REGULATORY ANALYSIS

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

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

RULE TITLE OR SUBJECT:

Regulation Number 3
Stationary Source Permitting and Air Pollutant Emission Notice Requirements

1. INTRODUCTION

On October 15, 2019, the Colorado Oil and Gas Association (COGA), Colorado Petroleum Council (CPC), the Board of County Commissioners of Weld County (Weld County), and Western Local Governments Coalition (WLG Coalition) filed a Request for Issuance of a Regulatory Analysis for Proposed Provisions of the Ozone Action Plan (Request) with the Colorado Air Pollution Control Division (Division) per C.R.S. §24-4-103(4.5)(a) and the Air Quality Control Commission (Commission) procedural rules, 5 Code Colo. Reg. §1001-1:1.5.5(12). 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 State Administrative Procedure Act ("APA") serves as the legal authority for this rule-making process, and it sets forth requirements for both cost-benefit and regulatory analyses.[1] Under the APA, any person may request an agency engaged in a rule-making 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.

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

During the 2019 legislative session, Colorado's General Assembly adopted Senate Bill (SB) 19-181 (Concerning additional public welfare protections regarding the conduct of oil and gas operations), revising §25-7-109, C.R.S. SB 19-181 directs the Commission to "adopt rules to minimize emissions of methane and other hydrocarbons, volatile organic compounds (VOC), and oxides of nitrogen (NOx) from oil and natural gas exploration and production facilities and natural gas facilities in the processing, gathering and boosting, storage, and transmission segments of the natural gas supply chain." These revisions include:

- Section 2.1. Clarifying existing definitions and adding an existing definition from Regulation Number 7 to promote consistency across State regulations;
- Section 2.2. Update the APEN reporting and permitting requirements for oil and gas well production facilities;
- Section 2.3. Clarifying and narrowing existing APEN and permitting exemptions and repealing certain exemptions related to oil and gas wastewater impoundments;
- Section 2.4. More closely aligning language with Colorado Statute;
- Section 2.5. Clarifying when transfer of ownership forms are due and where the compliance responsibilities lie during the transfer process.

In addition to these more prominent revisions, the proposal also corrects typographical, grammatical, and formatting errors in Regulation 3. This Regulatory Analysis focuses on the more significant revisions and does not address typographical, grammatical, and formatting changes. While the proposed revisions' primary class of persons that will be affected and bear the costs of this rule change is the oil and gas industry, this analysis will include a description of other classes of persons where appropriate.

This analysis represents information gathered from various stakeholders in an effort to generate the most complete and accurate assessment of the costs and benefits of the proposed strategies. Where additional data was not reasonably available, the Division utilized assumptions that are set forth in this analysis. This analysis builds upon the Final Economic Impact Analysis (Final EIA) submitted to the Commission on November 5, 2019 and the Cost Benefit Analysis requested by rulemaking parties and submitted to the Department of Regulatory Agencies on November 29, 2019, and provides additional detail as required by statute. The Division incorporates the content of the Final EIA and Cost Benefit Analysis into this Regulatory Analysis, and attaches copies of those materials hereto as Attachments A and B, respectively. The Division also refers herein to filings by the Division and other parties in this rulemaking proceeding; these materials are available on the Commission's website in the monthly materials folder for the December 2019 Commission meeting, at:
https://drive.google.com/drive/folders/1MKiAOE7v1F0G0Ohc_QvAwC6x8G9jYYCV

2. ANALYSIS

2.1. Definition Revisions

The Division is proposing to supplement the definition of "Commencement of Operation" in Part A, Section I.B. to ensure clarity for oil and gas operations, to aid with compliance, and ensure consistency across state air regulations. The Division is also proposing to include the definition of "Well Production Facility" from Regulation Number 7 in Regulation Number 3 to ensure consistency.

2.1.1. Classes of Persons

"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. However, there are no costs associated simply with the definitions proposed for Regulation 3.

2.1.2. 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 Division does not believe that there are economic impacts related to the proposed definition revisions. In its Initial Economic Impact Analysis, the Division requested any information to the contrary, but received no such information from stakeholders that would inform the Final EIA, the Cost Benefit Analysis, or this Regulatory Analysis.

2.1.3. 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."

There are no expected costs to the Division to implement the definition revisions. The revision to the definition of "Commencement of Operation" will allow the Division to better ensure clarity for oil and gas operations and to aid with compliance and enforcement efforts. The Division currently relies on operators to report the "date of first production" to the Colorado Oil and Gas Conservation Commission (COGCC). However, the COGCC term does not reflect that APENs are generally submitted to document emissions associated with a specific piece of equipment, not facility-level emissions. 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. Additionally, these revisions will have no effect on COGCC protocols or operations.

2.1.4. Compare 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 declines to adopt the proposed definition revisions, there will be inconsistency between state regulations. The Division will also have to continue to rely on inconsistent reporting of "first date of production" as a trigger for APEN and permit timings.

The Division has not identified any benefits to inaction on the definition section.

2.1.5. Less Costly or 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 has not identified any less costly or less intrusive methods to achieve to purpose of the proposed revisions.

2.1.6. Alternate 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 Joint Industry Work Group (JIWG) have suggested aligning the definition of "Commencement of Operation" with the COGCC term "date of first production."[3] However, the Division's intent in proposing this term is expressly to move away from the COGCC term "date of first production," given the Division's experience in its application, which is that operators do not report this term to the Division or COGCC in a consistent manner. Further, the COGCC term does not reflect that APENs are generally submitted to document emissions associated with a specific piece of equipment, not facility-level emissions.

