COST-BENEFIT ANALYSIS AND REGULATORY ANALYSIS

DEPARTMENT: **DEPARTMENT OF NATURAL RESOURCES**

AGENCY: **COLORADO OIL AND GAS CONSERVATION COMMISSION**

CCR: **2 CCR 404-1**

DATE: **OCTOBER 29, 2021**

INTRODUCTION

This serves as the combined cost-benefit and regulatory analysis ("Analysis") for the Colorado Oil and Gas Conservation Commission's ("Commission") rulemaking, Docket Number 210600097, that was noticed via publication in the Colorado Register on June 25, 2021 (tracking number 2021-00376). The Commission refers to this rulemaking as the "Financial Assurance Rulemaking."

Background and Purpose of the Financial Assurance Rulemaking

During the 2019 legislative session, the Colorado General Assembly adopted Senate Bill 19-181 (concerning additional public welfare protections regarding the conduct of oil and gas operations) ("SB 19-181"). This bill significantly amended the Colorado Oil and Gas Conservation Act ("Act"), C.R.S. §§ 34-60-101–131, both substantively and procedurally. SB 19-181 changed the Act's legislative declaration from directing the Commission to "[f]oster the responsible, balanced development, production, and utilization of the natural resources of oil and gas in the state of Colorado in a manner consistent with protection of public health, safety, and welfare, including protection of environment and wildlife resources," C.R.S. § 34-60-102(1)(a)(I) (2018), to directing the Commission to "[r]egulate the development and production of the natural resources of oil and gas in the state of Colorado in a manner that protects public health, safety, and welfare, including protection of the environment and wildlife resources," C.R.S. § 34-60-102(1)(a)(I) (2020). Accordingly, SB 19-181 required the Commission to conduct several rulemakings to address various topics. Many of those topics were addressed through the 2019 500-Series Rulemaking, 2019 Flowline Rulemaking, 2020 Wellbore Integrity Rulemaking, 2020 Mill Levy Rulemaking, and 2020 Mission Change Rulemakings.

SB 19-181 also required the Commission to undertake a rulemaking to update its financial assurance regulations to "require every operator to provide assurance that it is financially capable of fulfilling every obligation imposed by this article 60 as specified in rules adopted on or after April 16, 2019." C.R.S. § 34-60-106(13). Specifically, SB 19-181 requires the Commission to consider

> Increasing financial assurance for inactive wells and for wells transferred to a new owner; requiring a financial assurance account, which must remain tied to the well in the event of a transfer of ownership, to be fully funded in the initial years of operation for each new well to cover future costs to plug, reclaim, and remediate the well; and creating a pooled fund to address

> orphaned wells for which no owner, operator, or responsible party is capable of covering the costs of plugging, reclamation, and remediation.

Id.

The General Assembly also amended the definition of "minimize adverse impacts," a term it used in the broad instruction that the Commission review and amend its financial assurance regulations. Previously, the definition of "minimize adverse impacts" directed the agency to avoid adverse impacts only "wherever reasonably practicable" and "tak[ing] into consideration cost-effectiveness and technical feasibility." *See* C.R.S. § 34-60-103(5.5) (2018). Under the new definition, minimizing adverse impacts means "to the extent necessary and reasonable to protect public health, safety, and welfare, the environment, and wildlife resources." C.R.S. § 34-60-103(5.5) (2021). The new definition of "minimize adverse impacts" does not include considerations of cost-effectiveness and technical feasibility, and replaces "wherever reasonably practicable" with "to the extent necessary and reasonable."

Pursuant to SB 19-181, the Commission transitioned from volunteer commissioners to full-time commissioners on July 1, 2020. C.R.S. § 34-60-104.3. The Commission is supported by approximately 140 staff members. Staff handles the Commission's day-to-day business. Accordingly, Staff drafted and researched the proposed rules and this Analysis. Because Staff was performing those functions on behalf of the Commission, throughout this Analysis the terms "Staff" and "Commission" can be used interchangeably unless context requires otherwise.

Overview of Analysis Requirements and Methodology Review

On June 15, 2021, Staff provided notice of the Financial Assurance Rulemaking as required by the Administrative Procedure Act ("APA"). C.R.S. § 24-4-103(3). The notice included changes to the 200-Series, 300-Series, 400-Series, 500-Series, 700-Series, 800-Series, and 900-Series Rules and related 100-Series definitions of the Commission's Rules (the "Financial Assurance Rules"). This notice was published in the Colorado Register on June 25, 2021.

Pursuant to the APA, C.R.S. § 24-4-103(2.5)(a), any member of the public can request that the Executive Director of the Colorado Department of Regulatory Agencies ("DORA") direct a state agency to prepare a cost-benefit analysis within five days of the rules being published in the Colorado Register. The APA also allows any member of the public to request that an agency issue a regulatory analysis of a proposed rule at any point up to 15 days prior to a rulemaking hearing. C.R.S. § 24-4-103(4.5)(a).

On June 17, 2021, a cost-benefit analysis for the Commission's noticed Financial Assurance Rules was requested through DORA. After DORA staff consulted with Commission Staff, the DORA Executive Director determined that this analysis was required. The Financial Assurance Rulemaking was originally noticed to begin on September 21, 2021. However, on July 9, 2021, the Commission voted to vacate the originally-noticed hearing dates and reschedule the dates of the Financial Assurance Rulemaking hearing to commence on October 26, 2021. On August 31, 2021, the Commission filed an Amendment to Notice of Rulemaking Hearing to continue the rulemaking to begin on November 9, 2021.

Prior to and following notice of the proposed rules on June 15, Staff engaged with stakeholders in significant discussions concerning the proposed rules. Staff also considered all written position statements (including written comments submitted on July 30, 2021) submitted by most of the 93 parties that had filed for party status. The process of preparing this Analysis has allowed Staff to more comprehensively examine and consider the costs and benefits of the proposed rules and alternatives to the proposed rules.

These discussions, written statements, and the process of preparing this Analysis will inform Staff's subsequent revisions to the proposed rules, and Staff released revised proposed rules on October 8, 2021. Staff also expects that some of the proposed rules will be further refined and amended by the Commission during the rulemaking hearing. Accordingly, and consistent with the APA's requirements, this Analysis addresses the costs, benefits, and regulatory impacts of the rules noticed on June 15, 2021, rather than any future changes that may be proposed to the rules by Staff or the Commission.

The cost-benefit analysis is due no less than ten days prior to the rulemaking hearing, which will commence on November 9, 2021. A regulatory analysis is due no less than five days prior to the rulemaking hearing. Staff timely submitted this Analysis to DORA on October 29, 2021.

Cost-Benefit Analysis Requirements – C.R.S. § 24-4-103(2.5)(a)

Staff created the cost-benefit portion of this Analysis while acting in good faith to meet the statutory requirements. *See* C.R.S. § 24-4-103(2.5)(d). These requirements are listed in C.R.S. § 24-4-103(2.5)(a)(I)–(V), and include:

- The reason for the rule or amendment;
- The anticipated economic benefits of the rule or amendment, which shall include economic growth, the creation of new jobs, and increased economic competitiveness;
- 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;
- Any adverse effects on the economy, consumers, private markets, small businesses, job creation, and economic competitiveness; and
- 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.

Regulatory Analysis Requirements – C.R.S. § 24-4-103(4.5)

Similarly, Staff created the regulatory portion of this Analysis while acting in good faith to meet the statutory requirements. *See* C.R.S. § 24-4-103(4.5)(d). These requirements are listed in C.R.S. § 24-4-103(4.5)(a)(I)–(VI), and 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;
- 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; and
- In addition, 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.

Methodology for Data Collection and Assessment

Over several months, a core group of Staff facilitated the collection and assessment of data necessary to complete this Analysis. Staff conducted both structured and unstructured interviews of subject matter experts ("SMEs") inside and outside the Staff as the primary data collection method. These interviews yielded quantitative and qualitative data, which Staff then evaluated and refined so that the costs and benefits of the proposed rules could be quantitatively estimated or fully characterized.

The data used in the Analysis was required to meet each of the following criteria:

- Each SME possessed the necessary skills to describe costs and benefits;
- The data resulted from unbiased inferences;
- The estimates followed acceptable norms for the oil and gas industry;
- Each SME provided honest and accurate assessments;
- The data was presentable in a complete and easy-to-understand manner; and
- Interview questions fit the extent of the Analysis.

Staff members are divided into eight organizational units: Community Relations, Engineering, Environmental, Compliance, Finance, Hearings and Regulatory Affairs, Planning and Permitting, and Information and Applied Technologies. Staff also includes an Orphaned Well Program, which is part of the Engineering unit. Acting in good faith to prepare a thorough and thoughtful Analysis, SMEs from each unit and program reviewed relevant rules, accessed Staff data, and provided relevant input. In contributing data to the Analysis, Staff relied on their expertise, gained by both education and experience, as well as historical Commission data, industry data sources, and operator and community stakeholder comments. Collectively, Staff brings hundreds of years of experience in all aspects of the oil and gas industry.

Staff in the Environmental, Engineering, and Compliance Units, and a combined Planning and Permitting Unit plus Information and Applied Technologies Unit possess an average of 20, 27, 25, and 15 years' professional experience, respectively, in the oil and gas industry, environmental consulting, or regulatory agencies. SMEs who contributed data hold educational degrees including but not limited to MPAs, JDs, and PhDs, and Staff members who assisted in preparing this Analysis hold relevant professional licenses, such as professional engineer, professional geologist, and attorney licensure.

Staff engaged in an iterative interview process to obtain needed data. All information provided for this Analysis was reviewed by the core Staff group consisting of at least three individuals, all of whom were working on the entire Analysis and could ensure consistency in data collection methods and could request clarification and follow up data when necessary. The core team included a Staff economist with more than 20 years of professional experience with regulatory impact analyses, fee and rate studies, and technical evaluation of resource economics matters related to energy, recreation, real estate, and air quality.

Staff ultimately decided to build an easy-to-understand and comprehensive Analysis on the following five basic principles of economic analysis:

1. **Uncertainty**. The Analysis will estimate the costs and benefits for rules that have not yet been promulgated or subject to the complete public rulemaking process, and for those reasons, all these estimates possess varying degrees of uncertainty. By carefully considering relevant issues, Staff has worked to minimize the role of uncertainty in each estimate, but the Analysis can never eliminate uncertainty. Staff does not intend for this Analysis to be used by any party, or by the Commission itself, to commit funds or other resources, at any time, because actual costs and benefits may be greater or smaller for that party than might be estimated in this Analysis. Moreover, the rules ultimately adopted likely will not mirror those analyzed.

2. **Types of Impacts**. Costs and benefits are identified as *one-time* or *ongoing*, and the Analysis reports each category of cost or benefit as separate subtotals. No discount rate was required in the analysis, because costs and benefits are expected to grow no faster than the rate of general inflation in the economy. This assumption is supported by language in the proposed rules to allow the Commission to adjust most required financial assurance levels by inflation, so that many of the impacts cited in the Analysis will not decrease in real terms over time. Ongoing costs can be expected to recur each year. A one-time cost may occur during the first year following the effective date of rule changes, or a one-time cost may be the cumulative value of costs occurring irregularly during the period of an oil and gas business cycle.

   Each impact belongs to one of seven impact types, and labels for groups of impacts are provided in the margins of this Analysis. **Table 1** (below) explains each type. Lines in gray highlight identify the four impact types found in this Analysis.

Table 1
Glossary of Analysis Impact Labels

Party / Label in Margin	Meaning of Label
Industry and Community	
($ Cost)	Rule adds to baseline industry costs
($ Benefit)	Rule reduces baseline industry costs
(Qualitative)	Rule has a positive or negative impact on a nonmonetary value in the community
State Government	
(FTE Cost)	Rule adds to State government workload
(FTE Benefit)	Rule reduces State government workload
($ Cost)	Rule decreases State government program total revenues during the program lifetime
($ Benefit)	Rule increases State government program total revenues during the program lifetime

Note:
(1) These labels are placed in the margin of the Analysis to help the reader search the document for particular impacts and better understand the detailed impact.

3. **Market Cycles**. Staff accounted for volatility in industry prices and activity during an economic cycle by using longer-term historical data whenever available and projecting impacts that blend peak and trough years in these cycles. In some cases, averaging 12 to 25 years of data contributes to estimates in the Analysis that are independent of the multiple boom and bust periods during that timeframe. Staff did not prepare the Analysis with any specific market conditions such as "rising global commodity prices" in mind.
4. **Statewide Scope**. Similarly, Staff acknowledges that costs and benefits will vary not only over time, but also between operators and geographic locations. Staff prepared this Analysis using weighted averaged data that reflect the full range of operator locations and practices across Colorado's oil and gas basins, as documented by Commission data and SME field experience. Where a rule applied to only a specific geographic area, Staff applied GIS tools or other estimation methods to identify the subset of locations impacted by the rule.
5. **Data Evaluation**. Staff checked all data for consistency and sought to remedy outlier or contradictory sets of economic data before using it in calculations. Staff also remedied gaps found in the survey data by requesting additional data from SMEs. In each instance, Staff relied on SME expertise to determine the best course of action for completing the Analysis.

Economic Assumptions

All estimates in the Analysis follow these conventions:

1. All impacts are estimated and expressed in 2022 dollars or full-time equivalents ("FTEs"), and one FTE is defined as 2080 paid hours per year following Colorado State government conventions;

2. The impact on industry from a change in workload for its staff or contractors is assumed to average $150/hour, which is a total compensation figure that includes not only take-home pay, but also benefits, employment taxes, employee overhead, and other employee-related indirect costs;

3. Net industry impacts are represented by increased costs, such as -$1.5 million per year caused by the proposed rule changes;

4. Net State government staffing impacts are represented by additional staff workload (a cost), such as 0.50 FTE recurring annually caused by rule changes;

5. All time periods are best approximations;

6. A reference to "industry" is a reference to all operators combined; and

7. The Analysis gives full credit for an operator's financial assurance on deposit with the State before the rulemaking begins. That is, Staff allowed each operator to meet proposed financial assurance requirements by adjusting each one's current levels of financial assurance. This assumption presents a more realistic estimate of total net cost of the proposed rules to industry, because impact calculations started with operator-by-operator financial assurance account balances.

