It's Closing Time: The Huge Bill to Abandon Oilfields Comes Early

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Carbon Tracker Initiative

About Carbon Tracker

Carbon Tracker is a team of financial specialists making climate risk real in today's 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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1. Executive Summary

- The industry is legally obligated to Plug and Abandon (P&A) oil and gas wells, but it has not set aside the resources to pay for this. This is because financial assurance requirements for oilfield asset retirement obligations have to date been a race to the bottom.
- States have inadvertently created a moral hazard: it's always in the operator's financial interest to delay permanent abandonment of wells as long as possible, often by selling late-life and marginal assets to weaker companies.
- As a predictable result, inventories of largely self-bonded idle wells, some that have been nonoperational for more than 100 years, have ballooned. This trend will only accelerate as the industry enters a state of permanent decline.
- Covid-19 has temporarily shut-in tens of thousands of producing wells. The energy transition may destroy any chance for the reactivation of these and hundreds of thousands more idle wells.
- The industry's asset retirement obligations (AROs) are accelerating, and the ultimate cost to permanently retire the millions of producing, idle and orphaned wells in the U.S. in accordance with law will be much greater than expected.
- Current liabilities are calculated based on an average cost of $20-40k, but the actual expected cost for a modern shale well is closer to $300k.
- Industry – not just a few insolvent companies but the entire U.S. oil and gas industry – may not have sufficient revenues and savings to satisfy liabilities for hundreds of billions of dollars in self-bonded AROs as they come due. Industry-funded orphan well programs are barely a drop in the bucket.
- Self-bonded AROs have left industry and oil producing states in a deep hole. If millions of wells with no future beneficial value are to be plugged as the law requires, it will mostly be at taxpayer expense. If instead, they are not plugged, the price will be paid by landowners, citizens, and the environment.
- By continuing to extend free unsecured credit for AROs, states are subsidizing oil and gas to the detriment of their citizens, the environment, and the competitiveness of renewable energy needed to combat climate change.
- All oil- and gas-producing states should be asking themselves these basic questions:

- What can I do to obtain cost data and estimates that are reflective of the true costs, for industry to fulfill its obligation to retire producing and idle wells in my state in the ordinary course of operations?
- What will it cost industry to plug and retire the existing inventory of producing, idle and orphaned wells in my state?
- How much of this cost is currently secured by bonds or other collateral?
- What is the total ARO liability exposure (both in and out of state) for operators in my state and what is the likelihood they will be able to satisfy those liabilities over the short, medium and long term?
- What actions can I take now to reduce the financial and environmental risks to my state?

2. Introduction

A. The flip side of stranded assets – stranded liabilities

Carbon Tracker pioneered work on the oil and gas industry's "stranded assets"; as investors increasingly ask whether oil demand is or will soon be in terminal decline, we are turning attention to the flipside of stranded assets – "stranded liabilities." Specifically, the cost of retiring long-lived oil and gas infrastructure. This paper is the first in our series focusing on the dynamics that are driving the acceleration of these risks and a method for assessing the magnitude of the problem.

By law, after production ceases, all oil and gas wells must be permanently plugged and abandoned. In finance, these debt-like legal obligations to Plug and Abandon wells are called "asset retirement obligations" (AROs).[1] They are reported in company financial statements on a discounted present value basis.

Companies typically assume that the bulk of ARO costs will be incurred in the distant future, but the low carbon energy transition will bring them forward – further accelerating the industry's woes brought on by the coronavirus pandemic.

There's no money set aside to cover retirement costs, and lax regulations are to blame.

And this illuminates the problem: regulators have not required the industry to set aside funds to retire these wells. In short, the industry cannot afford to retire. If industry can't pay, then its lenders, investors, creditors and ultimately oil producing states will eventually be forced to foot the bill. Else, landowners and citizens will be left to live with the consequences of millions of unplugged wells.