The Clean Air, Climate, and Health Coalition (CACHC) has also proposed a different definition[4] for "Commencement of Operation" However, as the Division understands it, CACHC's definition would move commencement of operation significantly earlier than the Division's proposal, even before the first well at the proposed facility had been completed and potentially while only temporary equipment is on site. The Division recognizes the importance of assessing and ultimately controlling these emissions. However, the Division has not yet undertaken the type of analysis needed to inform a comprehensive approach to addressing emissions during pre-production activities and from temporary equipment. Rather, the Division intends to look at those activities and emissions as it progresses through subsequent stages of SB19-181 implementation, after close consultation with the COGCC, who has historically regulated these operations. CACHC's proposal would leapfrog over this process and could lead to conflicting regulatory regimes and control requirements that are not optimized for pre/early-production activities.

2.1.7. 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."

Data used in this analysis includes existing economic impact analyses, stakeholder comments and input into the rule-making process as presented in the Final EIA[5] for the Request for Hearing.

2.2. Oil and Gas APEN and Permitting Revisions

Currently, Regulation 3, allows certain oil and gas operations to defer APEN submittal for up to 90 days after the first date of production. The current language of the rule refers to "exploration and production operations (well site and associated equipment)", though the Division's proposal clarifies the applicability by referring to well production facilities, a defined term. The Commission adopted this APEN deferral in 1993 to allow sources sufficient time to determine production levels before being required to submit APENs. While the Division is proposing to narrow or eliminate other associated permitting deferrals, as discussed in more detail below, the Division is not proposing to remove this APEN deferral because the Division believes it remains appropriate for operators to submit APENs and pay emission fees based on actual emissions, as opposed to projected emissions. However, to clarify that this APEN deferral is not an exemption from APEN requirements, but more of a delay in the timing of submittal, the Division is proposing to relocate the APEN requirement for oil and gas from Section II.D.1.lll to the APEN applicability provisions of Section II.A. The Division is also proposing to align the requirement with the newly revised term "Commencement of Operation" in lieu of the undefined "first date of production." Taken together, the language of Section II.A.1 clarifies that APEN-reportable sources at oil and gas well production facilities must submit those APENs no later than 90-days after commencement of operation.

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[3] COGA_API-CPC_JOINT_PHS, pp.38-39.
[4] CACHC_PHS, p.10.
[5] *See* Attachment A.

As noted, under exemptions established in 1993, oil and gas exploration and production operations may currently wait to submit a construction permit application until 90 days after the date of first production. While this 90-day deferral was appropriate when it was adopted, the Division believes that this deferral period for permits is no longer necessary. Therefore, the Division is proposing to repeal the deferral. The Division's proposal would have the result that oil and gas well production facilities would now require a pre-construction permit just like all other sources subject to Part B.

As a result of the proposal to remove the 90-day permitting deferral, the Division is proposing a related revision to Section III.B.2, which provides for the content of permit applications. Because the Division is not proposing to change the timing of APEN submittals for these sources, it would be incongruous to require the submittal of an APEN with the permit application. Therefore, the Division is proposing to allow flexibility for emissions information to come in with permit applications on Division-approved forms apart from APENs, as required by the Division.

The proposal also adds a new requirement in Part B, Section III.G.1.a. for oil and gas well production facilities to submit a notice of startup to the Division at least 15 calendar days prior to any well completion activities (operators may submit a notice earlier if so desired). The notice must include the date on which well completion activates are scheduled to begin.

However, HighPoint Operating Corporation (HighPoint) and the JIWG have objected to this requirement on two grounds. First, HighPoint and the JIWG point out that because the Division does not have the authority to implement or enforce NSPS OOOOa completion requirements, this requirement reflects only an administrative burden.[6] That is not correct. The Division does not dispute that the Commission has not adopted NSPS OOOOa's completion requirements. However, observing and understanding emissions during completion is only one motivation for the rule, and is a permissible one.[7] Yet another motivation is to ensure time to coordinate inspections during the first days of production, when emissions are typically expected to be high. Further, SB19-181 clarifies that the Commission has the authority to regulate emissions during pre-production activities. While historically these activities have been regulated by the COGCC, as part of the broader directive to minimize emissions, the Division, working with COGCC, intends to take a comprehensive look at these activities from an air quality perspective in order to inform potential future action. Adding a Notice of Start-Up as part of this rulemaking will assist the Division in performing the analysis and determining appropriate measures for these activities.

HighPoint and the JIWG also point out that both NSPS OOOOa and OGCC Form 42 require only 48 hours' notice of these activities, and suggest it is unreasonable for the Commission to require more.[8] They suggest instead that the Division rely upon the copy of the COGCC notice that it receives. Again, the Division disagrees. The Division is not aware that the purpose of the notice required by EPA or OGCC is to allow for the agency to coordinate inspections during the activity. Even if it were, the Division's inspection program is not so nimble as to be able to arrange for inspections upon 48 hours' notice. The Division has determined that fifteen days is the minimum necessary for inspection staff to coordinate schedules and conduct these inspections.

[6] HPOC_PHS pp.2-3; JIWG_PHS_EX-001, pp.29-30.
[7] *See* §25-7-111, C.R.S. (recognizing that the Division has the authority to conduct studies and research with respect to air pollution, and that the Division also has the authority to require sources to furnish any information that the division may require related to the emissions of that source); *see also* §25-7-106, C.R.S. (recognizing the Commission's authority to carry out the purposes of the Colorado Air Act by requiring sources to maintain and furnish information).
[8] HPOC_PHS pp.2-3; JIWG_PHS_EX-001, pp.29-30.

2.2.1. Classes of Persons

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

The proposal affects the oil and gas industry and supporting businesses in Colorado. Companies that will bear the costs of this rule change include the oil and gas companies operating well production facilities that have emissions above APEN and permitting thresholds.

2.2.2. 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 Division believes that there are additional permitting fees associated with the revisions related to the Oil and Gas APEN and Permitting Revisions. These revisions change only the timing of existing APEN and permitting requirements but also allow for an alternate reporting and permit application process that will have associated fees. The Division requested cost additional information from stakeholders, but none was provided.

