year.

1. General Cost Estimates for Flares

Using the data obtained from the APCD Initial Economic Impact Analysis, we assume that the estimated annualized cost of a flare control device with auto-igniter is about $6,287.

2. Annualized Cost for Buffer Bottles

As reported in the Division's initial economic impact analysis, the annualized costs for buffer bottles is $3,024 per unit.

3. Lowering Statewide Condensate Tank Control Threshold (from 6(5) tpy to 2 tpy)

The Local Community Organization is proposing to lower the uncontrolled VOC emission control threshold from the state-proposed 6 tpy to 2 tpy on all tanks within 1,320 feet of a Building Unit, or a Designated Outside Activity Area.

As stated above, the COGCC currently requires tanks to control VOCs to five (5) tons per year within 1,320 feet of a home so the regulation only affects those tanks that emit two (2) to five (5) tpy.

Using numbers obtained from the APCD, there are 1,506 tanks that are emitting between 2-5 tpy VOCs.

Of this number, at least 2/3 of the tanks would not be located within 1,320 feet of a home or designated outdoor recreation area. The COGCC supplied data during the setback hearing that indicated that approximately 26% of new and expanded well sites were located within 1,000 feet of a building unit. (COGCC analysis is attached). Expanding the area from 1,000 to 1,320 feet we have allowed for the percentage of wells affected to climb to 1/3 or 33%. Therefore, 2/3 of the potential tanks affected will not be affected by this regulation and are listed in Table 1 as "cancelled tanks".

Using the assumption of 33% of tanks being within 1,230 feet of a building unit we get 497 tanks.

Table 1: Tank Battery Analysis

	2-3 TPY	3-4 TPY	4-5 TPY	5-6 TPY	Total Tanks 2-5 TPY	Total Tanks 2-6 TPY
Tanks	610	485	411	374	1,506	1,880
Cancelled Tanks	409	325	275	251	1,009	1,260
TOTAL AFFECTED TANKS (2-5 tpy)	201	160	136	123	497	620

The annual cost of installing 497 flare control devices is about $3,125,000 with an average cost effectiveness of about $1,884.5 per ton of VOCs reduced. See Table 2. VOC reduction in the 497 tanks that are within 1,320 feet of a building unit or designated outside activity area AND emit =>2 tpy of VOCS but less than 5 tpy of VOCs was calculated by summing the VOC emissions of ALL tanks that emit =>2 tpy but less than 5 tpy and then multiplying this sum by 0.33, assuming only 33% of all such tanks lie within 1,320 feet of a building unit or designated outside activity area. The emission data came from the APCD.

Table 2: Tanks over 6 tpy – Control Cost Estimates for Flare Control Devices (inc. buffer bottle)				
Affected Tanks [count]	Each Flare + buffer bottle Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
497	$9,310.8	$4,627,467.6	1,658	$2,791

B. Emission Capture Requirements for Controlled Petroleum Storage Tanks

In order to prevent leaks and ensure that oil and gas facilities closest to homes and schools are being properly maintained, the Local Community Organizations are proposing that tanks within 1,320 feet of a building unit or designated outdoor recreation area be subject to more frequent instrument based monitoring using Method 21, an IR camera or other Division approved monitoring device or method. As proposed by the APCD, the frequency of this instrument based monitoring will depend on the level of uncontrolled actual emissions from the tank.

Table 3: Proposed Tiering for Instrument Based Tank Inspections - ¼ mile of building units				
Tank Uncontrolled Actual VOC Emissions	Number of Tanks Affected	Inspection Frequency	Additional Number of Inspections	Additional Inspection Costs
≥ 2 tpy to ≤ 6 tpy	497	Annually	497	$98,406
>6 tpy to ≤ 12 tpy	459	Quarterly	1,376	$272,448
>12 tpy to 50 tpy	962	Monthly	7,698	$1,524,204

In assessing the cost-effectiveness of the proposed requirements, the Local Community Organizations first calculated the number of tanks that would be affected (1/3 in each category of tanks) and then the additional inspections necessary. That is, going from annual inspection to quarterly inspections would require an additional three inspections, quarterly to monthly would require an additional eight inspections per tank. These figures were then multiplied by the state's estimate of $198 per inspection to come up with the figures in Table 3.

C. Leak Detection and Repair Requirements for Compressor Stations and Well Production Facilities

The Local Community Organizations have requested that major leaks of over 10,000 ppm within 1,320 feet of building units should be repaired within 24 hours. We do not believe there will be any additional costs associated with this practice since the leaks would already have to be repaired within five days and most operators will make immediate repairs if major leaks are discovered for safety purposes and to conserve the oil and gas.

D. Require the APCD to Place Annual Inspection Reports on their Website

The Local Community Organizations have requested that the APCD assist in finalizing this economic impact analysis. They hope to receive that information as to the cost of this provision in the coming weeks. In the meantime, we would expect that the COGCC would be willing to post the annual inspection reports on its website. The cost to post on the COGCC website would be much less given the website is already set-up to allow the public to search by API well number.

IV. CONCLUSION

The Local Community Organizations estimate that their requested revisions to increase tank controls within 1,320 feet of building units will cost $4,627,467– reducing 1,658 tpy of VOCs at a cost of $2,791 tons/year. The total cost for the increased inspection schedules within 1,320 feet of homes is $1,895,058.

The cost to the APCD for design and maintenance of a website that will contain annual inspection reports is still to be determined.

LGC EXHIBIT A. ALTERNATIVE PROPOSED REGULATION

AMENDED REVISIONS BY THE LGC TO:

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS

(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

Field Code Changed

5 CCR 1001-9

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II. General Provisions

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II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation.

(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Sections XVII. and XVIII.

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XVII. (State Only, except Section XVII.E.3.a. which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines

XVII.A. (State Only) Definitions

XVII.A.1 "Air Pollution Control Equipment," as used in this Section XVII, means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section XVII.B.2.e.

XVII.A.2. ”Approved Instrument Based Monitoring Method,” as used in this Section XVII. means an infra-red camera, Method 21, or other Division approved instrument based monitoring device or method. If an owner/operator elects to use a Division approved Continuous Emission Monitoring program, the Division may approve a streamlined inspection and reporting program for such operations. Any instrument based monitoring method approved by the Division under this definition must be at least as effective as Method 21 or an infra-red camera.

XVII.A.3. ”Auto-Igniter” means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.

XVII.A.4. “Component” means each pump seal, compressor seal, flange, pressure relief device, connector, open ended line, and valve that contains or contacts a process stream with hydrocarbons. Process streams consisting of glycol, amine, produced water, or methanol are not components for purposes of this Section XVII.

XVII.A.5. “Connector” means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Jointed fittings welded completely around the circumference of the interface are not considered connectors.

XVII.A.6. “Date of First Production” means the date reported to the COGCC as the “first date of production.”

XVII.A.7. “Glycol Natural Gas Dehydrator” means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

XVII.A.8. “Multi-Well Site” means a common well pad from which multiple wells may be drilled to various bottomhole locations.

XVII.A.9. “Natural Gas Compressor Station” means a facility which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure and recompress natural gas prior to processing.

XVII.A.10. “Normal Operation” means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes but is not limited to liquid dumps from the separator.

XVII.A.11. “Stabilized” when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited to those commonly referred to within the industry as working, breathing, and standing losses.

XVII.A.12. "Storage Tank" means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage vessel is as defined in 40 CFR Part 60, Subpart OOOO. Storage tanks may be located at a well production facility or other location.

XVII.A.13. "Unsafe to Monitor" means a component is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of such monitoring.

XVII.A.14. "Visible Emissions" means observations of smoke for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation. Visible emissions do not include radiant energy or water vapor.

XVII.A.15. "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or gas wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

XVII.B. (State Only) General Provisions

XVII.B.1. General requirements for prevention of emissions and good air pollution control practices for all oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.B.1.a. All intermediate hydrocarbon liquids collection, storage, processing, and handling operations, regardless of size, shall be designed, operated, and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the extent reasonably practicable.

XVII.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment shall be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

XVII.B.2. General requirements for air pollution control equipment, flares, and combustion devices used to comply with Section XVII.

XVII.B.2.a. All air pollution control equipment shall be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates and to handle reasonably foreseeable fluctuations in emissions of volatile organic compounds and hydrocarbons during normal operations. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

XVII.B.2.b. If a flare or other combustion device is used to control emissions of hydrocarbons, it shall be enclosed, have no visible emissions during normal operations, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other means approved by the Division, determine whether it is operating properly.

XVII.B.2.c. Any of the effective dates for installation of controls on storage tanks, dehydrators, and/or internal combustion engines may be extended at the Division's discretion for good cause shown.

XVII.B.2.d. Auto-igniters: All combustion devices used to control emissions of hydrocarbons shall be equipped with and operate an auto-igniter as follows:

XVII.B.2.d.(i) All combustion devices installed on or after May 1, 2014, will be equipped with an operational auto-igniter upon installation of the combustion device.

XVII.B.2.d.(ii) All combustion devices installed before May 1, 2014, will be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

XVII.B.2.e. Alternative emissions control equipment shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section XVII, if the Division approves the equipment, device or process. As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section XVII.

XVII.B.3. Oil refineries are not subject to Section XVII.

XVII.B.4. Glycol natural gas dehydrators and internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard ("NSPS") under 40 CFR Part 60 are not subject to this Section XVII.

XVII.C. (State Only) Emission reduction from storage tanks at oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.C.1. Control requirements for storage tanks

XVII.C.1.a. Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of volatile organic compounds equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must operate air pollution control equipment that has an average control efficiency of at least 95% for VOCs.

XVII.C.1.b. Owners or operators of all storage tanks with uncontrolled actual emissions of volatile organic compounds equal to or greater than six (6) tons per year based on a rolling twelve-month total must operate air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.C.1.b.(i) A storage tank constructed on or after May 1, 2014, must be in compliance by the date that the storage tank commences operation.

XVII.C.1.b.(ii) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

XVII.C.1.b.(iii) A storage tank not otherwise subject to Sections XVII.C.1.b.(i) or XVII.C.1.b.(ii), above, that increases uncontrolled actual emissions to six tons VOC or more per year on a rolling twelve month basis after May 1, 2014, must be in compliance within sixty days of discovery of the emissions increase.

XVII.C.1.c. Control requirements within 90 days of the date of first production.

XVII.C.1.c.(i) Beginning May 1, 2014, owners or operators of storage tanks at well production facilities shall collect and control emissions by routing emissions to operating air pollution control equipment during the first 90 calendar days after the date of first production. The air pollution control equipment shall achieve an average hydrocarbon control efficiency of 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons. Except that this requirement does not apply to storage tanks that are projected to have emissions less than 1.5 tons of VOC during the first 90 days after the date of first production.

XVII.C.1.c.(ii) The air pollution control equipment and any associated monitoring equipment required pursuant to Section XVII.C.1.c., above, may be removed at any time after the first 90 calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank are below the threshold in Section XVII.C.1.b., above.

XVII.C.2. Capture requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.

XVII.C.2.a. Beginning on the applicable compliance date specified in Section XVII.C.1.b., owners and operators of storage tanks shall route all hydrocarbon emissions to air pollution control equipment, and shall operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment.

XVII.C.2.b. Beginning on the applicable compliance date specified in section XVII.C.1.b., owners and operators of storage tanks shall develop, certify, and implement a document Storage Tank Emission Management System (STEM) plan to identify appropriate strategies to minimize emissions from venting at thief hatches (or other access points to a storage tank) and pressure relief devices during normal operation. As part of STEM, owners and operators shall evaluate and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section XVII.C.2.a., above, and will update the STEM plan as necessary to achieve or maintain compliance. Owners and operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed below.

XVII.C.2.b.(i) STEM must include a monitoring strategy that incorporates the minimum monitoring frequency set forth in Section XVII.F.5.e., procedures for evaluating ongoing storage tank emission capture performance, and, if applicable, the selected strategies.

XVII.C.2.b.(ii) STEM must include a certification by the owner or operator that the selected STEM strategy or strategies are designed to minimize emissions from storage tanks and associated equipment components at the facility or facilities, including thief hatches and pressure relief devices.

XVII.C.3. Monitoring: The monitoring strategy of each STEM plan must include monitoring in accordance with Approved Instrument Based Monitoring Methods, as specified in Section XVII.F.5.

XVII.C.3.a. In addition to any applicable Approved Instrument Based Monitoring Methods, audio, visual, olfactory ("AVO") inspection of the storage tank and any associated equipment (i.e. separator, air pollution control equipment, or other pressure reducing equipment), must be completed as often as liquids are loaded out from the storage tank. However, AVO inspection is required no more frequently than every seven (7) days or less frequently than every thirty (30) days. AVO monitoring is not required for components and tanks that are unsafe to monitor. AVO inspection must include, at a minimum:

XVII.C.3.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are enclosed and properly sealed;

XVII.C.3.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment;

XVII.C.3.a.(iii) If a flare or other combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light, to ensure they are functioning properly;

XVII.C.3.a.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open; and

XVII.C.3.a.(v) If a flare or other combustion device is used, inspection of the device for the presence of absence of smoke. If smoke is observed, either the equipment will be immediately shut-in to investigate that potential cause for smoke and perform repairs, as necessary, or Method 22 shall be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

XVII.C.4. Recordkeeping: The owner or operator of each storage tank subject to XII.D. or XVII.C. must maintain records of STEM as applicable, including the plan, any updates, and the certification, to be made available to the Division upon request. In addition, for a period of two years, the owner or operator must maintain records of any required monitoring and make them available to the Division upon request, including:

XVII.C.4.a. The AIRS ID for the storage tank.