By employing this thoughtful and deliberative approach, Staff believes this Analysis is a straight-forward, good faith assessment of expected costs and benefits for the rules associated with the Financial Assurance Rulemaking.

Quantitative vs. Qualitative Costs and Benefits Explained

This Analysis addresses costs and benefits that are both quantitative and qualitative. Both types of data are amenable to analysis and help illustrate the true costs and benefits of the relevant rules.

Quantitative data is concrete and objective. Such data consists of measures of values or counts and are expressed as numbers. Examples of quantifiable costs include: expenditures to comply with a regulatory change, *i.e.*, equipment purchases; the cost and duration of actions required to comply with rule changes, *i.e.*, how many additional groundwater samples will be taken per year; and the number of hours it will take Commission staff to review newly-produced data. Examples of quantitative benefits include reduced Staff hours to review updated form submissions and reduced remediation costs for operators from avoided spills and releases due to improved environmental safeguards. Quantitative data can be collected using scientific principles and can be easily expressed as cause-and-effect relationships. Because of the objective nature of quantitative data, Staff endeavored to identify, collect, and assess this type of data whenever possible for this Analysis.

Qualitative data, while just as meaningful as quantitative data, is more subjective and ambiguous. Intangible costs and benefits do not lend themselves easily to direct and quantitative measures. In other words, these types of attributes do not have readily available standard measurement scales and tend to be subject to great inter-individual measurement variability. This data is about categorical variables, or groups of data that are based on similar features. Qualitative data can be collected using more open-ended methods, such as through observation and interviews. Examples of qualitative benefits include increased public confidence in operators and government regulators; improved public health from reduced pollution; and avoided environmental contamination that otherwise might harm ecosystems, crops, soil, and groundwater; and protection of wildlife resources and their habitat.

The distinction between these types of costs and benefits is very important because many of the specific regulatory outcomes that the General Assembly instructed the Commission to achieve through the Financial Assurance Rulemaking—protecting public health, safety, welfare, the environment, and wildlife resources by ensuring the operator is capable of plugging, reclaiming, and remediating each of its wells—are outcomes that are better assessed qualitatively than quantitatively. However, many of the costs of achieving those statutorily mandated outcomes are monetary costs incurred by operators.

With this in mind, Staff performed both quantitative and qualitative analysis to obtain a complete picture of the Financial Assurance Rulemaking's expected costs and benefits using the rules noticed on June 15, 2021. Collecting and analyzing quantitative data allowed Staff to confirm and test historical trends to assess the costs and benefits of the rules. Collecting and analyzing qualitative data allowed Staff to better understand the scope and full nature of the proposed rules' costs and benefits.

Accordingly, throughout the Analysis, Staff collected both quantified cost and benefit data where possible, and also identified qualitative costs and benefits that cannot be quantified. Although the APA's requirement for a cost-benefit analysis is silent as to whether data must be quantitative or qualitative, this approach is consistent with the APA's analogous requirement that agencies consider both qualitative and quantitative costs and benefits when conducting a regulatory analysis, a similar but distinct form of analysis. *See* C.R.S. § 24-4-103(4.5)(a)(II). Because this Analysis is a combined cost-benefit analysis and regulatory analysis, Staff determined that it was appropriate to consider both qualitative and quantitative data.

RESULTS IN SUMMARY

After the implementation of proposed rules, **Table 2** (below) shows a cost impact to industry between $35.7 and $106.3 million per year, of which 71 to 90 percent is the statewide net cost for industry to provide the State with approximately $624 million in additional blanket and single well financial assurance. Between nine and 26 percent of this cost impact is the annual well registration fee. The Analysis also estimates a one-time cost impact on industry from compliance workload of $3.9 million.

The Analysis finds that State agencies will experience an increase in ongoing workload of 3.8 FTE, and a 6.9 FTE one-time staffing need. There are two important and overarching benefits of the proposed rules. State Programs, in particular the Commission's Orphaned Well Program ("OWP"), will receive an increase in revenue of $9.2 million each year from the annual well registration fee. Second, the OWP's revenue, during the 25-year assumed maximum lifetime of current wells, will also increase by an estimated one-time amount of $14.9 million, as the new rules make additional financial assurance available in case of operator default. The State must claim this amount of financial assurance to fund OWP closure work at orphaned sites.

Table 2
Financial Assurance (FA) Rulemaking Full Summary of Quantifiable Impacts

Impact	Type of Impact	Low	High	Timeframe
Industry and Community				
Workload and Operating Cost Impacts	cost	-$35,659,973	-$106,293,683	annual
of which are the Costs of Additional Financial Assurance		*-$25,424,440*	*-$96,058,150*	
Share of Total Annual Costs		*71%*	*90%*	
of which is the Annual Well Registration Fee		*-$9,160,583*	*-$9,160,583*	
Share of Total Annual Costs		*26%*	*9%*	
Workload Impacts	cost	-$3,943,725	-$3,943,725	one time
State Government				
Workload Impacts	cost	3.8	3.8	annual FTE
Workload Impacts	cost	6.9	6.9	one time FTE
Program Revenue Impact *Annual Well Registration Fee*	benefit	$9,160,583	$9,160,583	annual
Program Revenue Impact *Funded Site Closure Costs Due to Added FA*	benefit	$14,861,381	$14,861,381	one time

Notes:
(i) All figures are estimates and expressed in 2022 dollars or FTE.
(ii) The Analysis assumes that the total compensation cost of all operator technical staff and contractors averages $150/hour.
(iii) Regulatory workload uses averages of industry form submissions across full market cycles (minimum 12 to 25 year averages when available).
(iv) The Analysis assumes 1.000 FTE is equivalent to 2080 paid hours per year following Colorado State government conventions.
(v) The Annual Well Registration Fee benefits the State's Orphaned Well Program (OWP) by generating revenue that must be used to fund orphaned site closure for legacy or unknown operators.
(vi) Proposed rules generate a benefit to the State's Orphaned Well Program by providing revenue from claimed Financial Assurance to pay for orphaned site closure costs. Absent the Rule changes, these costs would otherwise be appropriated from the Oil and Gas Conservation and Emergency Response Fund.

It is important to note that the net impacts discussed above and presented in **Table 2** (above) should not be viewed as a definitive description of actual impacts to industry and communities, State Government, or any other party. Additional context is necessary for any conclusions to be drawn about the data in **Table 2**. In one example, the net quantifiable costs to industry of the Financial Assurance Rulemaking may be contextualized in numerous ways. Net quantifiable costs could be considered on a per-well basis, per-operator basis, or in comparison to the average annual revenue generated by individual wells or for individual operators. For example, distributed across the 50,065 currently active wells in Colorado, the annual net costs to industry of $35.7 and $106.3 million is equivalent to $712 to $2,123 per well, and one-time impacts to industry of $4.0 million is equivalent to $80 per well.

However, Staff did not deem it appropriate to choose or rely upon any one specific method of contextualizing net quantifiable costs to industry, because ultimately all methods share the same two limitations. First, they are estimates developed by the Commission's team of expert staff that are limited by numerous uncertainties, and those uncertainties are compounded in the process of summing costs and benefits into a single dollar value. Second, the net costs and benefits estimated in this Analysis reflect only quantified costs and benefits, and a significant portion of the costs and benefits of the Financial Assurance Rulemaking are not quantifiable and were therefore analyzed qualitatively.

Staff determined that all the costs and benefits estimated and described below, considered separately or combined, will have no measurable impacts on job creation or the economy because many of the items that will incur costs will be absorbed by current employees. In addition, Staff believes that the changes proposed in the Financial Assurance Rules were the most effective way for the Commission to effectively comply with the General Assembly's mandates in SB 19-181. Staff also believes that, despite the additional cost imposed on industry, the importance of the short- and long-term qualitative benefits to the industry and community warrant the changes to the Financial Assurance Rules because of the protections the rules provide to public health, safety, welfare, the environment, and wildlife resources of the state of Colorado when the cost to plug, reclaim, and remediate each well is fully funded.

As required by the APA, C.R.S. § 24-4-103(2.5), this Analysis addresses the Financial Assurance Rules as initially proposed on June 15, 2021, and does not reflect potential future revisions to those Rules by Staff prior to the commencement of the rulemaking hearing, or the changes that the Commission will likely make to the proposed rules during the forthcoming rulemaking hearing. Accordingly, it would be inaccurate, and potentially misleading, for Staff or any other party to draw a firm conclusion about the actual net quantifiable costs of the Financial Assurance Rulemaking to industry (or any other party) due to the limits of this Analysis.

<u>FINANCIAL ASSURANCE RULES</u>
DETAILED DESCRIPTION OF COSTS AND BENEFITS

OVERVIEW OF CHANGES

The Financial Assurance Rulemaking fulfills the Commission's statutory obligation under C.R.S. § 34-60-106(13) because it requires every operator to provide assurance that it is capable of fulfilling every obligation imposed by the Act and the Commission's Rules. Oil and gas operations are sophisticated, complex, and have a variety of impacts for each step in the exploration, production, plugging, and reclamation processes. While substantially revising the Commission's Rules to align with the statutory amendments adopted in SB 19-181, the Financial Assurance Rulemaking also integrates the financial assurance regulatory requirements into each series in an effort to provide greater regulatory understanding by all interested parties.

Financial assurance is an important component to the Commission's Rules. Under these rules, operators must demonstrate that they have the financial resources necessary to properly plug and abandon, remediate, and reclaim wells that have reached the end of their useful lives. In order to comply with SB 19-181's revised statutory directive, Staff has proposed several revisions to and newly-defined terms in the 100-Series. For example, Staff has proposed to revise the definition of inactive well to address challenges that arose in the course of implementing its prior definition and to better reflect the new array of regulatory standards. Staff also updated and amended rules in the 200-Series, 400-Series, and 700-Series to facilitate full-cost bonding for transferred inactive wells, to incentivize timely plugging and abandonment of inactive wells, and to allow for different levels of bonding depending partly on an operator's percentage of low producing or inactive wells. Staff added consistent references to the above rules and terms from all other rules affected by the changes, including Hearings (500-Series), Commercial Disposal Wells (800-Series), and Site Investigations and Remediation (900-Series). For additional background on the revisions contemplated as part of the Financial Assurance Rulemaking, see *COGCC, Draft Statement of Basis, Specific Statutory Authority, and Purpose, Cause No. 1R Docket No. 210600097, Financial Assurance Rulemaking* at 2–6 (June 15, 2021).

RULES FOR WHICH COSTS AND BENEFITS ARE IMPLICATED

Table 3 (below) compiles all quantified costs and benefits to industry and communities that are expected after the Financial Assurance Rules are implemented. Staff expect a wide spectrum of impacts on a per rule basis, from an annual recurring cost to industry of $1,250 to an annual recurring cost to industry of $30.4 million. Qualitative impacts also exist and, although they are not shown in the table, may be among the most important impacts of the Rules.

Table 3
Industry and Community Impact Detail

Rule	Impact Description	Impact Type	Low	High	Timeframe
205	Annual Well Registration Fee	Cost to Industry	-$9,160,583	-$9,160,583	annual
205	Form 1B guidance	Cost to Industry	-$291,000	-$291,000	one time
205	Form 1B submissions	Cost to Industry	-$72,750	-$72,750	annual
218	Financial Assurance Hearings	Cost to Industry	-$6,000	-$6,000	annual
218	Form 9 guidance	Cost to Industry	-$291,000	-$291,000	one time
218	Form 9 submissions	Cost to Industry	-$22,500	-$22,500	annual
306	Form 2C guidance	Cost to Industry	-$15,000	-$15,000	one time
306	Form 2C submissions	Cost to Industry	-$1,250	-$1,250	annual
434	Net New Surety Purchases: Single Well	Cost to Industry	-$3,600,000	-$18,100,000	annual
434	Net New Operator Direct Funded Financial Assurance: Single Well	Cost to Industry	-$7,700,000	-$24,600,000	annual
434	Financial Assurance Hearings	Cost to Industry	-$7,500	-$7,500	annual
434	Form 3A guidance	Cost to Industry	-$291,000	-$291,000	one time
434	Form 3A submissions	Cost to Industry	-$52,500	-$52,500	one time
434	Form 3A submissions	Cost to Industry	-$52,650	-$52,650	annual
434	Form 6A guidance	Cost to Industry	-$291,000	-$291,000	one time
434	Form 6A submissions	Cost to Industry	-$183,750	-$183,750	annual
434	Form 4 guidance	Cost to Industry	-$145,500	-$145,500	one time
434	Form 4 submissions	Cost to Industry	-$33,750	-$33,750	annual
701	Financial Assurance Hearings	Cost to Industry	-$3,000	-$3,000	annual
701	Form 3 guidance	Cost to Industry	-$291,000	-$291,000	one time
701	Form 3 submissions	Cost to Industry	-$129,600	-$129,600	one time
701	Form 3 submissions	Cost to Industry	-$78,000	-$78,000	annual
702	Net New Surety Purchases: Blanket	Cost to Industry	-$4,500,000	-$22,400,000	annual
702	Net New Operator Direct Funded Financial Assurance: Blanket	Cost to Industry	-$9,500,000	-$30,400,000	annual
702	Financial Assurance Plan guidance	Cost to Industry	-$291,000	-$291,000	one time
702	Financial Assurance Plan submissions	Cost to Industry	-$1,273,125	-$1,273,125	one time
702	Financial Assurance Plan submissions	Cost to Industry	-$341,250	-$341,250	annual
702	Financial Assurance Hearings	Cost to Industry	-$7,500	-$7,500	annual
703	Net New Surety Purchases: Other Facility Types	Cost to Industry	-$47,580	-$237,900	annual
703	Net New Operator Direct Funded FA: Other Facility Types	Cost to Industry	-$76,860	-$320,250	annual
704	Financial Assurance Hearings	Cost to Industry	-$1,500	-$1,500	annual
705	Form 1 guidance	Cost to Industry	-$291,000	-$291,000	one time
705	Form 1 submissions	Cost to Industry	-$5,250	-$5,250	annual
705	Form 19 guidance	Cost to Industry	-$145,500	-$145,500	one time
705	Form 19 submissions	Cost to Industry	-$63,750	-$63,750	annual
706	Financial Assurance Hearings	Cost to Industry	-$3,000	-$3,000	annual
707	Financial Assurance Hearings	Cost to Industry	-$7,500	-$7,500	annual
913	Financial Assurance Hearings	Cost to Industry	-$1,500	-$1,500	annual
913	Form 27 guidance	Cost to Industry	-$145,500	-$145,500	one time
913	Form 27 submissions	Cost to Industry	-$182,550	-$182,550	annual

Notes:
(i) All figures are estimates and expressed in 2022 dollars or FTE.
(ii) The Analysis assumes that the total compensation cost of all operator technical staff and contractors averages $150/hour.
(iii) Regulatory workload uses averages of industry form submissions across full market cycles (minimum 12 to 25 year averages when available).