The Division also recognizes an administrative burden to operators from preparing and submitting the Notice of Startup in advance of well completion activities, but believes this burden is necessary and appropriate for the reasons discussed above. Further, as many oil and gas operators will, instead of seeking coverage under an individual construction permit, register under General Permit 09 or General Permit 10, which separately have Notice of Startup provisions, this requirement will apply only to a subset of operators.

2.2.3. 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 oversee the administration and implementation of the proposed revisions. There will be increased workload for the Division as a result of increased APEN and permitting submissions. The Division will also develop procedures for and conduct inspections during well completion activities. However, the workload resulting from the proposed revisions will be absorbed by existing and anticipated staff.

2.2.4. Compare 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 decides not to adopt these revisions, oil and gas operations will be allowed to operate for up to 90 days without an APEN or emissions permit.

The Division believes that these provisions are appropriate and necessary for the Division to collect fees and develop an accurate emissions inventory. The Denver Metro/North Front Range area (DMNFR) is facing a serious nonattainment reclassification and accurate emissions information is vital as the Division further develops its emission reduction strategies.

The Division does not currently receive any notice when the operator is engaged in pre-production activities, such as well completions or flowback, nor does the Division receive notice when production is expected to begin following the end of pre-production activities. SB 181 directs CDPHE to minimize emissions from the entire oil and gas supply chain, including pre-production activities. As part of its effort to collect information about these activities, the Division intends to include well completions and flowback activities in its inspection program. The Division also intends to conduct inspections during the first 90 days of operations during a period of time when production can be the highest. To do so, the Division must receive notice when these activities will begin.

2.2.5. Less Costly or 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 has not identified any less costly or less intrusive methods to achieve to purpose of the proposed revisions.

2.2.6. Alternate 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 identify any alternate methods for achieving the purpose of the proposed revisions except as otherwise discussed above.

2.2.7. 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."

Data used in this analysis includes existing economic impact analyses, stakeholder comments and input into the rule-making process as presented in the Final EIA[9] and Cost Benefit Analysis.

2.3. APEN and Permitting Exemptions Revisions

The Division is proposing to revise the exemptions in Part A, Section II.D.1.uuu., Part B, Section II.D.1.m., and Part C, Section II.E.3.uu. and II.E.3.yyy., to no longer exclude oil and gas production wastewater impoundments that contain less than 1% by volume crude oil on an annual average from APEN and permitting requirements. Even at these low concentrations, these sources may have significant emissions, and APEN exemptions are meant to be limited to emission points with minimal impacts on air quality.

[9] *See* Attachment A.

Since this APEN exemption was adopted in 1996, the Division has become aware of produced water tanks that meet or have claimed the 1% crude oil exemption but have uncontrolled actual emissions that are not negligible, including some tanks owned by Kerr McGee, a subsidiary of Occidental Petroleum (see Table 1 below for two examples).

Table 1

AIRS	Description	Uncontrolled VOC (tpy)	Uncontrolled Total HAP (tpy)
123/9FF7/004	Two (2) 400 bbl fixed roof produced water storage vessels	44.5	4.9
123/6794/002	Two (2) 420 bbl produced water tanks	164.2	18.2

Further, in another example not cited in Table 1, actual sampling of the water in the tank showed crude oil by volume of 0.01%. However, the product entering the tank was coming from a pressurized separator and was flashing from the separator pressure at 40 psig down to the tanks at 0%. Based on a flash liberation analysis on the produced water, 1.8 scf of flash was generated per barrel of produced water, and this flash gas was 32 wt% VOC. Therefore, the working and breathing losses for the tank were low enough to be considered negligible. However, the flash emissions were not, even though technically the exemption could arguably apply. This example demonstrates that when the exemption was originally conceived, the Commission likely did not contemplate situations where flash emissions would occur.

Sources are not generally required to submit information about the percentage of crude oil in produced water tanks or storage impoundments, and so the Division does not have enough of a dataset to estimate the total number of emission points or the total amount of emissions that are excluded from its APEN and permit database due to the exemption. The Division further notes that the APEN exemption at Part A, Section II.D.1.a (for sources with actual uncontrolled emissions of criteria pollutants less than 2 (or 1) tpy) remains unchanged. Sources may still rely upon the general APEN exemption found in Part A, Section II.D.1.a, as long as emissions remain below the applicable threshold. The removal of the 1% exemption with the backstop of the existing exemption allows the Division to ensure that sources with non-negligible emissions are appropriately included in the inventory while maintaining the Commission's directive to exempt negligible sources.

Currently, Regulation Number 3 exempts "venting of natural gas for safety purposes" from APEN and permitting requirements. The Division has determined that it is no longer appropriate to exempt from APEN and permitting requirements those venting activities that are routine or predictable, and which are likely to result in emissions. The Division is also proposing to clarify that these routine or predictable activities that take place across the year are to be grouped together for purposes of APEN reporting and permitting. For example, the "routine or predictable" blowdown of oil and gas equipment, such as storage tanks, for maintenance (e.g., preventive maintenance, well swabbing, or unloading), gauging, and loadout, must be aggregated across the year and reported and permitted accordingly.

2.3.1. Classes of Persons

"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 Division's proposal to revise Regulation Number 3, Part A, Sections II.D.1.uuu and II.D.1.zzz, Part B, Section II.D.1.m, and Part C, Sections II.E.uu, II.E.3.yyy, and II.E.3.dddd, may affect sources that are trying to determine whether they qualify for an exemption to the APEN, permitting, and Title V permitting requirements in Regulation Number 3.

Based on preliminary analysis, the Division believes the majority of the costs will be associated with upstream oil and gas well production facilities. Owners and operators of compressor stations, gas plants and those in the transmission sector may also incur costs. There may also be costs upon non-oil and gas operators that must now report and permit emissions from venting.