XVII.C.4.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions.

XVII.C.4.c. The date and duration of any period where the air pollution control equipment is not operating.

XVII.C.4.d. Where a flare or other combustion device is being used, the date and result of any Method 22 test.

XVII.C.4.e. The timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions.

XVII.D. (State Only) Emission reductions from glycol natural gas dehydrators

XVII.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of a condenser or air pollution control equipment.

XVII.D.2. The control requirement in Section XVII.D.1. shall apply where:

XVII.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and

XVII.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.

XVII.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, and drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.D.4. The control requirement in Section XVII.D.3. shall apply where:

XVII.D.4.a. Actual uncontrolled emissions of volatile organic compounds from a single new glycol natural gas dehydrator are equal to or greater than two tons per year; or

XVII.D.4.b. Actual uncontrolled emissions of volatile organic compounds from a single existing glycol natural gas dehydrator are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.

XVII.D.4.c. For purposes of Section XVII.D.4.:

XVII.D.4.c.(i) Building Unit shall mean a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.

XVII.D.4.c.(ii) A designated outside activity area shall mean an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a Designated Outside Activity Area; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

XVII.E. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

XVII.E.1. (State Only) The requirements of this Section XVII.E. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.2. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.2.a. Except as provided in Section XVII.E.2.b. below, the owner or operator on any natural gas fired reciprocating internal combustion engine that is either constructed or relocated to the state of Colorado from another state, on or after the date listed in the table below shall operate and maintain each engine according to the manufacturer’s written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section XVII.E.2.b. Table 1 below.

XVII.E.2.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table 1 below as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE 1				
Maximum Engine Hp	Construction or Relocation Date	Emission Standards is G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥100 Hp and < 500 Hp	On or after January 1, 2008 On or after January 1, 2011	2.0 1.0	4.0 2.0	1.0 0.7
≥500 Hp	On or after July 1, 2007 On or after July 1, 2010	2.0 1.0	4.0 2.0	1.0 0.7

XVII.E.3. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.3.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

XVII.E.3.a.(i) Except as provided in Sections XVII.3.1.(i)(b) and (c) and XVII.E.3.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

XVII.E.3.a.(i)(a) All control equipment required by this Section XVII.E.3.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

XVII.E.3.a.(i)(b) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to this Section XVII.E.3.a.

XVII.E.3.a.(i)(c) The requirements of this Section XVII.E.3.a. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.3.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1,2009.

XVII.E.3.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

XVII.E.3.b.(i) Except as provided in Section XVII.E.3.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

XVII.E.3.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.F. (State Only) Leak detection and repair program for well production facilities, storage tanks, and compressor stations

XVII.F.1. Beginning January 1, 2015, owners and operators of well production facilities and compressor stations will identify and repair leaks from components at these facilities in accordance with the requirements of this Section XVII.F. The following shall apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

XVII.F.2. Owners and operators of well production facilities or natural gas compressor stations that monitor components as part of this Section XVII.F. may opt to estimate emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

XVII.F.3. Owners and operators of well production facilities or natural gas compressor stations shall utilize the Approved Instrument Based Monitoring Method and AVO program as outlined in Section XVII.F. AVO monitoring is not required of components and tanks that are unsafe to monitor or inaccessible to monitor, pursuant to XVII.F.5.g.

XVII.F.4. Inspection schedules for natural gas compressor stations: Beginning January 1, 2015, owners and operators of natural gas compressor stations shall inspect components for leaks using an Approved Instrument Based Monitoring Method, in accordance with the following Table 2, except for components subject to XVII.F.5.g. For purposes of this Section XVII.F.4., fugitive emissions shall be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), of other Division approved method.

Table 2	
Fugitive VOC Emissions (tpy)	Inspection Frequency
>0 and ≤ 12	Semi-~~A~~annually

> 12 and ≤ 50	Quarterly
> 50	Monthly

XVII.F.5. Requirements for well production facilities and/or storage tanks

XVII.F.5.a. Beginning August 1, 2014, all new well production facilities shall have a documented pressure test performed on all equipment and piping prior to start up. Documentation of this 90 day testing and monitoring shall be provided in the first annual report to the Division, as required by Section XVII.F.9.

XVII.F.5.b. Beginning January 1, 2015, within 90 days of startup of all new well production facilities and/or storage tanks, owners and/or operators shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method. Such action shall qualify as an inspection pursuant to the inspection frequency schedule in Table 3.

XVII.F.5.c. Consistent with the provisions of XVII.F.5.f., owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks using an Approved Instrument Based Monitoring Method, in accordance with the implementation schedule in XVII.F.5.e. Inspection frequency shall be determined according to Table 3.

XVII.F.5.d. Consistent with the provisions of XVII.F.5.f., owners and operators of new well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method beginning on January 1, 2015. Inspection frequency shall be determined according to Table 3.

XVII.F.5.e. The estimated uncontrolled actual emissions from storage tanks determine the frequency at which inspections must be performed. If no storage tanks are located at the well production facility or multi-well site, operators will rely on the potential to emit of VOC for all of the emissions sources, including emissions from components located at the facility. All components at a well production facility or storage tank must be inspected:

Table 3	
Threshold (per XVII.F.5.e.) VOC Emissions (tpy, uncontrolled actual for sites with	Inspection Frequency

tanks or PTE for sites without tanks)	
> 0 and ≤ 6	~~One time using Approved Instrument Based Monitoring Method and thereafter using monthly AVO~~Every two years with monthly AVO
> 6 and ≤ 12	Semi-a~~A~~nnually with monthly AVO
> 12 and ≤ 50	Quarterly with monthly AVO
> 50	Monthly
Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 20 tpy VOC	Monthly

XVII.F.5.f. Phase-in of Approved Instrument Based Monitoring Methods: Owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method, in accordance with the following schedule:

XVII.F.5.f.(i) Beginning January 1, 2015, facilities with uncontrolled actual VOC emissions greater than ~~50~~ 6 tpy or multi-well sites.

~~XVII.F.5.f.(ii) Beginning July JanuaryMay 1, 2015, facilities with uncontrolled actual VOC emissions greater than 20 6 tpy but less than or equal to 50 tpy.~~

XVII.F.5.f.(ii~~i~~) Beginning January 1, 2016, facilities with uncontrolled actual VOC emissions ~~greater~~ less than or equat to~~than~~ 6 tpy ~~but less than or equal to 20 tpy~~.

~~XVII.F.5.g.(iv) By July 1, 2016, facilities with uncontrolled actual VOC emissions less than or equal to 6 tpy.~~

XVII.F.5.g. If a component is difficult, unsafe, or inaccessible to monitor, the owner or operator shall not be required to monitor the component until it becomes feasible to do so.

XVII.F.5.g.(i) Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

XVII.F.5.g.(ii) Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

XVII.F.5.g.(iii) Inaccessible to monitor components are those that are buried, insulated in a manner that prevents access to the components by a monitor probe, or obstructed by equipment or piping that prevents access to the components by a monitor probe.

XVII.F.6 Leak detection requiring repair: Leaks shall be identified utilizing the methods listed in this Section XVII.F.6.a. through XVII.F.6.d. Only leaks detected pursuant to this Section XVIII.F.6. shall require repair under Section XVII.F.

XVII.F.6.a. For Method 21 monitoring at existing facilities, a leak is any concentration of hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where leak is defined as any concentration of hydrocarbon above 500 ppm.

XVII.F.6.b. For Method 21 monitoring at facilities constructed after May 1, 2014, a leak is any concentration of hydrocarbon above 500 ppm.

XVII.F.6.c. For infra-red camera and AVO monitoring, a leak is any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

XVII.F.6.d. For other Division approved monitoring devices or methods, leak identification requiring repair will be established as set forth in the Division's approval.

XVII.F.7. Repair and remonitoring

XVII.F.7.a. First attempt to repair a leak shall be made no later than five (5) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists. If parts are unavailable, they shall be ordered promptly and the repair shall be made within fifteen (15) working days of receipt of the parts. If shutdown is required, the leak shall be repaired during the next scheduled shutdown. If delay is attributable to other good cause, repairs shall be completed within fifteen (15) working days after the cause of delay ceases to exist.

XVII.F.7.b. Within fifteen (15) working days of completion of a repair, the leaks shall be remonitored to verify the repair was effective.

XVII.F.7.c. Leaks discovered pursuant to the leak detection methods of Section XVII.F. shall not be subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section XVII.F.7.

XVII.F.7.d. For leaks identified using an Approved Instrument Based Monitoring Method, owners and operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.7. or conducting follow-up monitoring using Method 21 within five (5) working days of the leak detected. If the follow-up Method 21 monitoring shows that the leak concentration is less than or equal to 2,000 ppm hydrocarbon for existing facilities (other than existing well production facilities), or 500 ppm for new facilities or existing well production facilities, then the emission shall not be considered a leak for purposes of this Section.

XVII.F.8. Recordkeeping: The owner or operator of each facility subject to the inspection and maintenance requirements in this Section XVII.F. shall maintain the following for a period of two (2) years and make them available to the Division upon request.

XVII.F.8.a. Documentation of the pre-start-up pressure tests for new well production facilities;

XVII.F.8.b. The date and site information for each inspection;

XVII.F.8.c. A list of the leaking components and the monitoring method used to determine the presence of the leak;

XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

XVII.F.8.e. The date the leak was repair;

XVII.F.8.f. The delayed repair list including the basis for placing leaks on the list;

XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and

XVII.F.8.h. A list of identification numbers for components that are designated as unsafe or inaccessible to monitor, as described in Section XVII.F.5.g., an explanation for each component stating why the component is so designated, and the plan for monitoring such component(s).

XVII.F.9. Reporting: The owner or operator of each facility subject to the inspection and maintenance requirements in Section XVII.F. shall submit a single annual report on or before April 30th of each year summarizing inspection and maintenance activities at all of their subject facilities during the previous calendar year. This report shall contain at a minimum the following information:

XVII.F.9.a. The number of facilities inspected;

XVII.F.9.b. The total number of inspections;

XVII.F.9.c. The total number of leaks identified, broken out by component type;

XVII.F.9.d. The total number of leaks repaired;

XVII.F.9.e. The number of leaks on the delayed repair list as of December 31st; and

XVII.F.9.f. Each report shall be accompanied by a self-certification form. The form shall contain a certification by a responsible official of the truth, accuracy, and completeness of such form, report, or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

XVII.G. (State Only) Control of emissions from well production facilities

XVII.G.1 Control Standards

XVII.G.1.A Well Operation and Maintenance: On or after ~~August~~ January 1, 201~~5~~4, ~~during normal operation~~ gas coming off a separator produced from any newly constructed, hydraulically fractured, or recompleted oil and gas well must either be routed to a gas gathering line or controlled by air pollution control equipment ~~t~~that achieves an average hydrocarbon control efficiency of 95% from the date of first production. If a combustion device is used, it shall have a design destruction efficiency of at least 98% of hydrocarbons.

XVII.G.1.B Unless otherwise approved by the Division, on or before 90 days from the date of first production from the well or [January 1, 2015], whichever is later, the well must be connected to a gas gathering line. In determining whether to approve an extension of the 90 day period, the Division will consider the economic feasibility of connecting the well to a gas gathering line, the amount of gas being routed to air pollution equipment, the economic feasibility of alternative uses of the gas, the owner/operators' future plans for connecting the well to a gas line, and any other relevant information from the owner or operator. The division will also consider input received from the Colorado Oil & Gas Conservation Commission and will assess economic feasibility subject to a feasibility criterior of $2,500 per ton.

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XVII.G.2 Monitoring: The owner or operator of any well production facility that is using air pollution control equipment to comply with section XVII.G.1.A. shall visually inspect or monitor the air pollution control equipment to ensure that it is operating. In addition, if a flare or other combustion device is used, the owner or operator shall visually inspect the device for visible emissions. These inspections shall occur as often as liquids are loaded out from the well production facility. However, these inspections are required no more frequently than every seven days or less frequently than every 90 days.

XVII.G.3 Recordkeeping: The owner or operator of an oil or gas well shall maintain the following records for a period of five years and make them available to the Division upon request.

XVII.G.3.A The date of each visual inspection required under Section XVII.G.2

XVII.G.3.B The date, time and duration of any period where the air pollution control equipment is not operating. The duration of a period of non-operation is from the time that the air pollution control equipment was last observed to be operating until the time the equipment recommences operation.

XVII.G.3.C Where a flare or other combustion device is being used, the date and time of any instances where visible emissions are observed from the device.

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XVII.H. (State Only) Venting during downhole well maintenance and unloading events

XVII.H.1. Well Maintenance: Beginning May 1, 2014, hydrocarbon emissions from flowing wells must be captured or controlled during downhole well maintenance or servicing activities, unless venting is necessary for safety.