Table 4 (below) details all quantifiable impacts on State Government from implementation of the Financial Assurance Rules. Staff expects a wide spectrum of workload impacts on a per rule basis, from a 0.001 FTE cost or increase in ongoing State agency staffing to a 5.6 FTE cost or increase in one-time State agency staffing. Qualitative impacts also exist and, although they are not shown in the table, may be among the most important impacts of the Rules.

Staff estimates a one-time significant benefit or increase in lifetime total State agency program revenues of $14.9 million from the increased availability of financial assurance as needed to close orphaned sites, and a separate $9.2 million increase in State agency annual program revenues from the annual well registration fee.

The two revenue sources noted in the above paragraph have different purposes. Additional financial assurance provided after the proposed rules are adopted will fund a greater share of site closure costs for oil and gas sites that become orphaned in the future. In contrast, the State expects to use the registration fee revenue to cover the list of sites whose closure costs surpass the value of any financial assurance on deposit from legacy or unknown operators.

Table 4
State Government Impact Detail

Rule	Impact Description	Impact Type	Low	High	Timeframe
205	Annual Well Registration Fee	Benefit to State Government	$9,160,583	$9,160,583	annual
205	Form 1B guidance	Workload Impact on State Government	0.015	0.015	one time FTE
205	Form 1B development	Workload Impact on State Government	0.029	0.029	one time FTE
205	Form 1B data tools	Workload Impact on State Government	0.012	0.012	one time FTE
205	Form 1B processing	Workload Impact on State Government	0.117	0.117	annual FTE
218	Financial Assurance Hearings	Workload Impact on State Government	0.006	0.006	annual FTE
218	Form 9 guidance	Workload Impact on State Government	0.015	0.015	one time FTE
218	Form 9 development	Workload Impact on State Government	0.046	0.046	one time FTE
218	Form 9 data tools	Workload Impact on State Government	0.012	0.012	one time FTE
218	Form 9 processing	Workload Impact on State Government	0.433	0.433	annual FTE
306	Form 2C guidance	Workload Impact on State Government	0.004	0.004	one time FTE
306	Form 2C development	Workload Impact on State Government	0.029	0.029	one time FTE
306	Form 2C processing	Workload Impact on State Government	0.004	0.004	annual FTE
434	Financial Assurance Hearings	Workload Impact on State Government	0.007	0.007	annual FTE
434	Form 3A guidance	Workload Impact on State Government	0.015	0.015	one time FTE
434	Form 3A development	Workload Impact on State Government	0.029	0.029	one time FTE
434	Form 3A data tools	Workload Impact on State Government	0.008	0.008	one time FTE
434	Form 3A processing	Workload Impact on State Government	0.673	0.673	one time FTE
434	Form 3A processing	Workload Impact on State Government	0.225	0.225	annual FTE
434	Form 6A guidance	Workload Impact on State Government	0.015	0.015	one time FTE
434	Form 6A development	Workload Impact on State Government	0.029	0.029	one time FTE
434	Form 6A data tools	Workload Impact on State Government	0.008	0.008	one time FTE
434	Form 6A processing	Workload Impact on State Government	0.147	0.147	annual FTE
434	Form 4 guidance	Workload Impact on State Government	0.008	0.008	one time FTE
434	Form 4 development	Workload Impact on State Government	0.012	0.012	one time FTE
434	Form 4 processing	Workload Impact on State Government	0.054	0.054	annual FTE
701	Financial Assurance Hearings	Workload Impact on State Government	0.003	0.003	annual FTE
701	Form 3 guidance	Workload Impact on State Government	0.015	0.015	one time FTE
701	Form 3 development	Workload Impact on State Government	0.040	0.040	one time FTE
701	Form 3 processing	Workload Impact on State Government	0.130	0.130	one time FTE
701	Form 3 processing	Workload Impact on State Government	0.078	0.078	annual FTE
702	Financial Assurance Claimed for OWP	Benefit to State Government	$14,861,381	$14,861,381	one time
702	Financial Assurance Plan guidance	Workload Impact on State Government	0.012	0.012	one time FTE
702	Financial Assurance Plan workflow	Workload Impact on State Government	0.031	0.031	one time FTE
702	Financial Assurance Plan processing	Workload Impact on State Government	5.596	5.596	one time FTE
702	Financial Assurance Plan processing	Workload Impact on State Government	1.500	1.500	annual FTE
702	Financial Assurance Hearings	Workload Impact on State Government	0.007	0.007	annual FTE
704	Financial Assurance Hearings	Workload Impact on State Government	0.001	0.001	annual FTE
705	Form 1 guidance	Workload Impact on State Government	0.015	0.015	one time FTE
705	Form 1 development	Workload Impact on State Government	0.029	0.029	one time FTE
705	Form 1 data tools	Workload Impact on State Government	0.008	0.008	one time FTE
705	Form 1 processing	Workload Impact on State Government	0.006	0.006	annual FTE
705	Form 19 guidance	Workload Impact on State Government	0.004	0.004	one time FTE
705	Form 19 development	Workload Impact on State Government	0.012	0.012	one time FTE
705	Form 19 data tools	Workload Impact on State Government	0.002	0.002	one time FTE
705	Form 19 processing	Workload Impact on State Government	0.306	0.306	annual FTE
706	Financial Assurance Hearings	Workload Impact on State Government	0.003	0.003	annual FTE
707	Financial Assurance Hearings	Workload Impact on State Government	0.007	0.007	annual FTE
913	Financial Assurance Hearings	Workload Impact on State Government	0.001	0.001	annual FTE
913	Form 27 guidance	Workload Impact on State Government	0.004	0.004	one time FTE
913	Form 27 development	Workload Impact on State Government	0.012	0.012	one time FTE
913	Form 27 data tools	Workload Impact on State Government	0.002	0.002	one time FTE
913	Form 27 processing	Workload Impact on State Government	0.878	0.878	annual FTE

Notes:
(i) All figures are estimates and expressed in 2022 dollars or FTE.
(ii) The Analysis assumes 1.000 FTE is equivalent to 2080 paid hours per year following Colorado State government conventions.
(iii) Regulatory workload uses averages of industry form submissions across full market cycles (minimum 12 to 25 year averages when available).

DISCUSSION OF RULES

Rule 205 – Operator Registration

The Commission updated and revised Rule 205 by making clarifying changes to Rule 205.a and b, and introduced new Rule 205.c, which creates a new Form 1B, Annual Well Registration, and a new annual registration fee that will fund the new pooled fund for addressing orphaned sites. The new Form 1B will complement the Form 1A process adopted during the 200–600 Mission Change Rulemaking and ensure that the Commission has accurate and up-to-date records of both active operators and the number of active wells by requiring annual registration.

The subsections of Rule 205.c set forth certain requirements. Rule 205.c.(1) requires all operators that have filed a Form 1 and operate at least one well (including a well that is currently Temporarily Abandoned or Shut-In) to submit a Form 1B each year. Rule 205.c.(2) establishes an annual registration fee, which operators must remit with their Form 1B. To ensure that operators pay the appropriate fee for the correct number of wells, Rule 205.c.(3) requires operators to list all of their wells, including the well status as of December 31. This information will also allow the Commission to ensure that its records of the number of wells in Colorado, as well as their current status, are up-to-date and accurate. Rule 205.c.(4) prohibits the Commission from using the funds for any purpose other than addressing orphaned sites, ensuring that the fund will be appropriately spent.

- **Impacts on Industry and the Community**

($ Cost) Staff assumes that Rule 205.c will result in costs to industry. Importantly, Rule 205.c requires all operators with at least one active well to remit an annual registration fee. The fee was calculated based on the reasonably anticipated costs of addressing orphaned sites. The annual well registration fee will be due by April 1, 2022 at a rate of $100 per active well for the first year. Each year thereafter, the fee is set at $200 per active well. **Table 5** (below) averages the statewide impact of this added cost to industry over the first twelve years of the fee, or $9,160,583 per year.

Rule 205.c also requires each operator who operates at least one well (including a well that is currently temporarily abandoned or shut-in) to submit a Form 1B each year by April 1. Staff estimates that approximately 485 operators will review guidance provided by the State at an average cost of $600 per operator, or $291,000 in added one-time expense. This expense captures four hours of industry staff time at an estimated cost of $150 per hour. Staff further estimates industry will incur an annual cost of approximately $72,750 to prepare and submit 485 Form 1Bs each year.

Table 5
Annual Well Registration Fee During Years One To Twelve

Year After Rule Changes	Registration Fee	Active Wells	Industry Fee Payments or State Government Program Revenues
Year One	$100	50,090	$5,009,000
Year Two	$200	49,690	$9,938,000
Year Three	$200	49,290	$9,858,000
Year Four	$200	48,890	$9,778,000
Year Five	$200	48,490	$9,698,000
Year Six	$200	48,090	$9,618,000
Year Seven	$200	47,690	$9,538,000
Year Eight	$200	47,290	$9,458,000
Year Nine	$200	46,890	$9,378,000
Year Ten	$200	46,490	$9,298,000
Year Eleven	$200	46,090	$9,218,000
Year Twelve	$200	45,690	$9,138,000
Average Annual Amounts	**$192**	**47,890**	**$9,160,583**

Notes:
(i) All figures are estimates and expressed in 2022 dollars.
(ii) The Analysis assumes that the count of Active Wells falls gradually over time as operators drilling more productive horizontal wells plug multiple offset wells for each new well.
(iii) The Annual Well Registration Fee is both a cost to industry and a benefit to State Government.

(Qualitative) Staff assumes that Rule 205 and the Financial Assurance Rulemaking in general will produce benefits for the community that cannot be quantified in most instances. Rule 205.c's annual registration fee requirement will ensure the OWP is appropriately funded to meet needs for orphaned sites, which will allow the program to increase its capacity to fully address orphaned wells over time. The community will enjoy reduced timeframes for closure of oil and gas sites that would otherwise be orphaned, as operators will be strongly incentivized to satisfy all site closure obligations and reduce their ongoing financial assurance expenses by having the State release their bonds and certificates of deposit ("CDs") and return their cash deposits. The public will experience more reclaimed and remediated landscapes, and public records will verify that operators themselves plugged the wells at those sites in accordance with State rules, which will increase public trust in industry operations.

There will likely also be public health, environmental, and wildlife benefits from earlier closure of various types of inactive, temporarily abandoned, or marginally producing wells. The benefits to the community of reclaimed and remediated landscapes, in addition to safely plugged wells, also occur for these types of wells. These benefits will be both short- and long-term.

- **Impacts on State Government**

($ Benefit) Staff anticipates that Rule 205 will result in monetary benefits. Staff sets the fees paid by industry to an identical benefit to the OWP, the revenue from which will fund program activities. The benefit to the OWP averages $9,160,583 per year based on an average fee of $192 per active well, as presented in **Table 5** (above). This will allow the OWP to increase its capacity to address orphaned wells over time, concurrent with the anticipated expansion in the number of facilities becoming orphaned.

(FTE Cost) Staff assumes it will incur costs associated with Rule 205. With respect to management of the fee payment systems, Staff estimates that workload will increase by the following amounts and types:

- 40 hours to develop the new form, or 0.029 one-time FTE;
- 24 hours to engineer new data tools for operators and Staff, or 0.012 one-time FTE;
- 32 hours to develop guidance and offer operator training, or 0.015 one-time FTE; and
- 30 minutes to process each form at an annual volume of 485 forms, or 0.117 ongoing FTE.

Rule 218 – Form 9, Transfer of Operatorship

The Commission amended Rule 218, governing transfer of operatorship, in an effort to implement SB 19-181's instruction that the Commission consider increasing financial assurance for inactive wells and for wells transferred to a new owner. Rule 218 requires full-cost bonding for transferred inactive wells, and creates Commission-level oversight over transactions that transfer a high percentage of low producing wells.

More specifically, Rule 218.a includes definitions, except that more frequently used terms including "Selling Operator," "Buying Operator," and "Prior Operator" were moved to the 100-Series Definitions. Rule 218.b governs the informational requirements for the Form 9, Transfer of Operatorship – Intent, to facilitate full-cost bonding for transferred inactive wells, and Commission oversight of transfers involving a high percentage of low producing wells. The Rule also includes a requirement for a buying operator to update the Commission when a transaction subject to a Form 9 – Intent becomes final in Rule 218.d, and provides certain procedures for Director approval and Commission oversight in Rule 218.e through h.

- **Impacts on Industry and the Community**

($ Cost) Staff assumes that the changes to Rule 218 will result in various costs to industry. Rule 218 generally requires full cost bonding for transferred inactive wells. Based on a review of data contained in the administrative record, Staff determined that transactions involving the transfer of a large number of inactive wells and Low Producing Wells ("LPWs") are likely to result in higher risks of the new operator orphaning the wells. Rule 218 contemplates that the amount of financial assurance for all inactive wells subject to transfer must be the full cost of plugging, abandoning, and reclaiming the well. If the transaction involves more than 30% of LPWs, the Commission will review the transaction to determine the appropriate amount of financial assurance.