The Division anticipates that some companies may have to hire additional staff to accommodate the additional reporting and recordkeeping burden. Because operators may opt to hire outside contractors, third-party consultants may benefit from these revisions.

2.3.2. 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 Division has quantified the expected costs as presented in the FEIA[10] for the Request for Hearing. The Division anticipates that some companies may have to hire additional staff to accommodate the additional reporting and recordkeeping burden. Consistent with the 2014 Oil and Gas Rulemaking[11] the Division used a similar multi-step process to calculate the estimated costs and benefits associated with the hiring of staff to maintain records and submit reports of routine and predictable emissions. The total annual cost for each new reporting staff is estimated at $97,600, which equates to an hourly rate of $52.

2.3.3. 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 oversee the administration and implementation of the proposed revisions. There will be increased workload for the Division as a result of increased APEN and permitting submissions. However, the workload resulting from the proposed revisions will be absorbed by existing and anticipated staff.

2.3.4. Compare 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 decides not to adopt these revisions, the benefit would be the cost savings by the affected industries that would not have to report or permit emissions related to produced water impoundments or venting of natural gas.

However, there are a number of disbenefits to this approach. The DMNFR is facing a serious nonattainment reclassification and accurate emissions information is vital as the Division conducts modeling and further develops its emission reduction strategies. The Division would also be unable to collect appropriate APEN and permitting fees from sources that are above the applicable thresholds. Therefore, the Division believes that these provisions are appropriate and necessary for the Division to collect fees and develop an accurate emissions inventory.

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[10] *See* Attachment A.

[11] *See* the Colorado Department of Public Health and Environment Air Pollution Control Division Final Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7 (5 CCR 1001-9), dated January 30, 2014.

2.3.5. Less Costly or 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 did not identify any less costly or less intrusive methods for achieving the purpose of the proposed revisions, nor were any such alternatives identified by stakeholders.

2.3.6. Alternate 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 Center for Biological Diversity (CBD) submitted an alternate proposal that asks the Commission to remove several additional APEN and permitting exemptions, and to provide that methane and ethane are non-criteria reportable pollutants subject to all the regulations applicable thereto. However, the CBD recently withdrew the portion of its alternate proposal seeking to list methane and ethane as non-criteria reportable pollutants. The Division believes that while CBD's proposals deserve serious consideration, it would be better to consider them as part of later rulemakings. The Division has repeatedly advised stakeholders that this rulemaking is the first of many to implement SB19-181, HB19-1261 and SB19-096, as well as to further Colorado's progress towards attaining the 2008 and 2015 ozone NAAQS.

2.3.7. 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."

Data used in this analysis includes existing economic impact analyses, stakeholder comments and input into the rule-making process as presented in the Final EIA, the Cost Benefit Analysis, and materials submitted to the Commission.

2.4. Alignment with Colorado Statute and Division Implementation

The Division's proposal updates language in Part B, Sections II.A.1. and III.I.2.a., to align with existing language in the Air Pollution Prevention and Control Act provision and current Division practice regarding permits. These revisions are intended to reflect how the Part B permitting program has been operated and implemented, and to ensure more consistency with the governing statute. The Division does not intend a change in its regulatory program as a result of this revision and does not intend to apply its revisions retroactively.

2.4.1. Classes of Persons

"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 Division's proposal to revise Regulation Number 3, Part B, Sections II.A and III.I.2.will affect all sources subject to this regulation; however, the changes do not have anticipated practical impacts, other than clarifying ambiguity.

2.4.2. 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 Division does not believe that there are economic impacts related to revisions that ensure consistency with the governing statute. The Division requested additional information from stakeholders, but none was provided that would inform the Final EIA, the Cost Benefit Analysis or this Regulatory Analysis.

2.4.3. 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 costs for implementation or enforcement because it does not intend to change its regulatory program as a result of this revision. Any potential workload resulting from the proposed revisions will be absorbed by existing staff.

2.4.4. Compare 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 decides not to adopt these revisions, the Division does not believe there are any benefits related to inaction. The driving purpose of these revisions is to align the regulatory language with how the permitting program is implemented and enforced by the Division, and to achieve more consistency with its governing statute. The cost of inaction is a missed opportunity to clarify ambiguities.

2.4.5. Less Costly or 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 did not identify any less costly or less intrusive methods for achieving the purpose of the proposed revisions.

2.4.6. Alternate 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 identify any alternative methods for achieving the purpose of the proposed revisions.

2.4.7. 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."

Data used in this analysis includes existing economic impact analyses, stakeholder comments and input into the rule-making process as presented in the Final EIA, the Cost Benefit Analysis, and materials submitted to the Commission.

2.5. Transfer of Ownership Forms

The existing provisions regarding the submittal of forms to accomplish the transfer of liability for compliance following a transfer of ownership are ambiguous and inconsistently applied. As they are currently written, the rules apply to the "prospective owner"[12], which suggests that the forms need to be filed before the transfer of ownership occurs. The Division recognizes that this timing is not workable for many sources and so has proposed to recognize that sources should have 30 days following completion of the transfer of ownership in which to submit the appropriate forms (and thereby affect transfer of liability).

2.5.1. Classes of Persons

"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 Division's proposal to revise Regulation Number 3, Part B, Section II.B may affect sources that that sell or acquire an existing facility subject to Regulation Number 3.

2.5.2. 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 Division does not believe that there economic impacts of the proposed revisions related to clarifying when transfer of ownership forms are due. The Division requested additional information from stakeholders, but none was provided.

2.5.3. 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 oversee the administration and implementation of the proposed revisions. Any potential workload resulting from the proposed revisions will be absorbed by existing staff.

2.5.4. Compare 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 decides not to adopt these revisions, the Division does not believe there are any benefits related to inaction. The cost of inaction is a missed opportunity to provide clarity to operators.

2.5.5. Less Costly or 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 did not identify any less costly or less intrusive methods for achieving the purpose of the proposed revisions.