XVII.H.1.a. Operators shall use best management practices to minimize the need for well venting associated with downhole well maintenance and liquids unloading. During liquids unloading events, any means of creating differential pressure will first be used to attempt to unload the liquids from the well without venting. If these methods are not successful in unloading the liquids from the well, the well may be vented to the atmosphere to create the necessary differential pressure to bring the liquids to the surface.

XVII.H.1.b. Venting will be minimized to the extent possible, using best management practices during the well maintenance and liquids unloading events in XVII.H.1.a. The owner and/or operator shall be present on-site during any planned well maintenance and liquids unloading event in XVII.H.1.a. and shall ensure that any venting to the atmosphere is limited to the maximum extent practicable.

XVII.H.1.c. Records of the cause, date, time, and duration of venting events under this Section XVII.H. will be kept and made available to the Division upon request.

XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

XVIII.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B. Definitions

XVIII.B.1. "Affected Operations" shall mean pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B.2. "Enhanced Maintenance" is specific to high-bleed devices and shall include but is not limited to cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

XVIII.B.3. "High-Bleed Pneumatic Controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

XVIII.B.4. "Low-Bleed Pneumatic controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

XVIII.B.5. "Natural Gas Processing Plant" shall mean any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

XVIII.B.6. "No-bleed Pneumatic Controller" shall mean any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas.

XVIII.B.7. "Pneumatic Controller" shall mean an instrument that is actuated using natural gas pressure and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature.

XVIII.C. Emission Reduction Requirements

The owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

XVIII.C.1. In the 8-Hour Ozone Control Area:

XVIII.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, shall emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.1.c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.1.c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2. Statewide:

XVIII.C.2.a. All pneumatic controllers placed in service on or after May 1, 2014, shall:

XVIII.C.2.c.(i) Emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.; or

XVIII.C.2.c.(ii) Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and is technically and economically feasible.

XVIII.C.2.b. All high-bleed pneumatic controllers in service prior to May 1, 2014, shall be replaced or retrofitted by May 1, 2015, such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.

XVIII.C.2.c. All high-bleed controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.2.c.(i) All high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.D. Monitoring

This section applies only to high-bleed pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.D.1. In the 8-Hour Ozone Control Area

XVIII.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.1.b. Effective May 1, 2009, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2 , and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.D.2. Statewide:

XVIII.D.2.a. Effective May 1, 2015, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.2.b. Effective May 1, 2015, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2 , and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.E. Recordkeeping

This section applies only to high-bleed pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.E.1. The owner or operator of affected operations shall maintain a log of the total number of high-bleed pneumatic controllers and their associated controller numbers per facility, the total number of high-bleed pneumatic controllers per company and the associated justification that the high-bleed pneumatic controllers must be used pursuant to Sections XVIII.C.1.c. and XVIII.C.2.c. The log shall be updated on a monthly basis.

XVIII.E.2. The owner or operator shall maintain a log of enhanced maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, high-bleed pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

XVIII.E.3. Records of enhanced maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the Division upon request.

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XIX. Statements of Basis, Specific Statutory Authority and Purpose

XIX.N. February 21, 2014 (Sections II., XVII., and XVIII.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

<u>Basis</u>

The oil and gas industry is a source of volatile organic compounds ("VOCs"), an ozone precursor. Additionally, oil and gas operations are a source of other hydrocarbon emissions, such as methane, through the leaking and venting of natural gas.

On October 18, 2012, the Commission partially adopted federal Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 C.F.R. Part 60, Subpart OOOO ("NSPS OOOO") into Regulation Number 6, Part A. During the partial adoption of NSPS OOOO, the Commission requested the Air Pollution Control Division ("Division") to consider full adoption at a later date and directed the Division to identify additional oil and gas control measures that complement and expand upon NSPS OOOO. This rulemaking is the result.

The Commission supports the EPA's development of NSPS OOOO, and believes that additional hydrocarbon control measures are warranted in Colorado for several reasons. The Denver Metropolitan Area/North Front Range is in nonattainment with EPA's current 8-Hour Ozone National Ambient Air Quality Standard ("NAAQS"). It is also likely that EPA will lower the ozone NAAQS in the near future. In addition, Colorado has seen significant growth of oil and gas development in recent years, and that growth is expected to continue in the foreseeable future. The oil and gas industry is a significant source of VOC emissions (an ozone precursor). This is particularly true of oil and gas storage tanks. Oil and gas operations also emit methane, a negligibly reactive ozone precursor and a potent greenhouse gas. Division air monitors and other sampling indicate elevated levels of oil and gas related compounds in oil and gas development areas. Improved technologies and business practices can reduce emissions of hydrocarbons such as VOCs and methane in a cost effective manner. Many Colorado operators are already utilizing such technologies and practices to some degree including, without limitation, auto-igniters, low- or no-bleed pneumatic controllers, stabilized liquids or reduced tank pressures, flares achieving at least 98% destruction efficiency, and leak detection and repair (including the use of infrared ("IR") cameras). These technologies and practices have the added benefit of reducing several types of hydrocarbon emissions at the same time.

Colorado has vast experience with the regulation of oil and gas sources. In 2004, 2006, and 2008, the Commission established oil and gas industry emissions controls in Regulation Number 7, Sections XII., XVII., and XVIII. In March 2004, the Commission required condensate tank, controlled under the system-wide approach in what was known as the 8-Hour Ozone Control Area, to meet a 95% control efficiency requirement. This provision was approved into the State Implementation Plan ("SIP"). In December 2006, the Commission determined that on a state-wide, state-only basis, all (new and existing) condensate storage tanks must install air pollution control equipment and meet 95% destruction of VOC, if the total VOC emissions from the tank were equal to or greater than twenty (20) tons per year ("tpy"). Due to "flash," operators have had difficulty consistently meeting this 95% control requirement.

For these reasons and more, the Commission believes additional control measures beyond the current requirements in Regulation Number 7 and NSPS OOOO are appropriate. These regulations apply on a state-wide, state-only basis, and are not a part of Colorado's SIP. This approach gives the Commission, the Division, and stakeholders the opportunity to further assess the implementation and effectiveness of these requirements, to better inform future actions.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), C.R.S. § 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant and provides the Commission broad authority to regulate air pollutants. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons.

Purpose

The Commission adopts revisions throughout Regulation Number 7 to address hydrocarbon emissions from oil and gas facilities, including well production facilities and compressor stations. The revisions expand existing oil and gas control requirements and establish additional monitoring, recordkeeping, and reporting requirements. For example, regarding oil and gas storage tanks, the revisions increase control requirements and improve capture efficiency requirements. The Commission also seeks to minimize fugitive emissions from leaking components at compressor stations and well production facilities. Further, the Commission intends to minimize emissions at new and modified oil and gas wells, and wells undergoing maintenance. The Commission also expands control requirements for pneumatic devices and glycol dehydrators. The Commission believes that this combination of revisions is appropriate to fully adopt NSPS OOOO, and to further reduce emissions produced by the oil and gas industry.

Among other things, these revisions:

- Expressly address hydrocarbon emissions in Section XVII. and XVIII.;
- Amend definitions in Section XVII.A. and XVIII.B.;
- Strengthen good air pollution control practices, require use of auto-igniters, and remove the off-ramp for condensate tanks if subject to NSPS, MACT, or BACT in Section XVII.B.;
- Expand condensate tank control requirements to apply state-wide, to all hydrocarbon liquid storage tanks, and to smaller storage tanks in Section XVII.C.;

- Limit venting and establish a storage tank emissions monitoring system ("STEM"), and associated recordkeeping and reporting requirements in Section XVII.C.;
- Expand glycol dehydrator control requirements in Section XVII.D.;
- Establish a leak detection and repair program for compressor stations and well production facilities in Section XVII.F.;
- Establish control measures for oil and gas wells in Section XVII.G.;
- Limit venting during well maintenance in Section XVII.H.; and
- Expand pneumatic device requirements in Section XVII.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The Commission intends that all the revisions to Regulation Number 7, are state-only requirements.

The following explanations provide further insight into the Commission's intention for certain revisions.

Joint Applicability of NSPS OOOO and Regulation Number 7 Sections XII. and XVII.

It is possible for storage tanks to be subject to NSPS OOOO and Regulation Number 7, Sections XII. and XVII. While this creates an overlap between the different requirements, the requirements secure different emissions reductions. Regulation Number 7, Section XII. applies to condensate storage tanks in the 8-Hour Ozone Nonattainment Area, whereas NSPS OOOO applies to storage vessels that contain more than just condensate, such as produced water and crude oil storage vessels. NSPS OOOO also applies to individual storage vessels, whereas Regulation Number 7, Sections XII. and XVII. apply to single tanks and, if manifolded together, the series of tanks in tank batteries. In addition, NSPS OOOO applies to storage vessels with 6 tpy of controlled actual VOC emissions, whereas Regulation Number 7, Sections XII. and XVII. base applicability on uncontrolled actual emissions. For these reasons, and considering that portions of Regulation Number 7, Section XII. are approved in Colorado's SIP, the Commission intends for the federal and state rules to jointly apply to storage tanks in Colorado. Thus, the Commission intentionally removed storage tanks from the exemption in Section XVII.B.4. that allowed sources subject to an NSPS, MACT, or BACT requirement to avoid having to comply with overlapping requirements in Section XVII.

Furthermore, because NSPS OOOO allows oil and gas operators to avoid applicability by establishing enforceable emission limits below NSPS OOOO applicability thresholds through a state, federal, or local requirement, most storage tanks subject to Regulation Number 7 will not be subject to NSPS OOOO monitoring or recordkeeping requirements. In those limited cases where storage tanks are subject to both NSPS OOOO and current Regulation Number 7 control requirements, Regulation Number 7 will require some additional emissions monitoring.

However, joint applicability is anticipated to be limited to those storage tanks whose uncontrolled actual VOC emissions are one hundred and twenty (120) tpy (the equivalent of six (6) tpy VOC on a controlled actual basis). While this means that more storage tanks are regulated under Regulation Number 7, Section XVII., they are regulated on a state-only basis, and are not federally enforceable like NSPS OOOO. Thus, the Commission believes joint applicability is necessary.

It is the Commission's intent that compliance with Sections XII. and XVII. shall serve to establish legally and practically enforceable limits for the purpose of estimating emissions.

Applicability of Parts of Regulation Number 7 to Hydrocarbons

Many of the control measures set forth in these revisions have the benefit of reducing both VOC emissions and emissions of other hydrocarbons such as methane. Sections XVII. and XVIII. have been revised to reflect the Commission's intent that the provisions contained therein reduce emissions of the broader category of hydrocarbons.

Visible Emissions

Regulation Number 7, Sections XII. and XVII. have historically contained a prohibition on visible emissions from combustion devices, such as flares. The Commission is not proposing to relax this requirement. To address comments from diverse stakeholders, the Commission is clarifying how the Division inspectors and the regulated community are to determine compliance with the prohibition on visible emissions going forward. The Commission has qualified that visible emissions are emissions of smoke that are observed for a period in duration of one (1) minute during a fifteen (15) minute time period. The Commission expects that both Division inspectors and the regulated community will, if any smoke is observed, determine whether the emissions are considered visible emissions for purposes of Regulation Number 7.

Definitions (Section XVII.A.)

The Commission has revised or added definitions for several terms. Further explanation for a few of these terms is set forth below.

"Normal operation" is considered to include all operation, including maintenance and other activities, as long as the operation does not meet the definition of "malfunction" as set forth in the Common Provision regulations.

"Date of first production" is meant to coincide with the date reported to the Colorado Oil and Gas Conservation Commission's ("COGCC") as the "date of first production," as currently used in COGCC Form 5A. The Commission intends for oil and gas sources to use only one date for compliance with both the COGCC and Commission requirements.

“Storage tank,” means a single tank, as well as a tank battery if the tanks are manifolded together. In recent years, it has become more common for multiple tank batteries, sometimes containing different hydrocarbon liquids, to be manifolded at the emissions line and routed to a common control device. To further clarify the concept of manifolded within the definition of “storage tank,” the Commission revises the definition of storage tank to specify that a tank battery must be manifolded by liquid line, and not just be gas or emission line. This revision is in keeping with the rationale that a single tank could have been used to capture liquids in place of multiple small tanks in a battery. The Commission’s definition differs from EPA’s definition of “storage vessel” and the description of an affected storage vessel facility in NSPS OOOO. EPA considers each individual tank, even those in a battery manifolded by liquid line, to be a storage vessel for comparison against the applicability threshold. However, this approach differs from how Colorado has required emissions reporting and permitting for storage tanks, and the Commission intends to maintain that distinction. The Commission, therefore, deletes the previously used definition of “atmospheric condensate storage tank” and creates a new definition of “storage tank” which expands upon the definition of storage vessel in NSPS OOOO to include storage vessels manifolded together by liquid line.

“Well production facilities” are subject to leak detection and maintenance requirements. This definition is meant to include all of the emission points, as well as any other equipment and associated piping and components, located at the same stationary source (a defined term specific to permitting).

Good Air Pollution Control Practices (Section XVII.B.)