Overall, Rule 218 requires the identification and remittance of an estimated amount of financial assurance prior to the anticipated date of transfer. Such financial assurance, as identified by the selling operator, constitutes the amount of FA the buying operator must provide for the transferred items. Following a review of extensive data and analysis by Staff in the administrative record related to the costs of plugging, abandoning, and reclaiming oil and gas wells and their associated locations, the Commission determined that $78,000 is a reasonable statewide estimate of the average cost to plug, abandon, and reclaim an oil and gas location in Colorado as of 2021. This estimate was developed by Staff reclamation and financial analysis experts, who reviewed recently completed projects statewide to ensure that they provided a representative sample of different basins and regions, in roughly proportionate amounts to where current development is located. Specifically, ten sites were in the Denver-Julesburg Basin, five sites where in the San Juan basin, four sites were in the Piceance Basin, two sites were in the Sand Wash Basin, one site was in the Cañon City Embayment, and one site was in the Paradox Basin. All analyzed sites required both plugging and decommissioning work, including well plugging, flowline abandonment, and production equipment decommissioning. Acknowledging that in some cases reclamation expenses can increase costs, the Commission also included a list of factors that drive higher reclamation costs and may therefore require financial assurance above the default.

Rule 218 also allows operators to request a hearing in certain situations. First, a buying operator may request a hearing if such operator wishes to adjust the amount of financial assurance requested for approval of the asset transfer in a Form 9. The buying and selling operators will also jointly request a hearing when more than 30% of the wells subject to transfer are LPWs. As shown in **Table 6** (below), Staff estimates that four (4) such hearings will take place each year at cost of $6,000 to industry. The industry cost assumes its staff, at a $150 per hour rate, must work for 10 hours to submit the hearing application and staff the hearing.

Table 6
Impacts on Industry and State from Financial Assurance (FA) Hearings

Rule	Estimated Annual Applications for FA Hearings Before Commission	Annual Workload Impacts on: Industry (10 hours per application, $150/hr)	Annual Workload Impacts on: State Government FTE (3 hours per application, 2080 hours/FTE)
218	4	$6,000	0.006
434	5	$7,500	0.007
701	2	$3,000	0.003
702	5	$7,500	0.007
704	1	$1,500	0.001
706	2	$3,000	0.003
707	5	$7,500	0.007
913	1	$1,500	0.001
Total	**25**	**$37,500**	**0.036**

Notes:
(i) All figures are estimates and expressed in 2022 dollars or FTE.
(ii) The Analysis assumes 1.000 FTE is equivalent to 2080 paid hours per year following Colorado State government conventions.
(iii) The Analysis assumes that the total compensation cost of all operator technical staff and contractors averages $150/hour.
(iv) Regulatory workload uses averages of industry form submissions across full market cycles (minimum 12 to 25 year averages when available).

Rule 218 also requires each operator who transfers assets to submit a Form 9. Staff expects that guidance provided by the State will be reviewed by an estimated 485 operators at an average cost of $600 per operator, or $291,000 in added one-time expense. That expense captures four (4) hours of staff time at a cost of $150 per hour. Staff further estimates that the preparation and submittal of 300 revised Form 9s each year (one for the seller, and one for the buyer) will cost the industry approximately $22,500 annually, an ongoing expense resulting from 30 minutes of additional staff time for each form at a $150 per hour rate.

(Qualitative) Staff assumes that Rule 218 and the Financial Assurance Rulemaking in general will produce benefits for the community that cannot be quantified in most instances. These benefits include community enjoyment of reduced timeframes for closure of oil and gas sites that would otherwise be orphaned, as operators are strongly incentivized to satisfy all site closure obligations and reduce their ongoing financial assurance expenses by having the State release their bonds and CDs and return their cash deposits. The public will notice more reclaimed and remediated landscapes, and public records will verify that operators themselves plugged the wells at those sites in accordance with State rules, which will increase public trust in industry operations.

There will likely also be public health, safety, and environmental benefits from earlier closure of various types of inactive, temporarily abandoned, or marginally producing wells. The benefits to the community of reclaimed and remediated landscapes, in addition to safely plugged wells, also occur for these types of wells. These benefits will be both short- and long-term.

- **Impacts on State Government**

(FTE Cost) Rule 218 allows buying operators to request a hearing if these operators wish to adjust the amount of financial assurance requested for approval of the asset transfer in a Form 9. As shown in **Table 6** (above), Staff estimates that four (4) such hearings will take place each year at a cost of 0.006 FTE. This cost assumes an average of three (3) hours to prepare for and staff each hearing.

Staff anticipates that processing a revised Form 9 will increase State workload by the following amounts and types:

- 96 hours to develop the new form, or 0.046 one-time FTE;
- 24 hours to engineer new data tools for operators and Staff, or 0.012 one-time FTE;
- 32 hours to develop guidance and offer operator training, or 0.015 one-time FTE; and
- 3 hours to review each form at an annual volume of 300 forms, or 0.594 ongoing FTE.

<u>Rule 306 – Director's Recommendation on the Oil and Gas Development Plan</u>

Rule 306.a specifies when the Director may issue a recommendation to the Commission to approve or deny a proposed oil and gas development plan. Rule 306.a.(5) requires the Director to ensure that an operator is in compliance with all financial assurance requirements prior to making a recommendation. Consistent with adding the new Form 1B, Annual Registration fee in Rule 205.c, the Commission required the Director to verify that an operator has submitted its most recent Form 1B and paid all required annual registration fees prior to making a recommendation on a proposed oil and gas development plan.

- **Impacts on Industry and the Community**

($ Cost) Staff assumes that Rule 306 will result in costs to operators. Rule 306 requires each operator to certify on a revised Form 2C, OGDP Certification, that all financial assurance requirements have been met. An estimated 100 operators will likely review guidance provided from Staff at an average cost of $150 per operator, or $15,000 in added one-time expense. That expense captures one hour of industry staff time at a cost of $150 per hour. Staff estimates it will cost industry approximately $1,250 annually to prepare and submit approximately 100 revised Form 2Cs, an ongoing expense resulting from five minutes of added industry staff time for each form at a rate of $150 per hour.

- **Impacts on State Government**

(FTE Cost) Staff anticipates that use of a revised Form 2C, as required by Rule 306, will increase State workload by the following amounts and types:

- 60 hours to develop the revised form, or 0.029 one-time FTE
- 8 hours to develop guidance and offer operator training, or 0.004 one-time FTE
- 5 minutes to review each form at an annual volume of 100 forms, or 0.004 ongoing FTE.

Rule 434 – Abandonment

Rule 434 includes engineering and administrative standards for plugging and temporarily abandoning wells. Prior to the Financial Assurance Rulemaking, the Commission did not establish deadlines for plugging inactive wells. In an effort to minimize financial risks to the state of Colorado, the Commission revised Rule 434 to incentivize the timely plugging and abandonment of inactive wells by requiring operators to either plug or provide full-cost bonding for inactive wells.

The Commission revised and reorganized Rule 434.b in several ways. First, Staff moved certain equipment removal notification requirements from prior Rule 707.b to Rule 434.b. Requirements related to the first six months of temporary abandonment and extensions of such status beyond six months were also moved to Rule 434.b. Staff also moved prior Rule 707.c, which established standards for persons other than a well's operator who remove equipment from a well, to Rule 434.b.

The Commission also included a new Rule 434.c, which requires operators to timely plug and abandon inactive wells. Based on a review of best practices from other jurisdictions to minimize the financial risks to the agency posed by operators orphaning their wells, the Commission determined that it was appropriate to adopt similar requirements for timely plugging of inactive wells in Colorado.

- **Impacts on Industry and the Community**

($ Cost) Staff assumes that Rule 434 will result in various costs to operators. As discussed above, Rule 434.c. requires operators to address inactive wells in a timely manner. Thus, operators have four options for wells that remain inactive for six months: plug them, return them to production, "bond up" by providing additional financial assurance, or add the well to the operator's enforceable and binding plugging list.

Staff determined that these options each provide equal levels of protection to the state of Colorado from the risks posed by operators orphaning inactive wells, while also providing operators with flexibility to determine an appropriate path to address inactive wells that is consistent with their individual business models. While some of these options could be quite costly in some circumstances, and the Commission does not intend to overlook those costs in this analysis, Staff does not have sufficient data to estimate the exact monetary impact to industry. This is largely because the Rules do not require operators to choose any one way of addressing inactive wells, rendering a full quantified estimate of costs impossible.

However, Staff assumes that the Rule will result in costs to industry if operators choose to "bond up" and provide up to $78,000 per well in financial assurance for inactive and certain out of service wells. The Rule also permits a lower amount of $30,000 if wells are not plugged and abandoned within three years, in acknowledgement that such wells that have been inactive for only a limited period of time pose lower risks to the State than wells that have been inactive for a longer period of time. For the purposes of this Analysis, however, Staff calculated the impact based on the larger amount to avoid understating the impacts of the rulemaking. The Analysis' impact calculates the required financial assurance amounts as if no operator reactivated an inactive well within three years' time. In actual practice, Staff expects operators to place a large share of these wells back into production.

As shown in **Table 7** (below), Staff also assumes that approximately $126.4 million in operator excess inactive well financial assurance on deposit with the State will eventually be released as the proposed rule transitions financial assurance requirements to full cost bonding. Final net cost impacts of Rule 434 on all tiers of operators are explained in the Rule 702 section below. Both Rules are similar in that operator annual expenses increase as the amount of financial assurance required increases.

In the Analysis for Rule 434, Staff totaled each operator's inactive wells, applied a $78,000 maximum possible financial assurance requirement to each, and determined that overall financial assurance would increase by 2.2 times, growing from $126.4 million to $405.6 million (an increase of $279.2 million).

Expected industry costs to provide the added financial assurance range between $3.6 million and $18.1 million in ongoing expense to purchase sureties, and between $7.7 million and $24.6 million in ongoing expense to self-fund cash or CD-based financial assurance. These amounts are developed from base assumptions in the tables displayed for Rule 702 in a later section of this Analysis.

Table 7
Statewide FA Additions from Single Well Bonding Requirements in Rule 434

Tier	Excess Inactive Well Bonding from June 2021, Estimated ($ million)	Proposed Rule 434 Single Well Bonding ($ million)	Net Change to Statewide Bonding ($ million)	Factor Increase / Decrease for Statewide Bonding
Tier 1	$117.3	$357.7	$240.4	2.0
Tier 2	$8.5	$34.6	$26.1	3.1
Tier 3	$0.6	$13.3	$12.7	21.2
All Tiers	**$126.4**	**$405.6**	**$279.2**	**2.2**

Notes:
(i) All dollar figures are estimates and expressed in 2022 dollars.
(ii) Single well bonding requirements are assumed to be $78,000 per well. This assumption reflects the proposed rules' maximum impact on industry and avoids understatement of the impact.
(iii) References to bonding include the bonding for operators with at least one well not plugged and abandoned (PA status). Producing wells are LPW as well as non LPW.

Second, Rule 434 asks operators to submit a Form 3A if an inactive well is not plugged within six months, and the operator may request a hearing if the operator disagrees with the amount of financial assurance requested by the State for approval in a new Form 3A. As shown in **Table 6** (above), Staff estimates that five (5) such hearings will take place each year at cost of $7,500 to industry. This cost assumes that industry staff, at a $150 per hour rate, will likely work for 10 hours to file the hearing application and staff the hearing.

Third, for the new Form 3A, Staff estimates that approximately 485 operators will review Staff guidance at an average cost of $600 per operator, or $291,000 in added one-time expense. That expense captures four (4) hours of staff time at a cost of $150 per hour. Preparing and submitting 700 Form 3As in the first year after adoption of the proposed rules will cost the industry approximately $52,500, a one-time expense resulting from 30 minutes of added staff time for each form at a $150 per hour rate. Staff estimates that approximately 700 wells become newly inactive in any given year.

After the first year, the Form 3A will be used primarily to address wells of new operators and the inactive wells that keep an inactive status for longer than three years. In total, industry will prepare and submit 117 Form 3As on an ongoing basis, costing the industry approximately $52,650 per year. This expense results from three (3) hours of added staff time for each form at a $150 per hour rate.

Rule 434 also requires that operators with an Out of Service Well submit information on a new Form 6A about wells recently plugged and wells to be plugged. For this form, guidance provided by the State will be reviewed by an estimated 485 operators at an average cost of $600 per operator, or $291,000 in added one-time expense. That expense captures four (4) hours of staff time at a cost of $150 per hour. Preparing and submitting 1,225 revised Form 3As on an ongoing basis, costing the industry approximately $183,750 per year. This expense results from one hour of added staff time for each form at a $150 per hour rate. Staff estimates that approximately 225 wells receive temporarily abandoned status in any given year, and another 1,000 inactive wells will reach the three-year mark.

When an operator temporarily abandons ("TA") a well, the proposed rules require the submission of a Form 4 that allows the operator to request TA status for a period up to six months or longer than six months. The revised Form 4 will accept detailed information about the operator's plans for the well and the measures taken to protect public health, safety, the environmental, and wildlife. Guidance provided by the State will be reviewed by an estimated 485 operators at an average cost of $300 per operator, or $145,500 in added one-time expense. That expense captures two (2) hours of staff time at a cost of $150 per hour. Preparing and submitting 450 revised Form 4s on an ongoing basis will cost the industry approximately $33,750 per year. This expense results from 30 minutes of added staff time for each form at a $150 per hour rate. Staff estimates that approximately 225 wells are placed in TA status during any given year, and operators will notify the State that equipment will be removed from another 225 TA wells.