[12] Regulation Number 3, 5 Code Colo. Reg. §1001-5: Part B, II.A.

2.5.6. Alternate 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."

Some operators have requested that the Division allow for more than 30 days in which the transfer of ownership form may be submitted. The Division does not support allowing more than 30 days to submit the forms, having heard no reason that would prevent operators from being able to submit this relatively simple paperwork within that time.

2.5.7. 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."

Data used in this analysis includes existing economic impact analyses, stakeholder comments and input into the rule-making process as presented in the Final EIA, the Cost Benefit Analysis, and materials submitted to the Commission.

3.0 CLOSING SUMMARY

On October 15, 2019, interested parties and stakeholders filed a Request for Issuance of a Regulatory Analysis for Specific Provisions of the Ozone Action Plan. This document is a careful and considerate response to that Request 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. The Division believes that the proposal before the Commission reflects a balanced approach, developed with broad input and support from industry, local governments, and environmental stakeholders.

ATTACHMENT A

ECONOMIC IMPACT ANALYSIS
(Final Analysis)

Item Title: Regulation Number 3, Parts A, B, and C

Meeting Date: December 17-19, 2019

ISSUE

The Colorado Department of Public Health and Environment, Air Pollution Control Division ("Division") requests that the Colorado Air Quality Control Commission ("Commission") consider proposed revisions to Regulation Number 3, Stationary Source Permitting and Air Pollutant Emission Notice Requirements to address Senate Bill 19-181. Specifically, the Division proposes the following revisions: (1) in Part A, Section I.B., to clarify existing definitions and add an existing definition from Regulation Number 7 to promote consistency across State regulations; (2) in Part A, Sections II.A. and II.D., and Part B, Sections II.D., III.B., and III.G., to update the APEN reporting and permitting requirements for oil and gas well production facilities; (3) in Part A, Section II.D., Part B, Section II.D., and Part C, Section II.E to clarify existing APEN and permitting exemptions and repeal certain exemptions related to oil and gas wastewater impoundments; (4) in Part B, Sections II.A., and III.I., to more closely align language with Colorado Statute; (5) in Part B, Section II.B., to clarify when transfer of ownership forms are due and where the compliance responsibilities lies during the transfer process.

In addition, the Division may also make typographical, grammatical, and formatting corrections throughout Regulation Number 3.

The proposed revisions to Regulation Number 3 are State Implementation Plan ("SIP") revisions.

REQUIREMENTS FOR ECONOMIC IMPACT ANALYSIS ("EIA")

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

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

Per Section 25-7-110.5(2), C.R.S., the requirements of Section 25-7-110.5(4) shall not apply to rules which: (1) adopt by reference applicable federal rules; (2) adopt rules to implement prescriptive state statutory requirements where the AQCC is allowed no significant policy-making options; or, (3) adopt rules that have no regulatory impact on any person, facility or activity.

DISCUSSION

Definition Revisions

The Division is proposing to supplement the definition of "Commencement of Operation" in Part A, Section I.B. to ensure clarity for oil and gas operations, to aid with compliance, and ensure consistency across state air regulations. The Division is also proposing to include the definition of "Well Production Facility" from Regulation Number 7 in Regulation Number 3 to ensure consistency.

Oil and Gas APEN and Permitting Revisions

Regulation Number 3, Part A, Section II.D. and Part B, Section II.D., currently allow oil and gas exploration and production facilities to defer APEN reporting and construction permitting requirements for up to 90 days after the first date of production. This provision was established in 1993 to allow sources sufficient time to determine production levels before being required to submit APENs or construction permit applications. This deferral previously referred to an undefined term "exploration and production". In practice, that has been analogous with the currently defined term well production facility in the context of Regulation Number 3. The Division believes that this deferral period for permits is no longer necessary or appropriate. Therefore, the Division is proposing to repeal the deferral in Part B, Section II.D.7. The Division's proposal would therefore have the result that oil and gas well production facilities would now require a pre-construction permit just like all other sources subject to Part B.

However, the Division continues to recognize that oil and gas well production facilities will better understand and predict emissions once production is underway. Therefore, the Division also proposes to amend Part A, Section II.A.2 to maintain the requirements that owners or operators of well production facilities are required to: (1) submit APENs no later than 90 days following commencement of operation for new facilities after January 1, 2020; and (2) submit APENs prior to modifications of well production facilities.

Additionally, the Division is proposing changes to Part B, Section III.B.2. that will allow the Division more flexibility in the permitting process, such as allowing for emissions information to be submitted on forms other than APENs.

The proposal also adds a new requirement in Part B, Section III.G.1.a. for oil and gas well production facilities to submit a notice of startup to the Division at least 15 calendar days prior to any well completion activities (operators may submit a notice earlier if so desired). The notice must include the date on which well completion activates are scheduled to begin. This new provision is intended to create a notification mechanism so that Division staff can ensure they have the opportunity to conduct inspections while these well completion activates are occurring.

Exemption Revisions

The Division has clarified an existing APEN reporting and permitting exemption for emissions resulting from venting of natural gas lines for safety purposes. This exemption is contained in Part A, Section II.D.1.zzz., and Part C, Section II.E.dddd. These provisions were added in March

1996 and were intended to apply only to fuel gas lines on utility boilers within a generation building. However, as some stakeholders noted, the Statement of Basis explanation of the Commission's intent in 1996 was not reflected in the language ultimately adopted by the Commission. Nor is that Statement of Basis language consistently reflected in the permitting and enforcement practices of the Division. As a result, the Division has determined that it is no longer appropriate to exempt from APEN and permitting requirements those venting activities that are routine or predictable, and which are likely to result in emissions. The Division is also proposing to clarify that these routine or predictable activities that take place across the year are to be grouped together for purposes of APEN reporting and permitting. For example, the "routine or predictable" blowdown of oil and gas equipment, such as storage tanks, for maintenance (e.g., preventive maintenance, well swabbing or unloading), gauging, and loadout, must be aggregated across the year and reported and permitted accordingly.