The Commission intends that all oil and gas sources, including those below the control threshold or even below Regulation Number 3 APEN and permitting thresholds, be required to adhere to good general air pollution control practices. Examples of what the Commission considers to be a good air pollution control practice include, but are not limited to:

- Keeping the thief hatch, pressure relief valve, or other access point on storage tanks closed and properly sealed during normal operation, unless being actively used during periods of maintenance or liquids loadout from the storage tank;
- Inspecting and repairing seals on their hatches, access points, or other openings of storage tanks;
- Initiating timely action to address leaks or unpermitted emissions; and
- Maintaining equipment and facility in good operating condition.

Controls for Storage Tanks Over 6 tpy (Section XVII.C.)

EPA established a six (6) tpy VOC threshold for applying storage vessel controls. This threshold differs from Regulation Number 7, Section XVII. in that it applies to individual tanks on a controlled actual emissions basis. In contrast, Colorado uses the sum total emissions from a tank battery, where multiple tanks are manifolded together, on an uncontrolled actual emissions basis for reporting, permitting, and control requirements. This means that the EPA's six (6) tpy threshold on a controlled actual emissions basis applies to individual tanks having the equivalent of one hundred and twenty (120) tpy VOC on an uncontrolled actual basis. Thus, more storage tanks are regulated under Regulation Number 7, Section XVII. than under NSPS OOOO.

The Commission intends that under Regulation Number 7, Section XVII., air pollution control devices can be removed if the following conditions are met: (1) storage tank (including manifolded tanks) emissions are below the uncontrolled actual six (6) tpy threshold, on a rolling twelve month basis and (2) controls are not required by other applicable requirements. Conversely, if storage tank emissions increase above the six (6) tpy threshold, control equipment must be installed within sixty (60) days of discovery of the increase.

Control Efficiency (Section XVII.C.)

The Commission expands the 95% control efficiency requirement to apply to storage tanks containing any hydrocarbon liquids (including condensate, crude oil, produced water, and intermediate hydrocarbon liquids), for consistency with NSPS OOOO. Produced water and crude oil storage tanks, which in years past were thought to have insignificant emissions, can instead by significant sources of emissions. This rule change is also a result, in part, of the removal of the APEN exemption in 2008 for tanks containing crude oil and less than 1% crude. The Commission intends that the air pollution control equipment achieve an average hydrocarbon control efficiency of at least 95%, and if a combustion device is used, it must have a design destruction efficiency of at least 98%. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more than properly operated.

Venting vs. Leaking (Sections XVII.B., XVII.C., and XVII.F.)

The Commission believes that emissions caused by over pressurization of oil and gas equipment are foreseeable, are not adequately addressed by NSPS OOOO, and should be addressed in Colorado specific regulations. Venting includes emissions from equipment such as a storage tank at the thief hatch, pressure relief valve, or other access point. Access points are not limited to points of entry of liquids or gas into the storage tank, but include any route from which emissions can escape. However, there are limited circumstances which should not be considered venting, such as where storage tanks emit in emergency situations, during maintenance, gauging, or where necessary to ensure the safety of personnel and equipment. For example, an unplanned third party outage resulting in increased pressure along the system may be the type of malfunction or scenario where venting may be necessary for safety purposes. Inadequate design of a storage tank emissions capture system is not a legitimate reason for venting. The Commission intends that the burden remain on the owner/operator to demonstrate that an emission should not be considered venting as provided in Section XVII.C.2.

The Commission further intends that the malfunction affirmative defense in the Common Provisions regulation continue to be available to operators, provided that the operators demonstrate that the elements of the malfunction affirmative defense have been met. The Commission recognizes that pressure release valves and other devices are meant to operate as safety devices, and not as emission devices. Nothing in this revision is intended to increase risk or compromise safety of personnel and equipment. The Commission recognizes that venting for safety purposes may occur due to sudden, unavoidable equipment failures or surges beyond normal or usual activities that could not have been reasonably foreseeable, avoided, or planned.

In contrast with venting, leaking as used in Section XVII.F. more specifically relates to unintended emissions from components at well production facilities and compressor stations. Identification and repair of leaks in accordance with these revisions benefits the public, the environment, and the oil and gas industry. The Commission has determined that leaks discovered pursuant to the detection methods specified in Section XVII.F. shall not be subject to enforcement by the Division under certain circumstances. For example, if an operator has identified a leak and is in the process of timely and properly addressing the leak in accordance with these revisions, the Division should afford the operator the opportunity to fix the leak absent enforcement. However, by this provision, the Commission does not intend to exempt owners and operators from their obligation to operate without venting or to utilize good air pollution control practices at all times.

Storage Tank Emission Management System (STEM) Plan, Monitoring, and Recordkeeping (Section XVII.C.)

All owners and operators of any storage tank not containing only stabilized liquid must develop, certify, and implement a STEM plan designed, in part, to ensure compliance with the “without venting” requirement of Section XVII.C., among other requirements. Through STEM, owners and operators must evaluate and employ appropriate control technologies and monitoring, maintenance, and operational practices, to avoid venting of emissions from storage tanks. The Commission intends that sources have flexibility in the development of individualized STEM plans. STEM plans may be developed on an individual basis for each storage tank or may be developed for a swath of similarly designed or sized tanks. However, upon request, the owner or operator must be able to identify to the Division what STEM plan applies to a storage tank and make that plan available for review.

Owners and operators of storage tanks containing only stabilized liquids are not required to develop and implement a STEM plan. However, these tanks must still comply with applicable control, capture, monitoring, and recordkeeping requirements.

For purposes of clarification, the STEM plan is intended to include the following elements:

- A monitoring strategy with a minimum of the applicable inspection frequency and methodology;
- An identification of the personnel conducting the monitoring, and any training program, materials, or training schedule for such personnel. This element does not require training, but ensures that any training by documented to permit the operator to demonstrate the quality and achievements of its STEM plan;

- The calibration methodology and schedule for emission detection equipment used in the monitoring;
- An analysis of the engineering design of the storage tank and air pollution control equipment, and where applicable, the technological or operational methods employed to preventing venting;
- An identification of the procedures to be employed to evaluate ongoing capture performance after implementation of the STEM plan;
- A procedures to update the STEM plan when capture performance is not adequate, the STEM design is not operating properly, when otherwise desired by the owner or operator, or when required by the Division; and
- The certification made by the appropriate personnel with actual knowledge of the STEM design for each storage tank.

Monitoring for storage tanks must be conducted utilizing an Approved Instrument Based Monitoring Method, on a frequency schedule that is tied to an emissions from the tank. In addition to any applicable Approve Instrument Based Monitoring Method, the Commission intends that all owners or operators of a storage tank (whether or not it contains stabilized liquids) conduct applicable audio, visual, olfactory ("AVO") monitoring. AVO inspection is not required to occur at the same time as loadout. Instead, loadout triggers the requirement for AVO inspection, and indicates the frequency with which AVO inspection is required.

Documentation of the STEM plan should be maintained by the owner or operator for the life of the storage tank, while records of STEM monitoring only need to be retained for a period of two years. Upon sale or transfer of ownership of a storage tank, the relevant documentation and records should be transferred with the ownership. Owners and operators are encouraged to reevaluate any existing STEM plan for the storage tank upon purchase or acquisition of the storage tank.

Glycol dehydrators (Section XVII.D.)

The Commission expanded the state-wide control requirements for glycol natural gas dehydrators. Currently, any glycol natural gas dehydrator with uncontrolled actual VOC emissions of two tons per year or greater that is located at a facility where the sum of uncontrolled actual VOC emissions from all of the dehydrators at the facility is greater than fifteen tpy must be equipped with a control device that reduces emissions by at least 90%. This revision requires that all existing dehydrators with uncontrolled actual emissions of six (6) tpy or greater VOC must be controlled with air pollution control equipment achieving at least 95% reduction. This revision also provides that existing dehydrator with uncontrolled actual emissions of two (2) tpy or greater VOC must be controlled if they are located within 1,320 feet of a building unit or designated outside activity area. The definitions for building unit and designated outside activity area are taken from COGCC regulations. Finally, this revision requires that all new dehydrators with uncontrolled actual emissions of two (2) tpy or greater VOC must be controlled. The

Commission intends that the air pollution control equipment achieves an average hydrocarbon control efficiency of at least 95%, and if a combustion device is uses, it must have a design destruction efficiency of at least 98%. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more when properly operated.

Leak Detection and Repair Requirements (Section XVII.F.)

The Commission believes the detection and timely repair of leaks is important in the efforts to reduce hydrocarbon emissions. The use of appropriate inspection instruments and methods, such as IR cameras, enhances the detection and reduction of emissions. STEM targets venting from storage tanks, while the detection and repair program more broadly target leaks from components at compressor stations and well production facilities, even if they do not include storage tanks. The use of an Approved Instrument Based Monitoring Method as it relates to leak detection and repair frequency is generally intended to complement the STEM monitoring schedule. The Commission has created a phased schedule and tiered approach for leak detection and repair that is based on emissions, recognizing that smaller operators and facilities may need or want additional time to comply and may have lower emissions. Owner and operators have flexibility in how to meet the leak detection and repair requirements, including utilizing their own equipment and personnel or hiring a third party contractor.

The Commission has defined a leak in a manner that is dependent on the monitoring methodology used in detection. Leak detection methodologies have varied abilities to identify emission quantity and chemical makeup. EPA Reference Method 21, for example, detects and quantifies hydrocarbon emission concentration, but does not speciate hydrocarbons (e.g., methane from other hydrocarbons) or identifies the emission rate. IR cameras are becoming much more prevalent as a more affordable, time-saving, and user-friendly tool, but they also do not speciate hydrocarbons or quantify the emission concentration. The Commission provides owners and operators flexibility in choosing instrument based detection methodology.

If Method 21 is utilized, the Commission has set the threshold at which component leaks must be repaired at 2,000 parts per million ("ppm") hydrocarbons for existing compressor stations and 500 ppm for new (constructed after May 1, 2014) compressor stations and new and existing well production facilities. Where IR camera or AVO monitoring is used, a leak is any detectable emission not associated with normal equipment operation. These values were determined based in part on a review of current federal or state leak detection and repair requirements for natural gas processing plants, refineries, and other oil and gas sources. Leak detection values have decreased over time, in recognition of improved technologies and business practices. NSPS OOOO establishes leak detection at natural gas processing component type. Prior to NSPS OOOO, leaks were identified in other New Source Performance Standards (NSPS KKK and NSPS VVa) at 10,000 ppm. In addition, California, Wyoming, and Pennsylvania have varying leak detection and repair requirements and approaches to defining a leak. Some California air quality districts generally define a minor leak as between 1,000 and 10,000 ppm. Wyoming does not have a numerical limit. Pennsylvania essentially defines a leak at a well pad as anything with detectable emissions utilizing Method 21, as more than 2.5% methane or 500 ppm VOC, or no visible leaks using an

IR camera. Upon consideration of all of the evidence presented, the Commission chose to define component leak at the foregoing thresholds.

The Commission anticipates that many operators will choose to utilize IR cameras, in light of their relative ease of use and increased reliance by both by industry and regulators within Colorado and across the country. The Commission expects that leaks that are not located specifically at a component will be addressed and repaired, in accordance with the general requirements to minimize emissions and employ good air pollution control practices.

The Commission expects that in most instances the leak detection and repair requirements of this regulation will apply in lieu of leak detection and repair requirements in existing permits. The Commission recognizes that leak detection and repair requirements in a few state permits may be federally enforceable, and this state-only regulation cannot supersede federal requirements. The Commission expects the Division and operators to work cooperatively on the efficient implementation of leak detection and repair requirements, in those rare instances where there may be duplicative or competing requirements.

Well Maintenance and Unloading (Section XVII.H.)

Over time, liquids build up inside a well and reduce flow out of the well. These liquids can slow and even block gas flow in wet gas wells and are removed during a well blowdown, also called liquids unloading. As a result of recent information, EPA has significantly increased their emission factor for liquids unloading. The uncontrolled emission factor is based upon fluid equilibrium calculations used to estimate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blowdown. Similar to the issues with well completion emissions, considerable uncertainty for liquid unloading emissions arises from the limited data sources used and the applicability of Natural Gas STAR program activities to calculate industry baseline emissions. This is especially important as liquid unloading is estimated to comprise 33% of the uncontrolled methane emissions from the natural gas industry in the latest greenhouse gas inventory. EPA's Natural Gas STAR program advocates the use of a plunger lift system to reduce the need for liquids unloading, and indicates that such systems may pay for themselves in about one year. The Commission has determined that the use of technologies and practices to minimize venting, including plunger lift systems, are available and economically feasible, and encourages their use in Colorado.

Pneumatic Controllers (Section XVIII.)

The Commission recognized in a December 2008 rulemaking that pneumatic devices are a significant source of emissions. In addition, a 2013 University of Texas study concluded that methane emissions from pneumatics are higher than EPA previously estimated. Therefore, expanding the current low-bleed pneumatic device requirements statewide and further reducing emissions is appropriate and cost-effective. While the use of low-bleed pneumatics will result in a significant reduction of VOC and methane emissions from Colorado oil and gas facilities, no-bleed pneumatic controllers are currently commercially available to further reduce emissions from these sources. However, because these devices can only be used at facilities with adequate electric power, and given the high cost of electrifying a facility, the Commission is requiring the use of no-bleed pneumatics at facilities that are connected to the electric grid and using electricity to power equipment, but only where technically and economically feasible.