(Qualitative) Staff assumes that Rule 434 and the Financial Assurance Rulemaking in general will produce benefits for the community that cannot be quantified in most instances. These benefits include community enjoyment of reduced timeframes for closure of oil and gas sites that would otherwise be orphaned, as operators are strongly incentivized to satisfy all site closure obligations and reduce their ongoing financial assurance expenses by having the State release their bonds and CDs and return their cash deposits. The public will notice more reclaimed and remediated landscapes, and public records will verify that operators themselves plugged the wells at those sites in accordance with State rules, which will increase public trust in industry operations.

There will likely also be public health, safety, and environmental benefits from earlier closure of various types of inactive, temporarily abandoned, or marginally producing wells. The benefits to the community of reclaimed and remediated landscapes, in addition to safely plugged wells, also occur for these types of wells. These benefits will be both short- and long-term.

- **Impacts on State Government**

(FTE Cost) Rule 434 asks operators to submit a Form 3A if an inactive well is not plugged within six months, and the operator may request a hearing if the operator disagrees with the amount of financial assurance requested by the State for approval in a new Form 3A. As shown in **Table 6** (above), Staff estimates that five (5) such hearings will take place each year at a cost of 0.007 FTE. This cost assumes an average of three (3) hours to prepare for and staff each hearing.

Staff anticipates that development and use of a new Form 3A, as required by Rule 434, will increase State workload by the following amounts and types:

- 60 hours to develop the new form, or 0.029 one-time FTE;
- 16 hours to engineer data tools for Staff and operators, or 0.008 one-time FTE;
- 32 hours to develop guidance and offer operator training, or 0.015 one-time FTE;
- 2 hours to review each of 700 forms during the first year, or 0.673 one-time FTE; and
- 4 hours to review each form at an annual volume of 117 forms, or 0.225 ongoing FTE.

Staff anticipates that development and use of a new Form 6A, as required by Rule 434, will increase State workload by the following amounts and types:

- 60 hours to develop the new form, or 0.029 one-time FTE;
- 16 hours to engineer data tools for Staff and operators, or 0.008 one-time FTE;
- 32 hours to develop guidance and offer operator training, or 0.015 one-time FTE; and
- 15 minutes to review each line of the form at an annual volume of 1,225 lines, or 0.147 ongoing FTE.

Staff anticipates that use of a revised Form 4, as required by Rule 434, will increase State workload by the following amounts and types:

- 24 hours to develop the revised form, or 0.012 one-time FTE;
- 16 hours to develop guidance and offer operator training, or 0.008 one-time FTE; and
- 15 minutes to review each form at an annual volume of 450 forms, or 0.054 ongoing FTE.

Rule 503 – Applications for a Hearing Before the Commission

The Commission revised Rule 503 to account for the new types of hearing applications contemplated by the revised Financial Assurance Rules. Rule 503.g.(11) allows operators, the Commission, the Director, or a third-party holder of financial assurance to initiate a financial assurance hearing by filing an application with the Commission. In situations where the Commission or Director initiates a financial assurance hearing, the operator that is the subject of the hearing will nevertheless be required to compile all necessary information and submit it into the docket for the hearing, as appropriate. Rule 503.g.(12) authorizes the Director or a relevant local government to file an application to plug and abandon a well or close an oil and gas location or oil and gas facility pursuant to Rule 211. The Commission also revised Rule 503.h to clarify that the purpose of the Rule is to designate specific categories of hearings in which a decision must be made by the Commission in the first instance, rather than a Hearing Officer or Administrative Law Judge issuing a recommended order for the Commission's consideration.

- **Impacts on Industry and the Community**

  Staff assumes that implementation of Rule 503 will result in costs to industry when operators prepare for each financial assurance hearing, and the Analysis calculates these costs for each Rule section that authorizes a financial assurance hearing. *See* the impacts for Rules 218, 434, 701, 702, 706, 707, and 913.

- **Impacts on State Government**

  Staff expects that implementation of Rule 503 will result in costs to State Government when staff prepare for each financial assurance hearing. The Analysis calculates these costs for each Rule section that authorizes a financial assurance hearing. *See* the impacts for Rules 218, 434, 701, 702, 706, 707, and 913.

Rule 504 – Notice for Hearing

The Commission revised Rule 504.b to include unique notice requirements in order to account for the two new hearing application types in Rule 503.g. In Rule 504.b.(10), Staff identified specific parties who must be noticed for applications filed by an operator, the Commission on its own motion, the Director, a surface owner, and a third-party provider of financial assurance seeking reinstatement, respectively. Pursuant to Rule 504.b.(11), if the Director files an application for a hearing pursuant to Rule 503.g.(12), the Director must provide notice to the operator. If the relevant local government files an application for such a hearing pursuant to Rule 503.g.(12), it must provide notice to both the operator and the Director. Staff intends for the specific government agencies listed in Rules 504.c–f to receive notice of relevant financial assurance and well and location closure hearings, including the Bureau of Land Management for hearings that implicate federal surface and/or mineral estates.

- **Impacts on Industry and the Community**

  Staff assumes that implementation of Rule 504 will result in costs to parties when they prepare for each financial assurance hearing, and the Analysis includes these notice requirement costs in each Rule section that authorizes a financial assurance hearing. See the impacts for Rules 218, 434, 701, 702, 706, 707, and 913.

- **Impacts on State Government**

  Staff assumes that implementation of Rule 504 will result in costs to State Government when staff prepare for each financial assurance hearing, and the Analysis includes these notice requirement costs in each Rule section that authorizes a financial assurance hearing. See the impacts for Rules 218, 434, 701, 702, 706, 707, and 913.

Rule 505 – Evidence in Support of an Application

The Commission revised Rule 505, correcting certain typographic errors and adopting new requirements governing evidence in financial assurance and well location and closure hearings. Rule 505.f provides for flexibility in the evidence required in a financial assurance hearing. Rule 505.g governs the evidence in well location and closure hearings, and requires the applications to include all evidence necessary for the Commission to decide the matter.

- **Impacts on Industry and the Community**

  Staff assumes that implementation of Rule 505 will result in costs to parties when they prepare for each financial assurance hearing, and the Analysis includes these evidentiary requirements in each Rule section that authorizes a financial assurance hearing. See the impacts for Rules 218, 434, 701, 702, 706, 707, and 913.

- **Impacts on State Government**

  Staff anticipates that implementation of Rule 505 will result in costs to State Government when staff prepare for each financial assurance hearing, and the Analysis includes these evidentiary requirements in each Rule section that authorizes a financial assurance hearing. See the impacts for Rules 218, 434, 701, 702, 706, 707, and 913.

Rule 701 – Types of Financial Assurance

The Commission reorganized, revised, and amended its prior 700-Series Rules to follow a more logical, sequential order. Rule 701 now governs types of acceptable financial assurance and was moved from prior Rule 702. In Rule 701, the Commission explained that cash and surety bonds are preferred forms of financial assurance as both types of bonds provide a high degree of certainty that the Commission will be able to obtain the funds covered by the bond in the event it must access an operator's financial assurance. Furthermore, the Commission clarified that operators may seek permission to use an alternative type of financial assurance through the hearing process set forth in Rule 503.g.(11). Rule 701 also generally prohibits the use of bond riders and includes provisions establishing when an operator must submit a Form 3, Financial Assurance.

- **Impacts on Industry and the Community**

  ($ Cost) Staff anticipates that Rule 701 will result in costs to operators. First, Rule 701 enables operators to request a hearing if the operator wishes to provide a lien, Letter of Credit, security interest, escrow account, sinking fund, or other financial instrument that is not a Cash Bond or Surety Bond. As shown in **Table 6** (above), Staff estimates that two (2) such hearings will take place each year at cost of $3,000 to industry. The industry cost assumes its staff, at a $150 per hour rate, must work for 10 hours to file the hearing application and staff the hearing.

Rule 701 also defines the function of Form 3, which is the vehicle for operators to submit financial assurance to the State. Revising the form to incorporate the proposed rules will ask 485 operators to review Form 3 guidance provided by the State at an average cost of $600 per operator, or $291,000 in added one-time expense. That expense captures four (4) hours of staff time at a cost of $150 per hour. Preparing and submitting 216 Form 3s in the first year after adoption of the proposed rules will cost the industry approximately $129,600, a one-time expense resulting from four (4) hours of added staff time for each form at a $150 per hour rate. Staff estimates that approximately 216 operators have an inactive well in any given year and must submit both at least one Form 3A and one Form 3 according to proposed rules.

After the first year, only new operators and operators with one newly inactive well must submit at least one Form 3A and one Form 3. Staff estimates there will be 70 new operators and 60 operators with at least one newly inactive well annually. The cost impact for industry will be $78,000 per year, an ongoing expense resulting from four (4) hours of added staff time for 130 Form 3s at a $150 per hour rate.

- **Impacts on State Government**

(FTE Cost) Staff anticipates that Rule 701 will result in various costs. Rule 701 asks operators to submit a Form 3 if an inactive well is not plugged within six months, and the operator may request a hearing if the operator disagrees with the amount of financial assurance requested by the State for approval in a new Form 3. As shown in **Table 6** (above), Staff estimates that five (5) such hearings will take place each year at a cost of 0.003 FTE. Staff assumes an average of three (3) hours to prepare for and staff each hearing.

Staff also anticipates that development and use of a revised Form 3, as required by Rule 701, will increase State workload by the following amounts and types:

- 84 hours to develop the new form, or 0.040 one-time FTE;
- 32 hours to develop guidance and offer operator training, or 0.015 one-time FTE;
- 2 hours to review 216 forms during the first year if the form is rejected 25 percent of the time and must be resubmitted; but 1 hour to review 216 forms during the first year if the form is complete 75 percent of the time; in total, 0.130 one-time FTE; and
- 2 hours to review 130 forms during each subsequent year if the form is rejected 25 percent of the time and must be resubmitted; but 1 hour to review 130 forms annually if the form is complete 75 percent of the time; in total, 0.078 ongoing FTE.

Rule 702 – Financial Assurance for Plugging, Abandonment, and Reclamation

In Rule 702, the Commission established the financial assurance requirements for plugging, abandonment, and reclamation of oil and gas wells, oil and gas locations, and associated oil and gas facilities. The purpose of this Rule, like prior Rule 706, is to protect public health, safety, welfare, the environment, and wildlife resources, as well as air, water, soil, and biological resources, by ensuring that operators have the financial capability to fulfill all of their obligations under the Act and the Commission's Rules. *See* C.R.S. § 34-60-106(2.5)(a), (13). Specifically, Rule 702 is intended to ensure that operators are capable of fulfilling their obligation to plug and abandon wells pursuant to the Commission's 400-Series Rules, to fully reclaim oil and gas locations pursuant to the Commission's 1000-Series Rules, and to properly clean up and abandon oil and gas facilities such as tanks and flowlines pursuant to the Commission's 600- and 1100-Series Rules. The Commission intends to use financial assurance as one tool to ensure that operators fulfill all of their plugging, abandonment, and reclamation obligations under the Act and the Commission's Rules.

- **Impacts on Industry and the Community**

($ Cost) Staff estimates that Rule 702 will result in various costs to operators. Rule 702, taken as a whole, raises the amount of required financial assurance that operators will deposit into a custodial account managed by the State. Rule 702.c establishes three tiers of financial assurance plans, and all operators will fall into one of the identified tiers unless the operator seeks an exception. Staff established the tiers in Rule 702.c based on characteristics that are related to an operator's financial health, and the risk of an operator orphaning its assets. These factors include what percentage of an operator's wells are low-producing wells, and what percentage of wells an operator has plugged in the prior year. The tier that an operator falls within determines the type of financial assurance plan it must submit pursuant to Rule 702.d.

As indicated above, the increase in financial assurance for each currently registered operator depends on two factors: (1) The number of wells the operator has plugged (a plugged and abandoned ("PA") status has been assigned to the well) as a share of all wells registered to the operator's name during the past 12 months; and (2) The amount of the operator's active wells that meet the definition of LPWs. In **Table 8** (below), Staff measures how frequently an operator plugs at least 20 percent (Tier 1) or at least 10 percent (Tier 2) of its wells. The results show that only 3.3 percent of operators fall first into Tier 1 (PA status was assigned for 20% or more of the wells in one calendar year), leaving 2.3 percent of operators to fall into Tier 2 (PA status was assigned for 10 to 19.999 percent of the wells in one calendar year). Most operators (83 percent) plug zero wells each year. This data spans 12 calendar years and blends variation expected during oil and gas market cycles.

In contrast, many more operators meet the criterion for LPW quantities in Rule 702. **Table 9** (below) estimates that 45 percent of operators in the most recent completed calendar year have fewer than 20 percent of their wells defined as LPW (Tier 1), while the next 22 percent of operators have 20 to 59.999 percent of their wells defined as LPW (Tier 2). Accordingly, Staff estimates that up to 33 percent of current operators will be classified as Tier 3.

The type of the financial assurance chosen by the operator plays an important role in the costs facing an operator required to provide additional financial assurance. Surety company financial assurance products predominantly require payment of regular premiums to the surety, so the operator expense is ongoing. Direct or self-funded financial assurance is paid by the operator in full, but the expense is best expressed as annual finance charges the operator pays for use of the money. Staff have assumed that, based on current financial assurance records summarized in **Table 10** (below), approximately 65 percent of new financial assurance purchased to comply with the proposed rules will be a surety industry product, and approximately 35 percent of new financial assurance required to comply with the proposed rules will be self-funded. This data is based on an analysis of the frequency of single source financial assurance on an operator-by-operator basis— that is, a count of operators using 100 percent surety product versus 100 percent cash versus 100 percent CD funding. More specific data on the 13 percent of operators using combination sources (part surety, part cash, for example) was not possible during the timeframe of the Analysis.

Rule 702 also prescribes blanket bond amounts that vary by an operator's well count and by tier. The Analysis assigns each operator a tier based on its share of LPWs, calculates the difference between the proposed rule's new blanket bond amount and the total plugging financial assurance on deposit as of June 2021. The difference across all current operators will be Rule 702's impact on the industry. The Analysis assumes full cost bonding at $78,000 per well for all Tier 3 operators to avoid understating the impacts of the proposed rules on industry. In practice, Tier 3 operators may use the sinking fund provisions of the Rule to provide less than $78,000 per well by reactivating or plugging the wells prior to fully funding the sinking fund.

