COLORADO
Energy & Carbon Managemen
Commission
Department of Natural Resources

Orphaned Well Program FAQ

Introduction: The Energy & Carbon Management Commission (ECMC) is committed to regulating oil and gas development and production in a manner that is protective of public health, safety, welfare, wildlife and the environment.

By the Numbers

As of February 27, 2024:

- Orphaned Sites with work planned or in progress: 1,410
- Remaining Wells to Plug on those Sites: 649
- Updated Backlog numbers and charts with backlogs by fiscal year are available on the Orphaned Well Program Backlog.
- FY 23-24 Funding Sources for project work:
  - $ 424,580 expended through January from Bond Claims, which are summarized in Annual Reports on Table 2.
  - $ 1,877,638 expended through January from the Orphaned Well Mitigation Enterprise Fund, a continuous appropriation. To learn more, click here.
  - $ 3,848,632 budgeted from the Orphaned Well state legislative appropriation
  - $13,874,756 budgeted from the contractual portion of the federal Infrastructure Investment & Jobs Act Initial Grant
  - $ 1,111,518 budgeted from the contractual portion of a federal agreement with the Bureau of Land Management

Program Directives

ECMC's Orphaned Well Program identifies, prioritizes, and addresses oil and gas wells, locations, and production facilities statewide for which there are no known responsible parties ("Orphaned Wells or Sites") or for which financial assurance instruments have been claimed. If not addressed, these oil and gas locations may impair a surface owner's farming or ranching activity or other use of the property, harm wildlife, pose risks to the environment, or present a safety hazard to the public.

Annual Reports: Commission Rule 205.c.(6) requires that no later than September 1, 2022, and on or before September 1 each year thereafter, the Director will report the following information to the Commission:

A. The progress on plugging, Remediation, and Reclamation of Orphaned Wells and Sites as of the end of the previous Fiscal Year on June 30;

B. The total number of Orphaned Wells and Sites that are not plugged or closed;

C. Total funding received during the previous Fiscal Year; and

D. Total amount spent during the previous Fiscal Year.

An Orphaned Site list is provided in the Annual Reports as Table 4. Sites are ranked as low-, medium-, or high-priority.

Below are frequently asked questions received by the Orphaned Well Program, including questions related to ECMC's resources, budget, definitions, and processes.

1. **When did the ECMC start the Orphaned Well Program?**
    - The legislature first authorized a budget appropriation to plug and abandon historic oil and gas wells with no available financial assurance in the 1990 Legislative Session.
    - The program allows ECMC to plug wells; remove production equipment and debris; investigate and remediate soil and groundwater impacts; install safety equipment such as fences, signs, and locks or tags; and reclaim well pads, remote production sites, and access roads.

2. **How many ECMC staff work on this program? (FTE) and where are they located?**
    - FY 18-19, 4.0 FTE
    - FY 19-20, 5.4 FTE
    - FY 20-21, 5.2 FTE
    - FY 21-22, 5.8 FTE
    - FY 22-23, 11.7 FTE
    - FY 23-24, 13.2 FTE planned with a new hire expected in Spring 2024
    - Staff serve projects statewide
    - Not included but an integral part of the program: ongoing support from ECMC Finance staff, Department of Natural Resources (DNR) procurement and accounting staff, and DNR staff assigned to federal grant support

3. **How many orphaned wells and sites are there?**
    - The Orphaned Well Program Website provides information on orphaned wells and sites. The "Backlog" Page displays the current OWP Backlog, and the "Reports" Page provides links to Orphaned Well Program Annual Lists and Reports.

4. **How does the Orphaned Well Program keep up with new orphaned wells and sites?**
    - The Commission created and developed an Orphaned Well Program, which has a process for prioritizing work. As the number of orphaned wells or sites grows or shrinks, ECMC will respond accordingly.

5. **What happens to the wells of an operator that goes bankrupt?**
    - The wells may be bought or the operator's debt restructured in the course of the bankruptcy. Any purchaser or the reorganized operator must comply with the Commission's rules for operating a well. That includes continuing the maintenance and safety measures necessary to maintain a shut-in or temporarily abandoned well.
    - If an operator is unable to find a buyer for a well and is unable to continue to pay for the operation of the well (whether through a bankruptcy process or for

any other reason), that well will become a part of the ECMC's Orphaned Well Program. The Orphaned Well Program oversees the wells to ensure that they pose no threat to public health, safety, welfare, wildlife, and the environment, until the wells are plugged and abandoned.

6. **How much does it cost to plug a well and reclaim a site?**
    - For the 2021 Financial Assurance Rulemaking, The Orphaned Well Program estimated an average cost for closing a site with a well:
        - Average of $92,710 (plug the well, remove equipment, perform environmental remediation, and reclaim the site). This includes an average cost of $52,141 to plug the well. Click here for more details.

Orphaned Well Program Funding:

7. **Where does this money come from?**

    For funds from the State budget appropriation, expenditures are funded by oil and gas operators through financial assurance, a levy on oil and gas production, and penalty revenue paid by oil and gas operators. The State budget appropriation **does not** receive revenue from personal or corporate state income tax (i.e., General Fund).

    In 2022, the program received Federal Infrastructure Investment & Jobs Act Initial Grant: $25 Million for Oct. 1, 2022 - Sept. 30, 2024. After the Initial Grant expires, the Act authorizes Formula Grants and Performance Grants. For all Federal Infrastructure Investment & Jobs Act grants, click here for more information.

    In 2023, ECMC entered into an agreement with the Bureau of Land Management to perform work on federally-orphan wells.

    All funding for the Orphaned Well Mitigation Enterprise Fund is separate from the above. To learn more on the Enterprise fund, click here.

8. **How does industry participate?**

    Industry helps the Orphaned Well Program by participating in Public Projects and voluntary projects whereby the operator plugs wells or performs other work at orphaned sites, reducing costs that the Orphaned Well Program would otherwise occur for the work.

9. **What is the bond that is carried and does this cover the expense of restoring an Oil and Gas Location?**
    - ECMC adopted new Financial Assurance Rules in March 2022. The Financial Assurance Press Release and Fact Sheet are found in the ECMC Media section.
    - For more information, visit the Financial Assurance webpage.

10. **What is the typical process from identification of a new orphaned site through closure?**

    Below is an overview of the **Orphaned Well Program** process:

    The ECMC will receive a referral about a possible orphaned well site from a complaint; external agency; internal file review; or ECMC field inspection. Other ECMC work units determine applicability, checking to see if the site is already listed with the program or if there is an active oil and gas operator responsible for the work. ECMC Staff also check for any available financial assurance, and if any financial assurance exists, ECMC will commence a bond claim. If there is NOT an oil and gas operator responsible for an identified well, the site is then registered into the ECMC Orphaned Well Program through a Commission order.

    The OWP team will analyze the site using available file data, field inspection reports, photographs, and topographic maps to score the site for prioritization into low, medium and high rankings, considering multiple risk factors:

    - population density and urbanization;
    - environmental factors;
    - years in service;
    - active spills;
    - stormwater issues;
    - noxious weeds;
    - wildlife, livestock, or vegetation impacts;
    - surface equipment;
    - bradenhead pressure;
    - mechanical integrity test data; and
    - any documented history of venting or leaking.

    When selecting sites to include in a field project, the OWP team considers the site rank along with other factors, such as the proximity of multiple sites that are close to each other to reduce expenses, or the location of sites in Disproportionately Impacted Communities, and the availability of ECMC field staff to manage the project.

    Next, the OWP team defines the general scope of work for the site which may include:

    - Field Operations (signs, labels, locks, tags, fencing, fluid removal from production equipment, and equipment decommissioning including removal, disposal, or salvage);
    - Engineering (plug wells and abandon flowlines);
    - Environmental (sampling, analysis, and remediation); and
    - Reclamation (contouring, grading, seeding, and weed control).

    The OWP team also identifies relevant field inspection reports, photographs, and surface and mineral ownership.

    The OWP team works within the state procurement system to issue awards. The work is then scheduled and executed. The OWP team verifies the completed work with the contractor and the surface owner, and the team identifies follow-up monitoring activities, if any, for the site.

11. **What are the definitions of the key terms used in this document?**
    - The word "Abandonment" refers to the proper plugging, removal, or closure of a well, facility, location, or site in compliance with ECMC's rules.
    - Abandonment may be temporary or permanent, as described below in the definitions for a "Temporarily Abandoned Well" and [Permanently] "Plugging and Abandoning"
    - The words "Well", "Orphaned Well", "Well Site", "Orphaned Site", "Reclamation", and "Remediation" are defined below.
    - A "Site" is the physical location on the ground surface of a "Well" or other oil or gas Production Facility.
    - CAUTION: "abandoned location" is a term used on Form 4, Sundry Notice, and it is a valid location status in COGIS (code "AL"). An abandoned location is neither an Orphaned Site or nor is it an Orphaned Well. It is a location that an Operator permitted, but they did not construct. Abandoned location is not defined in ECMC's rules.

From the Colorado Energy & Carbon Management Commission's 100-Series Rules:

FLOWLINE means a segment of pipe transferring oil, gas, or condensate between a wellhead and processing equipment to the load point or point of delivery to a U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration or Colorado Public Utilities Commission regulated gathering line or a segment of pipe transferring produced water between a wellhead and the point of disposal, discharge, or loading. This definition of flowline does not include a gathering line… [The 100 Series Definition also lists several types of flowlines, which are omitted here for brevity]

ORPHANED WELL means a Well for which no Owner or Operator can be found, or where such Owner or Operator is unwilling or unable to Plug and Abandon such Well.

ORPHANED SITE means an Oil and Gas Location or Oil and Gas Facility for which no Operator with unclaimed Financial Assurance or an active Form 1, Registration for Oil and Gas Operations exists, and for which the Commission has not identified a Responsible Party. An Orphaned Site may or may not have Orphaned Well(s) associated with the Oil and Gas Location or Oil and Gas Facility.

PLUGGING AND ABANDONMENT means the permanent plugging of a Well, the removal of its associated Production Facilities, and the abandonment of its Flowline(s).

PRODUCTION FACILITY means any storage, separation, treating, dehydration, artificial lift, power supply, compression, pumping, metering, monitoring, flowline, and other equipment directly associated with a well.

RECLAMATION means the process of returning or restoring the surface of disturbed land to its condition prior to the commencement of Oil and Gas Operations.

REMEDIATION means the process of reducing the concentration of a contaminant or contaminants in water or soil to the extent necessary to ensure compliance with the concentration levels in Table 915-1 and other applicable Groundwater standards and classifications.

RESPONSIBLE PARTY shall mean an owner or operator who conducts an oil and gas operation in a manner which is in contravention of any then-applicable provision of the Act, or of any rule, regulation, or order of the Commission, or of any permit, that threatens to cause, or actually causes, a significant adverse environmental impact to any air, water, soil, or biological resource. RESPONSIBLE PARTY includes any person who disposes of any other waste by mixing it with exploration and production waste so as to threaten to cause, or actually cause, a significant adverse environmental impact to any air, water, soil, or biological resource.

TEMPORARILY ABANDONED WELL means:
A. Well that is neither currently producing nor permanently plugged, but has all downhole completed intervals isolated with a plug set above the highest perforation such that the Well cannot produce without removing a plug.
B. A Well which is incapable of production or injection without a downhole intervention or the addition of one or more pieces of wellhead or other equipment, including, but not limited to, valves, tubing, rods, pumps, heater-treaters, separators, dehydrators, compressors, piping, or Tanks.

WELL means an oil or gas Well, a hole drilled for the purpose of producing oil or gas (including nonhydrocarbon gases such as carbon dioxide and helium), a Class II UIC Well, a Stratigraphic Well, a Gas Storage Well, or a Well used for the purpose of monitoring or observing a reservoir.

WELL SITE shall mean the areas that are directly disturbed during the drilling and subsequent operation of, or affected by production facilities directly associated with, any oil well, gas well, or injection well and its associated well pad.

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Rocky Mountain Highs and Lows

Decommissioning Colorado's Two Oil Industries

Dwayne Purvis

Carbon Tracker Initiative

Analyst Report | June 2024

About Carbon Tracker

The Carbon Tracker Initiative is a team of financial specialists making climate risk real in today's capital markets. Our research to date on unburnable carbon and stranded assets has started a new debate on how to align the financial system in the transition to a low carbon economy.

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Rob is Executive Director of Carbon Tracker's North American office. Rob leads Carbon Tracker's outreach and data provision to the Climate Action 100+ Initiative, as well as its work with securities market regulators and accounting standard setters around the globe. He has authored several papers on how climate-related risks are likely to impact financial reporting and the role that securities markets regulators can play. He has also published on the intersection of environmental obligations and bankruptcy law.

Prior to joining Carbon Tracker in 2014, Rob was an assistant attorney general with the New York State Office of the Attorney General and, prior to that, a litigator in the New York City offices of Paul, Weiss, Rifkind, Wharton & Garrison LLP. He is a graduate of The Yale Law School.

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1 Key Findings

- The current cost to decommission nearly 48,000 unplugged oil and gas wells and related facilities in the state of Colorado is estimated to be $6.8 to $8.5 billion, not including the remaining cost of surface reclamation for thousands of other wells.
- Recent bonding reforms do not protect against the fiscal liability falling to the state's taxpayers. In a best-case scenario, all forms of financial assurance—plus state and federal funding for orphan wells—amount to only about $654 million over the next five years, even as the population of orphan wells is set to increase dramatically.
- Production from the state peaked five years ago. The recent renaissance includes many wells and higher production rates but is isolated to a fraction of one producing basin. The remainder of the state, including eight other basins, has continued the systematic, legacy decline of low-producing wells.
- Drilling and new production located east and north of Denver is dominated by the only three public oil companies still active in the state. Legacy areas are dominated by companies with concentrated portfolios of systematically low-producing wells.
- Though there are a large number of oil companies in the state, ownership is concentrated in a small number of companies, mostly large and private. Of 375 oil companies, the bottom 80% account for 3.3% of wells and 1.6% of production, including 86 oil companies with no active production to fund the decommissioning of their wells. The top 10% of companies account for 93% of wells and 95% of production, they are almost exclusively private companies with hundreds or thousands of wells.
- Despite low production and many idle wells, operators of legacy areas plug only about 0.4% of their wells each year. If this pace were held constant, these companies would spread out the cost of decommissioning over about 250 years.
- Legacy areas range across 30 counties and include more than 27,000 wells, 57% of the statewide total. In these areas, we estimate a decommissioning cost of $4.0 to $5.0 billion but only about $1 billion of remaining cash flow. It is unreasonable to expect or hope that future production can pay for asset retirement, even if every future dollar of projected profit were dedicated to decommissioning.
- Previous policy reform took many years and ultimately failed, leaving the state's legacy areas more depleted and owned by smaller companies. Taking this history into account, the state will require new and still undefined concepts of policy—implemented quickly—to protect Colorado and its citizens. The solution must be tailored to the present reality if the state wishes to manage the near-zero-sum issue of whether the industry pays for its clean-up or whether the public does.

2 Executive Summary

In 2018, Colorado became one of the first US states to recognize the insufficient financial assurance that oil companies would plug, remove, and remediate tens of thousands of aging wells. Nearly six years after the issuance of an executive order and statutory mandate to ensure that oil and gas companies can afford to decommission their wells and sites in Colorado, it is clear that the revised system for financial assurance has not materially increased the total financial assurance in the state. Meanwhile, drilling continues in only one region, but production in legacy regions continues their long decline.

The need for additional assurance that oil companies will not leave the task to taxpayers is both urgent and complex. For most areas of the state—particularly in its mountainous parts—the estimated decommissioning liability exceeds the estimated future cash flow from operations available to pay for decommissioning. In another area, those future profits do exceed current estimates of end-of-life costs, but our work shows that the inversion will occur within a few years. For these areas starting now or in a few years, every dollar of profit from oil and gas operations distributed to owners will be a dollar less that operators have to fulfill their decommissioning obligations, yet the pace of voluntary decommissioning remains trivial. Despite years of hard and diligent effort by regulators, we find that the reform has not accomplished its intention. Thus, minimizing the costs to taxpayers requires quick and comprehensive action by the state.

Understanding the need and designing a solution requires the four scopes of our analysis: (1) the current population of oil companies and how those are likely to change in the future; (2) the amount of existing financial assurance; (3) an estimate of decommissioning costs, and (4) an estimate of expected future cash flows from production and new drilling.

The state has nearly 48,000 unplugged wells and over 30,000 plugged ones spread across nine unique sedimentary basins in every part of the state. Development of these basins has been layered as different areas proceeded at different times and in different ways. Production for most areas of the state crested years ago, but the latest wave of horizontal drilling drove the state to its all-time production peak only five years ago. This mismatch between old and young gives the mistaken headline impression that the industry statewide remains robust.

The oil industry in Colorado is strongly split in two dimensions: size of company and types of assets they focus on. Only three significant public companies remain in the state, and all three have off-loaded legacy assets to focus on the horizontal drilling boom in the Denver-Julesburg basin. These companies have large cash flow from more diversified portfolios, and they are actively plugging wells (though not necessarily completing the required surface decommissioning) in order to replace them with horizontal wells.

Despite years of testing, the horizontal drilling and fracturing revolution did not find a foothold in most producing basins in the state. Wells in legacy basins are systematically idle and low-producing wells. There are many operating companies, but wells and production are concentrated in the hands of a modest number of companies with large portfolios of these old wells, often backed by private or private-equity investors. Despite the late stage of depletion, plugging in these areas has been proceeding slowly, with about 0.4% of wells plugged each year. If this pace held constant, the companies would spread out the cost of decommissioning over about 250 years. Of course, the costs will come due far sooner.

More to the point, the mostly public companies that own the high-producing wells are not the same companies that own the low-producing wells. So, absent of regulatory reform, cash flow from the former cannot be used to resolve the liabilities of the latter. In broad strokes, if the widespread legacy production does not guarantee their impending liability, then the costs will fall to taxpayers.

Colorado's recent financial assurance reform used conventional tools to motivate oil companies to decommission their non-productive fields or set aside the money to do so in the future. The reforms increased well site bonds, added the possibility of additional bonding at transfers, and enacted fees on the industry to fund the plugging of orphan wells. As we noted in our *False Start* report[1], the state may have less overall financial assurance today than it did in 2021. Whether characterized as multi-pronged or piecemeal, the loopholes between the policies are greater than their coverage, and the total protections for taxpayers in all forms will likely amount to only about $654 million by 2029 in a best-case scenario.

Little information exists in the public domain about the total cost of decommissioning secured by these bonds. Oil companies rarely and obliquely disclose these costs. Considering multiple lines of evidence, we find that statewide decommissioning costs will likely total $6.8 to $8.5 billion dollars if the individual well work were performed today. This total does not include thousands of wells for which decommissioning has begun but is not complete, and additional work on shared facilities may raise the total higher still. Thus, the planned-but-not-provided financial assurance over the next five years covers 7% to 9% of expected costs and leaves taxpayers exposed to billions in liabilities.

To analyze the ability of both low and high producers to fund decommissioning, we divided the state's production into over 50 more homogeneous groups of wells and applied traditional evaluation techniques. Primary inputs come from public data: extrapolation of historical production data and estimates of future sales prices from the futures market. Additional inputs, such as estimated operating costs, relied on experience and research.

Two major parts of the state and a couple of minor areas are currently able to fund their own decommissioning, but if full assurance is not provided now, they will eventually deplete into the same position as the rest of the state. Ongoing horizontal drilling will require first plugging thousands of additional wells drilled in the vicinity to the same formations. But it won't be all of them, and it is not yet clear how many.

We estimate that 27,000 wells—half of the total in the state—reside in groups or portfolios that will be unable to pay for their own decommissioning. They have little or no economic life remaining without substantial cuts from normal, sustainable operating costs. They may continue to operate, but they are likely falling into disrepair and are unlikely to make enough money in the future to change our conclusion that they cannot pay for their decommissioning.

[1] Gibson, Drew and Schuwerk, Rob. *Carbon Tracker Initiative* "False Start: How Colorado's Bonding Rules Reduce Coverage." (February 2024)
https://carbontracker.org/reports/false-start/

Given the substantial delay and deficiency of the first effort at reform, another round of policymaking must consider novel and muscular alternatives that can provide comprehensive coverage simply and quickly or else decide by omission to allow oil companies to conclude their business in the state and leave their mess behind for taxpayers to clean up. In the interim, depletion continues.

3 Introduction

In 2019 Colorado became one of the first jurisdictions in North America to foresee and act upon the need for increased financial assurance on the depleting base of oil and gas fields. First, its governor in 2018 required by executive order that the regulatory agency "promulgate rules to ensure the sufficiency of financial assurance."[2] The following year, the Legislature drove the point home with the force of statute: "The Commission shall require *every operator* to provide assurance that it is financially capable of fulfilling *every obligation* imposed by this article. . ."[3] (emphasis added)

After an extensive consultation process, the Colorado Oil and Gas Compact Commission (COGCC), as it was called then, finalized new rules in early 2022. The chairman of the agency praised their work as "the most robust in the country with by far the highest financial assurance requirements."[4] Another commissioner explained his confidence that the rules "fundamentally change how financial assurance for oil and gas activities in the State of Colorado are addressed."[5] The executive director of the Department of Natural Resources lauded that, together with other changes, they had created "the strongest protections and oversight of oil and gas development in the country."[6]

Now, nearly six years after the original executive order and two years after the final rules, the effects of the rulemaking can be measured. As we noted in our report *False Start*,[7] the results have fallen further short of than we predicted.[8] The years of effort failed to materially increase statewide oil and gas financial assurance. In fact, the work demonstrates that the first year of bonds under the new system provides marginally *less* assurance than the previous system.

This report places that financial assurance in the context of these liabilities and the value of ongoing production of the upstream oil and gas industry in Colorado. The quantum of decommissioning costs of any variety are rarely discussed publicly. Operating costs and other economic factors remain buried in company disclosures, but our research tracks multiple lines of evidence to triangulate reasonable estimates of both decommissioning costs and the cash flow available to pay them.

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[2] Executive Order D 2018-12 by Governor John Hickenlooper. https://drive.google.com/file/d/1CsgDIxo-AP1ZIH7rjaUptTCj1GIGq-Xw/view.

[3] Colorado Revised Statutes § 34-60-106(13) https://ecmc.state.co.us/documents/reg/Rules/LATEST/Appendix%20V%20-%20Oil%20&%20Gas%20Conservation%20Act%20Title%2034%20-%20Article%2060%20(Amended2023).pdf.

[4] Castle, Megan, *Colorado Oil and Gas Conservation Commission Press Release* "Colorado Oil & Gas Conservation Commission Votes Unanimously to Adopt SB 19-181 New Financial Assurance Rules." (March 1 2022) https://ecmc.state.co.us/documents/media/Press_Release_FA_Rulemaking_Adoption_20220301.pdf

[5] *Ibid.*

[6] *Ibid.*

[7] Gibson, Drew and Schuwerk, Rob. *Carbon Tracker Initiative* "False Start: How Colorado's Bonding Rules Reduce Coverage." (February 2024) https://carbontracker.org/reports/false-start/

[8] Greenslade, Stephen, *Carbon Tracker Initiative* "Feet to the Fire: An analysis of potential outcomes of the Colorado 700-Series Rulemaking." (September 2022) https://carbontracker.org/reports/feet-to-the-fire-an-analysis-of-potential-outcomes-of-the-colorado-700-series-rulemaking/

The tremendous growth of production from Colorado since the start of the shale revolution masks the fact that the large majority of wells, fields, and regions in the state have continued to decline. Horizontal drilling, however, is also past its peak, likely to decline significantly within the next handful of years. Ownership is split in the state; the companies that own and drill shale wells are not the companies who own the mature fields already sliding toward economic death.

Despite the clear mandates, hard work, and bold claims made about Colorado's financial assurance, our results suggest that more than half of the state's oil industry already bears liabilities far greater than the combination of bonds and all projected future cash flows from operations.

4 Colorado has two oil industries: young horizontal wells and old vertical wells

4.1 After generations of development, production peaked five years ago

Starting more than 100 years ago, Colorado has produced gas and oil from over 80,000 wells in nine sedimentary basins stretching to every corner of the state from mountains to plains. Much of the production has been natural gas, but oil dominates the largest single basin located north and east of Denver. The diversity creates a layered historical landscape, which nevertheless reduces to a handful of macroscopic dynamics over the last few decades when most of the development has occurred. Together, these megatrends set the stage and expectations for today's industry.

Production was established in all of the major basins of the state by the time the energy crises of the 1970s had ensconced energy security of oil and gas as a national priority. In the late 1970s and early 1980s, initial deregulation of natural gas prices created a short spike and subsequent crash, but robust federal subsidies created a sustained boom in the drilling of coalbed methane (CBM) and tight gas, the original "unconventional" reservoirs. These subsidies provoked extensive drilling and spiked production, particularly in the gassy basins on the southern side of the state. Technologies developed to capture the subsidies allowed development to continue with horizontal wells after the subsidies ended.