ADDITIONAL CONSIDERATIONS

In accordance with C.R.S. §§ 25-7-105.1 and 25-7-133(3) the Commission states the rules in Section XVII. and XVIII. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to be incorporated into Colorado's SIP at this time.

In accordance with C.R.S. § 25-7-110.5(5)(b), the Commission determines:

I. The revisions to Regulation Number 7 address hydrocarbon emissions from oil and gas facilities, including well production facilities and compressor stations. The majority of sources subject to the revised rules will not also be subject to NSPS OOOO or other federal law for such emissions. One goal of the revisions is to address individual sources below NSPS OOOO thresholds, yet that collectively contribute significantly to ozone formation in Colorado. Additionally, it is the Commission's determination that the venting of emissions from storage tanks at oil and gas facilities, caused primarily by over pressurization, is not adequately addressed under NSPS OOOO and therefore warrants Colorado-specific regulations. Moreover, leaks or fugitive emissions of hydrocarbons, such as VOCs and methane, particularly from well production facilities and compressor stations, are not adequately addressed under NSPS OOOO. Thus, Colorado specific regulations are appropriate. Finally, some very large sources (e.g. storage vessels emitting 120 tpy uncontrolled VOC) will be subject to both the revised rules and NSPS OOOO, including the reporting and monitoring requirements.

   In addition to NSPS OOOO, several other federal NSPS, as well as National Emission Standards for Hazardous Air Pollutants ("NESHAP") that apply Maximum Achievable Control Technologies ("MACT") may apply to the tanks, dehydrators, leaking components, and pneumatic devices at oil and gas facilities subject to these revisions. These include, but are not limited to, NSPS Kb and NSPS KKK (which incorporate NSPS VV or VVa) and NESHAP HH and HHH. However, the Regulation Number 7 revisions apply on a broader basis to more tanks, dehydrators, leaking components, and pneumatic devices, and address more hydrocarbon emissions. Some examples include: tank and dehydrator control measures that apply at lower thresholds; leak detection and repair requirements applicable to components beyond gas processing plants; and pneumatic device provisions that require the use of lower emitting devices.

II. NSPS OOOO is primarily technology-based in that it largely prescribes the use of specific technologies in order to comply. EPA has provided some flexibility by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold (greater than or equal to 6 tpy controlled actual VOCs). The

Commission chose to set the revised Regulation Number 7 controls at 6 tpy on an uncontrolled actual emissions basis, and therefore provide Colorado's oil and gas operators a limit for calculating the controlled PTE of their storage vessels, which may be used to avoid NSPS OOOO applicability.

III. There are no federal requirements related to the revisions to Regulation Number 7 that specifically and fully address the issues of concern to Colorado, or take into account concerns that are unique to Colorado. NSPS OOOO addresses VOC emissions and certain co-benefits of reducing such emissions, but does not address hydrocarbon emissions in the more comprehensive manner addressed by these revisions. Following these revisions, Regulation Number 7 will surpass federal requirements in several ways, including, without limitation: (a) Regulation Number 7 will apply to a broader class of tanks than NSPS OOOO; (b) Regulation Number 7 will require a leak detection and repair program for more categories and components that NSPS OOOO; and (c) Regulation Number 7 will require storage tanks with uncontrolled actual emissions equal to or greater than 6 tpy VOC to control emissions with 95% efficiency, while NSPS OOOO's threshold is 6 tpy controlled actual emissions (i.e. 120 tpy uncontrolled actual emissions). It is the Commission's determination that, given the current and projected levels of oil and gas development in Colorado, combined with the advances in technology and business practices utilized by oil and gas operators, the revisions to Regulation Number 7 are appropriate to address hydrocarbon emissions from this sector. Such emission reductions will, among other things, protect public health and the environment, address current and future ozone concerns specific to Colorado, reduce greenhouse gas emissions, and ensure the maximum beneficial use of a valuable natural resource.

IV. Compliance with the control requirements in the revisions to Regulation Number 7 provide Colorado's oil and gas operators a limit for calculating the controlled potential to emit of their storage vessels, thereby allowing many of these sources to avoid regulation under NSPS OOOO. Additionally, the revisions may prevent or reduce the need for more costly retrofits at a later date. The Denver Metro/North Front Range area is currently in nonattainment with the ozone NAAQS. Other areas in the State are seeing elevated ozone levels, including areas of increasing oil and gas development. Colorado may also be required to comply with a future ozone NAAQS that is lower than the current standard. The revised rules are intended to reduce ozone levels now by utilizing controls and techniques already being used or readily available. Utilizing these controls and techniques may prevent the need for more costly retrofitting in the future by addressing ozone precursor emissions now and not waiting until after ozone levels have increased.

V. Adoption at this time allows many of Colorado's oil and gas operators to utilize the controls established in the revisions to Regulation Number 7 to avoid being subject to

NSPS OOOO storage vessel requirements. Postponement of adoption would potentially subject these sources to compliance with NSPS OOOO and then compliance with State requirements once State controls become effective.

VI. The revisions to Regulation Number 7 do not place limits on the growth of Colorado's oil and gas industry. Instead, the rules address hydrocarbon emissions from the sector to assure air quality is maintained while also allowing for continued growth of Colorado's oil and gas industry. Indeed, the oil and gas industry has already grown in Colorado while widely utilizing many of the technologies and practices set forth in these revisions.

VII. The revisions to Regulation Number 7 establish reasonably equity for oil and gas facilities subject to these rules by providing the same standards for similarly situated sources. The revisions to Regulation Number 7 were proposed after a lengthy stakeholder process. Rules of general applicability have been developed along with tiered requirements and exclusions that tailor the rules to the regulated sources within the oil and gas sector.

VIII. The oil and gas industry is a large anthropogenic stationary source of VOCs, a precursor pollutant to ozone. If the revisions to Regulation Number 7 are not adopted, other aspects of oil and gas operations or other sectors may be looked to for additional emission reductions.

IX. The majority of sources subject to the revised rules in Regulation Number 7 will not be subject to federal procedural, reporting, or monitoring requirements. Those few sources subject to both NSPS OOOO and Regulation Number 7 will be required to comply with both regulations. The procedural, reporting, and monitoring requirements of Regulation Number 7, to the extent different than federal requirements, are necessary to achieve the Commission's goals while maintaining flexibility for the operators.

X. Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand requirements already applicable in the 8-Hour Ozone Nonattainment Area state-wide, such as the auto-igniters and pneumatic devices. In addition, many oil and gas operators are already using the control devices and techniques intended to be used to comply with these revisions. The lead-in time provides operators time to install control devices and develop plans for compliance. Should unanticipated events occur, such as a lack of availability of control devices, the rules provide for Division approved extensions to compliance.

XI. As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will contribute to the prevention of hydrocarbon emissions in a cost-effective manner. Significantly, the Commission expressly finds that the cost-effectiveness of the VOC emission reductions alone supports the revisions to Regulation Number 7. The reductions of other hydrocarbon emissions such as methane add to the already cost-effective and appropriate emission reduction requirements.

XII. Alternative rules requiring differing or additional controls for oil and gas facilities could also provide reductions in hydrocarbon emissions. The Commission could adopt some or all of these proposed revisions. However, the revisions to Regulation Number 7 were proposed after a lengthy stakeholder process and provide a balanced approach, reducing emissions from the oil and gas industry while allowing the sector to continue to play a critical role in Colorado's economy and the nation's energy independence. A no action alternative would very likely only delay future reductions in hydrocarbon emissions, including ozone precursors pollutants, necessary for attaining or maintaining the ozone NAAQS in Colorado.

XIII. The Commission has taken into consideration any evidence submitted regarding the factors set forth in C.R.S. § 25-7-109(1)(b).

The incorporation by reference of NSPS OOOO in Regulation Number 6 does not affect the requirements of these revisions to Regulation Number 7. Instead, these revisions to Regulation Number 7 are designed and intended to address the differences and overlaps between NSPS OOOO and current state requirements, and to include additional emission control measures for oil and gas production and equipment. To the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, the Commission hereby makes the determination that:

I. These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

II. Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of hydrocarbon emissions.

III. Evidence in the record supports the finding that the rules shall being about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

IV. The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

V. The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

LEAK DETECTION AND REPAIR (LDAR) INSPECTION PROGRAM - ESTIMATED TRAVEL, EQUIPMENT AND LABOR COSTS

1.0 INTRODUCTION

There is economic burden for oil and gas (O&G) companies in the State of Colorado to implement leak detection and repair (LDAR) programs for their Colorado O&G facilities. Recently, a proposed amendment to Regulation 7 of the Colorado Department of Public Health and Environment (CDPHE), Air Pollution and Control Division (APCD) air regulations would lower the volatile organic compound (VOC) emissions threshold for which LDAR would be required. For this task, Boulder County requested that Terracon analyze the estimated travel time, labor and equipment costs for three typical mid-size Colorado O&G companies with multiple well production facilities (with the potential to emit 6 to 12 tons of uncontrolled VOC emissions per year per facility) and assuming that the company would self-perform its LDAR inspection program with leased monitoring equipment.

Terracon's task was to prepare geographical information system (GIS) simulations to estimate O&G company travel times, labor and equipment costs to self-perform LDAR inspections for their well production facilities in Colorado. Three "mid-sized" O&G companies (2013 statewide gas production volumes of 1.2 to 42 million MCF of gas) in Colorado were evaluated. Production values were obtained from the Colorado Oil and Gas Conservation Commission (COGCC) online database.

2.0 MODELING APPROACH

The initial modeling approach was to evaluate one worst-case scenario where an O&G company would conduct LDAR inspections for its well production facilities in both "urban" and "rural" settings. For purposes of this model, an "urban" setting includes the Denver-Julesburg (DJ) Basin north of Denver, and a "rural" setting includes the Piceance or Paradox Basins on the western slope. Additionally, the modeling approach was intended to evaluate two O&G companies in "rural" settings. However, based on our review of the COGCC database, we were unable to identify companies with well production facilities in the 6 to 12 tons per year uncontrolled VOC emissions range in only "rural" areas. Therefore, the remaining two modeling approaches included two companies with 6 to 12 ton emission well production facilities in "urban" Colorado.

For these simulations, Terracon used ESRI's Network Analyst to compute a least-cost (least-time) path using ESRI's Detailed Streets Layer (2007) and well production facility locational information provided by CDPHE.

3.0 MODELING ASSUMPTIONS AND ATTRIBUTES

The following assumptions were made in preparing the following LDAR inspection travel time and cost estimates:

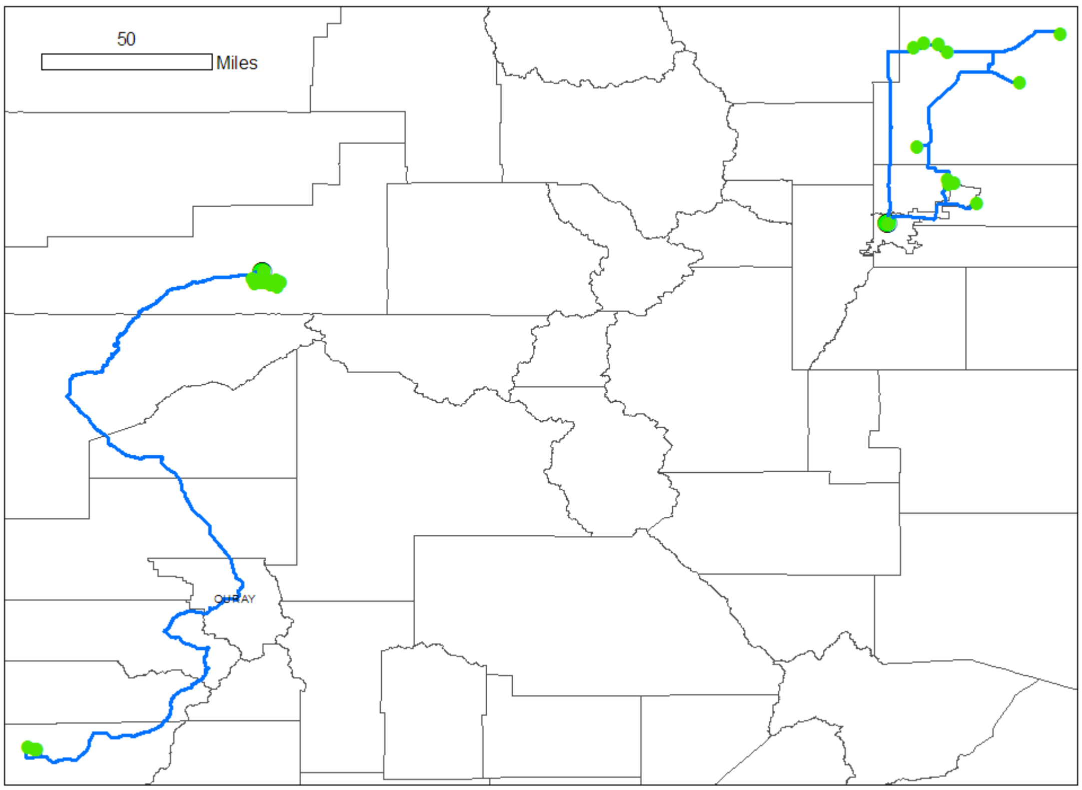
1. An LDAR inspection/monitoring loop consists of a round trip circuit to each well production facility containing equipment with uncontrolled VOC emissions ranging from 6 to 12 tons per year.
2. Each O&G operator self-performs the LDAR inspections using rented monitoring equipment, either a total vapor analyzer (TVA) or an infrared (IR) camera.
3. An average of three hours of monitoring time are required at each facility regardless of the instrument used. This time estimate is based on discussions with several LDAR vendors in Colorado.
4. One technician and one LDAR monitoring instrument is used
5. The ESRI 2007 street network is conservative for estimating distances between sites.
6. Although actual well production facility location information was provided by CDPHE, minor modifications to the latitude and/or longitude values were inputted into the GIS to preserve the anonymity of the O&G companies used for the GIS evaluation.