As displayed in **Table 11** (below), Staff estimates that blanket financial assurance amounts will increase $105.0 million for Tier 1 operators, by $52.5 million for Tier 2 operators, and by $187.4 million for Tier 3 operators. In total, the proposed rules will increase blanket financial assurance by $344.9 million statewide. Staff adds to this amount the $279.2 million in increased single well financial assurance from Rule 434 earlier in the Analysis. Note that the $624 million amount will not be paid in full by the industry, as the use of surety products do not require payment of the full bond amount. In addition, the amount paid by operators for cash bonds or CDs is best expressed as the cost of capital for the operator (or the lender's rate of return) as the operator sets aside the funds to access credit equal to the face value of the bond or CD.

Table 8
Plugged and Abandoned (PA) Well Share 2009-2020 and Operator Distribution Among Tiers

Share of Each Operator's Active Wells PA'd in Same Calendar Year (%)	Number of Operator-Years by PA Share, 2009-2020	Average Operator Count Per Year	Assigned Tier in Proposed Rules	Share of Total Operator-Years 2009-2020	Operator Active Well-Years 2009-2020	Average Active Well Count Per Year	Share of Total Active Wells 2009-2020
At least 20%	207	17	**Tier 1**	3.3%	3,436	286	0.5%
10-19.9999%	143	12	**Tier 2**	2.3%	28,116	2,343	4.4%
Less than 10%	702	59	**Tier 3**	11.1%	480,389	40,032	74.8%
Plugged Zero Wells	5,253	438	**Tier 3**	83.3%	130,537	10,878	20.3%
Total	**6,305**	**525**		**100.0%**	**642,478**	**53,540**	**100.0%**

Notes:
(i) Each operator has at least 1 active well in each calendar year.
(ii) An operator with "Plugged Zero Wells" for the preceding 12 months meets the proposed rule criterion to be assigned to blanket FA Tier 3.
(iii) Most operators (average 438) have plugged zero wells, but most wells (average 74.8%) belong to operators that have PA'd less than 10% of their active wells.
(iv) The share of wells PA'd in the preceding 12 months is one of two criteria for assigning an operator to a blanket FA tier. The other criterion is the share of Low Producing Wells (LPWs).

Table 9
Low Producing Well (LPW) Shares from 2020 and Operator Distribution Among Tiers

Operator Low Producing Well (LPW) Share of All Wells (%) in 2020	Number of Operators by Tier	Assigned Tier in Proposed Rules	Share of Total Operators	Total Active Wells By Tier	Share of Total Active Wells
Less than 20%	162	**Tier 1**	45%	30,942	74%
20-59.9999%	78	**Tier 2**	22%	8,445	20%
60-100%	117	**Tier 3**	33%	2,452	6%
Total	**357**		**100%**	**41,839**	**100%**

Notes:
(i) A LPW is any Well that produces less than 5 Barrels of oil equivalent (“BOE”) per day, calculated as a trailing 12-month average of the Operator’s reported BOE for the Well.
(ii) Operators in table are those with at least one well not plugged and abandoned (PA status).

Table 10
Operator Sourcing of Financial Assurance On Deposit in 2021

Financial Assurance On Deposit	Operator Count in 2021	Share of Operators Using a Single Source of FA	Share of Operators Using All Sources of FA
Surety Sourced			
Bonds	356	58%	51%
Riders	42	7%	6%
Subtotal, Surety Sourced	**398**	**65%**	**57%**
Operator Self Funded			
Certificates of Deposit	56	9%	8%
Cash	159	26%	23%
Subtotal, Operator Self Funded	**215**	**35%**	**31%**
Subtotal, All Single Sources	**613**	**100%**	
Other			
Combinations of Any Above or Other	90		13%
TOTAL	**703**		**100%**

Notes:
(i) Data for shares of operator FA source in the 13% of operators using a combination of sources was not readily available.
(ii) Operators whose FA was 100 percent riders are assumed to continue to purchase surety products after adoption of new rules.

Table 11
Statewide FA Deposited from Blanket FA Requirements in Rule 702

Tier	Estimated Current Statewide Rule 706 (Plugging) Bonding ($ million)	Proposed Rule 702 Blanket Bonding ($ million)	Added Statewide Blanket Bonding in Proposed Rule 702 ($ million)	Factor Increase / Decrease for Statewide Bonding
Tier 1	$9.1	$114.1	$105.0	11.5
Tier 2	$4.8	$57.3	$52.5	10.9
Tier 3	$3.9	$191.3	$187.4	48.1
All Tiers	**$17.8**	**$362.7**	**$344.9**	**19.4**

Notes:
(i) All dollar figures are estimates and expressed in 2022 dollars.
(ii) Bonding requirements differ by tier. The tier differences are found in the proposed Rule 702.

In **Table 12** (below), the total purchase price of financial assurance required by Rules 702 and 434 is estimated for the scenario that *operators use surety products for 100 percent of the additional financial assurance*. Staff believes that surety companies will charge a range of premiums based on risk factors unique to each operator's field operations and financial health, and that this range is 2 percent of the face value of the bond at the low end and 10 percent of the face value of the bond at the high end. To satisfy proposed rules, the Analysis estimates for this scenario a $12.5 million to $62.4 million ongoing cost impact to industry.

For a scenario in which *operators self-fund 100 percent of the additional financial assurance* that Rule 702 and Rule 434 require, **Table 13** (below) shows a cost of capital that varies across all operators. At the low end, self-funding will cost the operator six percent of the face value of the financial assurance annually. This cheaper source of capital will be available to the highest rated operators from private lenders. At the high end, for an operator whose financial resilience is rated lower by private lenders, self-funding will cost 25 percent of the face value of the financial assurance. In total, an "all self-funding" scenario will cost the industry between $48.8 million and $156.6 million per year.

For final numbers, the Analysis blends the 65 percent use of surety products and the 35 percent use of self-funding shares from **Table 10** (above), and produces an estimated cost impact on industry between $25.3 million per year and $95.5 million per year, as presented in **Table 14** (below).

Table 12
Operator Cost Impacts from Net New Financial Assurance Purchases, Surety Sources

Rule / Tier	Net Change in Bonding From Proposed Rules ($ million)	Operator Cost to Purchase FA - Low End ($ million / year)	Operator Cost to Purchase FA - High End ($ million / year)
		2% annual bond premium	*10% annual bond premium*
702			
Tier 1	$105.0	$2.1	$10.5
Tier 2	$52.5	$1.1	$5.3
Tier 3	$187.4	$3.7	$18.7
All Tiers	**$344.9**	**$6.9**	**$34.5**
434			
Tier 1	$240.4	$4.8	$24.0
Tier 2	$26.1	$0.5	$2.6
Tier 3	$12.7	$0.3	$1.3
All Tiers	**$279.2**	**$5.6**	**$27.9**
ALL RULES	**$624.1**	**$12.5**	**$62.4**

Notes:
(i) All dollar figures are estimates and expressed in 2022 dollars.
(ii) Surety sources of FA commonly include bonds with an annual premium due from the operator.
(iii) References to bonding include the bonding for operators with at least one well not plugged and abandoned (PA status). Producing well are LPW as well as non LPW.
(iv) Bond premium rates vary by quality of operator financials and credit scores. A 2% cost applied to the bond face value is for operators with the highest surety industry risk ratings; a 10% cost is estimated for operators with the lowest surety industry risk ratings.

Table 13
Operator Cost Impacts from Net New Financial Assurance, Direct Funding by Operators

Rule / Tier	Net Change in Bonding From Proposed Rules ($ million)	Operator Cost to Direct Fund FA - Low End ($ million / year)	Operator Cost to Direct Fund FA - High End ($ million / year)
		6% cost of capital	*25% cost of capital*
702			
Tier 1	$105.0	$8.2	$26.3
Tier 2	$52.5	$4.1	$13.2
Tier 3	$187.4	$14.7	$47.0
All Tiers	**$344.9**	**$27.0**	**$86.6**
434			
Tier 1	$240.4	$18.8	$60.3
Tier 2	$26.1	$2.0	$6.5
Tier 3	$12.7	$1.0	$3.2
All Tiers	**$279.2**	**$21.8**	**$70.1**
ALL RULES	**$624.1**	**$48.8**	**$156.6**

Notes:
(i) All dollar figures are estimates and expressed in 2022 dollars.
(ii) Self funded sources of FA include operator cash or bank issued Certificates of Deposit (CDs) provided to the State Treasurer. The cost to the operator is assumed to be the annualized cost of capital for the funding amount provided to the State.
(iii) Operator cost of capital is the payment made to a lender (on a range of 6% to 25% rate of return for the lender) over an estimated 25 year life cycle for FA. Large, publicly traded E&P companies who are financially stable may face a 6% cost of capital, while a small operator with tight cost margins and volatile revenue may face a 25% cost of capital.

Table 14
Operator Weighted Cost Impacts Based on Financial Assurance Sourcing

Funding Source / Rule	Estimated Allocation of Financial Assurance Sources	Operator Annual Impact - Low End ($ million / year)	Operator Annual Impact - High End ($ million / year)
Surety Sourced			
Rule 434	if 100%	$5.6	$27.9
Current Split	**65%**	**$3.6**	**$18.1**
Rule 702	if 100%	$6.9	$34.5
Current Split	**65%**	**$4.5**	**$22.4**
Operator Self Funded			
Rule 434	if 100%	$21.8	$70.1
Current Split	**35%**	**$7.7**	**$24.6**
Rule 702	if 100%	$27.0	$86.6
Current Split	**35%**	**$9.5**	**$30.4**
Total Using Current 65%-35% Splits		**$25.3**	**$95.5**

Notes:
(i) All dollar figures are estimates and expressed in 2022 dollars.
(ii) Surety sources of FA commonly include bonds with an annual premium due from the operator.
(iii) Self funded sources of FA include operator cash or bank issued Certificates of Deposit (CDs) provided to the State Treasurer. The cost to the operator is assumed to be the total finance charge for the funding provided to the State.

Rule 702 also defines what operators must include in a financial assurance plan ("FA Plan"). For FA Plans to be correctly prepared by operators and reviewed by Staff and the Commission, Staff estimates that 485 operators to review FA Plan guidance provided by the State at an average cost of $600 per operator, or $291,000 in added one-time expense. That expense captures four (4) hours of staff time at a cost of $150 per hour. These figures are displayed in **Table 15** (below).

Preparing and submitting 485 FA Plans in the first year after adoption of the proposed rules will cost the industry approximately $1,273,215, a one-time expense resulting from 17.5 hours of added staff time for each form at a $150 per hour rate. All operators with an active Form 1 must submit a FA Plan by July 1, 2022.

After the first year, Staff assumes that only new operators and operators with one newly inactive well will submit an FA Plan. Staff estimates there will be 70 new operators and 60 operators with at least one newly inactive well annually. The cost impact for industry will be $341,250 per year, an ongoing expense resulting from 17.5 hours of added staff time for each form at a $150 per hour rate.

Rule 702 enables operators to request a hearing if the operator wishes to request an exception to financial assurance requirements stated in the Rule. As shown in **Table 7** (above), Staff estimates that five (5) such hearings will take place each year at cost of $7,500 to industry. The industry cost assumes its staff, at a $150 per hour rate, must work for 10 hours to file the hearing application and staff the hearing.

(Qualitative) Staff assumes that Rule 702 and the Financial Assurance Rulemaking in general will produce benefits for the community that cannot be quantified in most instances. These benefits include community enjoyment of reduced timeframes for closure of oil and gas sites that would otherwise be orphaned, as operators are strongly incentivized to satisfy all site closure obligations and reduce their ongoing financial assurance expenses by having the State release their bonds and CDs and return their cash deposits. The public will notice more reclaimed and remediated landscapes, and public records will verify that operators themselves plugged the wells at those sites in accordance with State rules, which will increase public trust in industry operations.

There will likely also be public health, safety, and environmental benefits from earlier closure of various types of inactive, temporarily abandoned, or marginally producing wells. The benefits to the community of reclaimed and remediated landscapes, in addition to safely plugged wells, also occur for these types of wells. These benefits will be both short- and long-term.

- **Impacts on State Government**

($ Benefit) The Analysis identifies a portion of the $624 million of statewide additional financial assurance as a benefit to the OWP, because the Program's experience with receiving orphaned sites since 2015 suggests that a small share of total financial assurance provided by operators will be claimed each year. In **Table 16** (below), this benefit is estimated based on a 0.0953 percent share (less than one-tenth of one percent) of all active wells moving into the OWP annually. As a share of the proposed rule's added financial assurance value, revenue to the OWP is estimated to be a cumulative $14.9 million over a 25-year period. The revenue acts as OWP avoided costs that would otherwise be appropriated from the Oil and Gas Conservation and Emergency Response Fund and spent to close orphaned sites. The Analysis chooses a cumulative timeframe because the impact to State government is one-time funding received from each claim made upon the operator's financial assurance for those wells or sites. The 25-year time period represents the reasonable maximum lifetime of most wells currently being operated in Colorado.

(FTE Cost)

As shown in **Table 15** (below), Staff anticipates that development and continued use of FA Plans, as required by Rule 702, will increase State workload by the following amounts and types:

- 64 hours to develop data tools and FA Plan workflow, or 0.031 one-time FTE;
- 24 hours to develop guidance and offer operator training, or 0.012 one-time FTE;
- 24 hours spread among Financial Assurance, Engineering, and Environmental Staff to review 485 FA Plans during the first year, or 5.596 one-time FTE; and
- 24 hours spread among Financial Assurance, Engineering, and Environmental Staff to review 130 FA Plans each year after the first, or 1.500 ongoing FTE.

Last, Rule 702 asks operators to request a hearing if the operator wishes to request an exception to financial assurance requirements stated in the Rule. As shown in **Table 6** (above), Staff estimates that five (5) such hearings will take place each year at a cost of 0.007 FTE. This cost assumes an average of three (3) hours to prepare for and staff each hearing.