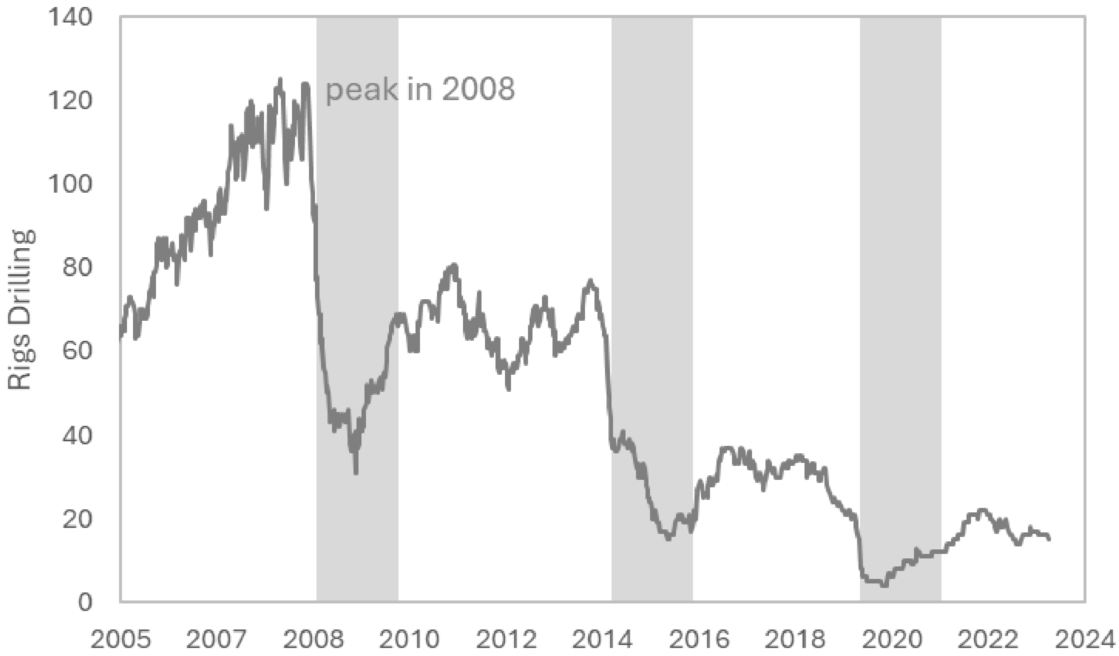
Gas drilling slid overall until market gas prices began to rise in the early 2000s, together with the application of newer hydraulic fracturing technology. As prices of both oil and gas rose by multiples to a crescendo in 2008, drilling also spiked to over 120 rigs running at once, an enormous leap from 10 rigs less than a decade prior. Production from gas basins hit its maximum just a couple of years later, as the shale revolution seized Colorado's oily Denver-Julesburg basin.

The shale revolution began expanding past the seminal Barnett Shale in the mid-2000s, and a storm of exploration over about 10 years tested the new fracturing technology on shale formations in practically every corner of the country, including a number of basins in Colorado. But as results came in, most formations proved uneconomic to develop. Companies high-graded their opportunities, and drilling concentrated in only a handful of basins with adequate financial returns. Horizontal drilling and hydraulic fracturing were attempted in a number of Colorado basins, but the results mostly did not justify development. Testing of the Niobrara formation north and east of Denver began in about 2009. Among tight formations in the state, it alone has proved economically viable.

Drilling and production in the Niobrara, as well as from older plays, ramped up in the early 2010s as the oil price hovered around all-time highs, but suffered a contraction when oil prices collapsed in 2015. After retrenching to reduce costs, focusing on the most productive rock, and engineering higher initial rates, production growth resumed in 2017. Then promptly peaked. The highest production of both oil and gas ever seen from the state of Colorado occurred in 2019, just months before COVID disrupted the industry across the country.

The rig count peaked in 2008 and has halved three times since, as shown in Figure 1. The rig count collapsed with each of the price collapses in 2008, 2015, and 2020. Each time it recovered to roughly half its previous figure. At the same time, the focus shifted from gas drilling, which dominated through the early 2010s. For the last eight years from 2016 to present, the state has averaged about four rigs drilling for gas compared to well over 100 at its peak.

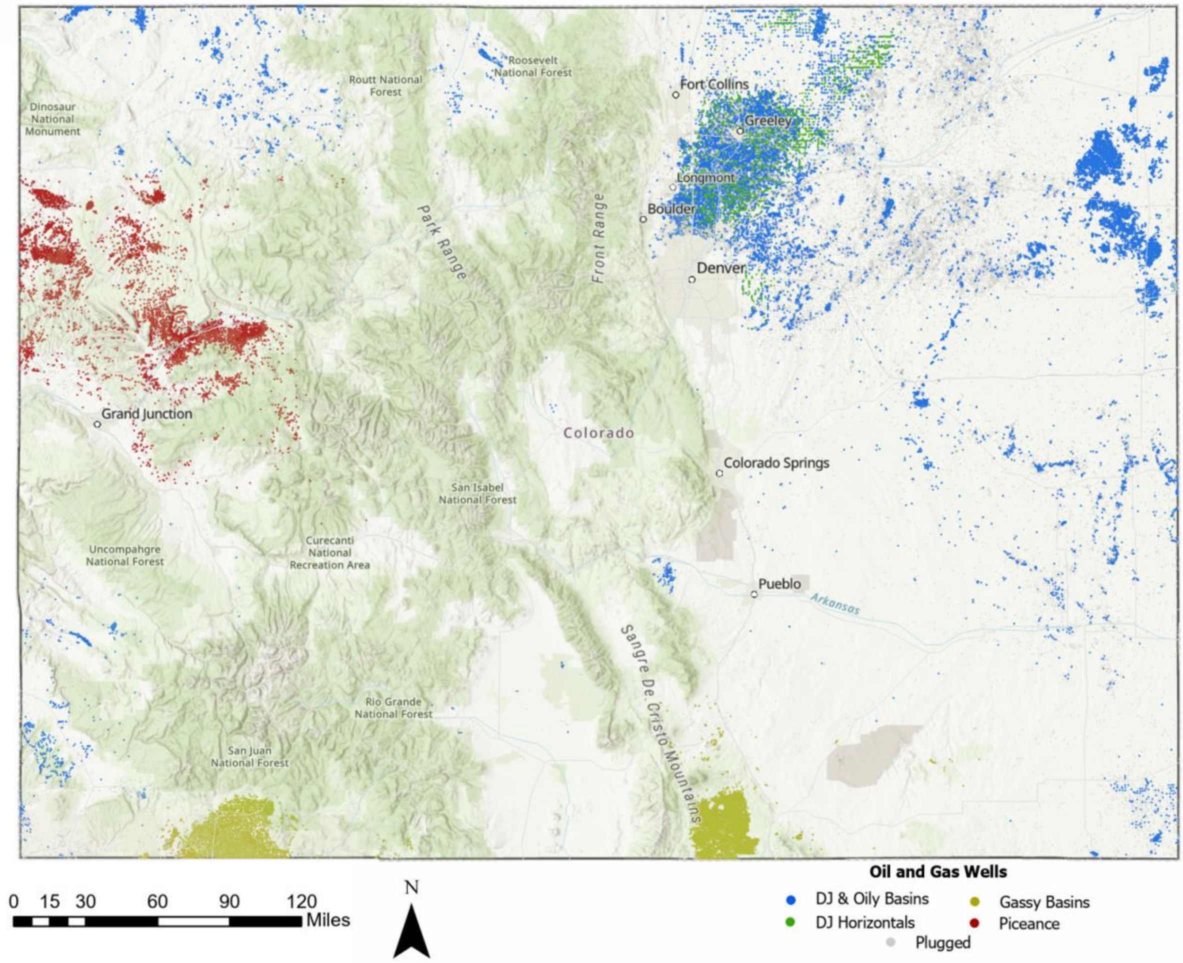
FIGURE 1: NUMBER OF DRILLING RIGS ACTIVE IN THE STATE OF COLORADO. (SOURCE: BAKER-HUGHES)



The pace of drilling has rebounded since COVID, and so has production from a small number of highly prolific wells. The state has averaged only 17 rigs since the start of 2023 including four for gas, enough to recover from the COVID dip and maintain overall production but not enough to approach the peak of 2019. What is more, analysis shows that the plans for future drilling are depleting quickly as available locations are drilled and as estimates of future recovery contract, as discussed below.

Unlike states like California, which is clearly long past its peak, and unlike Pennsylvania which is maintaining a steady pace of drilling and production from an outsized reserve base, Colorado seems to just recently have passed its overall peak production. Figure 2 shows the wells drilled at this point in the state, and Figure 3 in the next sections shows the production from those wells grouped at a high level to illustrate the history above.

FIGURE 2: MAP OF PLUGGED AND UNPLUGGED OIL AND GAS WELLS IN COLORADO COLORED BY PLUGGING STATUS AND SIMILARITY OF FLUIDS PRODUCED. (SOURCES ESRI, USGS, USFWS, FAO)



Conventional-style production from oily basins began early as in most states, chiefly the Denver-Julesburg. Then government subsidies, the resulting technology, and exceptionally high prices combined to unlock various gas resources at various times. The gassy unconventional basins on the south side of the state peaked next, dominated by the San Juan basin south of Durango. Next came the Piceance basin near the town of Grand Junction on the western slope. Finally, the venerable Denver-Julesburg basin was redeveloped with horizontal wells and modern hydraulic fracturing, overcoming the declines in other basins to achieve the state's all-time high production. Prior to the redevelopment, the basin had declined deeply. As drillers re-develop the same historical formations, they plug wells nearby in order to prevent hydraulic fracturing from breaching these older wells.[9]

Today nearly 48,000 unplugged wells remain in 40 counties, as drilling remains highly concentrated in just two areas. The drilling of vertical wells has practically ceased, though some directional wells have been drilled in the Piceance basin. Data from Baker Hughes shows that since at least 2011, more than 95% of drilling has targeted either the Denver-Julesburg or Piceance

[9] See also Rogers, Greg and Schuwerk, Rob. *Carbon Tracker Initiative* "They only fill when they drill: The economic motives behind plugging uneconomic wells." (July 2021), https://carbontracker.org/without-appropriate-bonding-incentives-taxpayers-may-be-forced-to-pay-billions-in-clean-up-costs/

basins. In most years, more than 80% of drilling was situated in just two counties: Weld and Garfield. The top five counties—adding Adams, Arapahoe, and Rio Blanco—account for more than 90% of drilling activity.

4.2 Production rates are pervasively low outside young horizontals

Figure 3 below traces the history of the basin more quantitatively, using the same divisions shown in the map above. Each of the three panels shows a different measure of the groups of basins, and vertical lines mark pivot points in the history. The first and second panels show gas production and oil production, and the third shows the number of actively producing wells. For decades, gas production dominated the state and grew slowly as technology and prices evolved. Except for the success of horizontal drilling in Denver-Julesburg basin and notwithstanding some additional development in the Piceance and gassy basins, production from the state began a pervasive decline by 2012 and has dropped more than 50% in the last 12 years.

Horizontal drilling for oil shown in blue has eclipsed all previous production despite the relatively small number of wells, as shown in the third panel. Slowdowns of horizontal drilling follow oil price collapses in 2015 and 2020, though production had already turned down in the months before COVID. Oil production in 2023 slightly exceeded that of 2022, but 2023 still fell 17% short of production in 2019. Gas production has not declined the same way largely because, as wells deplete, they produce a higher proportion of gas compared to oil.

FIGURE 3: HISTORICAL PRODUCTION FROM THE STATE OF COLORADO GROUPED INTO FOUR GROUPS OF SIMILAR PRODUCTION. (SOURCE: ENVERUS)

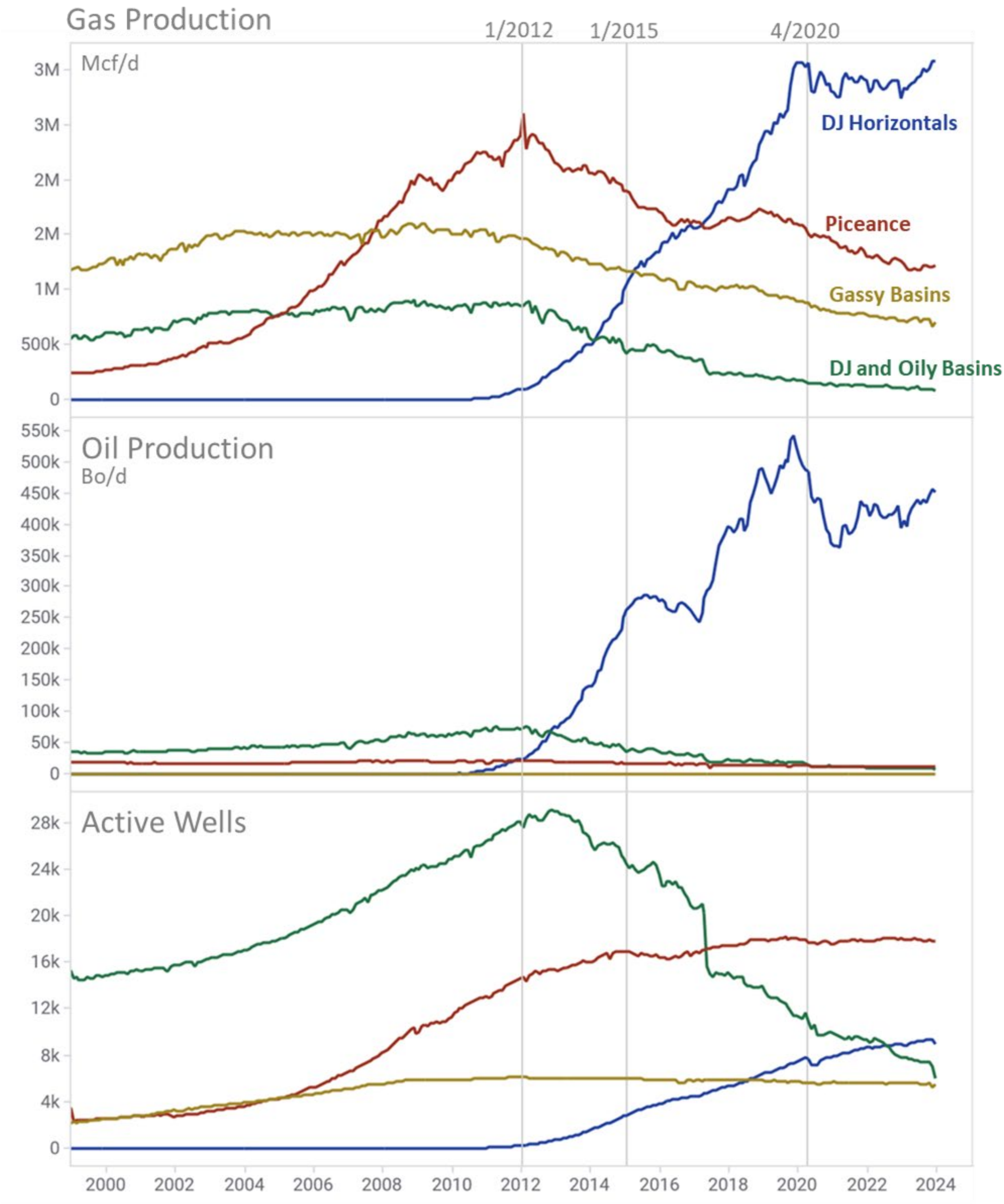


Figure 4 contrasts the discrepancy between the highs and lows of the state by showing the average production per active well in each of these groups of wells. For this graph and for comparisons throughout the remainder of our analysis, we convert gas production to an equivalent production of oil on a price equivalence of 20 Mcf per barrel of oil, a figure called "barrels of value" or "bov". We use this unit rather than "barrels of oil equivalent" or "boe", which focuses on energy equivalence, given our focus on related cash flows. The gray line of the chart marks 15 barrels of oil per day, which is the rate used by both Colorado and federal regulations to define "stripper wells", which qualify for tax breaks. Most areas fall deeply below this threshold while the smaller population of new horizontals average dozens of times more production per well than the historical areas.

FIGURE 4: AVERAGE DAILY PRODUCTION PER ACTIVE WELL, BARRELS OF VALUE PER DAY.(SOURCE: ENVERUS)

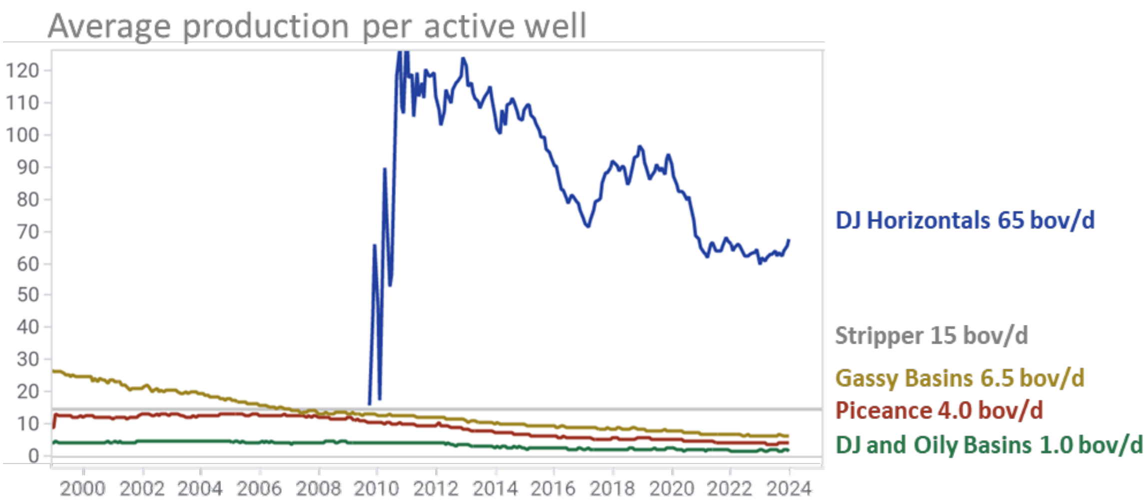


Table 1 provides more detail to compare among the areas: unplugged well counts, rates, and the distribution of rates. The DJ Horizontals drilled over the last 15 years account for 23% of the unplugged wells in the state but 81% of the state's production. Average daily production in Figure 4 is appropriate to illustrate how close to the end of economic life the surviving wells remain, but Table 1 shows a fuller picture. The median rate of all wells shown in the table better represents the overall financial position of the basin, that is, the ability of active wells to pay for their decommissioning, undistorted by a small number of high-rate wells. Recent development runs about 10 times as productive as the historical development, partly because the median of historical development runs less than three bov/d in all the areas.

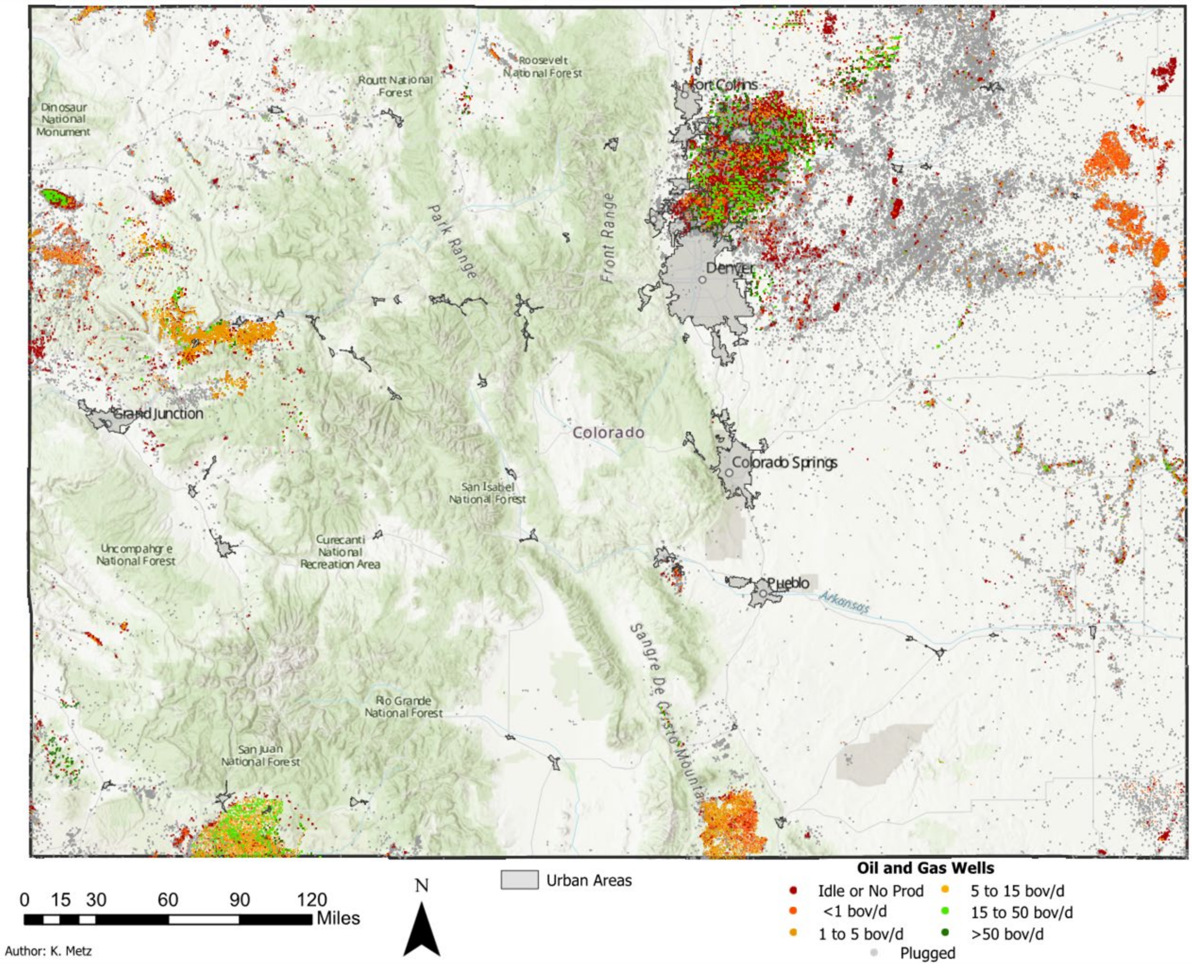
Worst are the oily basins scattered across the state where less than one percent of wells are not stripper wells and 85% of wells produce less than 1 bov/d. In fact, more than half of these wells already stand idle. The Piceance and gassy basins are extremes, but only 5% and 8% of wells do not qualify as stripper wells. Notably, 39% of all the DJ Horizontals have already depleted into stripper status. 18% are idle or produce less than 1 bov/d, demonstrating how shale wells decline much more rapidly than conventional wells.

TABLE 1: SUMMARY OF WELLS, TOTAL RATES AND DISTRIBUTION OF INDIVIDUAL WELL RATES.(SOURCE: ECMC)

Groups of Basins	Unplugged Wells	Total Production Rate bov/d		Distribution of Production Rate all wells bov/d			
Piceance	16,157	80,601	1,378 MMcf/d	median	2.5 bov/d	22%	0-1 bov/d
						58%	1-5 bov/d
			11,709 bo/d			15%	5-15 bov/d
						5%	>15 bov/d
Gassy Basins	6,276	37,725	754 MMcf/d	median	2.7 bov/d	32%	0-1 bov/d
						34%	1-5 bov/d
			26 bopd			26%	5-15 bov/d
						8%	>15 bov/d
DJand Oily Basins	14,138	17,376	114 MMcf/d	median	<1 bov/d	85%	0-1 bov/d
						12%	1-5 bov/d
			11,698 bo/d			2.5%	5-15 bov/d
						0.9%	>15 bov/d
DJHorizontals	11,217	580,580	2,950 MMcf/d	median	21 bov/d	18%	0-1 bov/d
						4%	1-5 bov/d
			433,089 bopd			19%	5-15 bov/d
						59%	>15 bov/d
Total	**47,788**	716,282	5,195 MMcf/d	**median**	**2.1 bov/d**	**41%**	**0-1 bov/d**
			456,522 bo/d			**17%**	**>15 bov/d**

Figure 5 shows the same distribution of well rates on a map of the state. Red wells are not producing, and orange are stripper wells. Higher producers are shown in shades of green. Gray are wells already plugged but may require remediation in the future. The largest contrast is in the DJ basin. The San Juan basin in the southwest does include a number of non-stripper gas wells, but most areas of the state show pervasive red and orange of low-producing wells.

FIGURE 5: MAP OF WELLS IN COLORADO COLOR-CODED BY CURRENT PRODUCTION RATE. (SOURCE: ECMC)



4.3 Plugging proceeds slowly

Notwithstanding the low rates, the plugging of wells proceeds slowly and incompletely. In most areas of the state, the pace of plugging has decreased in recent years, but plugging has accelerated in the DJ basin, driven not so much by regulations as by new drilling activity.

Regulation requires, as does prudence, that existing wells located close to a new horizontal well be plugged prior to the fracturing that can reach out thousands of feet. Before the boom in horizontal drilling, operators were plugging only about 130 wells per year in all the Denver-Julesburg (DJ) basin, but it has recently averaged about 1,400 wells per year. If it were not for the opportunity of shale development, the DJ basin would likely have followed a similarly modest pace as other areas have. Statewide, the pace of plugging is about 300 wells per year outside of the Denver-Julesburg basin. Table 2 provides more detail on the same four groupings.