The proposal also revises the exemptions in Part A, Section II.D.1.uuu., Part B, Section II.D.1.m., and Part C, Section II.E.3.uu. and II.E.3.yyy., to no longer exclude oil and gas production wastewater impoundments that contain less than 1% by volume crude oil on an annual average from APEN and permitting requirements. Even at these low concentrations, these sources can have significant emissions. However, in both cases, sources may still rely upon the general APEN exemption found in Part A, Section II.A. if emissions are sufficiently low.

<u>Alignment with Statute</u>

The proposal updates language in Part B, Sections II.A.1. and III.I.2.a., to align with existing language in the Air Pollution Prevention and Control Act provision regarding permits. *See* §25-7-114.2, C.R.S. These revisions are intended to reflect how the Part B permitting program has been operated and implemented, and to ensure consistency with the governing statute.

<u>Transfer of Ownership</u>

The Division is proposing changes to Part B, Section II.B. to clarify that a transfer of ownership form is due to the Division within 30 days of completion of a transfer or assignment of ownership for reissuance of existing permits. The language has also been modified to explicitly state that the responsibility for compliance with existing permitting requirements transfers to the new owner or operator when the forms are submitted.

Based on the data the Division has at this time, the Division provides the following information to satisfy the economic analysis relating to the proposed revisions to Regulation Number 7:

(A) Identification of the industrial and business sectors that will be impacted by the proposal;
(B) Quantification of the direct cost to the primary affected business or industrial sector; and
(C) Incorporation of an estimate of the economic impact of the proposal on the supporting business and industrial sectors associated with the primary affected business or industry sectors.

Section 25-7-110.5(4)(c)(III), C.R.S.

(A) Identification of the industrial and business sectors that will be impacted by the proposal

Definition Revisions

The Division's proposal to revise two definitions in Part A, Section I, may affect oil and gas operations that will use the new definition for "Commencement of Operation" to determine compliance with Regulation Number 3.

Oil and Gas APEN and Permitting Revisions

The Division's proposal to revise Regulation Number 3, Part A, Section II and Part B, Section III may affect oil and gas operations that have emissions above APEN and permitting thresholds.

Exemption Revisions

The Division's proposal to revise Regulation Number 3, Part A, Sections II.D.1.uuu and II.D.1.zzz, Part B, Section II.D.1.m, and Part C, Sections II.E.uu, II.E.3.yyy, and II.E.3.dddd, may effect sources that are trying to determine whether they qualify for an exemption to the APEN, permitting, and Title V permitting requirements in Regulation Number 3.

Based on preliminary analysis, the Division believes the majority of the costs will be associated with upstream oil and gas well production facilities. Owners and operators of compressor stations, gas plants and those in the transmission sector may also incur costs. The Division believes that oil and gas operations are the primary industry affected by these revisions but requests more information from stakeholders.

Alignment with Statute

The Division's proposal to revise Regulation Number 3, Part B, Sections II.A and III.I.2. will affect all sources subject to this regulation; however, the changes do not have impacts.

Transfer of Ownership

The Division's proposal to revise Regulation Number 3, Part B, Section II.B may affect sources that that sell or acquire an existing facility subject to Regulation Number 3.

(B) Quantification of the direct cost to the primary affected business or industrial sector

Definition Revisions

The Division does not believe that there are economic impacts related to the proposed definition revisions, as they are generally clarifying in nature. In its Initial Economic Impact Analysis, the Division requested any information to the contrary, but has received no such information from stakeholders.

Oil and Gas APEN and Permitting Revisions

The Division believes that there are additional permitting fees associated with the revisions related to the Oil and Gas APEN and Permitting Revisions. These revisions change only the timing of existing APEN and permitting requirements but also allow for an alternate reporting and permit application process that will have associated fees.

Exemption Revisions

The Division believes that there are economic impacts related to the proposed revision to the exemption for venting of natural gas lines for safety purposes because, in practice, the revision narrows what sources may use the exemption. Based on preliminary analysis, the Division believes the majority of the costs will be associated with upstream oil and gas well production facilities for activities such as "routine or predictable" maintenance (*e.g.*, the blowdown of oil and gas equipment). Owners and operators of compressor stations, gas plants and those in the transmission sector may also incur costs.

For owners and operators of well production facilities, the Division estimates that there about 232 statewide operators (based on 2018 COGCC data) with oil production that will be impacted by narrowing these exemptions. These operators will likely need to file APENs for maintenance activities. The Division estimates that one (1) hour is required to prepare an APEN and the estimated hourly rate is about $52 per hour (*see* Table 1). The total costs of filing APENs resulting from the narrowing of this exemption could range from $0 to upwards of tens of thousands per operator.

Table 1: Cost for maintaining records and filing an APEN for Routine or Predictable Emissions – Annualized Cost Analysis

Item	Non Recurring (one time)	Annual Costs (recurring)	Annualized Total Cost
Reporting Staff		$50,000	
Supervision (@20%)		$10,000	
Overhead (@10%)		$5,000	
Travel (@15%)		$7,500	
Recordkeeping (@10%)		$5,000	
Reporting (@10%)		$5,000	
Fringe (@30%)		$15,000	
Spreadsheet tracking software	$500		
Subtotal Costs	$500	$97,500	
Annualized Costs*	$100	$97,500	$97,600

Annualized Hourly Rate $52

** Annualized over 5 year period at 6% rate of return*

Consistent with the 2014 Oil and Gas Rulemaking[1] the Division is using a similar multi-step process to calculate the estimated costs and benefits associated with hiring staff to maintain records and submit reports of routine or predicable emissions. First, the Division calculated an hourly rate based on the total annual cost for each staff member divided by an assumed 1,880 annual work hours. To calculate the total annual cost for each staff member, the Division included salary and fringe benefits for each staff member and annualized costs to account for supervision, overhead, travel, record keeping, and reporting. There is also a one-time fee associated with modifying existing spreadsheet tracking software to account for these sources of $500. The total annual cost for each new reporting staff member is estimated at $97,600, which equates to an hourly rate of $52.