Table 15
Impacts on Industry and State Government from Financial Assurance (FA) Plan Requirements

Timeframe	FA Plan Count	Impact Type	FA Plan State Government Data Tools and Workflow Design Impact (64 hours, 2080 hours/FTE)	FA Plan Guidance to Operators Impact: Industry Expenses (4 hours per operator, $150/hr)	FA Plan Guidance to Operators Impact: State Government FTE (24 hours, 2080 hours/FTE)	FA Plan Workload Impact (Prepare and Submit or Review and Respond): Industry Expenses (17.5 hours per Plan, $150/hr)	FA Plan Workload Impact (Prepare and Submit or Review and Respond): State Government FTE (24 hours per Plan, 2080 hours/FTE)
			FTE	*$*	*FTE*	*$*	*FTE*
First Year							
All Operators	**485**	**one time**	**0.031**	**-$291,000**	**0.012**	**-$1,273,125**	**5.596**
Ongoing							
New Operators	70	ongoing				-$183,750	0.808
Operators With New Inactive Wells	60	ongoing				-$157,500	0.692
Subtotal, Ongoing	**130**	**ongoing**				**-$341,250**	**1.500**

Notes:
(i) All figures are estimates and expressed in 2022 dollars or FTE.
(ii) The Analysis assumes 1.000 FTE is equivalent to 2080 paid hours per year following Colorado State government conventions.
(iii) The Analysis assumes that the total compensation cost of all operator technical staff and contractors averages $150/hour.
(iv) Regulatory workload uses averages of industry form submissions across full market cycles (minimum 12 to 25 year averages when available).

Table 16
State Orphaned Well Program (OWP) Costs Funded By Added FA During Lifetime of All Current Wells

Item	Timeframe	Result	Units
Added Statewide FA from Proposed Rules			
Rule 434	Lifetime of all Current Wells in Colorado	$279.2	million 2022$
Rule 702		$344.9	
Subtotal, All Rules		**$624.1**	**million 2022$**
Estimated Rate for Wells to Enter OWP Via State Claimed FA	Calendar Years 2015-2021	0.0953%	annual percent of all active wells
OWP Funded Site Closure Costs Due to Added FA			
Rule 434	Annual	$0.27	million 2022$
Rule 702		$0.33	
Subtotal, All Rules		**$0.59**	**million 2022$**
Benefit to the OWP	**Annual**	**$0.59**	**million 2022$**
Maximum Years of Life, All Current Wells in State	Lifetime of all Current Wells in Colorado	25	years
OWP Cumulative Benefit from Proposed Rules	**Lifetime of all Current Wells in**	**$14.9**	**million 2022$**

Notes:
(i) All figures are estimates and expressed in 2022 dollars or FTE.
(ii) The Analysis assumes that the total compensation cost of all operator technical staff and contractors averages $150/hour.
(iii) Regulatory workload uses averages of industry form submissions across full market cycles (minimum 12 to 25 year averages when available).
(iv) Proposed rules generate a benefit to the State's Orphaned Well Program by providing revenue from claimed Financial Assurance to pay for orphaned site closure costs. Absent the Rule changes, these costs would be appropriated from the Oil and Gas Conservation and Emergency Response Fund.

Rule 703 – Financial Assurance for Other Oil and Gas Facilities & Operations

In Rule 703, the Commission consolidated all of its prior Rules that addressed financial assurance requirements for oil and gas facilities and operations that are not wells into a single Rule. A majority of the additional revisions to the Rule were made to specify or clarify certain processes associated with the submission of financial assurance, amount of financial assurance, and when such financial assurance would be released.

The Commission moved prior Rule 704, governing financial assurance for centralized exploration and production ("E&P") waste management facilities, to Rule 703.a. The Commission also moved prior Rules 436.g.(1)–(5) and 705, governing financial assurance for seismic operations, to Rule 703.b. In addition, the requirements governing financial assurance for gas gathering, gas processing, and underground gas storage facilities were also moved from prior Rule 711 to Rule 703.c. The Commission also moved prior Rule 712, governing financial assurance for produced water transfer systems, to Rule 703.d. Prior Rule 713, governing financial assurance for commercial disposal wells, was also moved to Rule 703.e.

- **Impacts on Industry and the Community**

($ Cost) Staff estimates that Rule 702 will result in various costs to operators of gas gathering and gas processing systems, as well as operators of commercial disposal wells. Rule 703.c.(2) specifies the amount of financial assurance that operators of gas gathering, gas processing, and underground gas storage facilities must provide. The purpose of Rule 703.c.(2) is to provide financial assurance to ensure compliance with the Commission's 900-Series Rules in the event of a spill or release. When such spills and releases do occur, they can be very costly. Gas gathering systems are almost always buried belowground, and for this reason it is possible for spills and releases to go undetected for some time. Additionally, some gas gathering systems and gas storage facilities transport or process very high volumes of hydrocarbons. And when spills or releases reach groundwater, although this is a rare occurrence, they can be very costly to clean up. Accordingly, Staff determined it was appropriate to increase the financial assurance for these gas facilities from a $50,000 blanket bond to $50,000 per facility. Rule 703.e.(2) increases the amount of financial assurance required for a commercial disposal well from $50,000 to $100,000 per well. Commercial disposal wells process high volumes of E&P waste. Accordingly, Staff determined that remediation costs associated with spills and releases at such facilities are generally higher than $50,000, and that $100,000 in financial assurance is a more appropriate amount for those facilities.

Table 17 (below) calculates the net additional financial assurance that operators of each facility type will provide based on new requirements. Using current data on active facilities, Staff anticipates that the operators of gas gathering and gas processing systems will benefit from a net decrease of $890,000 in financial assurance on deposit with the State. In contrast, the financial assurance provided by commercial disposal well operators will double, a net increase of $4,550,000.

The Analysis calculates the annual cost impact on industry from the combined financial assurance changes, based on a statewide split of 35 percent operator self-funding and 65 surety product purchases for the financial assurance. **Table 18** (below) presents an ongoing self-funded financial assurance cost between $76,860 and $320,250 per year, and ongoing surety purchases between $47,580 and $237,900 per year.

- **Impacts on State Government**

Staff assumes that the volume of Form 3 submissions by operators of these two facility types is small compared to the 216 forms that Rule 701 forecasts. In particular, there are few operators with multiple gas processing or gas gathering systems for whom a blanket bond amount will no longer satisfy financial assurance rules. For that reason, the Analysis estimates no State Government cost or benefit.

Table 17
Added Financial Assurance (FA) for Other Facilities

Rule / Item	Calculation
Rule 703c. - Gas Gathering/Processing Facilities	
Current FA on Deposit	$5,420,000
Count of Facilities <5 Million Standard Cubic Feet Per Day (Small)	46
Count of Facilities >=5 Million Standard Cubic Feet Per Day (Large)	86
Required FA Per Small Facility, Proposed Rules	$5,000
Required FA Per Large Facility, Proposed Rules	$50,000
Statewide FA Subtotal, Small Facilities, Proposed Rules	$230,000
Statewide FA Subtotal, Large Facilities, Proposed Rules	$4,300,000
Change in FA for Gas Gathering/Processing Facility Operators	**-$890,000**
Rule 703e. - Commercial Disposal Wells	
Current FA on Deposit	$4,550,000
Current Rule FA Requirement Per Facility	$50,000
Proposed Rule FA Requirement Per Facility	$100,000
Factor Increase / Decrease for Statewide Bonding	2.0
Change in FA for Commercial Disposal Well Operators	**$4,550,000**

Notes:
(i) All dollar figures are estimates and expressed in 2022 dollars.
(ii) Surety sources of FA commonly include bonds with an annual premium due from the operator.
(iii) Self funded sources of FA include operator cash or bank issued Certificates of Deposit (CDs) provided to the State Treasurer. The cost to the operator is assumed to be the total finance charge for the funding provided to the State.

Table 18
Operator Weighted Costs for Other Facility Added Financial Assurance

Item	Statewide FA Change	FA Cost (% of FA Value)	Operator Annual Impact ($ million / year)
Proposed Rules for Other Facility Types			
Rule 703c. - Gas Gathering/Processing Facilities	-$890,000		
Rule 703e. - Commercial Disposal Wells	$4,550,000		
Subtotal	**$3,660,000**		
Surety Split - 65%	$2,379,000		
Operator Self Funded Split - 35%	$1,281,000		
Surety Sourced			
Low		2%	$47,580
High		10%	$237,900
Operator Self Funded			
Low		6%	$76,860
High		25%	$320,250
Total Operator Cost Impact, Other Facility FA			
Low			**$124,440**
High			**$558,150**

Notes:
(i) All dollar figures are estimates and expressed in 2022 dollars.
(ii) Surety sources of FA commonly include bonds with an annual premium due from the operator.
(iii) Self funded sources of FA include operator cash or bank issued Certificates of Deposit (CDs) provided to the State Treasurer. The cost to the operator is assumed to be the total finance charge for the funding provided to the State.
(iv) Bond premium rates vary by quality of operator financials and credit scores. A 2% cost applied to the bond face value is for operators with the highest surety industry risk ratings; a 10% cost is estimated for operators with the lowest surety industry risk ratings.

(v) Self funded FA cost is equal to the payment made to a lender (on a range of 6% to 25% rate of return for the lender) over an estimated 25 year life cycle for FA. Large, publicly traded E&P companies who are financially stable may face a 6% cost of capital, while a small operator with tight cost margins and volatile revenue may face a 25% cost of capital.

Rule 704 – Surface Owner Protection Bonds

Staff moved prior Rule 703, which governs surface owner protection bonds and implements a specific provision of the Act, C.R.S. § 34-60-106(3.5), to Rule 704. Many of the revisions to the rule were non-substantive, providing substructure and clarifying important procedural details. Staff determined that the amount of financial assurance required by Rule 704.a continues to be a "reasonable security" within the meaning of the Act. C.R.S. § 34-60-106(3.5). Furthermore, Staff more clearly articulated the procedures for a surface owner to access a surface owner protection bond and explained the situations in which a surface owner protection bond would be released.

- **Impacts on Industry and the Community**

($ Cost) Staff anticipates that Rule 704 will result in costs to industry. Rule 704 now enables surface owners to request a financial assurance hearing if the surface owner cannot remediate crop loss or other land damage caused by oil and gas operations. As shown in **Table 6** (above), Staff estimates that one (1) such hearing will take place each year at cost of $1,500 to industry. The industry cost assumes its staff, at a $150 per hour rate, must work for 10 hours to file the hearing application and staff the hearing.

- **Impacts on State Government**

(FTE Cost) Staff assumes that surface owner requests for a financial assurance hearing will have a State Government workload cost. As shown in **Table 6** (above), Staff estimates that one (1) such hearing will take place each year at a cost of 0.001 FTE. This cost assumes an average of three (3) hours to prepare for and staff each hearing.

Rule 705 – Insurance

The Commission expanded upon its prior insurance requirements in Rule 705, adding a new requirement that operators maintain environmental liability insurance. Staff moved prior Rule 708, governing general liability insurance, to Rule 705.a and made additional clarifying edits to improve transparency on operators' insurance coverage. The Commission adopted a new Rule 705.b, governing environmental liability insurance based on the recognition that a critical part of SB 19-181's mandate that the Commission "require every operator to provide assurance that it is financially capable of fulfilling every obligation imposed by [the Act and the Commission's Rules]" is to ensure that operators are financially capable of fulfilling all their remediation obligations pursuant to the Act and the Commission's 900-Series Rules.

- **Impacts on Industry and the Community**

($ Cost) Staff estimates there will be various costs to industry associated with Rule 705. First, Rule 705 requires operators to obtain environmental liability insurance in the minimum amount of $5,000,000 per occurrence. Staff determined that the best approach to address financial assurance for remediation is to require operators to maintain sufficient environmental liability insurance coverage to address the vast majority of remediation projects that an operator must complete. The principal advantage of an insurance-based approach is that it provides financial certainty that funds will be available to address remediation issues as they arise, without requiring a complex administrative system that must be overseen by Staff to determine appropriate financial assurance for remediation projects on a case-by-case-basis. Moreover, when operators orphan their oil and gas wells, locations, and facilities so that they become liabilities to the state of Colorado, a significant amount of the costs borne by the OWP relate to remediation. While not every orphaned site has contamination that requires remediation, when sites do require remediation the costs of those remediation activities can often dominate the overall costs of plugging, abandoning, and reclaiming the orphaned site.

While requiring financial assurance for remediation is important, it also poses unique challenges because of its uncertain nature. Some oil and gas wells, locations, and facilities never have spills or releases that must be remediated. And even when spills and releases do occur, they vary widely in scope, nature, and volume. Remediation costs therefore vary widely. Accordingly, Staff does not have sufficient data on insurance pricing and current operator insurance levels to estimate the exact monetary impact.

Rule 705 also adds insurance coverage data to what operators must submit on the Forms 1 and 19, and both forms must be revised. Staff estimates that 485 operators will review Form 1 guidance provided by the State at an average cost of $600 per operator, or $291,000 in added one-time expense. That expense captures four (4) hours of staff time at a cost of $150 per hour.

Staff estimates there will be 70 new operators who submit a revised Form 1 each year. The cost impact for industry will be $5,250 per year, an ongoing expense resulting from 30 minutes of added staff time for each form at a $150 per hour rate.

Staff estimates that 485 operators will review Form 19 guidance provided by the State at an average cost of $300 per operator, or $145,500 in added one-time expense. That expense captures two (2) hours of staff time at a cost of $150 per hour.

Staff further expects that operators will submit an average of 850 Form 19s each year. The cost impact for industry will be $63,750 per year, an ongoing expense resulting from 30 minutes of added staff time for each form at a $150 per hour rate.