TABLE 2: SUMMARY OF THE PACE OF PLUGGING FOR THE GROUPS OF BASINS. (SOURCE: ECMC)

Groups of Basins	Unplugged Wells	Drilling new producers / year		Plugging old wells / year		Plugging to complete
Piceance	16,157	245	1.5%	80	0.5%	203 years
Gassy Basins	6,276	14	0.2%	24	0.4%	257 years
DJ and Oily Basins	14,138	67	0.5%	1,595	11.3%	9 years
DJ Horizontals	11,217	1,052	9.4%	31	0.3%	357 years
Total	**47,788**	1,379	2.9%	1,730	3.6%	

Old vertical wells in the DJ and Oily Basins group are plugged to make way for the DJ Horizontals, and this pattern will continue as long as drilling continues. It is not clear how extensive that plugging-then-drilling will be. As discussed below, about 8,500 old wells remain in the areas of ongoing drilling, meaning the inventory would be worked off in about six years at the current pace. On the other hand, the inventory of remaining drilling has been depleting consistently and significantly since 2017 and may be exhausted in fewer than six years.

Outside of this trade-off between the last two groups, we see that plugging has been slow. In the Piceance and gassy basins, the average pace of plugging over the last five years would take more than 200 years to complete the task on the existing wells. Plugging comes due when profitable production ends, and the low production rates demonstrate that time will arrive sooner rather than later.

Individual areas tell a more colorful, qualitative story of accumulating liabilities against waning production. Among the nearly 3,000 unplugged wells in the Raton basin, active producing wells average about 40 Mcf/d, but in the last five years, five have been plugged. In the Anadarko basin to its east, two wells were plugged in 2023. Zero wells have been plugged in the Paradox basin since 2021. Of the 16,200 wells in the Piceance basin, only 10 were plugged in 2023.

However, even after ECMC changes a well status to “plugged,” the work is not yet done. Decommissioning in Colorado also requires removal of all surface equipment and facilities, remediation of any surface pollution, and restoration to pre-drill conditions, and these contribute the majority of the total costs. Decommissioning is not complete until the regulator approves these additional steps of surface decommissioning, and this consummation of decommissioning often waits. For example, operator Noble Energy (now a subsidiary of Chevron but still operated as a separate company) has filed paperwork showing plugging of 3,952 wells for which surface remediation is not yet approved. This single group of wells makes the list of wells still to be decommissioned higher by 8% than assumed in our analysis, but we have not quantified how many thousand other such wells may exist, nor the cost to complete their decommissioning.

Data limitations require us to assume – incorrectly but conservatively – that having been plugged means that all costs have been incurred. Our remaining analysis considers only

unplugged wells, and financial assurance associated only with those, even though the single example of Noble could represent hundreds of millions of dollars of decommissioning liability still outstanding.

4.4 Separate ownership of the separate production

As Colorado's oilfields have matured, the operating companies and their financial strength have changed. Old fields have migrated to smaller, and less diverse companies, away from the handful of larger companies conducting shale development. Thus, the companies that own much of the liabilities are not the same companies that own the most productive assets.

After the historical fields began their concerted decline, major oil companies began selling them off to smaller companies. During the mid-2010s, companies like ConocoPhillips and Encana sold to companies like Hilcorp Energy and Caerus Oil & Gas as the depleting assets were deemed "non-core." This process was practically complete before Colorado's legislative reforms, starting in 2019.

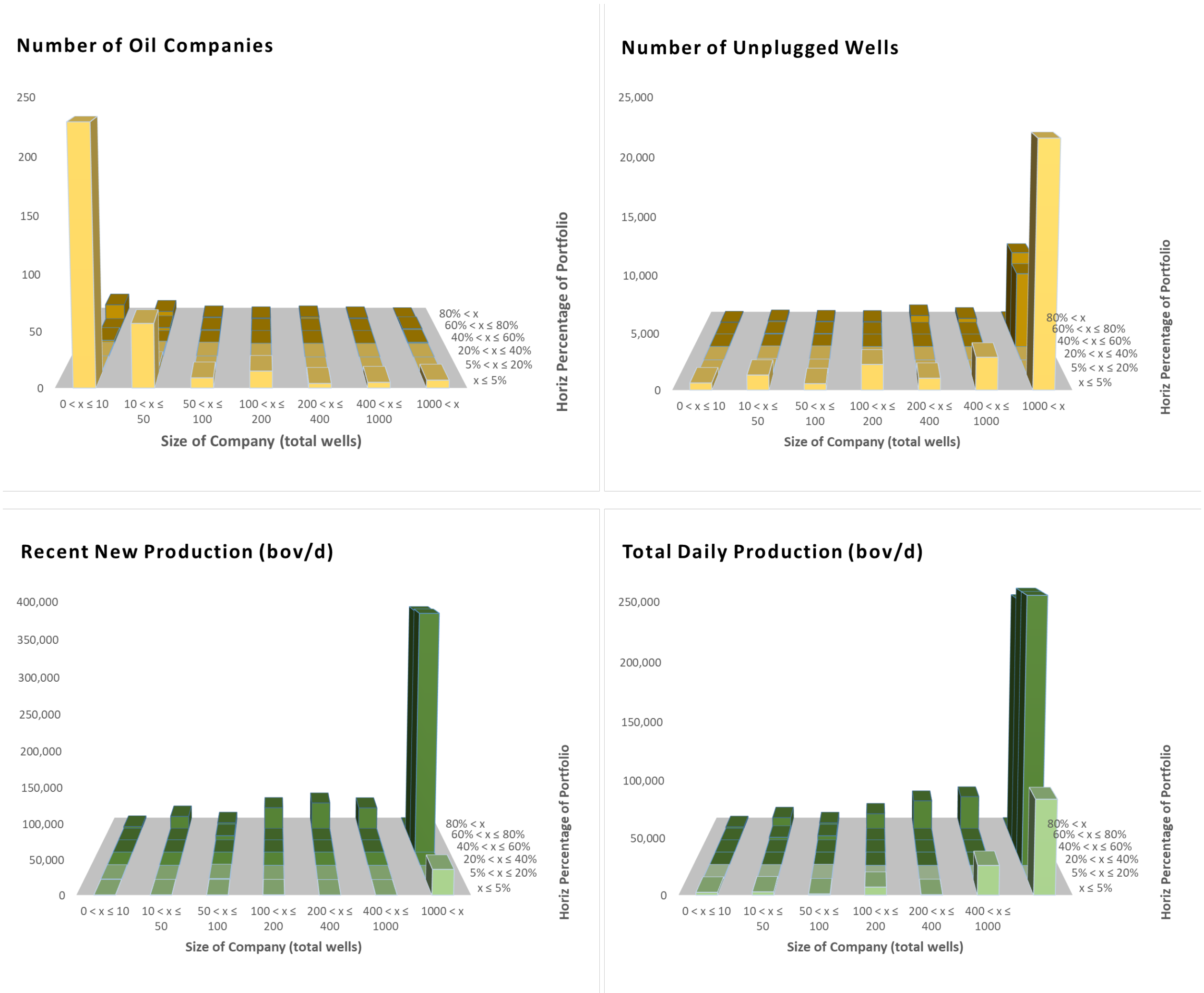
In addition, a couple of large companies with legacy positions in the Niobrara play took the opportunity to divest older fields and double-down on the Niobrara. At this point, three large public oil companies remain in the state of Colorado: Chevron, Occidental, and Civitas.[10] Both Chevron and Occidental have sold off non-core regions of the state and bought smaller companies in the horizontal play. In the last couple of years, all three have consolidated a number of smaller companies with mergers and acquisitions. Oddly, all three continue to operate the acquired companies as separate corporate entities within the state. Depending on the law and its enforcement in Colorado, the effect could be to isolate responsibility for actions in one part of the portfolio from assets in other parts, and it could also prevent requirements of additional bonding at transfer.

Shale plays ramped up as historical plays turned down, bringing start-ups backed by private equity to some areas gambling on the potential for redevelopment. However, the funding of new management teams focused within Colorado collapsed with oil prices in 2015. The successful PE-backed companies mostly finished their life cycle in the spate of sales and mergers in the last few years; just a couple of acquisition targets remain. Not all such companies succeeded and not all have sold out—as described below, the Piceance basin in particular is dominated by a handful of private equity-backed companies with no reasonable prospect remaining for the kinds of development that could fund decommissioning of historical wells.

Figure 6 demonstrates the strong three-way division among oil companies in Colorado at present. There are a very large number of oil companies in the state with very little or even zero production, but the large majority of wells reside in larger companies which are strongly split between horizontal drillers and more conventional producers. The assets and the activity concentrate in the small group of companies dominated by the three public companies, but the liabilities and systematic risk reside in separate portfolios.

[10] A few other public companies like Dominion Energy and Kinder-Morgan operate only a small number of wells in the state.

FIGURE 6: CONCENTRATION OF VARIOUS MEASURES OF THE OIL INDUSTRY BY PORTFOLIO TYPE. (SOURCE: ECMC AND ENVERUS)



In each panel, the arrangement of bars remains the same, and each bar represents a different kind of company portfolio. From left to right, the columns represent smaller companies to larger ones. From front to back, the rows represent lower to higher proportions of horizontal wells with the companies. Front-left of the chart represents small portfolios of conventional companies, and the back-right represents large portfolios of horizontal drillers. The height of the bars measures different features of the portfolios that fit within the group.

In the upper-left panel, the height of the bars shows the number of oil companies without regard to the size of each, demonstrating that the large majority of legal entities own only a few wells and almost exclusively vertical or directional wells. The upper-right panel shows the concentration of unplugged wells, demonstrating that the majority of wells reside in the ownership of large conventional producers. Because decommissioning liabilities are proportional to well count, this graph also represents the approximate distribution of decommissioning obligations concentrated in a few companies of large portfolios.

The lower-right translates the well count to total production. Like the nation as a whole dominated by shale production, conventional portfolios provide a minority of overall production. More importantly, the lower-left shows how ongoing drilling has contributed to production over the last five years and thus indirectly what can be expected from oil companies in the future. The dark green bars represent the large majority of new production came from horizontal wells, and the light green represent the development attempts made mainly in the Piceance basin.

The next two figures examine more precisely the relative contributions of large companies versus small and horizontal drilling companies vs others. Figure 7 shows the bottom 10% of oil companies ranked by wellcount in dark purple fading into the top 10% of oil companies shown in dark green, demonstrated in the first bar. It turns out that the small companies are, indeed, small. In fact, 86 registered oil companies in the state have zero active producers. The top 10% of companies by size bear responsibility for 93% of wells, 95% of production, and 95% of new production. The bottom 80% of producers by size account for 3.3% of wells but only 1.6% of production in 2023 and 1.1% of new production in the last five years. Policy must focus first on the security of the large companies, not of the mom-and-pop operators of the state.

FIGURE 7: RELATIVE CONTRIBUTIONS OF OIL COMPANIES IN COLORADO. (SOURCE: ECMC AND ENVERUS)

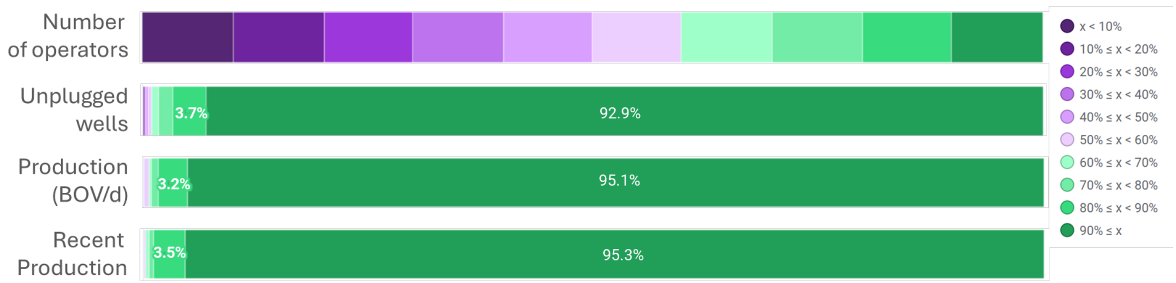
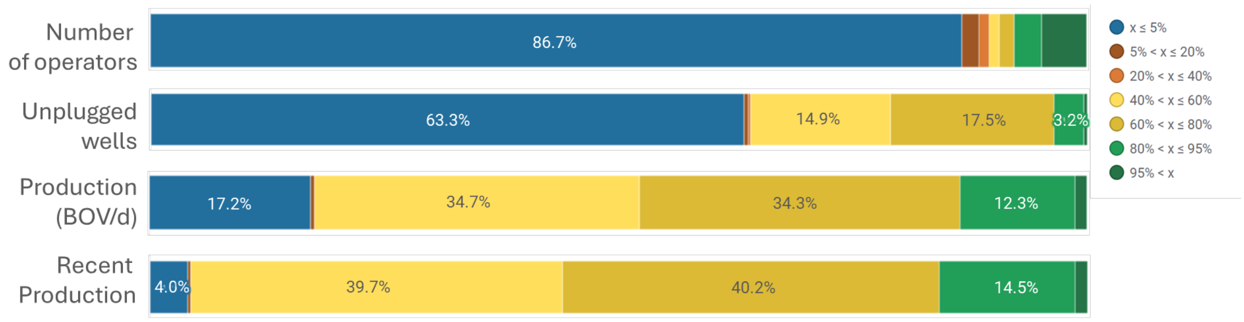


Figure 8 shows a similar style of presentation but colored according to portfolio style. The first bar shows that the large majority of companies focus on the vertical and directional style of wells of the legacy production in the state. There are a number of companies that focus almost exclusively on the new horizontal drilling. Many of these are private equity companies that have taken acreage positions in frontier areas. The three dominant producers fit in the gold-colored bars as they are drilling horizontals within the same areas previously developed with verticals. The 87% of companies with fewer than 5% horizontal wells own 63% of unplugged wells but only 17% of production and 4% of new production over the last five years. Policy must focus first on the risk presented by systematically low-producing portfolios.

FIGURE 8: RELATIVE CONTRIBUTIONS ACCORDING TO PORTFOLIO STYLE. (SOURCE: ECMC AND ENVERUS)



4.5 Production will soon decline

While Colorado remains near its peak all-time production by the efforts of a small number of large companies, it is unlikely to maintain that current production for many years, much less to see another revival. Most plays are well past their peak, the horizontal Niobrara responsible for recent growth is playing out, and no new technology or play promises another renaissance.

The history of the state certainly shows a pattern of successful expansion. Over decades, historical government subsidies specifically targeted known but uneconomic resources. Later, oil and gas prices both quintupled. Technology compounded success, notably horizontal drilling and hydraulic fracturing, and the shale revolution unlocked a new class of resources.

Looking forward, though, prices seem unlikely to quintuple again, and there are no technologies or classes of resources emerging to repeat the past successes. Commodity prices will continue to be volatile, but it would require much higher prices to capture the reserves that could not be developed with the high prices already seen. Moreover, the same volatility can mean lower prices that end the economic life of existing fields sooner than expected. And there is no other class of geologic resources beyond shale in the state. Technologies for re-fracturing old wells and for enhanced recovery by injection have been researched and tested for many years, but they have yet to reach commercial viability.

Without the prospect of another savior from the wings, the currently known reserves in the state form the foundation for policy and planning purposes, both current development and eventual decommissioning. Of course, oil and gas are non-renewable resources, and the current boom must eventually bust. By their inherent nature, the resources deplete until they are exhausted.

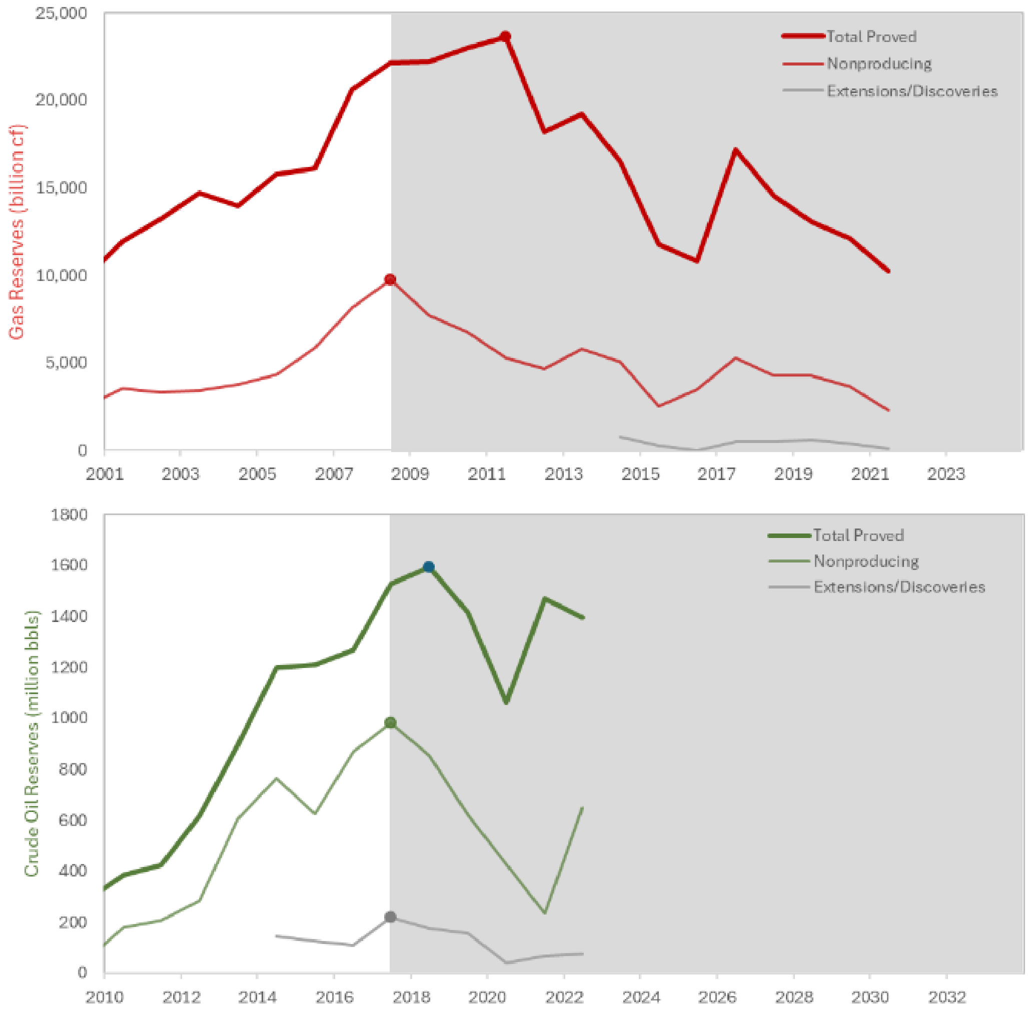
4.6 Undrilled reserves are dropping

For perspective on the remaining life of the Denver-Julesburg drilling boom, we look to reserves reported by the operators themselves. The data shows that drilling inventory has already peaked and declined significantly as the pace of drilling has outstripped the pace of finding new drilling opportunities. Production has already peaked, as discussed above, though current production is holding flat. We have not attempted to quantify timing, but the pattern of lifecycles suggests that production from the horizontal drilling boom will start declining in earnest within a handful of years, and the underlying decline of shale production is much steeper than other kinds of oilfields.

Each year the Energy Information Agency (EIA) surveys operators across the country about their production and internal estimates of reserves, attempting to collect this confidential, firsthand information related to at least 90% of production in each study area. From 2014 to 2022, headline crude oil reserves figures have stayed above one billion barrels. However, the types of volumes, their trends, and their revisions paint a much more dynamic picture.

By analogy to what may be expected of the crude oil drilling boom, the development and production from the Piceance basin and other gassy basins is more mature than crude oil. Figure 9 shows first how reserves have evolved for the more mature non-associated gas[11] in the state, then for the crude oil volumes of the state. The graph of crude oil reserves is shifted to align with the point in time when the drilling inventory peaked.

FIGURE 9: TOTAL RESERVES, NONPRODUCING RESERVES AND EXTENSIONS/DISCOVERIES IN COLORADO AS REPORTED IN EIA'S "PROVED RESERVES OF CRUDE OIL AND NATURAL GAS IN THE UNITED STATES" FOR A) NON-ASSOCIATED GAS FROM 2005 TO 2024, AND B) CRUDE OIL ALIGNED TO THE PEAK OF NONPRODUCING RESERVES. (SOURCE: EIA)



The top line on each graph represents the bottom-line grand total of reserves, and its changes over time represent the net effect of producing the volumes, changing the estimates of remaining

[11] Natural gas produced from gas wells instead of oil wells.

volumes, and adding new drilling plans. Total reserves include two substantively different types. "Producing" reserves are those volumes expected to be recovered from existing wells with known production rates, and "nonproducing" reserves pertain to planned wells which have not yet been drilled or otherwise begun producing and thus involve more uncertainty. The middle line in the graphs represents the volume attributable to this nonproducing drilling inventory. The lowest line isolates the replenishment of the drilling inventory by extensions or discoveries.

The lifecycle of reserves is straightforward. Reserve volumes start as part of the lowest line: incremental new discoveries or plans. Those plans sit in the nonproducing category until they are drilled and move into the category represented by the space between the top line and the middle line. Revisions to estimates of recovery can shift estimates of both categories up or down, but production always drains the grand total of reserves and thus ends the lifecycle.

The data shown comports with the series of peaks that would be expected from the lifecycle. First peaks growth of new nonproducing reserves during the exploration and delineation phase of the lifecycle. The explicit data does not extend that far back, but the largest growth of nonproducing reserves for analogous non-associated gas implies a peak around 2007. Then the inventory of undrilled reserves peaks during the development phase, as demonstrated in 2008. Next, total reserve volume crests as the development phase gives way to the production phase. In this example, gas reserves peaked in 2011 shortly before production peaked in 2012, as discussed above.

It is true that both new discoveries and ongoing drilling have continued since then, but not quickly enough to overcome depletion. New ideas and new opportunities no longer keep pace with production, and they continue to slow. The same trajectory should be expected from crude reserves. Indeed, the second graph in the figure shows that it has.

Both the addition of new reserves and the inventory of nonproducing reserves peaked in 2017. Total proved reserves peaked the following year in 2018, then production peaked just before the pandemic disrupted the trajectory. Nonproducing reserves declined steeply from 2017 to 2021—76%—as did the pace of extensions in the same manner, but faster than non-associated gas reserves a decade before.

It is notable that the national reserve report from year-end 2022 shows a step upward and thus delays what looked like an imminent exhaustion of drilling plans. Still, that one-year spike does little to change the conclusion of declining opportunities and near-term production decline.

The smaller effects of commodity price variations can be seen overprinting the larger historical trends of the lifecycle. High oil prices during 2022 associated with the Russian invasion of Ukraine spiked estimated volumes of nonproducing oil reserves at the end of 2022, and a temporary supply shortage of natural gas spiked its price simultaneously. We can expect the 2022 spike to be temporary in the same way that nonproducing oil reserves temporarily reversed course in 2015 before returning to the previous trend, and in the same way that non-associated gas reserves show above dipped and jumped within longer-term trends. What is more, the pace of field extensions which would add to new inventory did not increase, and we are not aware of any dynamics outside of the EIA data that would justify reserves continuing to grow or even to hold steady.

Thus, total reserves of crude oil will turn down again. A year and a half of drilling have already worked off some of 2022's inventory, and the depleting inventory will soon translate to declining production.

The overall pace of production decline depends on both the continued pace of drilling and the natural decline of existing wells. When drilling slows due to price changes or lack of inventory, the decline rate of existing wells will take over, and shale production declines much more steeply than other kinds of production. As demonstrated, the EIA data shows that producing reserves of oil have a reserves-to-production (R/P) ratio of only 4.9 years. R/P ratio is a conventional rule of thumb to measure decline and remaining life. It is reserves divided by annual production, expressing the number of years reserves would last if the rate of production did not decline. An R/P ratio of around eight is normally considered low, and by comparison, the current R/P ratio of non-associated producing gas in the state is 10.9 years. These imply that shale production will deplete on average more than twice as fast as the state has seen previously from other fields.

Lastly, notwithstanding their classification as proved reserves, estimates of proved reserves have a history of optimism and significant downward revisions. For example, after the low point of 2015 to 2021, downward revisions to estimates of crude reserves were 53% greater than upward revisions. From 2021 to 2022 when data was presented differently and prices were still exceptionally high, producing reserves still revised downward by more than 24%. The spike of 2022 may well suffer downward revisions.

Policy for financial assurance should consider what the principles and the data say about the future of the current drilling boom in Colorado. Reserves are not infinite, and the high levels of crude reserves will not be maintained. By the time a new policy is implemented, there will be significantly less remaining drilling inventory to be affected by the policy. Once drilling slows, production will decline rapidly. Oil company plans can change with oil prices, and recovery estimates have a history of write-downs.

As Colorado's horizontal drilling of crude oil then progresses through the subsequent production phase, the fields will leave the hands of the large, highly profitable companies with diverse portfolios. Without any opportunities for development, the companies will sell the fields to smaller companies focused on production. Production will continue to deplete until today's boom fields sit in the same position as today's legacy fields.

5 Decommissioning liability currently runs in the billions of dollars

Calibrating a response to the risk faced by the land and taxpayers of Colorado requires an estimate of the cost to return depleted fields to a safe and clean condition. Unfortunately, the costs are known to be required from the day a well is drilled, little decommissioning cost information is available in the public domain. However, multiple lines of evidence point toward a total figure of about $6.8 to $8.5 billion at today's capital costs.

5.1 Estimates from public disclosures make consistent pattern

Part of the difficulty of estimating decommissioning costs is that they have changed rapidly in recent years. Inflation in the oil field matched or exceeded consumer inflation over the last few years. Much of the information about actual, realized decommissioning costs predates this significant increase, making it necessary to adjust some figures upward to achieve a current estimate. What is more, cost inflation and degradation of materials will continue to pressure costs upward over the remaining years of existing production. "Ensuring" enough money for the costs as required by statute requires setting aside more money than is expected to be necessary. Policy should consider the margin and inflation necessary to cover the costs in the future.