The following attributes were used to prepare ESRI's Detailed North America Street Map into a network dataset with least-cost routing capability.

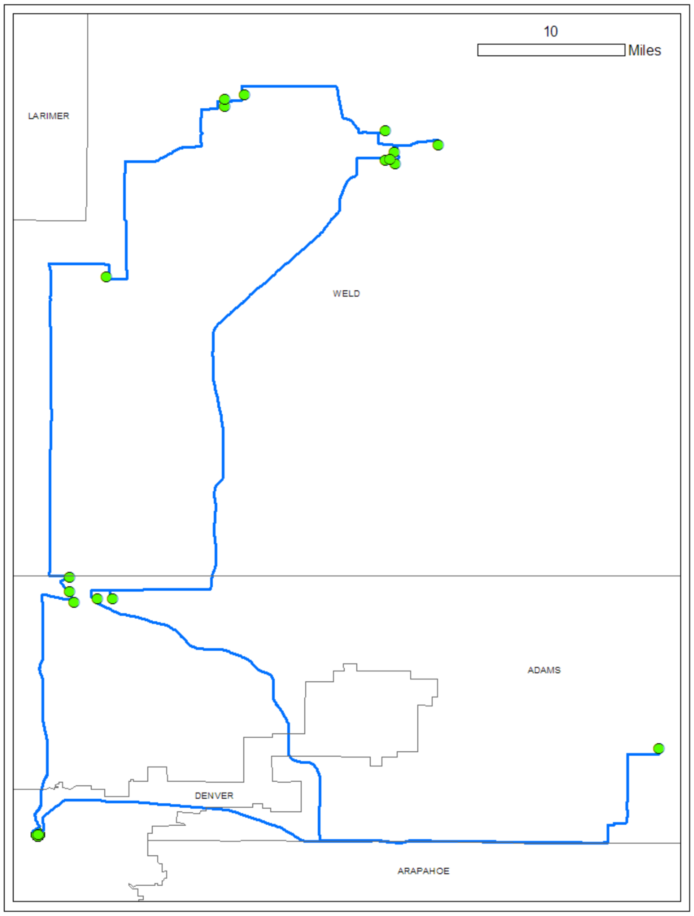
Name	Usage	Units	Data Type
Length	Cost	Miles	Double
Oneway	Restriction	Unknown	Boolean
RoadClass	Descriptor	Unknown	Integer
Minutes	Cost	Minutes	Double
Hierarchy	Hierarchy	Unknown	Integer

Figure 1 – Optimized Travel Routes for Companies A, B and C

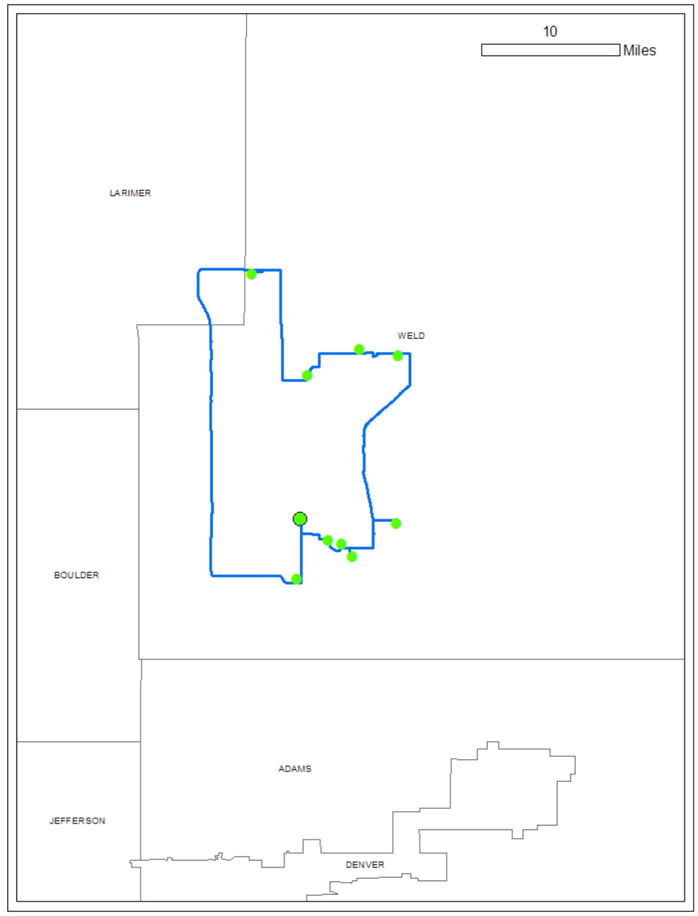
Company A



Company B



Company C



Map Legend

1. Green points represent well production facilities with tanks or equipment with 6 - 12 tons per year in uncontrolled VOC emissions.
2. The Blue route lines between points represent the calculated shortest distance along the road network between every facility, starting and finishing at a point of origin.
3. Company A has two loops. One loop in the DJ Basin. The second loop in the Piceance and Paradox Basins with a starting point at an office in proximity to the Basin.
4. Companies B and C each have one loop with their starting points originating near Denver.

4.0 CALCULATION OF ESTIMATED LDAR INSPECTION PROGRAM LABOR AND EQUIPMENT COSTS

The total time to complete one LDAR monitoring loop includes the travel time between well production sites and the LDAR monitoring time at each site. The total labor cost, in dollars, is the total time to complete one LDAR monitoring loop times the monitoring technician's hourly rate. The total equipment cost is the total time to complete one LDAR monitoring loop times the daily rental rate for the monitoring equipment. Table 1 (see Attachment A) provides a summary of estimated labor and equipment costs for Companies A, B and C to complete one LDAR inspection and annual LDAR inspection costs assuming biannual inspections.

4.1 Method 21 – TVA 1000B Instrument

As indicated in Table 1 (Attachment A), one-time estimated LDAR inspection costs with a TVA 1000B instrument ranged from $2,094 for Company C ("rural" setting) to $8,891 for Company A ("rural" and "urban" setting). Annual LDAR inspection costs using a TVA 1000B instrument, assuming two inspections per year, ranged from $4,188 for Company C ("rural" setting) to $17,782 for Company A ("rural" and "urban" setting).

4.2 Method 21 – IR Camera

As indicated in Table 1 (Attachment A), one-time estimated LDAR inspection costs with an IR camera ranged from $4,494 for Company C ("rural" setting) to $18,491 for Company A ("rural" and "urban" setting). Annual LDAR inspection costs using an IR camera, assuming two inspections per year, ranged from $8,988 for Company C ("rural" setting) to $36,982 for Company A ("rural" and "urban" setting). Inspection times with an IR camera were assumed to be the same as a TVA 1000B (3 hours per site). Actual inspection times may be less using an IR camera, but are not quantified in this analysis.

4.3 Cost Exceptions

The estimated costs do not include the following:

1. LDAR program development costs
2. Method 21 certification or employee LDAR training
3. Purchase of leak detection Instruments
4. Preparation of LDAR reports for submittal to CDPHE
5. Repair or replacement of faulty equipment
6. Internal auditing
7. Per diem (meals and lodging) expenses
8. Supervisor and administrative support
9. Equipment calibration or accessories

5.0 CONCLUSIONS

Terracon used GIS simulations to estimate travel time and costs for three O&G companies to self-perform LDAR inspections for multiple well production facilities in Colorado. The analysis only included facilities with uncontrolled VOC emissions between 6 to 12 tons per year. Three companies were evaluated; one “rural and urban” company (Company A) with facilities in the DJ, Piceance and Paradox Basins and two “urban” companies (Companies B and C) with facilities only in the DJ Basin area.

One-time estimated LDAR inspection costs with a TVA 1000B instrument ranged from $2,094 for Company C (“rural” setting) to $8,891 for Company A (“rural” and “urban” setting). Annual LDAR inspection costs using a TVA 1000B instrument, assuming two inspections per year, ranged from $4,188 for Company C (“rural” setting) to $17,782 for Company A (“rural” and “urban” setting).

One-time estimated LDAR inspection costs with an IR camera ranged from $4,494 for Company C (“rural” setting) to $18,491 for Company A (“rural” and “urban” setting). Annual LDAR inspection costs using an IR camera, assuming two inspections per year, ranged from $8,988 for Company C (“rural” setting) to $36,982 for Company A (“rural” and “urban” setting).

6.0 QUALIFICATIONS AND LIMITATIONS

GIS simulations were developed to provide Boulder County with estimates of reasonable costs that may potentially be incurred by three mid-sized O&G companies to conduct LDAR inspections at Colorado well production facilities with tanks having uncontrolled VOC emissions ranging from 6 to 12 tons per year. This is an order-of-magnitude evaluation that provides the basis for more detailed cost evaluations. Our estimates are based on metropolitan and field office origination points, use of a least-time travel route, and average labor and equipment rates provided by LDAR inspection vendors. An actual LDAR inspection cost proposal could be obtained from a vendor provided that the number and locations of facilities and number of components at each facility are specified.

Terracon has endeavored to use a reasonable cost estimate approach to derive the conceptual LDAR inspection cost estimates given the stated assumptions. Potential inspection costs that were not evaluated or estimated are stated in our assumptions section of this report. In preparing this analysis, our scope was strictly limited to an evaluation of costs associated with travel, equipment and labor for LDAR inspections, and we are not providing opinions as to the cost burden for full implementation of the proposed amendments to Regulation 7 of the APCD CDPHE air regulations.

ATTACHMENT A

TABLE 1

Table 1: Estimated Labor and Equipment Costs for Three Colorado O&G Companies to Perform LDAR Inspections

O&G Company	Facilities[1]	Urban or Rural[2]	Total Distance[3] (Miles)	Total Time (Hours)[4,5]	Cost per Inspection Event			Cost per Year (Assuming Biannual Inspections)		
					Travel and Inspection Cost[6]	Travel and Inspection Cost using TVA 1000B[7]	Travel and Inspection Cost using Infrared Camera[8]	Travel and Inspection Cost[6]	Travel and Inspection Cost using TVA 1000B[7]	Travel and Inspection Cost using Infrared Camera[8]
A (2 loops combined)	34	Urban and Rural	787	121	$6,491	$8,891	$18,491	$12,982	$17,782	$36,982
B	16	Urban	217	53	$2,771	$3,821	$8,021	$5,542	$7,642	$16,042
C	9	Urban	78	29	$1,494	$2,094	$4,494	$2,988	$4,188	$8,988

NOTES:

(See Figure 1 for route maps)

[1] Facilities with uncontrolled VOC emissions between 6 to 12 tons per year

[2] Location of facilities

[3] Obtained from GIS Model

[4] Total travel time from the GIS Model

[5] Includes 3 hours per facility to complete LDAR inspection

[6] Technician rate of $ 50 per hour and $0.56 per mile travelled

[7] "TVA 1000B" analyzer cost is $ 150.00 per day. Assume 8 hour days. Shipping costs are not included.

[8] Infrared camera cost is $ 750.00 per day. Assume 8 hour days. Shipping costs are not included.

OIL & GAS PRODUCTION FACILITIES
POTENTIAL SOURCES OF FUGITIVE VOC EMISSIONS

Prepared for

Boulder County Colorado

WHERE CAN FUGITIVE VOC EMISSIONS OCCUR?

Fugitive VOC emissions can occur on various types of equipment and devices involved in the production, storage, and conveyance of oil and gas.