How did this happen? Going back to the 1800s, the purpose of oil and gas regulation was to promote oil and gas production not to protect the environment. When oil and gas drilling began in the U.S., there was no regulation regarding the treatment of a well at the end of its useful life. Drillers simply "abandoned" unusable wells as gaping holes in the ground. When plugging and abandonment regulations came along, they were designed to protect the production zones from flooding by fresh water. As the number of abandoned wells mounted and the adverse environmental and safety implications of improperly abandoned wells became better understood, states began setting P&A standards designed to protect groundwater resources.

[1] FLIP SIDE: How stranded assets will give rise to stranded liabilities at https://www.carbontracker.org/reports/the-flip-side-stranded-assets-and-stranded-liabilities/. AROs are legal obligations to perform retirement activities when a long-lived tangible asset, such as an oil well, offshore platform, pipeline, or terminal, is permanently retired from service. In this paper, we focus exclusively on AROs associated with oilfield assets – oil and gas production wells, wastewater injection wells, offshore platforms, gathering lines, and related infrastructure. The most common type of oilfield ARO is the legal requirement to plug and abandon oil and gas wells at the end of their useful life. https://www.osha.gov/SLTC/etools/oilandgas/abandoning_well/abandoning.html.

As P&A standards evolved costs increased, and states began to require financial assurance (or "bonding") from oil companies to assure timely completion of permanent well closure and site restoration. Oil companies successfully argued for low bonding levels on the grounds that full bonding – bond amounts equal to 100% of the estimated cost to complete the work – was unnecessary to protect the state's financial interests and would make oil and gas production non-economic.

P&A and related bond carrying costs (annual premiums and collateral) provide no return on investment for oil companies, who want to keep capital expenditures and operating costs as low as possible. If a state proposed to increase bond levels, oil companies could threaten to move their activities elsewhere. Bonding became a race to the bottom.

With industry's support, governments established "orphan" well programs funded by industry to pay for wells orphaned to the state by failed oil companies. The idea was simple: thriving oil companies would pick up the bill for failed ones. Low bonding levels were an acceptable risk, as long as the vast majority of oil companies remained good credit risks.

States, however, failed to realize that they had created a moral hazard: when bonding levels are far below actual P&A costs, it's always in the oil company's financial interest to delay permanent retirement of wells as long as possible.[2]

As a predictable result, inventories of largely "self-bonded" idle wells, including "zombie" wells that have been [nonoperational for more than 100 years], have ballooned.

At the same time inventories of idle and orphan wells are sky-rocketing, the oil industry is entering a state of permanent decline. The ratio of thriving oil companies to failing ones is deteriorating and will continue to get worse. The assumption that the strong will pick up the bill for the weak is no longer valid. States must adopt new policies to reflect this new reality. The race to the bottom must be reversed.

As long as it remains financially optimal for companies to defer closure, this is the course they will take. To avoid this outcome, regulators must incentivize industry to fulfill its obligation to promptly retire non-economic wells in the ordinary course of operations, while there are still cashflows available to do so. This will require regulations that force industry to pay a market-based price – in the form of full bonding and fees on idle and marginal wells – for the option to defer permanent retirement. This requires an understanding of the actual costs to close wells.

[2] Idle Oil Wells: Half Empty or Half Full? at p. 7.0 https://www.iaee.org/en/students/best_papers/Muehlenbachs.pdf.

What does it cost to close a well?

Though wells are being closed all the time, data on industry well closure costs is surprisingly scarce. Moreover, damage from wear and tear over decades can complicate P&A and make it difficult to anticipate the cost of retiring any given well. However, to inform appropriate policies it is essential that states obtain reliable estimates of the average expected costs to plug and abandon all wells under their jurisdiction, including producing, marginal, idle and orphan wells.

States cannot expect the willing cooperation of industry, whose self-interest is to downplay P&A costs as negligible. A common industry theme is to imply that costs to close producing and idle wells will be the same as those incurred by states to close orphan wells. But this is a misleading comparison because orphan wells tend to be shallower and because states can time orphan closures to when rig costs are low and multiple wells in the same area can be plugged at the same time – a luxury industry may not always have.