The experience of the ECMC plugging orphan wells in Colorado—and its expectations based on that experience—may be viewed as a basis for future costs. Twice in early 2022, ECMC has used a consistent figure of $130,000 per well for its planning purposes. Its grant proposal for plugging funds from the federal government implied a cost of $128,400 per well, and it contemporaneously set the default bond.

It should be noted that another source of data about costs related to the bonding program is available, but we deem it unreliable on the whole. During the process of negotiating bonding amounts with the ECMC, oil companies had the opportunity to bond lower amounts if they could "demonstrate" that the lower amounts were more representative of their costs. We do not rely directly on this information because it suffers structural shortcomings likely to systematically and significantly bias the submissions.

The Denver International Airport has recently plugged, removed, and remediated 64 wells sites as well as associated flowlines and surface equipment in the Denver-Julesburg basin which is home to most of the wells and most of the liability in the state. The final cost in 2023 came to $195,000 per well, 36% higher than the 2019 estimate before the inflation mentioned above.

Lastly, we turn to three kinds of data reported in the investor filings of public companies to reverse-engineer companies' actual and estimated decommissioning costs: annual spending on decommissioning, transactions that change the present value of decommissioning liabilities, and the total present value of decommissioning liabilities. The information disclosed is generally superficial and indirect, but we have combed filings of multiple companies since 2017 and combined the disclosures with data from ECMC to isolate a number of instances with enough information to triangulate a figure we deem reliable.

Our research found seven instances from three companies for which we found both a sufficient disclosure of actual annual spending and a reasonable estimate of the number of wells plugged. The range of costs is wide, and it is not clear to what extent they include surface remediation as well as downhole plugging. With these limitations, we observe an average of $146,000 per well at an average date in 2019 spent by operators in the main Denver-Julesburg basin.

In some cases, filings describe changes in the financial records attributable to transactions within the state, and our research uncovered nine such reports seven transactions. As before, values range widely but tend to be higher in later years, plus the interpreted undiscounted value depends a good deal on the assumed discount rate. On average in the Denver-Julesburg basin, the figures suggest about $175,000 per well in 2020.

Most recent and most comprehensive are the statewide totals of corporate liabilities reported by two companies. We observe upward revisions of costs in previous years consistent with the same inflation documented above. For recent years, we used analog discount rates and stated schedules of liabilities over the next five years, then we compared the inputs and assumptions between the two years for further corroboration. One company's figures in this and previous analyses were consistently much lower than others. On balance, the best and most consistent information from years of disclosures by public companies suggests that the average cost to decommission a vertical well in the dominant Denver-Julesburg basin is currently running around $175,000 to $200,000 each.

5.2 Internal methodology is tailored by area and conservative

The public data above paints a consistent picture, but that picture focuses on the Denver-Julesburg basin. Carbon Tracker has created and used its own internal algorithm to estimate decommissioning costs broadly across the country in a series of reports since 2021, and we updated the methodology and improved our input data for this analysis of Colorado. Still, the vintage of the data and the fact that the data pertains only to single-well decommissioning suggests the estimates are conservative. More importantly, the model also has the flexibility to estimate costs in regions with substantially different well characteristics. The model predicts a statewide average cost of $141,000 per well, with an average of $151,000 in areas comparable to those described above but with costs just a third to half as great in the gassy southern basins.

5.3 Combining methods suggests $6.8 to $8.5 billion statewide

The parade of evidence summarized in Table 3 suggests that the average decommissioning cost per vertical oil well in the Denver-Julesburg basin today sits between $175,000 and $200,000. Some of those estimates should include the full scope of decommissioning for the full scope of facilities while our model was created from well-only costs. By comparison, our model calculates an average of $151,000 for a comparable subset of wells. About half of the unplugged wells in the state reside in the Denver-Julesburg basin, and more wells reside in basins of similar characteristics.

TABLE 3: SUMMARY OF DATA ABOUT UPSTREAM DECOMMISSIONING COSTS PER WELL.

Source	Cost per Well	
ECMC	$ 130,000	thru mid-2021: default bonds based on 23 orphan well costs statewide
Annual Corp. Spending (SEC filings)	$ 146,000	2019 avg: seven years of actual spending on 1010 wells by 3 companies
Asset Transactions (SEC filings)	$ 175,000	2020 avg: fair value of AROs for eight transactions
Corporate Liabilities (SEC filings)	$ 173,000 $ 201,000	2021 YE: Civitas Resources 2022 YE: Civitas Resources
Denver Int'l Airport	$ 195,000	2023: contract to plug 64 wells
Carbon Tracker	$ 141,000	statewide average based on well depth

We deem it appropriate to view our estimate as a low-side, and we extrapolate by 25% to reconcile our estimate with the progression of public evidence through 2022. Summarizing again by groups of basins with similar characteristics, Table 4 shows that current statewide retirement costs likely range from $6.8 to $8.5 billion. It may be noted, though, that the full scope of decommissioning may still be larger than this estimate because it is not clear to what extent those public estimates include necessary work beyond individual well site costs.

TABLE 4: ESTIMATED STATEWIDE COSTS FOR EACH GROUP OF BASINS ACCORDING TO CARBON TRACKER METHODOLOGY AND AVERAGE COST INTERPRETED FROM RESEARCH INTO REPORTED VALUES.

	Unplugged Wells	Carbon Tracker Model		Extrapolation to Actual Results	
		$/well	Total	$/well	Total
Piceance	16,157	$187,000	$3,020,000	$234,000	$3,775,000
Gassy Basins	6,276	$61,000	$380,000	$76,000	$475,000
DJ and Oily Basins	14,138	$120,000	$1,701,000	$150,000	$2,126,250
DJ Horizontals	11,217	$148,000	$1,660,000	$185,000	$2,075,000
Total	**47,788**		**$6,761,000**		**$8,451,250**

Additional detail and discussion of all of these angles of analysis can be found in Appendix A.

6 Bonds do not come close to securing the end-of-life liability

Decades ago, when the oil industry was in a different stage of its life cycle, Colorado and practically all jurisdictions adopted bonding as the primary form of financial assurance that oil and gas companies would clean up their infrastructure at the eventual end of their useful lives. A bond allows for a third-party to guarantee that funds are available, up to the value of the bond.

Over the years, the shortcomings of the system manifested. The value of the bonds was often set at a fraction of the overall cost and a lower fraction for larger companies, evidently on the assumption that large companies would present less financial risk, and in many venues, the required bonds were not adjusted over time to reflect increasing costs. Recognizing the shortcomings of the system, Colorado embarked on a reform of its principal type of bonds, those related to individual well sites.

To be clear, well site bonds are only part of the required decommissioning. The oilfield decommissioning required in Colorado includes three kinds of work, estimated in three parts, plus a contingency for subsequent problems.

For individual wells sites, operators must: 1) plug wellbores to prevent gas and liquids from moving to the surface or groundwater, called "plugging" or "plugging and abandonment", 2) remove surface equipment and restore the surface to its prior condition, called "reclamation", and 3) reduce contaminants, if any, in soil or water to acceptable levels, called "remediation". The same scope of work applies also to all of the other infrastructure in the field such as flowlines, tank batteries, central facilities, compressor stations, and water disposal systems.

Estimating the cost of this scope of work requires three layers of quantification: planned costs, contingency costs, and future costs. Planned costs are those associated with the work that is known to be required. Contingency costs pertain to unexpected complications encountered that increase the cost to achieve the required end result, and future costs or legacy costs pertain to the ongoing responsibility to repair or remediate problems created or discovered in the future.

Of course, oil companies retain responsibility for the decommissioning work if any problems develop in the future. And all costs are subject to inflation in the years before the costs are paid.

Financial assurance reforms fundamentally kept the same system with the addition of a couple of minor, conventional policy tools. Bonding reform to date has pertained exclusively the primary type of bond—those for individual well sites. The reform did allow for bonds to increase with time and did create other secondary mechanisms of protection against orphaning of these liabilities by oil companies. The following recapitulates and expands the discussion of the primary bonding, then examines secondary reforms in order to evaluate the complete suite of financial assurance currently available for the complete suite of obligations as closely as we can estimate them.

6.1 Reforms for well site decommissioning provide no more coverage than previous

Colorado's regulator maintains seven main kinds of bonds, each related to a different kind of oil and gas activity. Two-thirds of the decommissioning bonds held by the state and all of the reforms pertain to what regulations call "soil protection and plugging and abandonment," also known as "plugging bonds" or "well site bonds."

Due to gaps and issues described below, separate analyses by Carbon Tracker predicted that the reforms would cover at best 25% of the potential cost and then subsequently proved that the reforms provided less than 4% of those estimates of cost. In the May 22, 2024 ECMC Financial Assurance Update the total financial assurance "*in hand*" amounted to only $228 million, marginally less than the $243 million it had been before the new rules were implemented on April 01, 2022. Since that Update, the operator PDC, owned by Chevron, has refiled its Form 3 and reduced its total financial assurance from $40 million to $15 million. This reduces the total amount of financial assurance "*in hand*" to $203 million as of June 22, 2024, 16% less than what it was in 2022.[12]

Many of the approved plans do call for the assurance to increase with time, plus the statute allows for—but does not require—the ECMC to require additional financial assurance with inflation. The companies with the lowest-producing wells are afforded 10 or 20 years to fulfill their bonding requirements, so the total increases slowly. Because the longest delays are afforded to the least profitable companies, it is not at all clear that they will be able to meet their current commitments. Implementation of inflation adjustments during the same period is optional, but it is also difficult. More to the point, there is no other financial incentive for oil companies to plug the wells or to provide the bonds.

The process did, on the other hand, reinforce the fact of the risk faced by the public fisc. Sixty-six listed operators have still not taken the first step of submitting a proposal in the more than two years since official notice was given, and another 28 listed operators have failed to submit a plan that ECMC could approve. In other words, 37% of the listed operators targeted have not even responded to the multiple demands of the regulator, and another 10% have responded but not complied. More importantly, this suggests that at least 37% of listed operators stand on the verge of orphaning their wells as the ECMC has begun enforcement proceedings against them in the last few months.

The extensive and extended effort necessary to achieve the current reform forbodes an intimidating process for future changes or increases of the same system, making it impractical to maintain.

Separate reform on federal lands also falls short.

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[12] *ECMC Financial Assurance Update*, Presentation slide 11/20, "*FA Totals Before and After SB 181*," Colorado Energy & Carbon Management Commission website, Colorado Department of Natural Resources, May 22, accessed and downloaded 2024-06-22 8 a.m., Commission Portfolios 2024: 05_May > 22: Financial Assurance Update Final.pdf, https://drive.google.com/drive/folders/1lnANwtjKrkCtRqPYRa11d2lSG0ROoy9J

Implementation of the new bonding rules excluded wells on federal and tribal lands in apparent deference to a parallel rulemaking being conducted by the federal Bureau of Land Management (BLM). That is, the ECMC has not yet begun applying its new rules to 10,000 of the 48,000 unplugged wells in the state.

That BLM rulemaking published draft rules last summer and final rules in April 2024. As it was the first increase in about 70 years, it did represent a dramatic surge in required bonds, but it also fell far short of the actual cost that will be required.[13] Based on indirect information about state-level bonding before and after in BLM's analysis, we estimate that the current bonds provide less than $2.5 million of financial assurance in the state. We also estimate that the revision, if fully implemented in the next few years over industry complaints and claims of financial distress, would increase to about $50 million.

The ECMC requires $130,000 per well as the default bond for most wells, and the BLM analysis explained that its bonding plan assumed a future average cost of $150,000 per well. These figures imply that the estimated $50 million in bonds to be required will apply to $1.3 to $1.5 billion of liability.

6.2 Secondary bonds add little to the total, were not reformed

Among the other six types of activities covered by bonds for the state of Colorado, only bonds for waste management facilities are required to cover the full cost of decommissioning, and those represent the second largest category of guarantees from the industry to the people of Colorado. On the other hand, it is not clear that the required amount suffices, but it is clear that many of them have not been updated to the higher values required on more recent wells. Active bonds for 73 waste management facilities total $69 million.

There has also been no reform of other bonding protections, namely those for surface owners, gas facilities, commercial water injection, produced water transfer, or seismic acquisition. All of these kinds of bonds reach their maximum of $25,000 or $50,000, and all but one allow a single bond of that maximum amount to cover any number of facilities statewide. Hence, all other forms of active financial assurance total only $31.1 million to guarantee the removal and remediation of other relics of the upstream oil and gas industry in Colorado.

6.3 Other reforms suffer significant gaps

It must be noted that three additional state reforms recently took separate steps to reduce the need to rely on a guarantee from the current operator. But those are not as concrete as the bonding reform, and they also suffer significant loopholes.

[13] See separate analysis in Purvis, Dwayne. *Carbon Tracker Initiative* "Little Big Horn: How a bonding proposal can fall short." (April 2024), https://carbontracker.org/taxpayers-may-face-up-to-900-million-in-oil-and-gas-well-clean-up-costs-in-the-big-horn-basin/

6.3.1 *Plan to begin decommissioning, without promise or penalty ("out-of-service" wells)*

First, some oil companies may bypass the need to provide financial assurance for some of their wells by promising instead to begin the work of decommissioning within a fixed number of years. The operator need only declare its intention to plug and an intended date on an ECMC form to designate wells as "out of service." When initially added to the operator's "plugging list," most wells are allowed seven years to commence plugging, but some are allowed as little as four years. However, there is no fixed schedule for all work to be completed—only an operator's declared plan is required. They are not required to have completed the surface removal and reclamation nor to have begun the physical work of remediation of any pollution—the latter being one of the larger costs associated with decommissioning.

What is more, the operator faces no unique penalties for failing to meet this fraction of its overall obligation.

6.3.2 *Review of bonding at transfer will have little effect*

Second, the transfer of wells to the responsibility of a new operator triggers a review and possible revision of the financial assurance of the acquiring company. This provision suffers two defects.

First, the provision applies to a change of operators but perhaps not a change of ownership. Often oil and gas fields are transacted as stand-alone assets, with title moving from one company to another. In other circumstances, the ownership of an entire company can change hands. For instance, Occidental, Chevron, and Civitas have each acquired multiple companies (as mentioned above) but have not changed the operator of record. Kerr-McGee, Noble, HighPoint, and other companies continue to be listed as the operator of record, so it is not presently clear whether the provision would apply to recent, major transactions.

Third, it creates the option, but not the requirement, for increased bonding at transfer. Even if Colorado's new bonding rules are applied to such stock transfers, their recent application of those rules shows that the results of future applications will likely also fall short.

6.3.3 *Fee on active wells does not promote plugging or fund plugging of all orphans*

As a third backstop, the ECMC created in 2022 a way for industry to help fund the decommissioning of wells that do become orphans, reducing the burden on taxpayers. Called the Orphan Wells Mitigation Enterprise Fee, each operator must pay a fixed amount each year for each of its unplugged wells, and it is expected to generate $10 million each year for plugging. By comparison, the ECMC will use $10 to 15 million from federal taxpayers each of the next eight years for the same task, so the industry fee will cover half or less of the near-term budget.[14]

The fee does raise some money from the oil industry, honoring indirectly the governance principle that the polluter should pay. On the other hand, these funds are much less than what will be needed in the near term, very much less than the state's unsecured liability, unlikely to change the

[14] ECMC, "Orphan Well Enterprise" (accessed April 10, 2024). https://ecmc.state.co.us/owe.html#/owe

trajectory of wells orphaned by oil companies, and thus not a viable solution for the wind-down phase faced by most of the state's industry.

The state currently bears responsibility for nearly 1,000 orphan wells. Another nearly 350 wells are in the process of joining the list from a single operator, Omimex Petroleum Inc. Operator KP Kauffman Company Inc. operates more than 1,000 wells and has argued publicly that they lack the funds for the required bonds. In 2021, the company testified that it could not afford to pay even $1 million in fines for 22 violations of state regulations,[15] and the company has filed suit against the ECMC to resist the required increase in financial assurance. In addition to these larger companies, the ECMC has begun enforcement—the first step toward orphaning—for another 66 operators who have not submitted a bonding plan. Farther back but still in the queue to potentially orphan their wells, dozens more operators have not yet submitted an acceptable bonding plan more than two years after the requirement was announced.[16]

Table 5 below compares the funds expected to be available with a ballpark estimate of the needs over the next five years, and it shows a wide shortfall. The orphan well fees can be revised upward by the managing board, and it will need to increase by eight times to cover our estimate of likely orphans in the next few years. On a larger scale, the fee would have to increase by a factor of dozens more if it were to secure the entire gap statewide between bonds and liabilities.

TABLE 5: SUMMARY OF FUNDS AVAILABLE AND ESTIMATE OF FUNDS NEEDED FOR ORPHAN WELLS OVER THE NEXT FIVE YEARS.

Funding estimated by ECMC		Liabilities estimated at $130,000 per well	
$ 50 million	from Orphan Well Fees	$ 85 million	for remaining costs of orphans as of Sep 2023
$ 65 million	from federal grants	$ 44 million	for Omimex wells
		$ 136 million	for wells of 96 unresponsive operators
		$ 142 million	for KP Kaufman wells
		$ 135 million	for four subsequent years at 100 wells/year
$ 115 million	**over the next five years**	**$ 458 million**	**over the next five years**

The fee is too small to change the trajectory of likely orphaning in the future. The annual fee was set originally at $225 per well ($18.75/month) in each company with an average portfolio rate of 15 BOE/day or greater and $125 per well ($10.42/month) for companies below that threshold, and these costs provide no practical incentive to decommission wells. On an undiscounted basis, it would take 578 years for the high side fees to equal $130,000 as a proxy for today's cost.

What is more, oil companies instead would make decisions based on present value. Assuming for simplicity a discount rate of 10%, the present value of an indefinite stream of paying the applicable fee indefinitely is only $1,250 in present value terms. The fee does almost nothing to

[15] Jaffe, Mark. "Fine against KP Kauffman for leaks and spills upped to second largest ever by Colorado oil and gas regulators", The Colorado Sun (September 22, 2021). https://coloradosun.com/2021/09/22/kp-kauffman-oil-gas-fines-violations/

[16] ECMC, *ECMC Financial Assurance Tracking Report,* Colorado Energy & Carbon Management Commission website, Colorado Department of Natural Resources, accessed and downloaded 2024-06-22 8 a.m. https://ecmc.state.co.us/cogisdb/ReportTools/FA/FATrackRpt

change the comparison of choices; the choice remains as economically rational to defer rather than decommission as without the fee.

6.4 Bonds do not extend to all kinds of oilfield decommissioning

Regulations both before and after reform leave a number of gaps in the scope of coverage.

Reforms following the Firestone disaster in 2017 did require more public disclosure about flowlines and stricter requirements for the method of decommissioning, but they did not yet require specific financial assurance that those safety operations will be performed.

The reforms have also not provided for the decommissioning of all equipment necessary for production but not located on individual well sites. Though there is some secondary provision (e.g., for water disposal facilities), several kinds of shared equipment like tank batteries, central facilities for separation, and storage of produced fluids are not covered by existing forms of financial assurance.

Longer term, the reforms have also not provided any form of financial assurance to protect against the possibility of additional decommissioning costs after the initial work. Neither the rate of failure of plugged wells nor the frequency of finding additional soil or water pollution are well understood, but it is clear that sometimes wells do need to be re-plugged, and that sometimes new pollution is created or discovered. Policy should consider the full scope of decommissioning necessary, including the potential for this kind of long-term financial guarantee from the industry.

6.5 Financial assurances and available funds cover a fraction of oil companies' obligations

Each individual policy in the network provides only a small protection, and the gaps between policies are wide. Taken together, the network of policies is insufficient to the need. Table 6 summarizes and totals the review of the policies above. If they work as intended over the next five years, these policies collectively provide about $654 million toward the clean-up of the aging oil infrastructure estimated to cost $6.8 to $8.5 billion today. The full spectrum of assurance covers at best 7% to 9% of the current cost.

TABLE 6: SUMMARY OF VARIOUS FINANCIAL ASSURANCE AVAILABLE TO COVER THE COST OF DECOMMISSIONING IN COLORADO.[17]

Form of financial assurance	Value	Changes
Well site bonds	$245 million	increasing $29 million per year
Waste management bonds	$68 million	
All other state bonds	$31 million	
Federal bonds	$3 million	increasing to $50 million
Fee to fund orphan wells	$10 million	each year
Federal grants	$65 million	over five years
	$654 million	over five years

[17] ECMC, *ECMC Financial Assurance Tracking Report,* Colorado Energy & Carbon Management Commission website, Colorado Department of Natural Resources, accessed and downloaded 2024-06-22 8 a.m. https://ecmc.state.co.us/cogisdb/ReportTools/FA/FATrackRpt

7 Remaining production in most basins does not come close to funding decommissioning costs

Bonds are dramatically insufficient, and oil companies do not save for the retirement of their fields.[18] Instead, it is presumed by companies and regulators alike that companies will be able to pay for the final decommissioning out of ongoing cash flow from younger fields, the successful outcome of reinvestment. The logic breaks when, as discussed above, the industry has bifurcated between horizontal drilling companies with significant reinvestment and companies focused on terminally depleting assets. What is more, some companies focused on mature fields have smaller, more focused portfolios of the same risk. Small companies are more susceptible, but correlated risks like those that triggered the U.S. housing collapse in 2008 can lead to the sudden failure of even large companies. Meanwhile, profits distributed to investors have crossed the corporate veil and reside out of reach of the liabilities.

Given the near-term risks and bifurcation of assets from liabilities, the situation begs the question of how to ensure that oil companies fulfill their "every obligation." Our remaining analysis attempts to answer that question: How great are forecasted future profits from existing wells in Colorado, compared to decommissioning liabilities?

7.1 Calculation of future cash flow is conventional and conservative

To be clear, we compare undiscounted future profits and liabilities, not discounted values. Future operating cash flows are often reduced to a discounted present value, both revenues and costs, for investment analysis. Discounting is intended to compensate for the uncertainty and delay inherent to future profits, but neither concept applies to decommissioning costs. Unlike profits, these costs are mandatory; state law requires that the clean-up work be performed. And the estimates of cost are likely to increase over time due to inflation and deterioration of the equipment. The relevant question is not an investment analysis, but cash-flow planning.

Our analysis looks at the oil and gas fields within the state, not at individual companies which may also own assets outside of the state. Many oil companies focus on a single jurisdiction, and many others separate operations into subsidiaries in separate jurisdictions, effectively isolating operational liabilities within the state from the profits returned to owners across the corporate veil. The parent companies of Occidental and Chevron subsidiaries have deep portfolios, which may or may not provide a corporate financial guarantee to the subsidiary fields in Colorado. Most other large and small companies operate exclusively or almost entirely within the state.

[18] To be clear, bonds are not voluntary saving mechanisms. As described above, they are contracts with a third-party to act like a co-signor, guaranteeing delivery of funds up to the limit of the bond which is usually a minute fraction of the company's overall liability. In some cases, the oil company does put funds in escrow with the bonding company or with the regulator or provide some other form of assurance, but the method of assurance is independent from the quantum of assurance. And the quantum is set, and not exceeded, by regulators.

To evaluate future cash flows, we forecast future production, prices, and costs using the same techniques and tools standard for evaluation of oil and gas fields. We did not forecast by hand every active well in the state, but instead we divided the state into over 50 separate, more homogenous groups designed to improve the reliability of the forecasts. The two important inputs that control future revenue—production volumes and commodity prices—rely on public data. We researched other inputs by reviewing public company filings, information on assets transacted, our own experience, and conversations within the oil industry. Finally, we corroborated the reserves implied by our projections against the statewide reserves reported by the EIA as described above. More information can be found in Appendix B.

The future will certainly be more complicated than our forecasts. We have not attempted to forecast the ongoing development in the Denver-Julesburg basin. Commodity prices will oscillate down and up, and those might trigger alternatively more shut-ins or more drilling in a number of the basins. The concentration of fixed costs or operational constraints could trigger the collective economic limit for groups of wells depending on the same infrastructure. In some basins, scarcity of support services due to decreased activity can increase costs and accelerate declines. Still, in terms of balance, we conclude that our economic model is reliable and conservative for the current purpose.

7.2 About half of the wells in the state have no reasonable prospect of providing for their own decommissioning under any form of conventional financial assurance reform

Our work shows that, of the nine basins in the state of Colorado, five are profoundly unable to pay for their own decommissioning, and that parts of three more basins are in the same position. Only one complete basin representing a few thousand wells remains in a good position to supply now the funds necessary for its decommissioning.

We previously grouped basins according to the similarity of their type of production and thus similarity in their development history. However, the current financial condition does not depend as directly on the timing of historical development. For compatibility with previous summaries, Table 7 shows the economic condition subtotaled by similarity of production. More meaningful is Table 8, which shows the same data but subtotaled according to financial condition.

TABLE 7: COMPARISON OF ESTIMATED DECOMMISSIONING COSTS AND REMAINING CASH FLOW AVAILABLE FOR DECOMMISSIONING GROUPED BY PRODUCTION SIMILARITY AS IN THE HISTORICAL DISCUSSION ABOVE.