The Division believes that oil and gas operations are the primary industry affected by these revisions but requests more information from stakeholders.

There may be economic impacts related to no longer excluding oil and gas production wastewater impoundments that contain less than 1% by volume crude oil on an annual average from APEN and permitting requirements. These sources are not currently required to apply for APENS, therefore, the Division cannot quantify the economic impacting of repealing this exemption. In its Initial Economic Impact Analysis, the Division requested additional information on the costs of submitting APENs and permit applications for affected facilities, but received no such information.

<u>Alignment with Statute</u>

The Division does not believe that there are economic impacts related to revisions that ensure consistency with the governing statute. In its Initial Economic Impact Analysis, the Division requested any information to the contrary, but has received no such information from stakeholders.

<u>Transfer of Ownership</u>

The Division does not believe that there economic impacts of the proposed revisions related to clarifying when transfer of ownership forms are due. In its Initial Economic Impact Analysis, the Division requested any information to the contrary, but has received no such information from stakeholders.

(C) Incorporation of an estimate of the economic impact of the proposal on the supporting business and industrial sectors associated with the primary affected business or industry sectors

There may be an economic impact on environmental consultants that support APEN and permit application submittals, as they will have to become versed in these revisions and implement them. In its Initial Economic Impact Analysis, the Division requested any information to the contrary, but has received no such information from stakeholders.

SUMMARY AND CONCLUSION

The Division believes that there are additional permitting fees associated with the revisions related to the Oil and Gas APEN and Permitting Revisions. These revisions change only the

[1] See the Colorado Department of Public Health and Environment Air Pollution Control Division Final Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7 (5 CCR 1001-9), dated January 30, 2014.

timing of existing APEN and permitting requirements but also allow for an alternate reporting and permit application process that will have associated fees.

The Division believes that are no fiscal or economic impacts related to the proposed revisions to the definitions or alignments with Colorado statute. These revisions are clarifying only in nature and promote consistency across state regulations.

The Division believes that there are also no fiscal or economic impacts of the proposed revisions related to transfer of ownership forms because sources are currently required to submit these notices in a timely manner. The revisions related to permit compliance responsibility also do not have a fiscal or economic impact because the Division currently determines responsibility for one or both parties in the event of noncompliance with ongoing permit conditions.

The Division believes that there are fiscal or economic impacts related to the revision of which natural gas venting activities are exempt from APEN and permitting requirements. The costs are related to additional recordkeeping and reporting. These costs impact owners or operators of oil and gas operations and potentially other industries. The Division requests more information on impacted sources that fall outside of oil and gas operations.

The Division believes that there may be fiscal and economic impacts related to the proposed revisions to the exemption for produced water and wastewater impoundments. The Division does not have a count of affected facilities because these sources were previously exempt from reporting requirements.

The Division requests more information from affected sources and other interested parties on the economic impacts of these revisions.

ATTACHMENT B

COST-BENEFIT ANALYSIS

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

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

RULE TITLE OR SUBJECT:

Regulation Number 3
Stationary Source Permitting and Air Pollutant Emission Notice Requirements

Per the provisions of § 24-4-103(2.5)(a), Colorado Revised Statutes, the Colorado Department of Public Health and Environment, Air Pollution Control Division ("Division") has prepared the following cost-benefit analysis.

1. The reason for the rule or amendment

During the 2019 legislative session, Colorado's General Assembly adopted SB 19-181 (Concerning additional public welfare protections regarding the conduct of oil and gas operations), revising §25-7-109, C.R.S. SB 19-181 directs the Air Quality Control Commission (Commission) to "adopt rules to minimize emissions of methane and other hydrocarbons, volatile organic compounds (VOC), and oxides of nitrogen (NOx) from oil and natural gas exploration and production facilities and natural gas facilities in the processing, gathering and boosting, storage, and transmission segments of the natural gas supply chain."

The Division is proposing revisions to Regulation Number 3, Stationary Source Permitting and Air Pollutant Emission Notice Requirements. Specifically, the Division is proposing the following revisions: (1) in Part A, Section I.B., to clarify existing definitions and add an existing definition from Regulation Number 7 to promote consistency across State regulations; (2) in Part A, Sections II.A. and II.D., and Part B, Sections II.D., III.B., and III.G., to update the APEN reporting and permitting requirements for oil and gas well production facilities; (3) in Part A, Section II.D., Part B, Section II.D., and Part C, Section II.E to clarify and narrow existing APEN and permitting exemptions and repeal certain exemptions related to oil and gas wastewater impoundments; (4) in Part B, Sections II.A., and III.I., to more closely align language with Colorado Statute; (5) in Part B, Section II.B., to clarify when transfer of ownership forms are due and where the compliance responsibilities lie during the transfer process.

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

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

The Division anticipates that some companies may have to hire additional staff to accommodate the additional reporting and recordkeeping burden. Companies may choose to outsource these tasks to 3rd party consultants, resulting in additional jobs for the oil and gas services sector.

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

The Division will oversee the administration and implementation of the proposed revisions to Regulation Number 3. There will be increased workload for the Division as a result of increased APEN and permitting submissions. However, the workload resulting from the proposed revisions will be absorbed by existing staff.

The Division's assessment of the costs and benefits for each of the proposed strategies is set forth below. For each strategy, these assessments identify the cumulative costs of the proposed revisions for the affected industry. The Division also assessed whether any of the proposed strategies would impose a direct cost on the general public to comply, and determined that based on the available data there will be no direct costs on the general public for any of the proposed requirements.