- **Impacts on State Government**

(FTE Cost) Staff anticipates that development and use of a revised Form 1, as required by Rule 705, will increase State workload by the following amounts and types:

- 60 hours to develop the revised form, or 0.029 one-time FTE;
- 16 hours to engineer data tools for the revised form, or 0.008 one-time FTE;
- 32 hours to develop guidance and offer operator training, or 0.015 one-time FTE; and
- 10 minutes to review each of 70 forms each year, or 0.006 ongoing FTE.

Staff anticipates that development and use of a revised Form 19, as required by Rule 705, will increase State workload by the following amounts and types:

- 24 hours to develop the revised form, or 0.012 one-time FTE;
- 4 hours to engineer data tools for the revised form, or 0.002 one-time FTE;
- 8 hours to develop guidance and offer operator training, or 0.004 one-time FTE; and
- 45 minutes to review each of 850 forms each year, or 0.306 ongoing FTE.

<u>**Rule 706 – Release or Claim of Financial Assurance**</u>

The Commission consolidated its prior Rules pertaining to the termination of financial assurance —either through release or access—into Rule 706. The Commission moved prior Rule 709, which specified procedures for release of financial assurance, to Rule 706.a, and also added details to improve transparency and clarity. The Commission also moved the procedures and processes for accessing an operator's financial assurance from prior Rule 709 to Rule 706.b.

- **Impacts on Industry and the Community**

($ Cost) The Analysis determined in the section for Rule 702 (above) that wells (and the sites associated with them) are orphaned each year at a rate of 0.0953 percent of all active wells in the state. This rate suggests a yearly average of 50 orphaned wells and one to two operators associated with those wells each year. It is plausible that some portion of these outcomes (less than 100 percent) could be exacerbated by the Financial Assurance Rulemaking in future years.

In these events, the burden of closing those sites then falls to the State Government, and Rule 706 governs the claiming of any available financial assurance associated with those sites. The operator who exits the marketplace, either by relinquishing their assets to the OWP following a request for revocation of the operator's certificate of clearance, or after filing for bankruptcy, will realize certain costs and benefits in doing so. The costs include loss of production value net of operating expenses, if any, from the wells, and the administrative and legal costs of business default or reorganization. The benefits include the transfer of liabilities for site closure to the State Government, or financial gains realized by another operator who purchases any of the assets from the insolvent operator.

Staff does not have sufficient data to estimate the size of any positive cash flow or asset value lost to operators of orphaned wells (a rulemaking cost to industry), compared to the size of gains from the financial liabilities transferred to the OWP (a rulemaking benefit to industry) or sales of assets sold to other operators.

Rule 706 provides for the Director to request a hearing if the conditions for claiming an operator's financial assurance are met. As shown in **Table 6** (above), Staff estimates that two (2) such hearings will take place each year at cost of $3,000 to industry. The industry cost assumes its staff, at a $150 per hour rate, must work for 10 hours to file the hearing application and staff the hearing.

(Qualitative) Staff assumes that Rule 706 and the Financial Assurance Rulemaking in general will produce benefits for the community that cannot be quantified in most instances. These benefits include community enjoyment of reduced timeframes for closure of oil and gas sites that would otherwise be orphaned, as operators are strongly incentivized to satisfy all site closure obligations and reduce their ongoing financial assurance expenses by having the State release their bonds and CDs and return their cash deposits. The public will notice more reclaimed and remediated landscapes, and public records will verify that operators themselves plugged the wells at those sites in accordance with State rules, which will increase public trust in industry operations.

There will likely also be public health, safety, and environmental benefits from earlier closure of various types of inactive, temporarily abandoned, or marginally producing wells. The benefits to the community of reclaimed and remediated landscapes, in addition to safely plugged wells, also occur for these types of wells. These benefits will be both short- and long-term.

- **Impacts on State Government**

(FTE Cost) Staff anticipates that Director initiated hearings for the purpose of claiming financial assurance will have a State Government workload cost. As shown in **Table 6** (above), Staff estimates that two (2) such hearings will take place each year at a cost of 0.003 FTE. This cost assumes an average of three (3) hours to prepare for and staff each hearing.

Rule 707 – Review of Financial Assurance

Rule 707 creates the framework to govern periodic and annual review of financial assurance. Rule 707.a requires the Director to conduct an annual review of an operator's financial assurance, which should include a consideration whether to adjust an operator's financial assurance for inflation, a review of the operator's insurance coverage, and whether the operator's environmental liability insurance is sufficient to address the operator's remediation obligations pursuant to the Commission's 900-Series Rules. The Commission intends for the Director to review each operator's financial assurance at least once every fiscal year beginning one year from the date operators must submit their initial FA Plans. Rule 707 also provides a process by which the Director may request additional financial assurance based on the annual review and the opportunity for an operator to seek a hearing before the Commission if it disagrees with the Director's determination.

Consistent with SB 19-181 transitioning to a full-time Commission, the Commission determined that it was appropriate to increase its level of oversight over financial assurance, given its additional capacity. *See* C.R.S. § 34-60-104.3. As a result, Rule 707.b establishes two possibilities for Commission oversight of financial assurance. First, Rule 707.b provides a default requirement for a Commission oversight hearing as part of the annual review of any operator with more than 75% low producing wells or 50% inactive wells, as well as an ability for the Commission to initiate such hearings on its own motion. The Commission determined that both low producing wells and inactive wells pose additional risks to the State, because such wells generate less revenue in relation to their operational costs than higher producing wells. The Commission therefore determined that additional oversight of such operators' financial assurance is necessary and will both reduce potential risks to the State and also allow the Commissioners to work with operators on achieving the goals of their FA Plans. In addition to its annual oversight of higher-risk operators, the Commission included new procedures for financial assurance hearings commenced on its own motion. The Commission's choice to commence a hearing will be based on the individual judgment and experiences of each Commissioner. Accordingly, the evidence or information required for such hearing may vary and could include evidence relevant to the operator's financial situation, the production status and volume of the operator's wells, and whether the operator's current financial assurance is sufficient. In accordance with the Commission's notice procedures, operators would receive notice of what evidence or information the Commission seeks at its particular hearing.

- **Impacts on Industry and the Community**

($ Cost) Staff anticipates that Rule 707 will result in costs to industry. Rule 707 sets forth financial assurance hearing requirements as a result of Director or Commission oversight. As a result of either the Director or Commission pursuing a financial assurance hearing, the operator is required to provide certain information into the e-filing docket for the hearing that addresses its future plans for its inactive wells, a demonstration of its financial capacity to plug, abandon, and reclaim its inactive and low-producing wells, and any other information that Staff or the Commission deem to be relevant. Other information might include evidence relevant to the operator's financial situation, the production status and volume of the operator's wells, and whether the operator's current financial assurance is sufficient. As shown in **Table 6** (above), Staff estimates that five (5) such hearings will take place each year at cost of $7,500 to industry. The industry cost assumes its staff, at a $150 per hour rate, must work for 10 hours to file the hearing application and staff the hearing.

- **Impacts on State Government**

(FTE Cost) Staff assumes that Director or Commission initiated financial assurance hearings pursuant to Rule 707 will have a State Government workload cost. As shown in **Table 6** (above), Staff estimates that five (5) such hearings will take place each year at a cost of 0.007 FTE. This cost assumes an average of three (3) hours to prepare for and staff each hearing.

Rule 912 – Spills and Releases

Consistent with its approach to addressing financial assurance for remediation through environmental liability insurance in Rule 705.b, Staff adopted a new Rule 912.b.(6).C requiring operators to demonstrate that they carry sufficient environmental liability insurance when submitting either a Form 19, Spill/Release Report – Supplemental or Form 27, Site Investigation & Remediation Workplan to close a spill pursuant to Rule 912.b.(6). This will enable Staff to verify that the operator is financially capable of conducting all required remediation activities at the key juncture of reviewing the operator's plans for long-term remediation of a spill or release.

- **Impacts on Industry and the Community**

To comply with Rule 912, operators may need to purchase an environmental liability insurance policy for the first time or purchase higher coverage amounts of environmental liability insurance. This requirement is also listed in Rules 705 and 913. Staff does not have sufficient data on insurance pricing and current operator insurance levels to estimate the cost impact of these three rule changes.

Rule 912 also requires that insurance policy information be added by the operator to Form 19 submissions. This workload impact is included in the cost estimates provided for Rule 705.

- **Impacts on State Government**

The workload impact on State Government from Rule 912 is provided in Rule 705 under the Form 19 impact estimates.

Rule 913 – Site Investigation, Remediation, and Closure

Consistent with Rules 705.b and 912.b.(6), new Rule 913.e requires operators to identify whether their environmental liability insurance is adequate to cover the costs of all anticipated remediation activities on at least one of their quarterly supplemental Form 27 reports each year.

Staff determined that this annual reporting mechanism is necessary because the adequacy of environmental liability insurance may change over time, as remediation projects become more costly. Staff intends for the annual reports submitted with the Form 27 to inform its Environmental Unit Staff as to whether to require additional financial assurance during the annual review of an operator's financial assurance and in review of the Form 27.

The Commission also revised Rule 913.i to allow the Director to require an operator to provide additional FA to address the scope of required remediation activities based on Staff's review of the adequacy of the operator's environmental liability insurance pursuant to Rule 913.e. As with other discretionary financial assurance determinations, operators may seek Commission review of the Director's determination. The Commission also included a provisions specifying the conditions of release of such financial assurance.

- **Impacts on Industry and the Community**

($ Cost) Rule 913 allows the Director to require an operator to provide additional financial assurance as a condition of approval of the Form 27, and an operator may ask for a hearing in response. As shown in **Table 6** (above), Staff estimates that one (1) such hearing will take place each year at cost of $1,500 to industry. The industry cost assumes its staff, at a $150 per hour rate, must work for 10 hours to file the hearing application and staff the hearing.

Rule 913 also requires operators to provide additional information about insurance and deposited financial assurance in quarterly reports submitted through the Form 27 process. Staff estimates that 485 operators will review Form 27 guidance provided by the State at an average cost of $300 per operator, or $145,500 in added one-time expense. That expense captures two (2) hours of staff time at a cost of $150 per hour.

Staff estimates that 2,434 Form 27s will be submitted each year on new and continuing remediation projects. The cost impact for industry will be $182,550 per year, an ongoing expense resulting from 30 minutes of added staff time for each form at a $150 per hour rate.

- **Impacts on State Government**

(FTE Cost) Operator requests for a hearing pursuant to Rule 913 will have a State Government workload cost. As shown in **Table 6** (above), Staff estimates that one (1) such hearing will take place each year at a cost of 0.001 FTE. This cost assumes an average of three (3) hours to prepare for and staff each hearing

Staff anticipates that development and use of a revised Form 27, as required by Rule 913, will increase State workload by the following amounts and types:

- 24 hours to develop the revised form, or 0.012 one-time FTE;
- 4 hours to engineer data tools for the revised form, or 0.002 one-time FTE;
- 8 hours to develop guidance and offer operator training, or 0.004 one-time FTE; and
- 45 minutes to review each of 2,434 forms each year, or 0.878 ongoing FTE.

RULES FOR WHICH NO COSTS OR BENEFITS ARE IMPLICATED

Of the rules in the 200-, 300-, 400-, 500-, 700-, 800-, and 900-Series and related 100-Series Definitions included as part of the Financial Assurance Rulemaking, all were new, amended, or renumbered. However, Staff proposed amendments to eight rules that had no quantifiable or qualitative cost or benefit. These rules were created or amended to: comport with statutory requirements; to streamline processes; or to make other non-substantive edits. Accordingly, no measurable costs or benefits to any relevant party, either qualitative or quantitative, were determined to be present. For further explanation of these rules, refer to the Statement of Basis and Purpose.

- **Rule 211** – Plugging and Abandonment of Wells and Closure of Oil and Gas Facilities and Locations
- **Rule 217** – Form 8, Oil and Gas Conservation Levy
- **Rule 223** – Confidential Information
- **Rule 304** – Form 2A, Oil and Gas Location Assessment Application
- **Rule 413** – Form 7, Operator’s Monthly Report of Operations
- **Rule 436** – Seismic Operations, Notice, Consultation and Reporting
- **Rule 810** – Commercial Disposal Wells and Facilities
- **Rule 907** – Centralized E&P Waste Management Facilities

TWO ALTERNATIVES CONSIDERED TO THE FINANCIAL ASSURANCE RULES

Staff considered a "no action" alternative to **Rule 205.c – Form 1B, Annual Well Registration**, instead continuing to rely on the current funding mechanism of the Orphaned Well Program. Maintaining the status quo would provide a cost-savings to industry, as operators would not be required to submit the annual well registration fee, and the costs of addressing orphaned sites would be funded by industry through the mill levy. However, a "no action" approach would not be beneficial in the long run, as the sole purpose of the new annual well registration fee is to more transparently address the liabilities presented to the state of Colorado by orphaned sites. Staff determined that Rule 205.c, as proposed, reflects an appropriate balance of public health, safety, welfare, and environmental benefits with economic costs to the industry.

Staff also considered not including the **Form 6A – Plugging List in Rule 434.c**. Instead of providing the option to have the Director designate a well as out of service and add it to the operator's plugging list, Staff contemplated providing only three options for inactive wells: plugging and abandonment within six months, bring the well back into production, or "bonding up." In the course of evaluating this alternative, Staff determined it was appropriate to provide operators with the flexibility to determine an appropriate path to address inactive wells based on their individual business models. The plugging list option likely results in lower costs to comply, as operators are given a three-year time period to plug and abandon wells designated as out of service, while still providing a level of protection to the state of Colorado from the risks posed by operators orphaning inactive wells. Moreover, it assists COGCC planning for future operations in the state by better understanding plugging plans.

Based on Staff's review of evidence in the administrative record, out of service wells that have not been plugged and abandoned pose potential safety hazards and threats to environmental quality. Therefore, Staff determined that it was appropriate to offer a creative solution to encourage operators to timely plug and abandon out of service wells. This approach is consistent with the requirements of SB 19-181 to mitigate adverse impacts to public health, safety, welfare, the environment, and wildlife resources.