Grouped by production similarity

Groups of Basins	Unplugged Wells	Est. Decommissioning Cost ($M) per CTI method	Est. Decommissioning Cost ($M) Extrapolated	Est. Future Cash Flow ($M) Available for Decomm	Shortfall per CTI method	Shortfall Extrapolated
Piceance	16,157	($3,020,000)	($3,775,000)	$1,022,000	($1,998,000)	($2,753,000)
Gassy Basins	6,276	($380,000)	($475,000)	$1,858,000	$1,478,000	$1,383,000
DJ and Oily Basins	14,138	($1,706,000)	($2,133,000)	$234,000	($1,472,000)	($1,899,000)
DJ Horizontals	11,217	($1,659,000)	($2,074,000)	$17,852,000	$16,193,000	$15,778,000

TABLE 8: COMPARISON OF ESTIMATED DECOMMISSIONING COSTS AND REMAINING CASH FLOW AVAILABLE FOR DECOMMISSIONING GROUPED BY SIMILARITY OF FINANCIAL CONDITION.

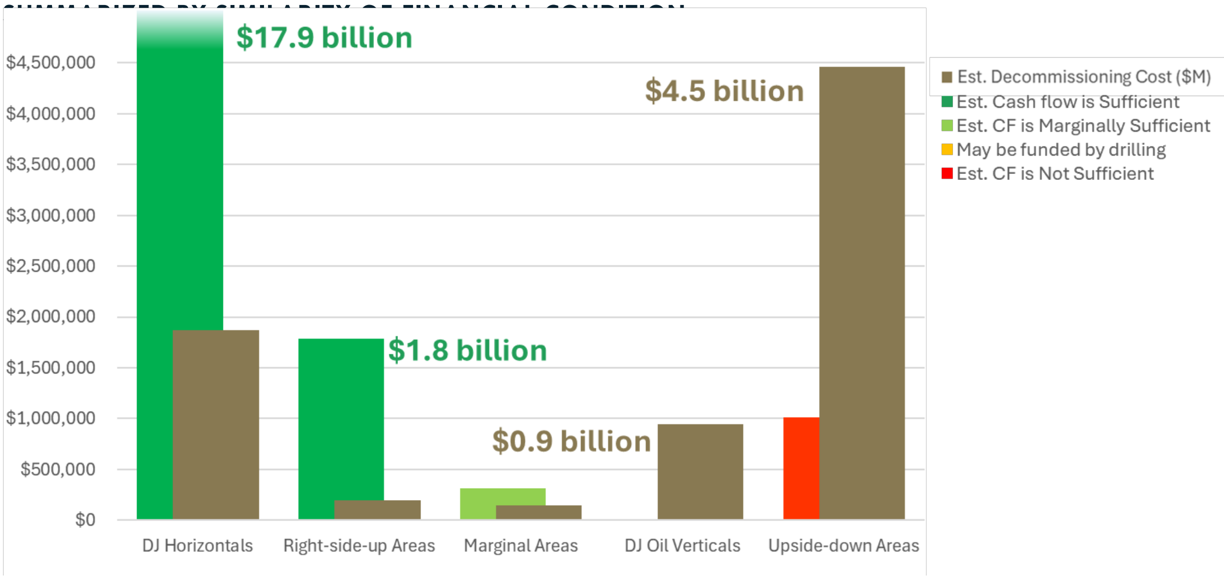
Grouped by financial similarity

Groups of Basins	Unplugged Wells	Est. Decommissioning Cost ($M) per CTI method	Est. Decommissioning Cost ($M) Extrapolated	Est. Future Cash Flow ($M) Available for Decomm	Shortfall per CTI method	Shortfall Extrapolated
DJ Horizontals	11,217	($1,659,000)	($2,074,000)	$17,852,000	$16,193,000	$15,778,000
Right-side-up Areas	2,462	($172,000)	($215,000)	$1,787,000	$1,615,000	$1,572,000
Marginal Areas	1,472	($133,000)	($166,000)	$316,000	$183,000	$150,000
DJ Oil Verticals	5,239	($838,000)	($1,048,000)	$0	($838,000)	($1,048,000)
Upside-down Areas	27,398	($3,963,000)	($4,954,000)	$1,010,000	($2,953,000)	($3,944,000)
Existing assurance over 5 years		$605,000				
Total exposure of taxpayers (current cost, avg)		**($7,006,000)**		**$20,965,000**	**Total cash flow of industry (existing wells only)**	

Figure 10 shows the same data graphically. Each pair of columns represents a group of basins or areas shown in the table above. For each, the dark column represents the middle of our range of estimated current decommissioning costs (without adjustment for inflation). The variously colored bars behind represent our estimates of future cash flow from existing wells (excluding ongoing drilling). The color of the cash flow bar indicates our interpretation of the sufficiency of projected future cash flow to cover the current estimate of costs.

Unplugged wells within groups calculated to have sufficient cash flow remaining to fund their own decommissioning are shown in green, including DJ Horizontals and other right-side-up areas detailed in the table above. Areas that are currently able to fund decommissioning but will become unable in a few years' time are called "marginally sufficient" and shown in light green. Vertical wells which may be plugged in order to accommodate horizontal drilling (as discussed below) would be shown in gold except that we calculate these areas already unable to pay normal operating expenses—so there is no projected revenue. Finally, areas clearly unable to fund their own decommissioning appear in red.

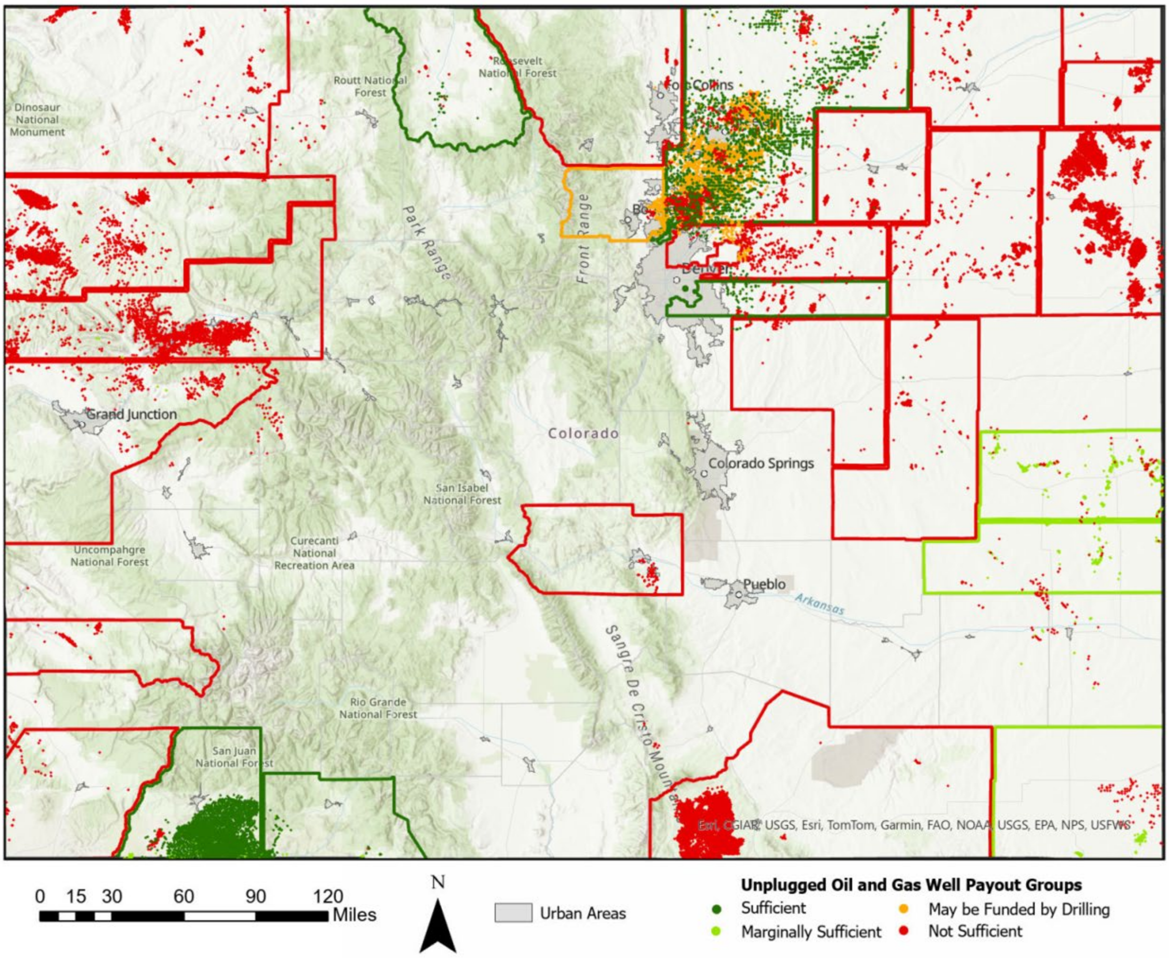
FIGURE 10: BAR CHART TO COMPARE CASH FLOW AND CURRENT DECOMMISSIONING COSTS AS



The graph reinforces how lopsided and separate the liabilities are from the profitable operations, separate regions but also separate oil companies. As a whole, however, the industry in Colorado has more than enough expected future revenue from existing wells to fund the statewide clean-up. We estimate about $21 billion in future profits within the state, plus the profits that will result from ongoing drilling activity that we have not quantified. Meanwhile, the total unsecured liability of the industry is about $7 billion without consideration for future increases.

Figure 11 maps the same categories using the same color scheme as above applied to unplugged wells in the state. The greens represent sufficient or marginally sufficient, the red represents clearly insufficient, and the gold represents wells that are insufficient but may be funded by ongoing activity. In addition, counties with more than 50 wells are outlined in the color most common within their borders. Appendix C includes a series of maps showing how these categories of wells are situated in relation to surface issues like water resources, political boundaries, and disadvantaged communities.

FIGURE 11: MAP OF UNPLUGGED WELLS COLOR-CODED BY SUFFICIENCY OF PROJECTED CASH FLOW TO FUND DECOMMISSIONING. COUNTIES WITH MORE THAN 50 WELLS OUTLINED IN THE COLOR MOST COMMON WITHIN ITS BORDERS. (SOURCES ESRI, USGS, USFWS, FAO)



The single basin in the state uniformly able to set aside money now to fund its decommissioning is the San Juan basin south of Durango. The wells are productive, decline slowly, and cost little to decommission. In the Denver-Julesburg basin, it is unsurprising that horizontal, massively fractured wells drilled recently retain the ability to pay for their own decommissioning; decommissioning costs a fraction of the cost of drilling and completing. Of course, if these wells do not save for their own retirement, then they also will deplete into poverty. More importantly, the basin also includes separate populations of wells owned by other companies, late-life liabilities not guaranteed by their neighbors' drilling success.

A small group of horizontal wells in the North Park basin also remain flush while old vertical wells teeter toward the orphan well list. Similarly in the Anadarko basin in the southeast corner of the state, a few hundred oil-producing wells seem capable while a few hundred gas wells appear to be systematically upside down. Assuming that the same companies own both oil and gas wells, projected cash flow is likely to suffice. However, we estimate that the remaining cash flow will fall below our estimate of decommissioning costs in less than four years. North Park and Anadarko are relatively minor, but the size of the DJ basin makes the disparity in value worth a detailed explanation.

The Denver-Julesburg basin subdivides into three areas. On the far east near Kansas sit nearly 4,000 unplugged wells that produce mainly gas. On the west side and impinging on the northern sprawl of Denver sits the Wattenberg field, which hosts the large majority of drilling activity. Situated in between is an area of old oil wells that demonstrated less success with horizontal drilling.

The gassy eastern counties are dominated by a single private company called OWN Resources, which bought the fields out of bankruptcy in 2018 when gas prices were lower. The wells are cheaper than most to decommission and may cost less than our model estimates. On the other hand, its nearly 3,300 unplugged wells average production of only 10 mcf/d. Only one new well has been drilled in the area since 2015, and OWN has plugged an average of only 11 wells (0.3% of its inventory) each of the last four years.

The story of the second-largest operator in the area tends to support this interpretation. In 2022, even as gas prices remained well above average, OMIMEX Petroleum abandoned its nearly 350 wells in the area, and the ECMC is now in the process of adding them to its orphan well list to be plugged with taxpayer money. While OMIMEX's wells did produce less than OWN's, it is interesting that neither OWN nor anyone else purchased these wells. OMIMEX simply walked away.

In contrast to the pace of plugging on the eastern side of the basin, the pace of plugging old vertical wells in the oily parts of the basin has been robust, as operators make space for horizontal drilling. The plugging will continue as long as the drilling of new horizontals, but it is highly unlikely that new drilling will take care of all the 5,200 remaining vertical wells in the oily parts of the basin. It is also unlikely that horizontal drilling will permeate to the same extent as historical vertical drilling in the Wattenberg field or the less active central oily area, both of which have already seen area drilling slow down.

The other basins of the state mostly resemble the situation of KP Kauffman in the oily part of the Denver-Julesburg basin and OWN Resources in the gassy part. We calculate the Piceance, Green River, Paradox, South Park, and Raton basins with nearly 20,000 unplugged wells to be profoundly unable to pay for their decommissioning. Most important are the 16,200 unplugged wells in the Piceance basin on the western slope near Grand Junction. Operators have in recent years tested several formations with modern drilling and completion techniques, but none have proven economically viable.

Three oil companies dominate the Piceance basin. All three are privately owned, and all three are focused within this region. Most important is Terra Energy Partners (TEP), which operates as many wells in the state as Chevron but is backed by the same private equity firm, Kayne Anderson, that backed HRM Resources. The shared backing deserves note because HRM Resources is currently being sued for the allegation that it sold wells knowing that they would be orphaned by the purchasers.[19] By our calculation, TEP has the largest decommissioning liability in the state, $1.34 billion to $1.67 billion, but its well plugging bonds total only $19.5 million.[20]

The second-largest company in the basin also holds the second-largest liability in the state. Caerus Operating is backed by private equity, and it also owns some similar wells in a closely related basin across the border in Utah. On the Colorado side, we estimate its liability to be $1.06 to 1.33 billion, and its well plugging bonds total $15.2 million.

The last company of note in the Piceance basin on the western slope is Laramie Energy, a privately held company with no wells outside of the basin. It has the sixth-greatest liability in the state at $280 to $360 million secured by $18.5 million of bonds. Together, these three companies have approved financial assurance of only $53.2 million compared to their collective liability of $2.68 to $3.35 billion.

Given the early potential for shale development in the Piceance basin, it made sense as a home for private-equity companies. It is possible that significantly higher commodity prices could stimulate more drilling in these plays, but as reality stands now, we estimate that all future cash flow over about 20 years of remaining economic life would suffice to fund about one-third of the current cost to decommission, as estimated by our methodology if those profits were all applied to decommissioning. The situation begs the question of what is likely to become of these old fields, given their type of owner, lack of diversity and lack of value in their portfolios.

Like the Piceance basin, the other low-producing areas unable to pay for their own are situated adjacent and among the mountains of the state. The Raton basin's 2,900 gas wells sit between the town of Trinidad and the spine of the Sangre de Cristo Mountains. Operations are dominated by Evergreen Natural Resources, a private limited liability company with nearly 2,300 wells in the basin and no other operations elsewhere. They acquired the properties from Pioneer Resources in 2018 at a price well below the going rate for gas properties, and Pioneer recorded a loss on the sale—both of which indicate the financial stress on the property six years ago. Pioneer had stopped drilling years before the sale but had maintained a pace of plugging several dozen wells each year. Since taking over, Evergreen has drilled only three wells and reportedly plugged only six wells, evidencing the lack of opportunity and the lack of willingness to use funds for clean-up. We estimate the company's liability to be $113 to $141 million by our methodology, but the company has only $1.55 million in well plugging bonds currently. More to the point, it has proposed to the ECMC a downward revision to only $6.57 million under

the reformed rules. ECMC has not yet approved the proposal.

Nearly 500 unplugged wells sit in the Green River basin in the northwest corner of the state, likely unable to pay for their decommissioning. Operators have been plugging an average of 13 wells per year over the last five years, including as few as two wells in 2023. Over 200 oil and gas wells sit in the Paradox basin around the town of Cortez in the southwest corner, and its dominant

[19] McCormick v. HRM Resources. Legal complaint in McCormick v. HRM Resources filed in District Court, Adams County, Colorado on Feb 22, 2024, https://www.clientearth.us/resources-publications/legal-complaint-mccormick-v-hrm-resources/

[20] ECMC, *ECMC Financial Assurance Tracking Report,* Colorado Energy & Carbon Management Commission website, Colorado Department of Natural Resources, accessed and downloaded 2024-06-22 8 a.m. https://ecmc.state.co.us/cogisdb/ReportTools/FA/FATrackRpt

operator remains in bankruptcy since filing last year. A smaller population of wells sit south of the town of Canyon City on the edge of the front range, and while they show low rates of production, plugging has averaged only one well per year. A similar population of older wells sits in the North Park basin in Jackson County, surrounded by ranges on all four sides, and plugging the last three years has also proceeded at the pace of one per year.

Back at the other end of the spectrum, the San Juan basin and the horizontal drilling of the Denver-Julesburg can currently afford to set aside funds to pay for decommissioning. If they do not set aside the funds, though, these formations will decline into the same position as other basins. Another 5,200 wells may be plugged in the course of additional drilling, but wells not plugged by the drilling companies will lack the funds for clean-up.

More importantly, over 27,000 wells reside in basins without reasonable prospect of meeting their clean-up obligations even under the reformed financial assurance. We estimate the current clean-up costs in these areas to be about $4.0 to $5.0 billion dollars. With no change in policy, these costs will inflate and fall to taxpayers in the coming years. Even if all available future cash flow from these areas were dedicated to the clean-up, taxpayers would still be exposed to billions of costs related to these former profit centers.

8 Conclusions

It is clear from the first well drilled that the field will eventually die, and decommissioning an oilfield involves much more than plugging wells. By the time most of those costs come due, the remaining profit in the field is, by definition, nil. The capital required to clean up and to protect the land and environment offers no financial return, and it is far larger than the preceding cash flow from operations. There are practically no market-based incentives to decommission defunct oilfield infrastructure; there is more money to be made by walking away from these obligations.

Policy protects the public, and that policy must follow from the nature of the risks. The public alone bears the risk to the land, but the fiscal risks are at least as substantial for the public as the costs are to oil companies. The basic alternatives are simple: either require oil companies to pay for clean-up or raise funds from taxpayers for the government to take over the task. It is at best a zero-sum decision between the industry's profits and the public's taxes. Whatever the industry does not pay will come from the tax-paying public, and possibly more.

Colorado is not the only jurisdiction to unsuccessfully reform its financial assurance regime. Like reforms on federal lands, recent experience in Colorado shows that negotiation and compromise cost six years of delay with no tangible improvement. Meanwhile, our analysis demonstrates the probability of widespread orphaning of oilfields in Colorado at a cost of billions to taxpayers, and it demonstrates that delaying reform exacerbates that risk.

The need for financial assurance and the track record of failed reform strongly recommends a search for new policy tools and different processes. A new policy would ideally be simple to implement, comprehensive to cover the full scope of costs for the full range of companies, and easy to adapt to unfolding dynamics during implementation. It must fit the current reality of the bifurcated industry, so it may have several parts.

It is certain to be imperfect, and oil companies are certain to object to their loss in this zero-sum policy game. If decommissioning requires most or all of the remaining cash flow from a field, then effective financial assurance will deprive the owners of the fields of most or all future profits from those fields. On the other hand, the need for plugging wells, removing facilities, remediating pollution, and restoring the land has always been clear since the first barrel was sold.

9 Appendices

APPENDIX A: ESTIMATES OF DECOMMISSIONING COST PER WELL.

APPENDIX B: BACK-UP MATERIALS FOR FORECASTS OF FUTURE CASH FLOW.

APPENDIX C: OIL AND GAS INFRASTRUCTURE MAPPED IN RELATION TO VARIOUS SURFACE CONSIDERATIONS

10 Appendix A: Estimates of decommissioning cost per well.

10.1 Recent inflation

Capital cost increases in the industry were anecdotally reported to range from 15% to about 40% at this time, but the three sets of recent survey results suggest a lower range. S&P Global Commodity Insights publishes a handful of cost indices each quarter, including its North American Capital Cost Index (NACI) which is most closely related. It shows that upstream capital costs have increased on average 22% since COVID, primarily during 2021 and 2022. Measured from the price levels before the decline triggered by COVID shut-downs, the increase is only 11% over costs in late 2019. The Bureau of Labor Statistics reports a monthly cost index for oil and gas field machinery, which is more removed from the costs of decommissioning. Still, it reflects a 16% increase since 2019. The Federal Reserve Bank of Dallas publishes a quarterly survey of the oil industry including qualitative feedback on cost increases. Its work shows a dip around COVID followed by increases that were several times as large as observed in some prior years.

At present, the overall rate of oil field inflation appears to have returned to normal levels which are generally expected to be on the order of 2% to 3% per year. It may be noted, however, that increasing demand, aging infrastructure, and the potential for increasing requirements put additional upward pressure on price while the use of inexpensive materials and the paucity of innovation suggest that technology is unlikely to bring costs down.

10.2 ECMC experience

The experience of the ECMC plugging orphan wells in Colorado—and its expectations based on that experience—may be viewed as a basis for future costs, but unfortunately, the information remains limited and possibly skewed.

As described above, the ECMC in mid-2021 relied upon the experience of decommissioning only 23 wells statewide to inform its default amount for single well bonds; it observed a historical average of $93,000 per site. The sites are scattered across the state but concentrated in the same region as most unplugged wells in the state. For individual sites, costs ranged from $25,000 to $291,000, and because they are actual costs, they do include the costs of any contingencies encountered. On the other hand, the data does not allow us to discriminate regional variations of costs nor the cost of contingencies.

Early the next year, the ECMC submitted a grant proposal for the Department of the Interior for funds to plug orphan wells in which it requested $11.0 million to plug 61 wells, remediate 104 sites, and reclaim another 202 sites. It is not clear which wells and sites it had in mind nor how it came to its estimate, but the detailed budget does show that the average cost to plug, remediate, and reclaim a single site is implied to be $128,400 including program and administrative costs.

Since that time, the ECMC has continued to work on orphan wells, but it appears not yet to have completed the decommissioning of any additional wells. A financial status report published in March of this year showed that, during the last four fiscal years the Orphaned Well Program worked on 484 sites, but it had completed work on only 23, the same number as in 2021. Various reports we reviewed about the program do not contain enough information to determine the cost or the progress achieved for any of those nearly 500 projects. We do observe that the program has spent an average of $66,900 per site to achieve whatever it did accomplish, but we cannot determine what these figures say about the accuracy of previous estimates.

Contemporaneous to its grant application two years ago and during the period when inflation continued to rise rapidly, the final rules promulgated by the ECMC set a default single-well bond value ranging from $110,000 to $140,000 depending upon the depth of the well. The median bond figure of $130,000 is 40% higher than the average of the 23 wells completed in the years before mid-2021, but is it also the same figure, with rounding, as solicited in its grant proposal. This remains the most concrete figure for statewide average well site decommissioning costs available from ECMC data. Weak as it is, it remains the most primary evidence of the liability taxpayers need to protect against.[21]

10.3 Operators' costs filed with the ECMC

In some cases, ECMC accepted the evidence presented by the companies and allowed for less bonding, but in other cases, the regulator deemed the company's estimates unreliable. This dataset suffers two structural shortcomings.

First, the system gives oil companies an incentive to understate their costs, as evidenced by the fact that ECMC rejected some companies' estimates. Second, operators with costs higher than the default per-well bond are incentivized to accept the lower default value instead. The systematic incentives for downside bias make the data unhelpful, though the submissions may help to clarify dynamics in select areas as described below.

10.4 Experience of Denver International Airport

The Denver International Airport has recently plugged, removed, and remediated 64 wells sites as well as associated flowlines and surface equipment in the Denver-Julesburg (DJ) basin which is home to most of the wells and most of the liability in the state. It thus serves as a concrete measure of current costs.

News reports suggest that the decommissioning costs were estimated in 2019 to be $9.2 million, making an average cost of $144,000 per well including facilities and flowlines before the recent inflation. The reporting also suggests that about one-third of that cost is related to the facilities and flowlines. When the final contract was signed last year, after the spurt of inflation, the cost totaled $12.5 million, or $195,000 per well, and 36% higher than the 2019 estimate. Using the same proportions implied by previous reporting suggests that the decommissioning costs ran about $130,000 per well and that the remaining third went to facilities and flowlines.

The sample is larger than the ECMC's, but still small. On the other hand, the costs are current, known, and relevant to the most important group of wells in the state. It will also be interesting to see what the final cost turns out to be in this sample once the work is complete.

[21] We also reviewed information about plugging orphan wells on federal land in the experience of the Bureau of Land Management but found no data.

10.5 Investor disclosures

To further constrain the likely cost of decommissioning we have researched filings made by public companies with the Securities and Exchange Commission. On the one hand, oil companies disclose little information about their decommissioning liabilities, mostly indirectly. On the other hand, our exhaustive search of companies focused in Colorado back to 2017, combined with third-party data, yielded several situations in which we could reasonably triangulate the underlying estimate of decommissioning costs. We have isolated a number of data points from annual spending on decommissioning, from transactions of assets in Colorado, and from overall decommissioning costs for companies concentrated there.

Companies disclosed their "asset retirement obligations" (AROs) among their liabilities. However, they have historically disclosed superficial information about current spending, timing of future spending, and total cost in the future. Mostly, public companies provide a grand total liability discounted to a present value without providing sub-totals by asset or type of work. Because they rarely provide either the discount rate used or the average years of delay, their estimate of the amount due and its timing remain obscured behind one discounted total. On a much smaller scale, companies disclose the AROs settled in the previous year and the total expected for the next year but again without supplying the wellcount, locations, or scope of work.