Definition Revisions

The Division's proposal to revise two definitions in Part A, Section I, may affect oil and gas operations that will use the new definition for "Commencement of Operation" to determine compliance with Regulation Number 3.

The Division does not believe that there are economic impacts related to the proposed definition revisions, as they are largely clarifying in nature. The Division requested additional information from stakeholders, but none was provided. The Administrative Procedures Act and the Air Pollution Prevention and Control Act require the Division only to use reasonably available data.

Oil and Gas APEN and Permitting Revisions

The Division's proposal to revise Regulation Number 3, Part A, Section II and Part B, Section III may affect oil and gas operations that have emissions above APEN and permitting thresholds.

The Division believes that there are additional permitting fees associated with the revisions related to the Oil and Gas APEN and Permitting Revisions. These revisions change only the timing of existing APEN and permitting requirements but also allow for an alternate reporting and permit application process that will have associated fees.

Exemption Clarifications

The Division's proposal to revise Regulation Number 3, Part A, Sections II.D.1.uuu and II.D.1.zzz, Part B, Section II.D.1.m, and Part C, Sections II.E.uu, II.E.3.yyy, and II.E.3.dddd, may affect sources that are trying to determine whether they qualify for an exemption to the APEN, permitting, and Title V permitting requirements in Regulation Number 3. The Division believes the majority of the costs will be associated with upstream oil and gas well production facilities. Owners and operators of compressor stations, gas plants and those in the transmission sector may also incur costs.

The Division believes that there are economic impacts related to the proposed revision to the exemption for venting of natural gas lines for safety purposes because, in practice, the revision narrows what sources may use the exemption. Based on its preliminary analysis, the Division believes the majority of the costs will be associated with upstream oil and gas well production facilities for activities such as the "routine or predictable" blowdown of oil and gas equipment. Owners and operators of compressor stations, gas plants and those in the transmission sector may also incur costs.

The Division anticipates that some companies may have to hire additional staff to accommodate the additional reporting and recordkeeping burden. Consistent with the 2014 Oil and Gas Rulemaking[1] the Division is using a similar multi-step process to calculate the estimated costs and benefits associated with the hiring of staff to maintain records and submit reports of routine and predictable emissions. First, the Division calculated an hourly rate based on the total annual cost for each staff member divided by an assumed 1,880 annual work hours. To calculate the total annual cost for each staff member, the Division included salary and fringe benefits for each staff member and annualized costs to account for supervision, overhead, travel, record keeping, and reporting. There is also a one-time fee associated with modifying existing spreadsheet tracking software to account for these sources of $500. The total annual cost for each new reporting staff is estimated at $97,600, which equates to an hourly rate of $52. See Table 1 of the Division's Final Economic Impact Analysis for Proposed Revisions to Regulation Number 3 (Attachment A).

The Division believes that oil and gas operations are the primary industry affected by these revisions but has requested more information to the contrary from parties to the rulemaking. No information has been provided as of the submittal of this Cost Benefit Analysis.

There may be economic impacts related to no longer excluding oil and gas production wastewater impoundments that contain less than 1% by volume crude oil on an annual average from APEN and permitting requirements. These sources are not currently required to apply for APENS, therefore, the Division cannot quantify the economic impact of repealing this exemption. The Division requested additional information from stakeholders, but none was provided. The Administrative Procedures Act and the Air Pollution Prevention and Control Act require the Division only to use reasonably available data.

<u>Alignment with Statute</u>

The Division does not believe that there are economic impacts related to revisions that ensure consistency with the governing statute. The Division requested additional information from stakeholders, but none was provided. The Administrative Procedures Act and the Air Pollution Prevention and Control Act require the Division only to use reasonably available data.

<u>Transfer of Ownership</u>

The Division's proposal to revise Regulation Number 3, Part B, Section II.B may affect sources that sell or acquire an existing facility subject to Regulation Number 3. The Division does not believe that there are economic impacts of the proposed revisions related to clarifying when transfer of ownership forms are due because the requirement has always existed and the proposed revisions change only the timing. The Division requested additional information from stakeholders, but none was provided. The Administrative Procedures Act and the Air Pollution Prevention and Control Act require the Division only to use reasonably available data.

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

[1] See the Colorado Department of Public Health and Environment Air Pollution Control Division Final Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7 (5 CCR 1001-9), dated January 30, 2014.

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

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

The Center for Biological Diversity (CBD) asked the Commission to consider an alternate proposal to remove several additional APEN and permitting exemptions, and to provide that methane and ethane are non-criteria reportable pollutants subject to all the regulations applicable thereto. However, CBD did not submit the supporting documentation required for an alternate proposal, including, importantly, an economic impact analysis of its proposal. The Division believes that while CBD's proposals deserve serious consideration, it would be better to consider them as part of later rulemakings. The Division has repeatedly advised stakeholders that this rulemaking is the first of many to implement SB19-181, HB19-1261 and SB19-096, as well as to further Colorado's progress towards attaining the 2008 and 2015 ozone NAAQS. The Division commits to the CBD and the public to evaluate the CBD's proposals for future rulemakings.

The Division also considered a "do nothing" alternative to the APEN and Permitting revisions. The obvious benefit of this approach would be the cost savings by the affected industries that would not have to report or permit emissions related to produced water impoundments or venting of safety lines. However, there are a number of disbenefits to this approach. The DMNFR is facing a serious nonattainment reclassification and accurate emissions information is vital as the Division further develops its emission reduction strategies. The Division would also be unable to collect appropriate APEN and permitting fees from sources that are above the applicable thresholds. Therefore, the Division believes that these provisions are appropriate and necessary for the Division to collect fees and develop an accurate emissions inventory.

The Division opposes the two alternatives identified above, and believes that the current proposal, reflecting consensus amongst diverse parties, including entities with private property and economic interests, properly reflects a balanced consideration of environmental and economic costs and benefits.

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