Well Heads

Valve seals
and joints

Compressor Engines

Seals, flanges and joints

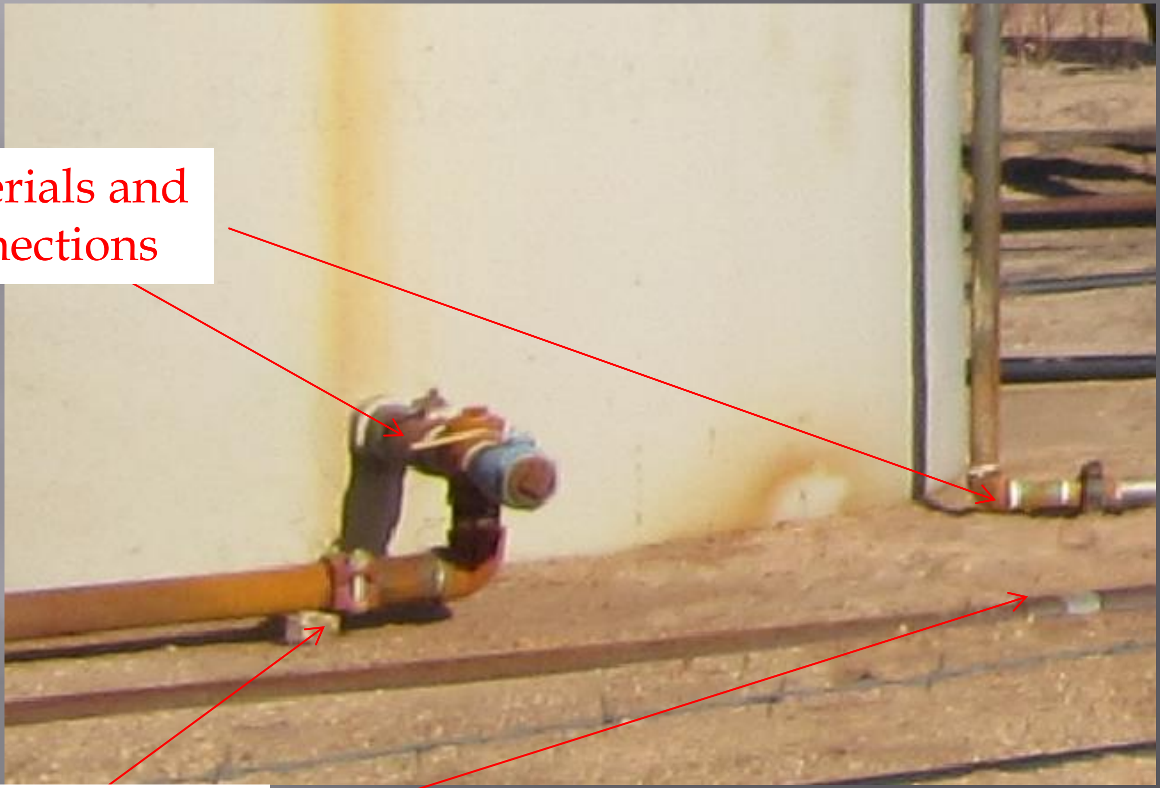
Process Equipment

Flanges and fittings

Tank Battery Site

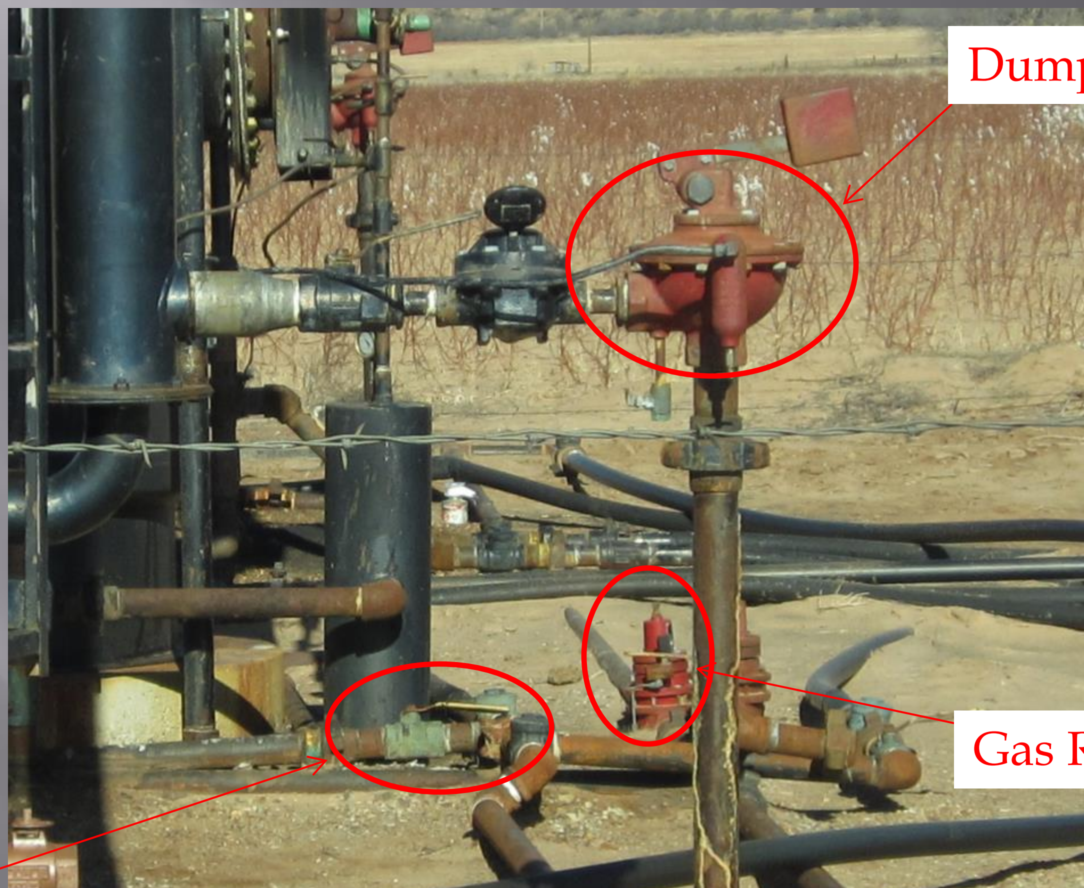
Tank Battery Site

Multiple materials and threaded connections



Inadequate support with threaded connections

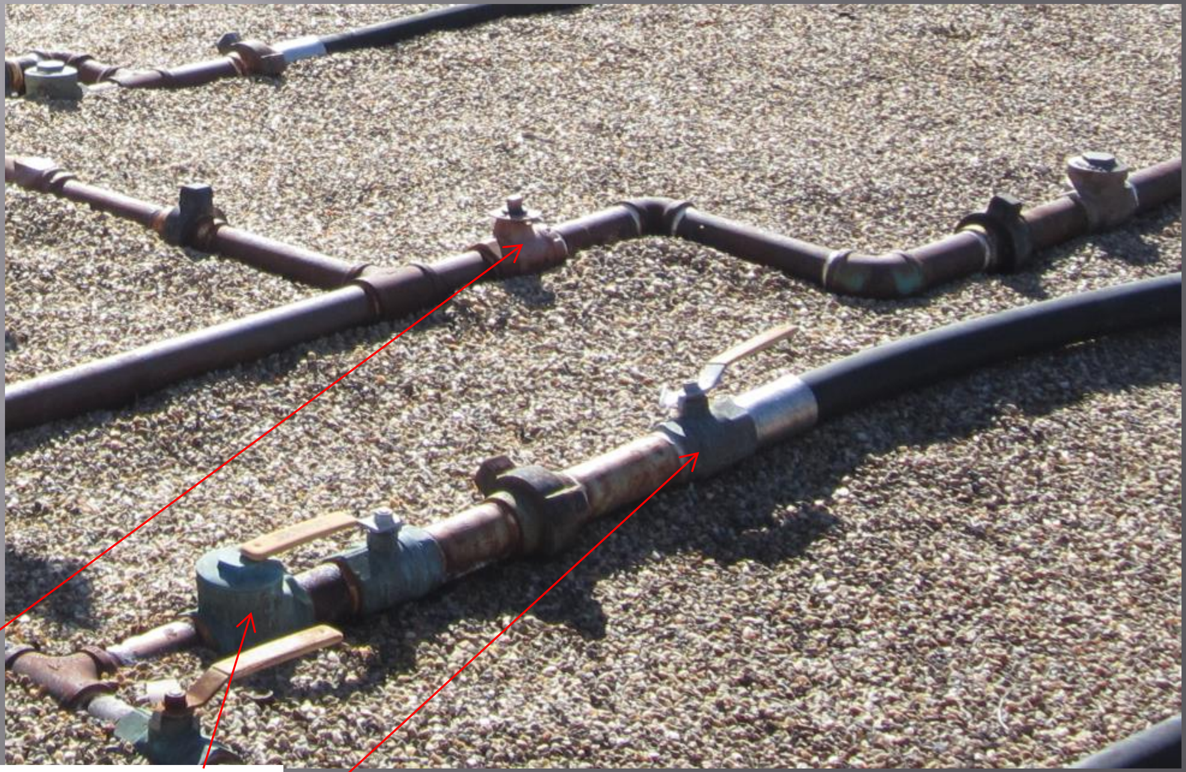
Tank Battery Site



Tank Battery Site

Gas regulator with threaded connections and frozen ground conditions

Tank Battery Site



Valves with
threaded connections

Tank Battery Site

Flanged connections

Tank Battery Site – Heater Treater

Fittings with
threaded connections

Tank Battery Site

Pneumatic Controller

Tank Battery Site

Elbow fitting with inadequate support

Tank Battery Site

(Unions, Couplings, Elbows and Valves)

What causes some leaks to occur?

- Threaded Connections:
  - Improper selection and/or application of thread tape can lead to material degradation or inability to create a seal. Thread tapes rated for greater than operating pressure and temperature should be chosen;
  - Inadequate support to pipes can lead to vibrations during pressure variations in the system, resulting in leaks; and
  - Connections near or under the ground in the presence of water may expand unevenly resulting in leaks.

Why do leaks occur? (cont..)

- Valves, Pressure Relief Valves (PRVs), Compressors, Pumps and Meters
  - Debris in the flow system can prevent the valve from completely closing allowing gas or oil to escape from the system downstream from the valve;
  - A damaged valve seat or seal;
  - Not performing scheduled re-greasing and/or equipment inspections per manufacturer recommendations; and
  - Lack or implementation of a regular operations and maintenance (O&M) program.

Why do leaks occur? (cont..)

- Inadequate O&M program may fail to identify:
  - Damage from impact;
  - Excessive corrosion;
  - Cracked seals;
  - Metal fatigue and stress cracks from hydrogen sulfide attack; and
  - Over-pressurization of storage vessel from inoperable PRV.

Potential Benefits of Implementing an LDAR Program*

- Reducing Product Losses,
- Decreasing exposure to surrounding community, and
- Potentially reducing emission fees

* Per EPA "Leak Detection and Repair-A Best Practices Guide"

LDAR SERVICE PROVIDERS

- http://www.dexterfs.com
- http://www.enrud.com
- http://www.erm.com
- http://www.flir.com
- http://www.guardiancompliance.com
- http://www.heathus.com
- http://www.ldarsolutions.com
- http://www.ldartools.com
- http://www.inficon.com
- http://www.thermoscientific.com
- http://www.americanleakdetection.com
- http://customstackanalysis.com
- http://www.afcintl.com
- http://www.pesldar.com
- http://www.ldarsolutions.com
- http://www.iprems.com
- http://www.emsi-air.com/
- http://www.iprems.com/
- http://www.trihydro.com/

LDAR SERVICE VENDORS OVERVIEW

Prepared for

Boulder County
Boulder County
Colorado

VENDOR CONTACT & INFORMATION COLLECTION

- Several subcontractors contacted that provide LDAR monitoring services to the oil and gas industry in Colorado.
- The objective was to approximate costs charged for LDAR monitoring.
- Of the companies contacted, four companies provided responses.

TYPICAL LDAR SERVICES VENDOR COST BREAKDOWN

VENDORS[1]	LDAR TECHNICIAN HOURLY COST[2]	LDAR SUPERVISOR HOURLY COST	EQUIPMENT CHARGES PER DAY [3]	MILEAGE CHARGE PER MILE	NOTES
Vendor 1	$ 35.00	$ 45.00	Included for Method 21	Did not provide	---
Vendor 2	$ 60.00	NA	$ 200.00 (Equipment and vehicle charge)	Did not provide	---
Vendor 3	$ 42.00	$ 46.00	Included for Method 21	$ 0.56	IR Camera - $ 750.00 per day additional charge
Vendor 4[4]	$ 48.00	$ 65.00	Included for Method 21	$ 1.00	IR Camera - $ 750.00 per day additional charge

1 Actual vendor names not provided as site specific information was not provided and to protect vendor competitive interests. Vendors have also indicated that pricing may vary based on site specific factors.

2 Technician hourly cost does not include food/per diem expenses, overtime, hotel expenses or other travel expenses.

3 Method 21 does not specify an instrument detector type, but the detector used must satisfy the performance criteria specified in the method. The detector can use catalytic oxidation, flame ionization, infrared absorption, or photoionization. Vendors 1, 2 and 4 indicated that for LDAR inspection as per Method 21, there will be no additional equipment charges. However, if IR cameras are employed, there will be additional charges. Vendors may charge additional for tag sets, wires and cables.

4 Vendor 4 indicated that if only IR camera is used for leak detection then the LDAR technician hourly cost will be $ 67.50 and Supervisor hourly cost will be $ 90.00.

Notes from Vendor discussions

- IR cameras approved for Method 21 may not be readily available because of cost.
- Due to differences in training required for IR cameras, technician charges are usually higher.
- IR cameras approved for Method 21 are typically used to detect high concentrations or larger leaks and other Method 21 equipment is typically used for lower concentrations. Some vendors indicated that they could use a combination of Method 21 equipment and IR cameras based on the size of the site and number of potential fugitive emission sources.
- Most commonly used equipment for Method 21 is Thermo Toxic Vapor (TVA) Analyzer, TVA-1000B. As per research, rental cost for the equipment averages around $ 150 per day, not including accessories or other miscellaneous parts/calibration kits.
- Most commonly used Infrared Camera was FLIR GasFindIR MW camera. As per research, rental cost for the camera averages around $750 per day.