10.5.1 Annual spending

Our research found seven instances from three companies for which we found both a sufficient disclosure of actual annual spending and a reasonable estimate of the number of wells plugged from the records of the ECMC. Table 9 summarizes those results.

TABLE 9: INTERPRETED ANNUAL SPENDING ON DECOMMISSIONING PER WELL BASED ON SEC FILINGS OF PUBLIC COMPANIES WITHIN THE DENVER-JULESBURG BASIN.

Year	Cost per Well		Company
2017	$	104,829	Extraction Oil & Gas
2018	$	159,238	Extraction Oil & Gas
2019	$	328,846	Extraction Oil & Gas
2019	$	104,411	Bonanza Creek Energy
2020	$	160,968	Bonanza Creek Energy
2021	$	77,806	PDC Energy
2022	$	84,016	PDC Energy
2019	**$**	**146,000**	**Average**

Interpreting these figures should bear in mind that the number of wells is the number of wells for which downhole plugging forms were submitted by the operator, but that is a mid-way point in the decommissioning operations. After downhole plugging, the surface must be cleared, remediated, and restored, and these subsequent costs can often be as much or much more than the downhole plugging. It is possible, then, that the costs each year represent a small portion of the necessary scope of work. It should also be noted that these historical activities probably address only individual wells and not the facilities shared among wells that will eventually need decommissioning.

We observe that one company is markedly lower than the other two, and that one year calculates a figure much higher than others. We further observe that annual spending per well does go up each year for all three operators studied. Given the caveats and timing of the data, we deem it most appropriate to average across all the years and operators, and we observe an average of $146,000 per well at an average date in 2019 spent by operators in the main Denver-Julesburg basin.

10.5.2 Transactions

Our research uncovered nine such reports seven transactions, though the reported ARO value is reported as a discounted present value. In order to estimate the cost implied by the transactions it is necessary to assume both a discount rate and a delay until they come due. Our research identified just a couple of instances in which the discount rate was identified, and those ranged from 10% to 14.25%. In the absence of explicit information, we assume the reported values used a discount rate of 10%, and we have assumed a range of delays to bracket the implied cost.

TABLE 10: SUMMARY OF PRESENT VALUE AND ESTIMATED UNDISCOUNTED COST PER WELL OF DECOMMISSIONING FROM TRANSACTIONS IN COLORADO.

	Discounted Cost	Undiscounted Cost			
Year	**per Well**	8 yrs	10 yrs	15 yrs	**Transaction**
2017	$ 41,847	$ 90,000	$ 109,000	$ 175,000	Hilcorp from ConocoPhillips in San Juan basin
2017	$ 27,469	$ 59,000	$ 71,000	$ 115,000	Bill Barrett from HRM
2018	$ 32,549	$ 70,000	$ 84,000	$ 136,000	Bayswater to PDC
2020	$ 116,667	$ 250,000	$ 303,000	$ 487,000	HighPoint to HRM
2020	$ 38,561	$ 83,000	$ 100,000	$ 161,000	SRC to PDC
2020	$ 67,705	$ 145,000	$ 176,000	$ 283,000	HighPoint to Civitas (HighPoint)
2021	$ 61,769	$ 164,000	$ 210,000	$ 386,000	HighPoint to Civitas (Civitas)
2020	$ 102,409	$ 220,000	$ 266,000	$ 428,000	Extraction to Civitas (Extraction)
2021	$ 74,282	$ 159,000	$ 193,000	$ 310,000	Extraction to Civitas (Civitas)
2020	$ 65,000	**$ 144,000**	**$ 175,000**	**$ 288,000**	**Average in Denver-Julesburg**

10.5.3 Corporate totals

The data above pertains mostly to smaller groups of wells and to previous years, but a similar analysis can be made of company-wide decommissioning costs in more recent years from the last two public companies while they reported Colorado operations separately: PDC Energy and Civitas Resources. In 2023, PDC was purchased by Chevron, and Civitas expanded into Texas. We can, however, deconstruct their reporting in 2021 and 2022 about discounted corporate AROs to estimate the implied undiscounted per-well costs, and the results are shown in Table 11.

TABLE 11: PER WELL DECOMMISSIONING COSTS IMPLIED BY TOTAL CORPORATE AROS FOR PUBLIC COMPANIES IN 2021 AND 2022.

	Asset Retirement Obligations		Cost Per Well		
	Discounted AROs (M$)	Net Wells	Discounted	Undiscounted <5 yrs	Undiscounted <7 yrs
PDC Energy					
2021 YE	$ 159,672	2,675	$ 59,695	**$ 85,000**	
2022 YE	$ 197,651	3,152	$ 62,707	**$ 92,000**	
Civitas					
2021 YE	$ 225,315	2,271	$ 99,205		**$ 173,000**
2022 YE	$ 291,026	2,536	$ 114,758		**$ 201,000**

In their corporate estimates of the present value of decommissioning costs, both companies recently recorded significant upward revisions, consistent with the experience of macroscopic inflation discussed above. From the start of 2020 to the end of 2022, PDC Energy recorded revisions to previous ARO estimates totaling around 22%. Civitas recorded a 28% upward revision just during 2022, but they previously recorded an upward revision of 7% in 2020 and between 6% and 46% during 2021 depending on whether the revision is assumed to apply to new acquisitions.

To unwind the present value estimates into undiscounted figures, we assumed as above that the companies used a 10% discount rate. In the case of Civitas, the choice is reinforced by the fact that the rate was explicitly stated for Extraction Oil & Gas in the 2021 "merger of equals" that created the company. Timing of the costs was estimated from the schedule of costs provided in some years. It is interesting to note that the companies in recent years stopped providing a schedule of costs, and it is more interesting given that the disclosures show the liabilities front-loaded in the near future. Reverse-engineering their schedules shows that the average delay until the realization of PDC's asset retirement obligations is less than five years and is probably less than seven years for Civitas, implying the short remaining economic life of much of their portfolios.

The figures of Civitas prove consistent with both transactions and single-year spending of its predecessors presented above. Estimates from PDC Energy are also consistent with the prior analyses, and like the prior analyses, their estimates are systematically lower than those of other companies. We do note, though, that the decommissioning costs added to the corporate total due to drilling imply a decommissioning cost much higher and more consistent with other operators, suggesting that PDC's figures may assume a narrower scope of work, or perhaps a narrow set of its wells.

10.6 Internal methodology

Carbon Tracker has created and used its own internal algorithm to estimate decommissioning costs broadly across the country in a series of reports since 2021; we updated that methodology and improved our input data for this analysis of Colorado. In the end, it generates figures on average somewhat below the actual costs demonstrated above, but it does adjust the figures to account for the substantial differences between wells in the Denver-Julesburg basin, which dominates the available data above, and the many other disparate basins in the state.

Our model correlates decommissioning costs in orphan well programs from a number of states with the true vertical depth of the well, a primary driver of costs and a well-documented data point.

The methodology does not adjust for inflation from earlier data points, and it does arrive at values similar to but lower than the best actual data above. For vertical oil wells in the same basin, the model predicts an average of $151,000 per well, though other nearby groups of wells range higher and lower. This most direct comparison suggests that current costs are 16% to 32% higher than our model. By comparison, when we have been able to compare our cost estimates to more detailed analyses in other jurisdictions, we have found that the all-in cost turned out to be two to three times as great as our estimate. [22]

The model also has the flexibility to estimate costs in regions with substantially different well characteristics. For example, the shallow gas wells of the Raton basin located in the hills and forests of south-central Colorado are estimated to average about $50,000 per well. Costs in the San Juan basin is estimated to average $69,000, but one data point in our research suggests that the cost was greater than $100,000 in 2017. At the other end of the scale, only 10% of wells are assigned retirement costs greater than $216,000.

11 Appendix B: Back-up materials for forecasts of future cash flow.

We divided the state into 56 groups for forecasting purposes, but we excluded from both our cost and cash flow estimates the small number of wells in the state dedicated to producing carbon dioxide and those used for natural gas storage. The groups vary widely in size, and they are rolled up to various levels in the report.

We forecast historical trends of production using standard engineering techniques that rely upon public data about rates reported by the companies to the ECMC. As is also common in the oil industry, we used recent prices set by futures contracts as the basis for our estimate of future commodity prices. They represent a market-driven snapshot estimate of future prices, though they do differ somewhat from historical averages. These two major inputs—production and price—from public and standard data go most of the way to controlling the future gross revenues from existing wells.

Other economic inputs were estimated from experience and research into public data. Like abandonment costs, information such as royalty burden, price differentials, and operating costs are not reported in the same way as production data. We researched annual reports and investor presentations of public companies as far back as 2015. We reviewed non-confidential material and public reporting about asset transactions. Besides drawing upon the experience within our team, we interviewed several individuals with experience conducting operations in the state. When research left us with an uncertain range for input, we favored assumptions that forecast greater cash flow in order not to dodge an undeservedly pessimistic outcome.

Because we are attempting to estimate the funds available to pay for decommissioning, we also estimated and subtracted the corporate general and administrative (G&A) costs related to the fields. Corporate costs are as needed, if less direct than operating costs incurred in the field, and

[22] (Purvis and Schuwerk 2022; Purvis and Purvis 2023)

those funds are equally unavailable to pay the capital costs of decommissioning. We do note that G&A costs like debt financing, executive management, and accounting services can vary significantly between operators, but we also note that corporate costs tend to be a greater portion of overall costs as wells deplete. For this input, we used the same concept used when oil companies bill each other for the overhead associated with production, a fixed number of dollars per well per month.

As a step of validation, we compared our forecasted volumes to the reserves reported by operators and compiled by the EIA into its national reserves reports. As described above, the report relies primarily upon reserves reported by companies to the EIA and extrapolates reported volumes for the minority of production not reported, making it mostly a firsthand account of reserves according to the owners of the fields. We find our forecasts rolled back to a previous date to be consistent with the reserves estimated at that previous point in time. Still, it should be noted that the pattern of reporting implied a good deal of uncertainty in the EIA estimates and that the agreement statewide says little about agreement within the minor basins.

			Price Differentials						Operating Costs			Oil Decline Params			Gas Decline Params			Well Count Decline Params		
Basin	Case Name	Royalty burden	Oil Price Diff	Gas Price Diff	Gas Shrink	Gas Energy MMBTU	NGL Yield, bbl/MMcf	NGL Price Diff	$ per well per month	$ / bw	$ / bo	Initial rate, bopm	Decline	Oil BFactor	Initial rate, Mcfm	Decline	Gas BFactor	In Group	Active	Decline
ANADARKO	Anadarko - Gas	12.5%	$ 3.70	$ (0.60)	0%	970	0	0%	$ 1,800	$ 1.50	$ -	1,971	9.4%	0	212,943	8.5%	0	924	150	2.0%
ANADARKO	Anadarko - Oil	12.5%	$ 3.70	$ (0.60)	22%	1000	0	0%	$ 4,200	$ 1.50	$ -	62,563	4.0%	0	130,853	3.3%	0	1,484	288	1.3%
DENVER-JULESBURG	DJ - Gas Counties	12.5%	$ -	$ (0.65)	10%	1000	0	0%	$ 550	$ 1.50	$ -	-	0.0%	0	974,760	8.0%	0	4,278	3,359	3.2%
DENVER-JULESBURG	DJ - Other Oil Horiz Gas 2014 - 2016	18.0%	$ (5.00)	$ (0.65)	5%	1100	0	0%	$ 5,000	$ 1.50	$ 1.50	262	53.3%	0	6,334	24.0%	0	43	8	13.2%
DENVER-JULESBURG	DJ - Other Oil Horiz Gas 2017	18.0%	$ (5.00)	$ (0.65)	5%	1100	0	0%	$ 5,000	$ 1.50	$ 1.50	745	30.7%	0.3	20,362	14.6%	0.8	7	5	3.0%
DENVER-JULESBURG	DJ - Other Oil Horiz Gas 2019	18.0%	$ (5.00)	$ (0.65)	5%	1100	0	0%	$ 5,000	$ 1.50	$ 1.50	5,253	34.4%	0.5	145,610	18.6%	0.8	18	17	3.0%
DENVER-JULESBURG	DJ - Other Oil Horiz Gas 2020 - 2021	18.0%	$ (5.00)	$ (0.65)	5%	1100	0	0%	$ 5,000	$ 1.50	$ 1.50	28,689	34.5%	0.5	720,386	24.7%	0.8	43	41	2.2%
DENVER-JULESBURG	DJ - Other Oil Horiz Oil 2014	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	73,067	17.4%	0.5	274,290	14.1%	0.8	510	319	6.0%
DENVER-JULESBURG	DJ - Other Oil Horiz Oil 2015	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	51,204	15.6%	0.5	262,805	3.6%	0	183	160	3.0%
DENVER-JULESBURG	DJ - Other Oil Horiz Oil 2016	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	16,941	17.5%	0.5	75,785	14.3%	0.8	61	53	3.0%
DENVER-JULESBURG	DJ - Other Oil Horiz Oil 2017	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	67,543	17.6%	0.8	337,281	15.2%	0.8	174	151	5.3%
DENVER-JULESBURG	DJ - Other Oil Horiz Oil 2018-19	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	206,584	20.5%	1	761,031	21.4%	0.8	319	268	5.0%
DENVER-JULESBURG	DJ - Other Oil Horiz Oil 2020	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	124,413	24.7%	1	676,228	23.6%	1	106	98	3.0%
DENVER-JULESBURG	DJ - Other Oil Horiz Oil 2021	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	349,251	36.1%	1	1,819,620	24.6%	1.2	176	167	3.6%
DENVER-JULESBURG	DJ - Other Oil Horiz Oil 2022	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	493,799	54.4%	1	1,752,890	30.8%	1.2	132	127	3.6%
DENVER-JULESBURG	DJ - Other Oil Horiz Oil 2023	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	988,955	70.7%	1	2,404,380	36.7%	1.2	139	125	3.6%
DENVER-JULESBURG	DJ - Other VUD	15.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 1,000	$ 1.50	$ -	77,607	14.3%	0	211,944	13.4%	0	10,283	1,384	7.0%
DENVER-JULESBURG	DJ - Wattenberg Gas Horiz	18.0%	$ (5.00)	$ (0.65)	5%	1100	0	0%	$ 5,000	$ 1.50	$ 1.50	612,339	28.7%	0	16,607,500	18.0%	0	2,193	1,861	3.3%
DENVER-JULESBURG	DJ - Wattenberg Oil Horiz 2014	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	313,938	15.0%	0	3,153,920	11.0%	0	1,747	1,221	4.8%
DENVER-JULESBURG	DJ - Wattenberg Oil Horiz 2015	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	155,109	15.0%	0	1,574,910	13.1%	0	636	496	5.8%
DENVER-JULESBURG	DJ - Wattenberg Oil Horiz 2016	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	112,705	20.0%	0.2	1,165,600	17.0%	0.2	400	307	5.0%
DENVER-JULESBURG	DJ - Wattenberg Oil Horiz 2017	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	249,172	22.1%	0.49	2,929,000	18.5%	0.5	620	554	3.4%
DENVER-JULESBURG	DJ - Wattenberg Oil Horiz 2018-19	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	927,055	24.3%	0.65	9,840,090	19.7%	0.6	1,545	1,362	3.0%
DENVER-JULESBURG	DJ - Wattenberg Oil Horiz 2020	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	341,504	28.1%	0.83	3,538,480	22.4%	0.8	353	319	3.2%
DENVER-JULESBURG	DJ - Wattenberg Oil Horiz 2021	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	977,444	36.0%	0.95	8,104,520	28.1%	1	599	558	3.2%
DENVER-JULESBURG	DJ - Wattenberg Oil Horiz 2022	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	1,555,490	51.9%	0.95	13,294,700	31.1%	1	487	456	3.2%
DENVER-JULESBURG	DJ - Wattenberg Oil Horiz 2023	18.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 5,000	$ 1.50	$ 1.50	5,265,310	81.0%	0.95	23,383,300	44.1%	1	610	579	3.2%
DENVER-JULESBURG	DJ - Wattenberg VUD	15.0%	$ (5.00)	$ (0.65)	25%	1000	100	-58%	$ 1,000	$ 1.50	$ -	30,899	27.8%	0	515,042	27.9%	0	27,753	1,350	25.4%
GREEN RIVER	Green River - Gas Horiz	18.0%	$ (4.20)	$ (0.71)	9%	1177	0	0%	$ 7,000	$ 1.50	$ 1.50	28	25.8%	0	6,540	23.4%	0	13	3	8.0%
GREEN RIVER	Green River - Gas VUD	12.5%	$ (4.20)	$ (0.71)	9%	1177	0	0%	$ 2,000	$ 1.50	$ -	1,899	12.9%	0	484,253	8.6%	0	775	348	2.3%
GREEN RIVER	Green River - Oil Horiz	18.0%	$ (4.20)	$ (0.71)	9%	1177	0	0%	$ 7,000	$ 1.50	$ 1.50	1,286	35.4%	0	2,854	28.4%	0	34	5	12.7%
GREEN RIVER	Green River - Oil VUD	12.5%	$ (4.20)	$ (0.71)	9%	1177	0	0%	$ 3,000	$ 1.50	$ -	10,479	6.4%	0	11,262	14.8%	0	268	67	2.0%
NORTH PARK	North Park - Horiz	12.5%	$ (8.50)	$ (0.65)	40%	1000	0	0%	$ 7,000	$ 1.50	$ 1.50	85,115	43.9%	0.5	138,345	34.1%	0.7	81	38	10.6%
NORTH PARK	North Park - VUD	12.5%	$ (8.50)	$ (0.65)	40%	1000	0	0%	$ 1,400	$ -	$ -	1,600	22.9%	0	786	21.8%	0	218	16	11.2%
OTHER - COLORADO	Other - Colorado	12.5%	$ (8.50)	$ -	0%	1000	0	0%	$ 2,000	$ 1.50	$ -	1,718	6.0%	0	114	12.3%	0	111	47	2.5%
PARADOX	Paradox	12.5%	$ (6.00)	$ -	0%	1000	0	0%	$ 2,000	$ 1.00	$ -	6,819	13.1%	0	119,275	12.0%	0	446	106	4.0%
PICEANCE	Piceance - Gas 2014	15.0%	$ (8.50)	$ (0.57)	4%	1088	0	0%	$ 2,000	$ 1.00	$ -	59,995	13.5%	0	18,036,600	8.8%	0	19,763	15,210	1.1%
PICEANCE	Piceance - Gas 2015	15.0%	$ (8.50)	$ (0.57)	4%	1088	0	0%	$ 2,000	$ 1.00	$ -	1,528	16.2%	0.5	672,521	11.7%	0.5	277	258	1.1%
PICEANCE	Piceance - Gas 2016	15.0%	$ (8.50)	$ (0.57)	4%	1088	0	0%	$ 2,000	$ 1.00	$ -	1,500	17.8%	0.57	861,171	13.3%	0.6	297	277	1.2%
PICEANCE	Piceance - Gas 2017	15.0%	$ (8.50)	$ (0.57)	4%	1088	0	0%	$ 2,000	$ 1.00	$ -	2,631	16.8%	0.6	1,411,470	13.0%	0.6	445	421	1.3%
PICEANCE	Piceance - Gas 2019	15.0%	$ (8.50)	$ (0.57)	4%	1088	0	0%	$ 2,000	$ 1.00	$ -	11,372	15.1%	0.8	4,149,590	17.6%	0.8	813	769	1.4%
PICEANCE	Piceance - Gas 2020	15.0%	$ (8.50)	$ (0.57)	4%	1088	0	0%	$ 2,000	$ 1.00	$ -	3,443	19.0%	0.8	1,207,300	22.7%	0.8	108	103	1.1%
PICEANCE	Piceance - Gas 2021	15.0%	$ (8.50)	$ (0.57)	4%	1088	0	0%	$ 2,000	$ 1.00	$ -	3,242	31.2%	1	1,407,360	29.1%	1	108	102	1.3%
PICEANCE	Piceance - Gas 2022	15.0%	$ (8.50)	$ (0.57)	4%	1088	0	0%	$ 2,000	$ 1.00	$ -	15,542	54.7%	1	2,254,090	45.3%	1	125	124	1.4%
PICEANCE	Piceance - Gas 2023	15.0%	$ (8.50)	$ (0.57)	4%	1088	0	0%	$ 2,000	$ 1.00	$ -	11,831	88.2%	1	5,502,680	74.7%	1	150	136	1.5%
PICEANCE	Piceance - Oil Horiz 2014	18.0%	$ (8.50)	$ (0.57)	1%	1088	0	0%	$ 5,000	$ 1.00	$ 1.50	2,018	15.1%	0	377,666	8.5%	0	65	58	1.1%
PICEANCE	Piceance - Oil Horiz 2015 - 2021	18.0%	$ (8.50)	$ (0.57)	1%	1088	0	0%	$ 5,000	$ 1.00	$ 1.50	112	14.2%	0.5	214,723	12.6%	0.5	14	14	1.1%
PICEANCE	Piceance - Oil VUD	15.0%	$ (8.50)	$ (0.57)	1%	1088	0	0%	$ 6,000	$ 1.00	$ -	221,931	4.1%	0	36,303	8.4%	0	1,261	424	1.0%
RATON	Raton	14.0%	$ -	$ (0.40)	16%	1000	0	0%	$ 2,000	$ 1.50	$ -	-	0.0%	0	3,132,760	8.9%	0	3,775	2,503	1.1%
SAN JUAN	San Juan - CBM Horiz	20.0%	$ (11.00)	$ (0.65)	4%	1000	0	0%	$ 8,000	$ 2.00	$ -	-	0.0%	0	2,717,290	10.3%	0	182	150	1.1%
SAN JUAN	San Juan - CBM VUD	20.0%	$ (11.00)	$ (0.65)	4%	1000	0	0%	$ 2,000	$ 2.00	$ -	-	0.0%	0	12,056,600	8.5%	0	2,518	2,022	1.1%
SAN JUAN	San Juan - Gas 2014	20.0%	$ (11.00)	$ (0.65)	4%	1000	0	0%	$ 2,000	$ 2.00	$ -	-	0.0%	0	255,166	44.2%	0.2	1,440	792	1.1%
SAN JUAN	San Juan - Gas 2015 - 2021	20.0%	$ (11.00)	$ (0.65)	4%	1000	0	0%	$ 2,000	$ 2.00	$ -	-	0.0%	0	556,824	29.3%	0.5	13	10	1.1%
SAN JUAN	San Juan - Gas 2022	20.0%	$ (11.00)	$ (0.65)	4%	1000	0	0%	$ 2,000	$ 2.00	$ -	-	0.0%	0	1,342,740	39.0%	0.5	9	9	1.3%
SAN JUAN	San Juan - Gas 2023	20.0%	$ (11.00)	$ (0.65)	4%	1000	0	0%	$ 2,000	$ 2.00	$ -	108	17.0%	0	1,302,130	4.2%	0	16	12	1.9%
SAN JUAN	San Juan - Oil	20.0%	$ (11.00)	$ (0.65)	4%	1000	0	0%	$ 2,000	$ 2.00	$ -	1,045	5.5%	0	832	11.8%	0	195	49	1.1%

12 Appendix C: Oil and gas infrastructure mapped in relation to various surface considerations

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ECONOMY ENVIRONMENT

Oil and gas regulators float tiered financial-assurance system, 'amnesty' for risky wells

Long-awaited changes to bonding rules under discussion at COGCC

BY: **CHASE WOODRUFF** - JANUARY 28, 2022 5:10 AM

A view of oil and Gas development on Bureau of Land Management lands in Colorado, on July 12, 2017. (Bob Wick/BLM/Public domain)

Six years ago, officials in one of Colorado's fastest-growing school districts set out to build a much-needed third high school to serve several north Denver suburbs.

The site they selected, on unincorporated land eventually annexed by the city of Thornton, became Riverdale Ridge High School and the adjacent Rodger Quist Middle School — but not before the district was forced to plug and remediate three low-producing oil and gas wells, at a cost to local taxpayers of over $300,000.

"First, we had to find the operator," Terry Lucero, chief operations officer for School District 27J, told the Colorado Oil and Gas Conservation Commission on Thursday. "He was difficult to locate – no longer existed in the state of Colorado."

The wells in question weren't technically "orphaned," the term for wells that are abandoned to the state following an operator's bankruptcy. But they belonged to a subset of thousands of aging, unprofitable wells that are generally agreed to be as good as orphaned already; they produced almost nothing, and their operator couldn't afford to plug them.

"He agreed to sign the forms necessary for the plugging and abandonment, (but) he had no resources to provide for it," Lucero said. "And if we were going to use those school sites for the development of schools, we would have to absorb those costs."

Orphaned wells, and those at risk of being orphaned, are at the center of a rulemaking process currently underway at the COGCC, the state agency that regulates drilling. The commission's new rules on financial assurance, also known as bonding, have been in the works for more than a year, and are the last major policy required to be implemented by Senate Bill 19-181, the overhaul of drilling laws passed by Democrats in the General Assembly nearly three years ago.

Financial assurances are the security deposits provided to Colorado regulators by oil and gas companies seeking to drill within its borders. They're meant to cover cleanup costs in the event that an operator goes bankrupt and their wells are abandoned or "orphaned" to the state.

COGCC regulators, oil and gas companies and other groups appear to be nearing broad agreement on a set of ideas aimed at limiting the negative impacts of Colorado's highest-risk wells. But precisely how to define that risk – and the scope and stringency of the requirements to be placed on tens of thousands of other active wells across the state — remains up in the air.