B. The true costs of plugging shale wells may be one of industry's best kept secrets

Reliable estimates of the cost to lawfully retire the oil and gas industry are essential for states but a threat to industry. Lower P&A cost estimates allow industry to argue that existing bond levels are sufficient. Orphan well cost data provides a convenient chimera.

Because industry does not report actual or estimated P&A costs, available U.S. cost data comes entirely from state orphan well programs. This has led the unwary to assume that all wells, shallow or deep, producing or orphaned, will cost in the low tens of thousands of dollars to close. Our research indicates, however, that those expecting the cost of permanently retiring hundreds of thousands of unconventional shale wells to be $20,000 to $40,000 per well are in for sticker shock. A more realistic estimate may be an order of magnitude higher on average, and in extreme cases as much as $1 million per well. This is because shale wells are deep, deep wells are expensive to close, and deep "problem" wells can cost an order of magnitude more than typical ones.

The true costs to plug deep U.S. shale wells may be one of industry's best kept secrets. As many of the newer deep wells become candidates for permanent Covid-induced shut-ins, understanding these costs and assessing state-wide and company-specific exposure is imperative for every oil producing state.

This paper examines the publicly available data to identify what they might expect to find.

3. Covid-19

The coronavirus pandemic has led to the fastest collapse of oil demand and prices in more than a generation. Nowhere have these impacts been more profoundly felt than in the U.S. shale patch. There is now talk of struggling companies being seized and operated by their lenders.[3]

Which brings us to this paper: unlike most other industries, oil and gas is lawfully required to clean up its mess when the music stops. That moment is unavoidable for every well and eventually for the entire industry. The energy transition was already quickening the pace, but for U.S. shale producers, Covid-19 has brought that day of reckoning forward, front and center.

Covid-19 is impacting the short, medium, and long-term outlook for the industry:

- **Short term:** Temporary shut-in of production because there is no place to store excess oil supply. Ironically, this includes many of the newest, most productive wells as these may be considered the most able to withstand the physical impact of being shut-in. It will cost money to restart them – Wood Mackenzie estimates that given restart costs – some portion of current production may never return.[4] While granting leniency on extended shut-in of productive wells, regulators may require many long-term idle "zombie" wells to be permanently plugged. These are wells that have been idle, often for decades, long before Covid-19 struck and now look even less likely to be reopened.
- **Medium term:** The virus is not going away anytime soon. And beyond the U.S. Energy Information Administration (EIA), most analysts believe that oil demand won't be snapping back overnight. Even industry is saying this may result in permanent changes to consumer preferences (i.e. less travel, more working remotely). Meanwhile, an extended reduction in demand for oil will give renewables and EVs time to take market share, leading some analysts to predict that 2019 was peak demand for oil. On the supply side, higher than expected decline curves in the U.S. shale patch were already causing concern about premature well failure. Add to that the risk that an extended shut-down could damage oil formations permanently. As a result, many new and highly productive wells will need to be plugged much sooner than expected.
- **Long term:** Covid-19 puts particular pressure on the U.S. fracking industry, which has never been cash flow positive. Major lenders were backing away before the virus. Worse, the larger backdrop to the current crisis is climate change

[3] https://www.reuters.com/article/us-usa-banks-energy-assets-exclusive/exclusive-us-banks-prepare-to-seize-energy-assets-as-shale-boom-goes-bust-idUSKCN21R3JI
[4] https://www.bicmagazine.com/expansions/upstream/woodmac-how-will-the-oil-price-crash-hit-the-upstream-sector/

and the energy transition, forces that will not recede. Those with oil industry counter-party risk are now thinking about the implications of an industry in terminal decline. The most affected are U.S. petro-states, who are both losing severance tax and royalty revenues and facing likely default on billions of dollars in self-bonded well closure obligations. Fracking could not generate an acceptable return on investment even with free, unsecured credit on closure obligations. As states take long overdue steps to de-risk, the industry's financial situation will only get worse.