List of Vendors contacted

- http://www.dexterfs.com
- http://www.enrud.com
- http://www.erm.com
- http://www.flir.com
- http://www.guardiancompliance.com
- http://www.heathus.com
- http://www.ldarsolutions.com
- http://www.ldartools.com
- http://www.inficon.com
- http://www.thermoscientific.com
- http://www.americanleakdetection.com
- http://customstackanalysis.com
- http://www.afcintl.com
- http://www.pesldar.com
- http://www.ldarsolutions.com
- http://www.iprems.com
- http://www.emsi-air.com/
- http://www.iprems.com/
- http://www.trihydro.com/

Not all vendors responded to requests.

The next worksheet is the final EIA for the 6-12 TPY well production facility (WPF) changes that the LGC alternate proposal addresses.

The main difference between the LGC alternate proposal and the Division's is that WPFs in the 6-12 TPY category get inspected twice per year in the LGC alternate proposal versus once per year in the Division's.

The initial EIA cost estimates for compressor stations in the 0-12 TPY category and the WPFs in the 0-6 TPY category, also proposed by the LGC to be inspected more frequently than the Division's proposal, remain as stated within the LGC - PHS.

The costs on the following worksheet are based off of data the LGC commissioned Terracon to develop for WPFs in the 6-12 TPY uncontrolled VOC range. The assumptions and results are included as rebuttal exhibits LGC - REB EXH A1, A2, and A3. These costs supersede the values for the 6-12 TPY facilities in the initial EIA, contained within the LGC - PHS.

Economic Impact Analysis for Biannual Inspections of Well Production Facilities as Recommended by the LGC

Number of Facilities	1412	6-12 TPY threshold
Inspections per facility per year	2	
VOC per facility - uncontrolled (6-12 TPY range)	9	TPY
Cumulative VOC - uncontrolled	12708	TPY
Current VOC capture rate	71.25%	(CDPHE EIA - Table 15)
Current VOC emissions - controlled	3654	TPY
Intended VOC capture rate	95%	(CDPHE EIA - Table 15)
Intended VOC emissions (with STEM and LDAR)	635	TPY (@ 95% effectiveness)
Potential VOC emissions avoided (w/ STEM & LDAR)	3018	TPY (going from 71.25% to 95% effectiveness)
Potential WPF VOC emissions avoided (w/ LDAR)	2598	TPY (CDPHE EIA Table 26, 6-12 TPY)
Total LDAR inspection costs @ 2x/year	$1,503,547	using TVA1000B rental costs (see below)
Total LDAR inspection costs @ 2x/year	**$2,350,747**	using FLIR camera rental costs (see below)
Total LDAR inspection costs @ 2x/year	**$1,327,986**	CDPHE EIA (Table 27, 6-12 TPY); multiplied $663K by 2 to compare with proposed LGC semi-annual inspections vs annual
Total LDAR inspection costs @ 2x/year	**$6,042,560**	DGS Client Group PHS EX C (Table 12 Part I, 6-12 TPY); multiplied $3M by 2 to compare with proposed LGC semi-annual inspections vs annual
Annual LDAR inspection costs per facility @ 2x/year	$1,065	(w/ TVA 1000B)
Annual LDAR inspection costs per facility @ 2x/year	$1,665	(w/ FLIR Camera)
Annual LDAR inspection costs per facility @ 2x/year	**$1,365**	Average of TVA and FLIR
Annual LDAR inspection costs per facility @ 1x/year	$926	(CDPHE EIA w/ FLIR - Table 14)
Cost per ton of VOC reductions (w/ LDAR)	$579	(using TVA 1000B costs)
Cost per ton of VOC reductions @2x per year (w/ LDAR)	**$905**	(using FLIR camera costs)
Cost per ton of VOC reductions (LDAR)	**$512**	CDPHE EIA (Table 27, 6-12 TPY); multiplied $256 by 2 to compare with proposed LGC semi-annual inspections vs annual
Cost per ton of VOC reductions (LDAR)	**$3,702**	DGS EIA (Table 14, 6-12 TPY); multiplied $1851 (Year 1) by 2 to compare with proposed LGC semi-annual inspections vs annual

Supporting data used to estimate LDAR inspection costs:

LDAR Inspection time	3	hours (per LGC REB EXH A1)		
Avg daily round trip distance	90	miles (@ 2 inspections per day)		
Per mile costs	0.56	per mile rate (2014 GSA)		
Avg speed	50	mph		
Travel time per inspection	0.9	hours		
Technician hourly rate	$50			
Additional staff costs multiplier	1.55	(CDPHE EIA - Table 20)		
Overhead multiplier	1.10	(CDPHE EIA - Table 20)		
Fringe multiplier	1.30	(CDPHE EIA - Table 20)		
Labor costs per inspection w/travel time	$432			
Mileage costs per inspection	$25			
Total Labor and mileage costs per Inspection	$457			
Total Annual Labor and Mileage Costs	**$1,291,747**	(@ 2 inspections per year per facility)		
Total number of inspections	2824	LGC @ 2x per year		
Inspections per day	2	LGC estimate		
Number of days	1412	to complete	2824	inspections
TVA equipment costs (rental)	$150	per day (Terracon)		
FLIR equipment costs (rental)	$750	per day (Terracon)		
	$211,800	**Annual TVA Costs (LGC)**		
	$1,059,000	**Annual FLIR Costs (LGC)**		
	$1,503,547	**Total Annual Inspection Costs with TVA (LGC)**		
	$2,350,747	**Total Annual Inspection Costs FLIR Costs (LGC)**		

BEFORE THE COLORADO AIR QUALITY CONTROL COMMISSION
COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

WORLDWIDE LIQUID SOLUTIONS, LLC ALTERNATIVE PROPOSALS

IN THE MATTER OF OIL & GAS RULEMAKING EFFORTS:
REGULATION NUMBER 3, PARTS A, B AND C
REGULATION NUMBER 6, PART A and
REGULATION NUMBER 7

Worldwide Liquid Solutions, LLC, by and through its attorney, Dan E. Wilson, Attorney at Law, LLC, files its Alternative Proposals in the above referenced matter.

1. In its initial Request for Party Status, Worldwide Liquid Solutions ("WLS") suggested the alternative of deleting ethane and methane from proposed Rule. 7 (5CCR 10001-9), to wit:

   a. In II. B. Exemptions, strike all proposed language for addition to the rule (specifically striking the addition of methane and ethane in Sections XVII and XVIII).

   b. Consistent with this change, change all references throughout the draft proposed rule noted as "hydrocarbons" to "volatile organic compounds". A more accurate description would be to identify them as precursors to ozone producing compounds within the definition of the rules.

   c. In XVII.C.4.c. Recordkeeping, please be informed that a properly functioning passive volatile organic compound absorption filter ("PVOCAF") will continue to capture VOCs in an upset condition until such filter is filled or replaced under a service schedule. This rule needs to be modified to reflect a release of "volatile organic compounds" released to the atmosphere, or to note repair of the "burp valve", or when the passive absorption filter is replaced.

2. Upon further review, WLS would suggest the complete incorporation of 40 CFR Part 60, subpart OOOO as revised through 9/23/2013.

   a. Such incorporation would likely be made into Rule 6, Part A. Rule 3, Parts A, B and C could be promulgated. If done, Rule 7 would be stricken in its entirety.

b. Such action would bring the Air Quality Control Commission ("AQCC") current from its partial incorporation of 40 CFR Part 60, subpart OOOO on October 12, 2012.

3. A good faith argument can be made to limit the application of proposed Rule 7 to the Denver Metropolitan/North Front Range nonattainment areas. Such an effort would require a major effort to compile the necessary data supporting analyses to support Rule 7 even in these non-attainment areas. The analyses will not likely support the addition of the de minimis, negligibly reactive compounds of ethane and methane for pollution purposes but may prove more cost effective in these locations.

Respectfully submitted this 6th day of January, 2014.

Dan E. Wilson
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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was sent via email to the following persons whose names and addresses are listed below on January 6, 2014.

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BEFORE THE COLORADO AIR QUALITY CONTROL COMMISSION
COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

WORLDWIDE LIQUID SOLUTIONS, LLC – ECONOMIC IMPACT ANALYSIS STATEMENT

IN THE MATTER OF OIL & GAS RULEMAKING EFFORTS:
REGULATION NUMBER 3, PARTS A, B AND C
REGULATION NUMBER 6, PART A and
REGULATION NUMBER 7

Worldwide Liquid Solutions, LLC, by and through its attorney, Dan E. Wilson, Attorney at Law, LLC, files its Economic Impact Analysis in the above referenced matter.

A. SUMMARY

Worldwide Liquid Solutions ("WLS") participated as a stakeholder in the above referenced rulemaking process. However, despite repeated promises by the Colorado Department of Public Health and Environment ("CDPHE" or "Division") to hold technical working group sessions to evaluate emerging technical solutions, no such meetings were ever held by CDPHE, nor alternative solutions evaluated in connection with the proposed rules.

WLS manufactures a passive volatile organic compound ("VOC") absorption filter ("PVOCAF"). The filter is passive and requires no outside source for electrical power to operate. Wind turbines or solar collection devices are adequate power sources for small storage tank filters to maintain negative pressure. The filters are housed in a non-absorptive, recyclable 'short stack' which holds a filter of absorptive carbon material that captures VOC compounds as they pass up the stack.

The PVOCAF is entirely constructed of material that can be recycled into a fresh filter. A WLS vendor will recover the captured VOCs and regenerate the carbon filtering material for reuse. Development of a full scale carbon recovery program is possible with a significant percentage of participants within the oil and gas industry.

The PVOCAF offers a low cost, low energy, carbon capturing, recyclable alternative to flaring and combustion devices without creating additional, secondary pollution. However, PVOCAF will not capture ethane and methane, not currently regulated by Quad O. The inclusion of ethane and methane in the draft Colorado Rule 7 will render this advanced technology unusable in Colorado.

When compared to published data from EPA, the PVOCAF demonstrates a cost savings advantage over flares and combustion devices for VOC emissions from storage tanks in many scenarios. The cost effectiveness of the PVOCAF is extended in remote areas where there is no electrical service or where generators would be required to power a flare or combustion device.

The PVOCAF offers an additional advantage over flares and combustion devices because it consumes no fuel (ethane and methane) to operate, reducing the cost of fuel and avoiding the secondary pollution of NOx, CO, methane and primarily CO2 created by these devices. Currently, EPA has set the Best System of Emission Reduction ("BSER") at 4 tpy VOC under Quad O determining that below this limit, flares and combustion devices are no longer cost effective, will create additional pollution and environmental impacts and consume too much energy to be effective. WLS is working with Wyoming, Texas, Utah, and U. S. EPA for use of the PVOCAF as an alternative to flaring. The PVOCAF may revolutionize the BSER for the oil and gas industry because it can cost effectively capture VOCs well below the current BSER limits.

B. ECONOMIC IMPACT ANALYSIS

WLS estimates that it can provide passive volatile organic compound absorption filters ("PVOCAF") for storage tanks at the initial start-up investment of $1,000 per filter and $1,100 per ton of VOC removal. This cost will include the initial potential to emit analysis, including VOC testing and gas chromatography. Actual VOC monitoring of the PVOCAF should be set at monthly to quarterly schedules depending on the initial potential to emit ("PET") determination or changes in tank usage. These estimates include maintenance, monitoring and filter replacement costs.

VOC (tpy)	PVOCAF	EPA	CDPHE
1	$2100 per ton		
2	$1600 per ton	$10,000 per ton	
3	$1433 per ton	$6900 per ton	
4	$1350 per ton	$5100 per ton	
5	$1300 per ton		
6	$1267 per ton		
7	$1243 per ton		
8	$1225 per ton		
9	$1211 per ton		
10	$1200 per ton		
11	$1191 per ton		
12	$1183 per ton		

The chart above is based upon the cost estimates provided by WLS and what has been most currently published by EPA in connection with the Quad O revisions, 78 FR 58416, at page 58429 (9/23/13). The CDPHE cost projections have not yet been submitted as part of the rulemaking process. However, it should be noted that EPA has expressed concern over CDPHE's costs being used in the current rulemaking process. See, 78 FR at page 58429.

Please keep in mind that there is no secondary pollution or fuel cost to operate the PVOCAF, so there is no corresponding BSER limit. In other words, the PVOCAF can cost effectively capture VOCs below the 4 tpy BSER limit established by EPA for flares and combustion devices.

WLS submits that the PVOCAF is a cost effective alternative to flares and combustion devices that should be utilized to capture VOCs in Colorado. The device has the potential to reduce VOC emissions below the current EPA BSER limit of 4 tpy VOC and could cost effectively be used in areas where VOC capture needs to occur below these limits, such as to protect residents in close proximity to VOC emissions or help achieve VOC compliance in non-attainment areas.

Respectfully submitted this 30th day of January, 2014.

Dan E. Wilson
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CERTIFICATE OF SERVICE

This is to certify that I have duly served the within **Worldwide Liquid Solutions, LLC-Rebuttal Statement** upon all parties herein by e-mail or by depositing copies of same in the United States mail, first-class postage prepaid, at Denver, Colorado, this 30th day of January, 2014, addressed as follows:

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