Agency staff have released three drafts of proposed rule changes, and are expected to release a fourth early next month. Jeff Robbins, chair of the COGCC, on Thursday described the commission's multi-pronged approach to the new rules.

"It's got an orphaned well backstop, it's got tiers, it's got financial assurance plans, it's got an out-of-service program, it's got plugging and abandonment incentives," Robbins said. "It's coming at it from various angles."

'Amnesty' program considered

Colorado's current financial assurance rules have long been criticized by environmental groups as inadequate. Operators can cover up to 100 wells statewide with a "blanket bond" of $60,000, while operators with more than 100 wells can provide a blanket bond of just $100,000. That's despite the fact that the typical cost to plug and reclaim a single well — a process that drastically reduces the potential for safety or environmental hazards — can exceed $80,000.

Oil and gas interests, in turn, have long warned that raising those bonding amounts could lead to drastic increases in the number of orphaned wells by pushing the operators of low-producing wells into bankruptcy.

Advocates for stricter rules say that may be true, but they argue that sooner or later, the state is going to have to reckon with a problem that isn't going away.

"I think there's probably going to be a minimum of 3,000 wells that are going to be orphaned if you do anything with these rules," said Matt Sura, an attorney representing several environmental groups before the commission.

"These orphaned wells are not going to be caused by these regulations, merely revealed by them," he added. "These wells were going to be orphaned regardless of what you (do) or don't do."

The COGCC has gotten a boost in its efforts to address orphaned wells from the federal government, in the form of more than $90 million over the next decade apportioned to Colorado by the recent congressional infrastructure bill. With federal funds and new financial assurance rules on the way, Robbins and other commissioners have floated what he described this week as “some form of amnesty” for high-risk operators.

“(Within) six months, you can give us the keys to your wells, you can give us all your financial assurance, you sign a pledge that you’ll never operate in the state again,” Robbins said. “And we take advantage of the fact that we’ve got federal funds coming in, and we use that to plug and abandon those wells.”

A fracking site in Greeley is pictured on June 24, 2020. The facility is located 828 feet from the soccer field at the Bella Romero Academy. (Andy Bosselman for Newsline)

Mark Mathews, an attorney with Brownstein Hyatt Farber Schreck representing the Colorado Oil and Gas Association before the commission, told Robbins that the amnesty concept had “facial appeal.”

But he and other industry representatives cautioned against enacting stricter requirements on individual wells or operators based solely on production levels, arguing that low production alone isn’t an indicator of high risk.

“There are many low-producing wells, they are low-producing for many different reasons – legitimate, operational reasons,” said Matt Lepore, a former COGCC director who testified Thursday on behalf of three Colorado oil companies. “There are routine maintenance issues and so forth.”

“It’s misleading, I think, to talk about an impending orphaned well crisis based on the number of inactive wells, the number of low-producing wells, without looking at the operators themselves," Mathews said.

Tiered system

The COGCC's new bonding rules will almost certainly sort operators into multiple tiers with a spectrum of financial assurance requirements.

In the agency's latest draft, the riskiest operators would be required to provide "single well financial assurance," at a full cost of $70,000 or more for each well they operate. It's an approach that, under certain circumstances, industry groups acknowledge may be necessary.

"There is no doubt that there are operators with extremely low production, that don't have an active well fleet to provide … an average daily well production value that's meaningful," said Mathews. "Those assets represent a risky proposition, and I think that in those circumstances single well financial assurance may be something that you want to consider."

On the other end of the spectrum, the largest companies would potentially still be able to provide financial assurance under a blanket-bond structure, though the amounts would be increased significantly — perhaps $30 million for operators like Occidental Petroleum and Chevron, Lepore suggested Thursday. Large operators, many of which are publicly traded companies that are required to account for "asset retirement obligations" on their balance sheets, are considered to be the lowest risk for orphaned wells.

A large percentage of operators in the middle could fall into what commissioners and industry representatives have referred to as a "bespoke" tier, in which companies would be required to submit a mix of bonds and other financial instruments, or otherwise demonstrate their solvency according to criteria yet to be determined by the commission.

Some environmental activists, however, continue to press for single well financial assurance, or "full cost bonding," to be applied to all of Colorado's roughly 50,000 active wells. Such an approach would effectively force drilling companies to obtain surety bonds on the private insurance market, which supporters of the idea say would allow the industry's risk to be efficiently managed — especially amid the growing uncertainty of its long-term future in an age of accelerating climate impacts and a global transition to clean energy.

Industry groups have repeatedly said that full-cost bonding is a “nonstarter” for the vast majority of operators, who wouldn’t be able to pay the premiums or put up the collateral that surety companies would require. It’s especially burdensome, they say, because over the last several years surety companies have increased their underwriting requirements for oil and gas drillers.

Those objections have raised some commissioners’ eyebrows.

“I’m wondering if that’s because oil and gas operations have become more risky over time, and so therefore it’s become more expensive to become bonded,” commissioner Karin McGowan said to a panel of industry witnesses during a Wednesday hearing.

Trevor Gilstrap, an insurance broker testifying on behalf of COGA, acknowledged that a wave of bankruptcies, including that of Texas’ Fieldwood Energy, had led the surety market to increase premiums and underwriting requirements on the oil and gas business, but claimed that this didn’t represent a systematic reevaluation of the industry’s risk.

“It’s like anything, right – when a hailstorm rolls through, and it damages houses in your neighborhood, even if your house wasn’t damaged, your property premiums are typically going to go up,” Gilstrap said. “It’s really some of these massive shock losses that have created this ripple effect throughout the market.”

Gilstrap told commissioners that he couldn’t say exactly where the COGCC should land on new bonding requirements.

“I know that the end result is that the (bonding) amount is going to go up … and it’s going to go up significantly,” he said. “I wish I could give you better direction on, ‘This is the magic number that would create a win across the industry.’ Admittedly, I don’t have that, because underwriting is so individually based on each company, their financial assets, their reserve reports, et cetera.”

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Decommissioning Orphaned and Abandoned Oil and Gas Wells: New Estimates and Cost Drivers

Daniel Raimi,* Alan J. Krupnick, Jhih-Shyang Shah, and Alexandra Thompson

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ABSTRACT: Millions of abandoned oil and gas wells are scattered across the United States, causing methane emissions and other environmental hazards. Governments are increasingly interested in decommissioning these wells but want to do so efficiently. However, information on the costs of decommissioning wells is very limited. In this analysis, we provide new cost estimates for decommissioning oil and gas wells and key cost drivers. We analyze data from up to 19,500 wells and find median decommissioning costs are roughly $20,000 for plugging only and $76,000 for plugging and surface reclamation. In rare cases, costs exceed $1 million per well. Each additional 1,000 feet of well depth increases costs by 20%, older wells are more costly than newer ones, natural gas wells are 9% more expensive than wells that produce oil, and costs vary widely by state. Surface characteristics also matter: each additional 10 feet of elevation change in the 5-acre area surrounding the well raises costs by 3%. Finally, we find that contracting in bulk pays: each additional well per contract reduces decommissioning costs by 3% per well. These findings suggest that regulators can adjust bonding requirements to better match the characteristics of each well.

KEYWORDS: *orphaned wells, methane, climate change, well plugging, decommissioning*

■ INTRODUCTION

Millions of oil and natural gas wells have been drilled in the United States since the mid-1800s. While at any given time, some of these wells may be idled for economic purposes and then later brought back into production, a much larger number are permanently idled and not properly decommissioned. The US EPA estimates that as of 2018, roughly 2.1 million wells were not being used for production, injection, or other purposes but had not been plugged.[1]

This estimate may significantly undercount the true number of such wells in the United States. In the industry's early years, most regulatory programs neither mapped the location of drilled wells nor incentivized operators to decommission sites at the end of their useful lives. As a result, hundreds of thousands—perhaps more than one million—additional unplugged wells exist but are neither mapped nor accounted for in state and federal inventories.[2,3] In the 20th century, modern regulatory frameworks have emerged and evolved, requiring operators to decommission well sites at the end of their useful lives. Because insolvent operators may be unable to pay for these decommissioning costs, regulators have adopted financial assurance requirements to cover these costs if companies go bankrupt. However, as previous work has demonstrated, e.g., ref 4, these requirements are often insufficient to cover the full costs of decommissioning. This problem is particularly germane for the issue of "blanket" bonds, which allow operators to cover all their wells within a state or territory with a single (often low) bond or other financial instrument. In addition, operators may idle wells with little intention of reactivating them yet report those wells to regulators as "temporarily" idled to avoid decommissioning obligations.[5]

Decommissioning an oil and gas well involves several steps, beginning with an assessment of the well's physical condition, including the underground steel casing and cement, and identification of any potential subsurface leaks or hazards. The wellbore is then cleaned. Next, workers use cement or other plugging materials to seal the wellbore (Depending on subsurface conditions and applicable regulations, the entirety of the wellbore or discrete portions may be sealed.). Finally, surface equipment is removed, and the surrounding well pad is restored (Again, the extent of surface restoration varies depending on the standards of companies and/or regulators.).

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In the 21st century, the proliferation of shale gas and tight oil development, which typically involves deep, horizontally drilled wells, has raised concerns that decommissioning costs for these wells may exceed those of conventional wells because of the former's greater depths and associated pressure, e.g., ref 6. In 2020, as oil prices crashed due to a global oversupply initiated by the effects of the COVID-19 pandemic, considerable interest emerged among state and federal policymakers to decommission wells as a way to support unemployed oil and gas workers and to reduce the environmental and climate risks of unplugged abandoned wells, e.g., refs 7−10.

Because definitions for what constitutes an "abandoned" well can vary across jurisdictions, it is helpful here to define several key terms as they are used in this paper. We follow the U.S. EPA[1] and define abandoned wells as those with no recent production, injection, or other uses (estimated at 3.2 million). Our focus in this paper is on the subset of unplugged abandoned wells (estimated to account for 2.1 of the 3.2 million total abandoned wells), which are typically the largest emitters of methane.[2] In addition, there is a subset of unplugged abandoned wells known as "orphans", which have no solvent owner and are effectively wards of the state. As noted above, there is large uncertainty over the true number of orphaned wells in the United States.

Looking forward, the number of orphaned wells has the potential to grow considerably if policies to reduce greenhouse gas emissions lead to substantial reductions in oil and natural gas demand. Unlike previous cyclical downturns during which struggling companies could sell their less profitable assets to other operators, a structural decline in oil and natural gas demand due to climate policy (or other factors) would make these investments less attractive, leaving few buyers for marginal wells, and ultimately a large increase in the number of orphaned wells that pose risks to the environment and human health.

Risks of Unplugged Abandoned Wells. Unplugged or improperly plugged oil and gas wells can pose a variety of environmental and health hazards. At the local level, degradation of the cement and steel that make up a wellbore can lead to migration of gases or fluids that may contaminate surface water or groundwater,[11,12] and in some cases, accumulations of gases can lead to explosion risks.[13] These hazards can be exacerbated if unplugged wells are proximate to new oil and gas development utilizing hydraulic fracturing, e.g., ref 14. Unplugged wells may also endanger human health through emissions of air pollutants such as benzene, hydrogen sulfide, or volatile organic compounds (VOCs), though this exposure pathway has not been studied in the literature to date.[15] In addition, unplugged wells pose a hazard if individuals trip over or step into an unmarked well.

The most closely examined environmental impact of unplugged abandoned wells is emissions of methane, a powerful greenhouse gas and an ozone precursor. The U.S. EPA estimates that, on average, each unplugged abandoned oil and gas well emits 0.13 t of methane per year.[1] Multiplied by an estimated 2.1 million such wells, the EPA estimated methane emissions of 276,472 t in 2019, equivalent to roughly 9.5 million metric tons (MMT) of carbon dioxide (CO_2) per year assuming a 100-year global warming potential (GWP) of 34, or 24 MMT of CO_2 per year assuming a 20-year GWP of 86.[16] This represents roughly 2.6% of total U.S. energy-related methane emissions or roughly 0.2% of total U.S. energy-related greenhouse gas emissions in 2019, assuming a 100-year GWP for methane of 34.[17]

As with other aspects of methane emissions across the oil and gas supply chain, e.g., refs 18 and 19, recent studies have found that a small number of wells contribute a large share of the total, with the highest emitting wells contributing as much as 0.66 t per year for one unplugged abandoned gas well[19] and 1.16 t per year for one "shut-in" oil well.[12] Although data remain quite limited, emissions rates appear to vary across well types (i.e., oil or gas wells), geology, and—most importantly—plugging status, with unplugged wells typically emitting more methane than plugged wells, e.g., refs 2 and 20−25.

Although there are considerable uncertainties surrounding the magnitude of environmental risks, some recent evidence has suggested that proximity to unplugged oil and gas wells reduces property values considerably. In a working paper, Shappo[26] estimates that property values are roughly $15,000 (11%) lower for each Pennsylvania home within 2 km of an unplugged well compared with similar homes that are not close to unplugged wells. Importantly, the analysis finds that home values fully recover if the well is properly decommissioned, suggesting that the benefits of decommissioning may outweigh their costs if multiple homes are within 2 km of the well, even without accounting for the climate damages associated with methane emissions.

Another recent analysis[27] estimates substantial ecosystem services benefits from decommissioning wells, including restored agricultural use, CO_2 sequestration, and other services (Again, the analysis excludes methane emissions mitigation.). The authors estimate that the present value of ecosystem services benefits from restoring the surface at 430,000 well sites in the United States would be roughly $21 billion or $49,000 per well.

Existing Decommissioning Cost Estimates. Policymakers in recent months have proposed spending billions of dollars to decommission unplugged abandoned wells, often focusing on the subset of orphaned wells, e.g., refs 7, 28, and 29. However, limited information on the location, environmental damages, and decommissioning costs for these wells makes it difficult for state and federal policymakers to identify how to prioritize among the millions of wells that could plausibly be targeted for decommissioning.

Along with uncertainty over the benefits of decommissioning (e.g., reducing methane emissions), there is considerable variation in costs, making planning difficult for policymakers. Mitchell and Casman[30] make a rough estimate that decommissioning shale gas wells in Pennsylvania would cost between $100,000 and $700,000 per well. Ho et al.[4] use cost data from plugging conventional wells in 11 states (excluding reclamation costs) and find that average costs range from less than $5,000 per well to roughly $50,000 per well at the high end. A 2020 report from the Interstate Oil and Gas Compact Commission[3] aggregates data from over a dozen US states, estimating that decommissioning costs have averaged roughly $24,000 per well, with wide variation.

Recent policy reports have estimated costs ranging from roughly $27,000 to hundreds of thousands of dollars per well for certain well types.[6,9] There are many factors that affect decommissioning costs. To develop better cost estimates, this paper substantially expands the data set analyzed by Ho et al.[4] by adding three states to the analysis representing data from an additional 7,000 wells. More importantly, we quantify how different well characteristics, such as depth, age, and other factors, may affect decommissioning costs across a large number of wells in multiple states. By developing detailed measures of decommissioning costs, this paper can help inform decisions about regulatory policy and help identify strategies for cost-effectively addressing the environmental and health hazards of abandoned oil and gas wells.

MATERIALS AND METHODS

Our initial data set includes decommissioning costs for more than 19,500 oil and gas wells, the largest data set that has been assembled to our knowledge. Data were gathered via email from state regulators in Kansas, Montana, Pennsylvania, and Texas. These states were chosen because they differ considerably in terms of geology, history, and regulatory structure and because author contacts within the relevant agencies made it relatively straightforward to gather the data. Costs were provided at the contract level, where state regulators contract with oilfield service providers to decommission one or more orphaned wells. For Kansas and Texas regulatory data, these costs only include plugging, as surface remediation is prioritized according to different criteria, which means that surface restoration is contracted separately and proceeds along a different timeline. We also gathered proprietary decommissioning cost data for several hundred wells in New Mexico and Texas from one large oil and gas operator, which include plugging and restoration costs. Using unique API identification numbers, we matched more than 10,000 wells in these contracts to oilfield data from Enverus (formerly DrillingInfo), allowing us to gather information about well location, depth, age, production type (e.g., oil or gas), drill type (e.g., vertical or horizontal), and more (Due to differences in state-level reporting and recordkeeping, complete data were not available for all wells.).

Because cost data from states were often provided at the contract level (rather than the well level), our unit of observation is the contract. When contracts include more than one well, we average information across each well of the contract (e.g., plugging cost, well depth, age of well). This process is unlikely to bias the data because when state regulators award contracts for plugging multiple wells, those wells are located close to one another, have similar ages, and share other key characteristics such as depth and production type. Using the contract as our unit of observation also allows us to estimate the extent to which contracting in bulk provides any economies of scale.

More than 7,500 wells across 3,997 contracts included complete or close to complete data, allowing us to perform statistical analysis on this subset of contracts. For plugging only, costs average roughly $20,000, while full decommissioning (i.e., plugging and remediation) costs average $76,000 across states. In rare cases, costs are on the order of $1,000 per well, while in others, they exceed $1 million per well. This wide range reflects the variety of conditions that may exist at well sites. For example, a shallow well with no mechanical integrity problems and no clear environmental hazard would fall on the low end of the cost spectrum and may take only several hours of work time. On the other hand, decommissioning can take weeks and become very expensive if there are major well integrity problems, which may contribute to surface or subsurface leakage of gas or fluids, and would require major remediation activities at or below the surface. In addition, differences in state standards, regulations, and other factors may affect costs, which we discuss in the following sections.

Tables 1 and 2 present summary statistics for decommissioning costs and other characteristics for contracts that involved only plugging (Table 1) and plugging and site remediation (Table 2).

Table 1. Decommissioning Costs (Plugging Only)

state	KS	TX	total
no. of contracts	unknown	2,280	3,084[b]
no. of wells	804	5,413	6,217
av wells per contract	unknown	2.4	unknown
mean cost per well ($2019)	$6,568	$25,055	$20,318
median	$4,627	$18,708	$14,451
minimum	$1,073	$1,440	$1,073
maximum	$78,544	$2,205,800	$2,205,800
P.10[a]	$2,383	$5,556	$3,422
P.90[a]	$12,305	$40,884	$37,038
av depth	1,295	4,232	3,466
av first year	1969	1984	1982
av plug year	2006	2018	2015
share vertical or unknown	100%	97%	98%

[a]P.10 and P.90 refer to the 10th and 90th percentiles of cost, respectively. [b]Data from Kansas regulators did not specify the number of contracts but did specify the number of wells. It is possible that the number of contracts is less than 3,084.

In our analysis, we examined dozens of factors that could plausibly affect decommissioning costs. Some of this information can be observed through data on the well itself, while others must be gathered using geospatial software. We use ArcGIS Pro and ArcGIS Online software[31] to gather these geospatial characteristics.

Based on previous research and conversations with experts from industry, the regulatory community, and other researchers, we developed hypotheses about how different factors may affect costs. These are

(1) Well depth: Deeper wells are more expensive to drill than more shallow wells.[32] We hypothesize that the same relationship would apply to decommissioning wells.
(2) Well age: Because well integrity may degrade over time,[33] we hypothesize that decommissioning costs vary linearly with well age.
(3) Site topography: We hypothesize that sites in hilly terrain will be more costly to decommission than those in flat terrain because of erosion concerns and the costs of transporting materials to the site. Plugging wells may also be more costly if the well itself is on a slope, which would make it more difficult to stabilize equipment, or require additional site preparation (i.e., land grading).
(4) Surface restoration: Other things equal, wells where both the well itself and the surrounding well pad are remediated will be more costly to restore than sites where the only actions are to plug the well.
(5) Wells per contract: While absolute costs will rise with the number of wells under contract, we hypothesize that there will be economies of scale for larger contracts, resulting in lower per-well costs for contracts with more wells.
(6) Oil vs gas well: We hypothesize that gas wells are harder, and therefore more costly, to decommission because the gas naturally flows to the surface, while a nonproducing oil well has presumably lost most of its natural pressure

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Table 2. Decommissioning Costs (Plugging and Site Remediation)

state	MT	NM	PA	TX	total
no. of contracts	unknown	158	103	448	913[b]
no. of wells	204	158	717	448	1,527
av wells per contract	unknown	1	7.0	1	unknown
mean cost per well ($2019)	$15,335	$171,652	$48,703	$75,307	$75,579
median	$9,504	$132,319	$24,065	$58,525	$52,629
minimum	$266	$8,043	$3,832	$1,859	$266
maximum	$222,275	$1,115,711	$469,274	$1,645,103	$1,645,103
P.10[a]	$2,507	$71,677	$5,730	$22,373	$7,620
P.90[a]	$27,583	$307,178	$124,292	$130,481	$159,764
av depth	2,409	5,987	2,056	4,226	3,880
av first year	1959	1988	1963	1976	1973
av plug year	2007	2016	2002	2016	2013
share vertical or unknown	100%	93%	99%	100%	99%

[a]P.10 and P.90 refer to the 10th and 90th percentiles of cost, respectively. [b]Data from Montana regulators did not specify the number of contracts but did specify the number of wells. It is possible that the number of contracts is less than 913.

(although associated gas may still be an issue). However, it is also possible that oil wells will be more costly to decommission because they may be more likely to have surface spills that need to be remediated.

(7) Location: Ho et al.[4] show that state regulations affecting site restoration and well plugging vary widely. In addition, differences in regional markets for oilfield services may affect labor and equipment costs. Therefore, we hypothesize that costs vary across states.

Table 3 summarizes the variables that we include in the statistical analyses that follow and the sources from which they are gathered, with details provided in the SI. As noted above, complete data for these variables were available for 3,991 out of our total of 3,997 contracts (2,984 contracts included details on the number of wells per contract, which were not available for Kansas and Montana).

Table 3. Variables That Affect Decommissioning Costs

variable	hypothesized effect on cost	data source
well depth	deeper wells may require additional labor and material	Enverus
well age	older wells may be more degraded	Enverus
topography	wells in hilly areas may be more costly to plug and restore the surface	ESRI[a] via ArcGIS
surface restoration	restoring the surface will add costs above simply plugging the well	regulators
wells per contract	contracts with more wells may offer economies of scale	regulators
well type	gas wells may differ from oil wells or oil and gas wells	Enverus
state	state regulations or other factors may affect plugging costs	regulators

[a]ESRI, Environmental Systems Research Institute.

We tested a substantial number of additional variables we hypothesized could plausibly affect costs by adding them to our regressions analysis and analyzing the results. These variables include proximity to water bodies, depth of water table at the well site, land use type, distance to population centers, distance to roads, oil and natural gas prices, and other factors. However, these factors did not meaningfully improve the predictive value (adjusted R^2 score) of the model, and because of data limitations, they substantially reduced the statistical power of our analysis. For those reasons, we exclude these variables and results in the following analysis. Additional information on these variables and their sources is provided in the SI.

Because plugging costs are highly skewed to the right (see SI Figures S1−S4), we conduct a logarithmic transformation and use the natural log of cost as our dependent variable. We then develop a log−linear regression model in our analysis.[34]

■ RESULTS

Our analysis reveals numerous statistically significant and economically meaningful results. Table 4 presents two

Table 4. Regression Results

dependent variable: change in natural log of decommissioning cost				
	specification 1 (preferred)		specification 2	
variable	estimate	std error	estimate	std error
surface reclamation[a]	1.18	0.03	1.14	0.03
TVD[b] (1000 feet)	0.20	0.004	0.18	0.004
age <20[c]	−0.23	0.04	−0.33	0.04
age 20−40[c]	−0.17	0.03	−0.27	0.04
age 40−60[c]	−0.09	0.03	−0.16	0.04
oil well[d]	−0.09	0.03	−0.12	0.03
Montana[e]	−1.15	0.08	omitted due to lack of data	
New Mexico[e]	0.94	0.08	0.86	0.08
Kansas[e]	−0.35	0.08	omitted due to lack of data	
Texas[e]	0.38	0.07	0.26	0.07
wells per contract	omitted due to lack of data		−0.03	0.003
elevation range (100 feet)	0.26	0.07	0.37	0.08
constant	8.73	0.07	9.10	0.08
diagnostics				
R-squared	0.69		0.63	
no. of observations (contracts)	3,991		2,984	

[a]Compared with wells that are plugged only. [b]TVD stands for total vertical depth, which measures the distance from the surface to the bottom of the well and excludes any horizontal portions of the well. [c]Compared with wells 60 years or older when plugged. [d]Compared with gas only wells. [e]Compared with Pennsylvania. Note: Because we do not have data on the number of wells per contract for Montana and Kansas, they are omitted from the regression analysis due to collinearity.

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specifications. The first, our preferred specification, includes data from 3,991 contracts across five states, while the second, which includes 2,984 contracts, adds the variable for the number of wells per contract, which was not available for Montana or Kansas. All the results shown in the table are statistically significant at the $p > 0.99$ level or above using a t test. Results can be interpreted as follows: decommissioning costs are correlated with the percentage change associated with the coefficient for each independent variable. For example, reclaiming the surface increases decommissioning costs by 118% in our first (preferred) specification and by 114% in our second specification.

As noted above, and as suggested by the differences between Table 1 and Table 2, site restoration more than doubles the cost of well decommissioning, increasing them on average by 118% in our preferred specification when controlling for other variables (all results in this section refer to our preferred specification unless otherwise noted). As expected, deeper wells are also more costly, with each additional 1,000 feet of total vertical depth increasing costs by 20% on average. The age of the well also correlates strongly with costs. Compared with wells that were more than 60 years old when decommissioned, wells aged 40 to 60 years old were 9% less expensive, and wells aged from 0 to 40 were roughly 20% less expensive. Higher costs for older wells are likely caused by degradation of steel and cement casing over time, which can create multiple challenges for plugging operations.

We also find that wells producing only natural gas are 9% more expensive to decommission than wells that produce oil (many of these wells produce both oil and natural gas). Based on discussions with industry experts, the additional time and equipment that is often needed to stop the (often high-pressure) flow of natural gas during well plugging operations, particularly in older wells, explains this difference. For wells producing oil, experts reported that while surface oil spills were costly when they occurred at large scale, they were relatively rare.

We found statistically significant and economically meaningful variation in costs by state. Compared with decommissioning in Pennsylvania (our reference state), costs in New Mexico and Texas are 94 and 38% higher, respectively, while costs in Montana and Kansas are 115 and 35% lower, respectively. Three potential explanations may play a role: First, differences in state regulatory requirements may contribute to variation in costs. Second, contractor costs may vary regionally due to variation in local supply and demand. For example, Ho et al.[4] found wide variation in service provider costs between Kansas, Pennsylvania, and Texas, with relatively high costs found in Texas (they did not examine data for New Mexico). Third (applicable only to Texas and New Mexico), as noted in the Materials and Methods section, most of our data was provided by state regulators, who contract with service providers to decommission orphaned wells. However, all our New Mexico data, and roughly 16% of our Texas data, come from a private company decommissioning their own wells at the end of their economic lives. This company reported to us that they go above and beyond regulatory requirements in the states where they operate, which would help explain the higher costs in New Mexico and Texas. However, we have no way to verify this claim.

Topography also appears to affect decommissioning costs. For each additional 10 feet of elevation change in the 5-acre area surrounding each well site, decommissioning costs increased by roughly 3%. For reference, a standard professional soccer pitch is typically 1.75 acres, and many modern oil and gas well pads are roughly one acre in size. Substantial changes in elevation could add costs for surface remediation, which typically involves heavy machinery, along with making it more difficult to site and stage a drilling rig or other equipment needed to plug the well.

Finally, our second specification allows us to examine the effects of economies of scale with respect to decommission costs. For each additional well on a given contract, decommissioning costs fall by roughly 3% per well, though data are not available for Kansas or Montana. This intuitive result likely reflects the economies of scale that oilfield service firms can achieve through reducing administrative and on-site costs, particularly when multiple wells on the same contract are located close together.

Policy Implications. This paper yields a variety of insights that can better inform private and public entities as they consider the future costs of safely decommissioning oil and gas wells.

First, these estimates can inform policy decisions related to financial assurance requirements for oil and gas operators. As noted above, all states and the federal government require companies to provide some type of financial assurance to decommission their wells if they become orphaned due to bankruptcy. However, these requirements are often an order of magnitude below the true decommissioning costs, especially for blanket bonds that can cover hundreds of wells in a given jurisdiction, as discussed in Ho et al.[4] Our results reinforce this finding: although some states set blanket bond levels as low as \$15,000 (Ohio) or \$25,000 (Pennsylvania) to cover every well in a state,[3] our median decommissioning cost is roughly \$75,000 per well. This finding highlights the risk to taxpayers from recent and future oil and gas industry bankruptcies and suggests the need for additional research into policy reforms that could limit the public's financial exposure to abandoned private infrastructure.

Our results suggest that, because they significantly affect decommissioning costs, financial assurance requirements could be improved by accounting for key factors including well depth, well age, and well type (oil, gas, or oil and gas). Our results can help regulators quantify the likely relationship between these factors and plugging costs. For example, our model estimates that fully decommissioning a 30-year-old oil well in Pennsylvania with total vertical depth of 2,000 ft will cost, on average \$23,377, while an 80-year-old gas well in Texas with depth of 6,000 ft will cost \$97,801 (assuming no elevation change and one well per contract). Thus, tying bonding requirements to these factors and ending the discount for blanket bonds (other than that based on observed economies of scale, such as that in this paper) could reduce the proliferation of future orphaned wells but not necessarily raise bonding requirements for all operators. If allowed by state and federal law, regulators could utilize information provided by operators in their drilling permits, which typically include well type, depth, surface location, and other characteristics to determine the applicable bond amounts.

Second, these estimates quantify the benefits to state regulators (and, perhaps, oil and gas companies) of contracting in bulk to decommission wells. Although we are not able to observe the mechanism, which could include competitive bidding pressures and legitimate economies of scale, we found that bulk contracting reduces per-well costs by more than 3%

per well. These results suggest that policymakers can get more "bang for the buck" by seeking to contract in bulk.

Third, our estimates quantify the intuitive but important finding that reclaiming the site surface adds considerable costs to decommissioning operations. This implies that if policymakers care most about reducing methane emissions and risks to groundwater, they could consider prioritizing plugging wells without remediating the surface. If, on the other hand, surface reclamation is a priority for environmental, aesthetic, job creation, or other reasons, our results will help policymakers quantify the costs associated with achieving those additional benefits (and perhaps adjust bonding requirements accordingly). As noted earlier, one recent analysis suggests that restoring the surface can have large ecosystem services benefits,[26] though these benefits will vary considerably by region and land use type.

Fourth, our estimates highlight the large differences in decommissioning costs across states. These results suggest that differences in the stringency of technical requirements for decommissioning may affect costs, potentially implying different levels of protection for public health and the environment. Unfortunately, our data do not allow us to identify the extent to which differences in regulations or other factors cause this interstate variation. Future research could examine this issue in more depth and seek to identify the role that regulations play in shaping decommissioning costs, along with the levels of health and environmental benefits provided by different regulations.

Millions of oil and gas wells will need to be decommissioned in the United States over the coming decades. However, reliable information on the costs of decommissioning wells, and how those costs vary across key characteristics, has not been available. Although some of these costs will be borne by companies and their investors, other costs will fall upon taxpayers through spending by federal, tribal, and state governments. Policymakers need better information on these costs, as well as the environmental benefits of decommissioning to develop policies that incentivize or require companies to bond and decommission their wells,and to make decisions about the appropriate scale of public dollars to devote to this environmental and health issue.

■ ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.est.1c02234.

Descriptions of all dependent variables considered for, and included in, regression analysis and figures plotting well depth and cost at various scales (PDF)

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Why Colorado's Celebrated Oil Well Cleanup Reforms Face a $3 Billion Shortfall

The state has 27,000 aging and potentially polluting wells that can't pump enough profit to offset their own cleanup costs, a new report says.

By **Joe Fassler (https://www.desmog.com/user/joe-fassler/)** on Jun 26, 2024 @ 21:01 PDT
12 min read

Colorado has tens of thousands of wells not pumping enough oil and gas to pay for the cost of their own cleanup. Credit: Earthworks.

Published in partnership with ***The Guardian (https://www.theguardian.com/us-news/article/2024/jun/28/colorado-oil-gas-well-cleanup)****.*

As costs related to aging oil and gas wells start to pile up across the U.S., regulators are looking for ways to force fossil fuel companies to foot the bill — and Colorado is supposed to have the answer. The state recently overhauled the financial and regulatory tools it uses to hold producers accountable, a **much-lauded (https://coloradonewsline.com/2022/03/02/colorado-oil-gas-strongest-financial-rules/)** approach that Colorado governor Jared Polis last year **called (https://ecmc.state.co.us/documents/media/Press_release_Orphaned_Well_Event_20230926.pdf)** "an example the nation can follow." And yet, unless the state acts quickly and decisively, those rules may end up with its taxpayers on the hook to pay for a $3 billion shortfall. That's according to a **new report (https://carbontracker.org/?post_type=report&p=32902&preview=true)** published Thursday by the Carbon Tracker Initiative, an energy-focused think tank.

Unless properly decommissioned, unplugged oil and gas wells can continue to leak **cancer-causing chemicals (https://insideclimatenews.org/news/06062023/abandoned-oil-gas-wells-health/)** and **the powerful climate pollutant methane (https://www.nytimes.com/2024/05/24/climate/orphan-wells-capping-methane-leaks.html#:~:text=The%20E.P.A.,%2C%20however%2C%20is%20highly%20uncertain.)**. But the process of shutting down extraction sites is costly and complex, requiring operators to plug deep holes with concrete, remove surface-level equipment, and restore the surrounding land. According to Colorado's Energy and Carbon Management Commission (ECMC), the state's energy regulator, it can cost $110,000 or more to close a single well.

In an exhaustive analysis, Carbon Tracker found that 27,000 oil and gas wells in Colorado — more than half of the state's total — cannot possibly generate enough revenue to cover their own cleanup costs. These wells are located in areas with rapidly declining production volumes, where most of the profits were sucked out of the ground years ago. Collectively, these wells can only hope to generate another $1 billion in revenue, according to Carbon Tracker's report. But all those sites will cost $4 to $5 billion to decommission responsibly, the analysts found — a looming cash shortfall of at least $3 billion.

Even if those 27,000 wells wring every last dollar from the ground, their operators won't be able to afford to pay what's coming due, the Carbon Tracker analysts argue. And unless rapid action is taken now, the public will forever be on the hook.

"The biggest problem here is just the nature of this activity: You make a lot of cash at the beginning, and then you have a big cost at the end," said Rob Schuwerk, executive director of Carbon Tracker and a co-author of the report. "The way you cover a cost like that is you make people save along the way, and this is not done now."

This dynamic is widespread across the U.S. In the 15 biggest oil- and gas-producing states, funds on hand for cleanup amount to less than two percent of estimated costs, a recent **analysis (https://www.propublica.org/article/the-rising-cost-of-the-oil-industrys-slow-death)** by ProPublica and Capital & Main has found.

> "It's frankly dangerous for Colorado to imply this is the best we can do."
>
> *Margaret Kran-Annexstein, Sierra Club Colorado*

Oil and gas companies are legally obligated to clean up their spent wells, and Colorado has long required operators to issue bonds for their wells as a form of financial assurance, like a security deposit. But those rules have never been rigorous enough to incentivize the prompt closure of well sites. For years, the state offered "blanket bonds" that allowed companies to meet the financial assurance requirement for **as little as $600 (https://grist.org/energy/colorado-abandoned-oil-well-bonding-rules/)** per site — just a tiny fraction of what the process costs.

It was cheaper to walk away, and many companies did just that. Today, there are nearly 1,000 "orphan" wells in Colorado, **according (https://sites.google.com/state.co.us/cogcc-owp/backlog?authuser=0)** to ECMC — wells that no longer have a financially solvent operator, and have become the responsibility of the state. A similar situation has played out in other regions across the country. Today, operators have stranded **more than 120,000 orphan wells (https://www.usgs.gov/centers/central-energy-resources-science-center/science/orphan-wells)** nationwide, a situation made possible by **years of permissive policy (https://www.propublica.org/article/oil-industry-lobbying-unplugged-wells)**.

"The bonding isn't enough. It's never been enough," said Kelly Mitchell, a senior analyst at Documented, an oil and gas industry watchdog group who monitors orphan well issues. "And I think the states typically aren't being very sober in considering the scale of the problem they're facing."

"Colorado may claim to be more forward thinking, or that it's the best oil and gas regulator in the nation, but companies are still taking advantage of major follies in state policy," said Margaret Kran-Annexstein, director of the Sierra Club's Colorado chapter. "Even under the new rules, the gap between projected cleanup costs and secured bonding is measured in the billions of dollars. It's frankly dangerous for Colorado to imply this is the best we can do."

ECMC declined to arrange interviews for this story, citing staffing changes and scheduling conflicts. In emailed comments in response to the findings of this story, ECMC community relations supervisor Megan Castle noted that plugged wells outnumber unplugged wells in Colorado.

“Colorado’s financial assurance structure is designed to ensure operators — not the State — remain responsible for the entire lifecycle of the well and site,” she wrote, adding that Colorado’s bonding programs are meant to act as “a backstop” only when companies cannot fulfill that obligation themselves.

The **Western States Petroleum Association (https://www.desmog.com/western-states-petroleum-association/)** did not respond to a request for comment.

Financially Unassured: The New System’s Failure

In 2019, Colorado became one of the first states to try to take comprehensive action on the ballooning costs of oil and gas cleanup. That year, lawmakers **passed (https://leg.colorado.gov/bills/sb19-181)** SB-181, a **sweeping piece of legislation (https://coloradosun.com/2019/04/16/senate-bill-181-oil-gas-law-colorado-signed/)** that set the stage for a broad regulatory overhaul, while also giving ECMC a mandate to protect human health and the environment over industry profits. The law was passed, in part, to hold fossil fuels companies accountable for their plugging obligation. Though it took a few years to work out the specifics, by 2022, the commission had finalized rules that chair Jeff Robbins **called (https://ecmc.state.co.us/documents/media/Press_Release_FA_Rulemaking_Adoption_20220301.pdf)** “the most robust in the country.”

The new rules included a fee on producers and also restrictions around transferring wells, an effort to stop **the industry-wide practice (https://www.propublica.org/article/the-rising-cost-of-the-oil-industrys-slow-death)** of bigger companies selling off low-producing wells to smaller, poorer companies. But the centerpiece was the revised financial assurance requirements, which Robbins called “by far the highest” in the nation.

“The financial assurance rules that were developed in this rulemaking are truly a paradigm shift,” ECMC commissioner John Messner said at the time. “They fundamentally change how financial assurance for oil and gas activities in the State of Colorado are addressed.”

In a first for the state, ECMC required every operator to develop a unique, company-specific bonding plan, a departure from the highly general blanket bonds of the past. This approach allows companies to choose from a suite of six financial assurance options as a starting point, depending on production levels and perceived financial risk. Though publicly traded companies with high-producing wells can skate by on a single $40 million bond, most other companies have bonding amounts determined on a per-well basis, a major departure from the past. The hope was that this more personalized framework would finally force companies to bond their wells sufficiently, making it harder to walk away.

Environmental advocates generally celebrated the new approach — which some hailed as a template for the country.

“Colorado has pretty much solved its orphan well problem, and kudos to them,” said Adam Peltz, an Environmental Defense Fund researcher, **in 2022 comments to the Washington Post (https://www.washingtonpost.com/climate-environment/2022/12/02/orphan-wells-infrastructure-law/)**. “The rest of the country needs to do it now, too.”

But two years later, the new rules have failed by a basic measure: Colorado has less financial assurance on hand today than it did in April 2022, the last month under the old paradigm.

‘More Loopholes Than Net’

In a May 22 presentation, ECMC commissioner Karin McGowan, who left the commision on June 14 to start **a new position (https://ecmc.state.co.us/documents/media/Press_release_McGowan_20240523.pdf)** as executive director of the Denver Department of Public Health, explained that the state so far only received $228 million in financial assurance, compared to the $243 million it had in 2022. That number is even lower today. PDC Energy, a publicly traded operator that is owned by multinational oil and gas giant Chevron, recently re-filed to reduce its financial assurance from $40 million to $14.5 million. That left ECMC with just $203 million on hand, 16 percent less than what it had in 2022.

That low total shows that the new rules still don’t do enough to reflect massive liabilities on the ground, according to the report. Though ECMC’s default estimate for the cost of plugging and remediating a well site ranges from $110,000 to $140,000, many companies aren’t required to put up that much assurance. Since they’re thought to be more secure, companies with higher production levels get a deep discount on their bonding requirement, ranging from $18,000 to just $1,500 per well — an approach that rewards them for their apparent financial stability but can discount the huge overall cost of plugging their wells.

Lower-producing companies must bond at an amount equal to the full cost of closing their wells, but they’re allowed to spread out the cost via annual contributions over a period 10 or 20 years. That makes compliance easier for companies but, in **a 2022 report (https://carbontracker.org/reports/false-start/)**, Carbon Tracker analysts called it a “big risk” to “assume that operators with low average production will be around 10 or 20 years.” Those companies may default before they’re fully bonded, in other words — with uncovered liabilities still on the books.

To make matters more complicated, the rules allow for a certain amount of exemptions and exceptions. For instance, companies can designate a certain number of “out of service” wells — idle wells that then don’t factor into the overall production calculation, allowing them to qualify for a more attractive plan.

“Only operators with the highest production and therefore lowest risk of stranding assets are allowed to declare wells as out of service. Operators using this route must commit to plugging these wells within 6 years,” ECMC’s Castle said, by email. But the Carbon Tracker report notes that there is currently no penalty for failing to do so.

Companies can also propose a fully custom plan based on demonstrated costs, a “choose your own adventure” approach to bonding. These carve-outs and loopholes give companies a range of compliance options, and require ECMC to constantly exercise discretion.

The end result, said Dwayne Purvis, a petroleum engineer and consultant in Texas who co-authored the report with Schuwerk, is that companies generally aren’t bonding enough to counter the state’s dramatic liabilities. There are so many alternatives to choose from that the rules end up being “more loopholes than net.”

Basin Economics

To demonstrate, the Carbon Tracker report analysts looked to examples in northwest Colorado’s Piceance Basin, where average production volumes have slowed to a trickle — about four barrels of oil equivalent per day on average. The three biggest companies in that region — Terra Energy Partners, Caerus Operating, and Laramie Energy — represent $2.68 to $3.35 billion in collective decommissioning liability, according to Carbon Tracker’s estimate. But they’ve only issued $53.2 million in well plugging bonds all together, an amount that covers thousands of sites and less than two percent of their total risk.

Meanwhile, the analysts write, future production from the entire Piceance Basin will only generate about $1 billion in cash flow, leaving operators there "profoundly unable to pay for their decommissioning." That same dynamic is in play throughout much of Colorado.

"Can these wells pay for their own retirement? What we're seeing really is that of the nine basins that can be covered, eight clearly cannot," Schuwerk said.

A fracking drill rig in Weld County, Colorado, in the Denver-Julesburg Basin in 2014. Credit: Julie Dermansky

The one bright spot? Rich reserves in a single region — the Denver-Julesburg Basin — can generate more than enough profit to one day close down all of the state's 47,000 wells, an inevitable prospect that will require an outlay of between $6.8 and $8.5 billion, according to Carbon Tracker's estimate. That's in stark contrast to a state like California, where **the value of all the state's remaining oil reserves fall far short (https://www.desmog.com/2024/02/06/wspa-cipa-oil-idle-wells-ab2729-california/)** of total decommissioning costs.

For Colorado, the problem is that most of those future profits are concentrated in the hands of just three public companies — Chevron, Occidental, and Civitas. The 27,000 low-producing wells owned by smaller, more vulnerable companies can't use the coming cash bonanza to offset their risk.

Schuwerk called it "a case of haves and have-nots," and existing ECMC policy doesn't do much to correct that fundamental imbalance: One group is sitting on billions in profits; the other can't afford to resolve its billions in liabilities.

Accounting for a Lack of Accountability?

At least one operator has already said it can't pay. K. P. Kauffman, Colorado's largest **reported (https://www.bizjournals.com/denver/news/2024/01/04/kp-kauffman-oil-cecmc-colorado-assurance-lawsuit.html)** owner of low-producing, so-called "marginal" oil wells, could not come up with a bonding plan that ECMC was willing to approve for its more than 1,000 sites. In response, ECMC ordered the company to bond at its default rate — $130,000 per well — which came to around $133.3 million, bonded over the course of 10 years. The company, which has said it could not afford to pay a $2 million fine from ECMC, **according (https://coloradosun.com/2023/10/28/kp-kauffman-colorado-oil-and-gas-wells/)** to the Colorado Sun, has **sued (https://www.bizjournals.com/denver/news/2024/01/04/kp-kauffman-oil-cecmc-colorado-assurance-lawsuit.html)** in protest of the amount.

Peter Morgan, a senior lawyer with the Sierra Club's Environmental Law Program, said, "One really perverse effect of inadequate bonding is that it creates a powerful disincentive for ECMC to take needed enforcement action."

Enforcement has been an issue more broadly, a sign that even the flexible bonding arrangements offered by the commission are already perceived as a burden. As of June 21, at least 26 operators had not yet filed financial assurance forms after ECMC approved their bonding plans, adding up to more than $26 million in required bonding that has still not come in. Though operators have 90 days to post their bonds after the commission's approval, several companies are very behind schedule. Two — Locin Oil Corporation and the Dover Atwood Corporation, who agreed to ten-year bonds of $20 million and $6.3 million respectively — are more than a year late, according to a review of public documents. Their second-year bonds are already due, and the first year installments haven't yet come in.

One of Colorado's orphan wells. Credit: Earthworks

Dozens of companies simply haven't complied with the new rules at all. As of June 25, according to **an ECMC database (https://ecmc.state.co.us/cogisdb/ReportTools/FA/FATrackRpt)** that tracks daily activity in the oil and gas bonding space, 66 companies hadn't even filed initial paperwork yet. Together, these companies represent 1,075 wells — and nearly $130 million in liability, if calculated at $130,000 per well site.

In the May 22 public webinar, then-commissioner McGowan said ECMC was working on the problem.

"They have been sent some enforcement letters," she said of the non-responsive companies. "They are currently in enforcement with the commission and we are trying to close that out and find out what's going on with those operators." She added that this group represented a small overall proportion of the total number of unplugged wells in the state, about two percent.

Still, it's unclear what will happen with those companies' wells — and given the huge amount of liability in the state, every dollar matters. After initially telling the Colorado Sun it planned to have $820 million in bonding in hand by 2044, ECMC has since **revised (https://coloradosun.com/2024/02/20/oil-wells-colorado-carbon-tracker-bonding/)** its 20-year estimate downward due to a double-count of certain bonds. On the May 22 webinar, McGowan said the commission now plans to have just $613 million in financial assurance 20 years from now.

There are reasons to believe that amount may ultimately be lower, including the large number of unresponsive operators, and the uncertain status of K. P. Kauffman's $133 million bond. But even if every dollar of that $613 million comes in as planned, it's not enough: Colorado still faces an imminent $3 billion shortfall from 27,000 low-producing wells. And a separate analysis by Carbon Tracker, shared with DeSmog and The Guardian, showed that the amount of liability due today from wells at near-term risk of being orphaned if their operators walk away is over $520 million. In other words, the amount of assurance ECMC plans on for 20 years from now may barely cover what's already needed today.

"Negotiation and compromise cost six years of delay with no tangible improvement," the Carbon Tracker analysts conclude. Meanwhile, the existing rules appear to be doing little to incentivize well plugging. In the legacy drilling areas outside the state's only profitable basin, operators plug just 0.4 percent of their wells each year, according to Carbon Tracker. The analysts found that, if this pace were to continue, it will take companies in those eight basins 250 years to fully decommission all their wells.

Going Beyond Bonding

I asked Adam Peltz, the Environmental Defense Fund lawyer who praised the ECMC's rules in 2022, if he still felt bullish about the program. He insisted that Colorado was still better off than other states, citing examples like Pennsylvania, where there is no bonding at all for wells drilled before 1987, and New Mexico, which has **struggled to pass more rigorous rules (https://www.propublica.org/article/oil-industry-lobbying-unplugged-wells)**, in part due to industry influence. Both states have many more unplugged wells than Colorado does.

Ultimately, he said, Colorado will need to look outside the bonding system to solve its massive shortfall.

"You can't solve this problem with bonds alone, because for so many companies it's too late," he said. "They'll never generate enough money to pay to close their own wells." But he pointed out another aspect of the rules developed in 2022 — the fee on producers. Currently, that program only generates $10 million a year, which Peltz conceded is not enough to overcome the billions Colorado faces in oil and gas liabilities, even considering that some of it is eligible to be matched by federal money thanks to a provision in the Inflation Reduction Act.

“It’s possible that, as this plays out in Colorado, ECMC will have to raise that $10 million a year figure to 20 to 25 million” to cover liabilities more sufficiently, he said. The good thing about that approach, he said, is that a fee on producers would help apply revenue generated in the resource-rich Denver-Julesburg to plugging in depleted areas of the state, helping to address the fundamental imbalance in the state. He feels the existing rules, while not yet sufficient, lay the groundwork for that approach.

“Colorado’s innovation was saying, here’s this additional fee, you need to pay to socialize the cost of plugging these wells among all operators,” he said. “I wish every state would do that.”

The Carbon Tracker report does not recommend specific policy solutions to address the looming shortfall. But it ends by suggesting that major reforms are needed.

“Given the substantial delay and deficiency of the first effort at reform, another round of policymaking must consider novel and muscular alternatives that can provide comprehensive coverage simply and quickly,” the analysts write, “or else decide by omission to allow oil companies to conclude their business in the state and leave their mess behind for taxpayers to clean up.”

That includes finding a way to force the public companies in the Denver-Julesburg Basin to start holding back profits now — something the current rules don’t do. Otherwise, they, too, will eventually go upside down, repeating the mistakes of the past.

Mitchell, the Documented analyst, remembers advice she first heard from a former colleague at the Department of the Interior: “The best time to collect is on payday.”

“In this period of record profits for the oil and gas industry,” she said, “this is kind of it.”

CORRECTION (6/27/24): The original version of this story stated that remaining production can offset two percent of cleanup costs in the 15 biggest oil and gas producing states, according to the ProPublica and Capital and Main analysis. That has been corrected.

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By **Joe Fassler (https://www.desmog.com/user/joe-fassler/)**

Joe Fassler is a writer and journalist whose work on climate and technology appears in outlets like The Guardian, The New York Times, and Wired. His novel, **The Sky Was Ours (https://www.penguinrandomhouse.com/books/639337/the-sky-was-ours-by-joe-fassler/)**, is forthcoming from Penguin Books.

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