4. ARO acceleration

> "We have got to change and change profoundly.... I get it. The world does have a carbon budget, and it is running out fast." –Bernard Looney, CEO BP

A. The energy transition, Covid-19, and maturing liabilities add up to a problem

Even industry leaders agree that some growth plans don't fit in a low carbon world. Were the trend not obvious, it can be seen in the ever more ambitious long-term emissions reduction targets that companies are announcing in response to investor demand.[5]

While climate change was already driving the oil and gas industry toward early retirement, the coronavirus pandemic hit the accelerator. The Covid-19 induced shut-ins[6] are at least an analogue – and perhaps the prologue, of how the industry will be impacted by the energy transition.

[5] https://carbontracker.org/totals-extended-emissions-ambition/; https://carbontracker.org/eni-the-first-oil-company-to-lay-out-a-strategy-of-managed-decline/.
[6] https://www.texastribune.org/2020/04/06/texas-oil-producers-shutting-wells-coronavirus-dispute-plummet-prices/ghgemissions_abandoned_wells.pdf

The looming costs are significant. It will cost hundreds of billions of dollars to close the estimated 3.3 to 4 million active, idle and abandoned but unplugged onshore wells in the U.S. An estimated 2.3 to 3 million of these wells are already abandoned.[7] Only a tiny fraction of that amount is bonded. And this ignores oilfield assets in the rest of the world as well as midstream and downstream assets everywhere.

If the U.S. shale oil industry were to live forever, its failure to save for retirement would not be a matter of immediate concern. Companies could pay retirement obligations as they come due from future earnings. But Covid-19, climate change and the energy transition obliterate the "forever" assumption. It is no longer reasonable, if it ever was, to assume that the U.S. oil industry will survive its longest living assets.

B. Self-preservation drives acceleration

In the first part of our paper series on AROs, we introduce the concept of "ARO acceleration." We define this as a series of self-reinforcing feedback loops that will pull asset retirement costs – both actual closure costs and the carrying costs of financial assurance – forward in time. Today, many regulators are already concerned that some of the temporary "shut-ins" sweeping the industry today may never return to service. This trend will only become more severe as the world transitions away from oil.

There are many types of AROs, but our focus here is on the most common type of oilfield ARO – the legal requirement to plug and abandon (P&A) and reclaim oil and gas wells at the end of their useful lives.[8] (See Appendix 1 for more on oilfield AROs.)

At root, readers should understand this: acceleration of the industry's retirement debt is driven simply by stakeholders protecting their own interests. In other words, ARO acceleration occurs when ARO counterparties demand timely closure of non-economic wells, higher fees for marginal and idle wells, and higher bond levels for new and producing wells.

None of this would be a concern but for the fact that industry was not required to save for retirement, and it didn't do so. The prospect that the industry will not survive long enough to pay its environmental debts will lead other parties, such as equity investors and banks, to protect themselves.

[7] https://www.epa.gov/sites/production/files/2018-04/documents/ghgemissions_abandoned_wells.pdf
[8] https://www.osha.gov/SLTC/etools/oilandgas/abandoning_well/abandoning.html. Although not addressed by this report, midstream and downstream AROs pose additional financial risks. For example, an analysis prepared for the State of Michigan found that, at an estimated cost of $855 per foot to remove pipelines from the ground, it would cost $23 billion to remove all of Enbridge's buried pipes in the U.S. alone. The oil industry generally does not report the estimated value of midstream and downstream AROs on the basis that they are expected to operate indefinitely. For this reason, the current analysis is just a portion of the industry's total liability.

1. Increased oilfield regulation impacts well-level economics, increasing risk of impairments.

Today, the oilfield regulatory system finances the industry's AROs by providing free credit on unsecured AROs – i.e., they don't require industry to fully bond these obligations, as they could. This lack of planning exposes these regulators to credit risk – if industry can't pay, the wells become wards of the state. It is in state interests to not allow this.

Unsurprisingly, even prior to the pandemic, regulators had begun the process of reducing their ARO credit exposure by increasing idle well fees and reducing tolerance for zombie wells. Doing this increases costs on industry.

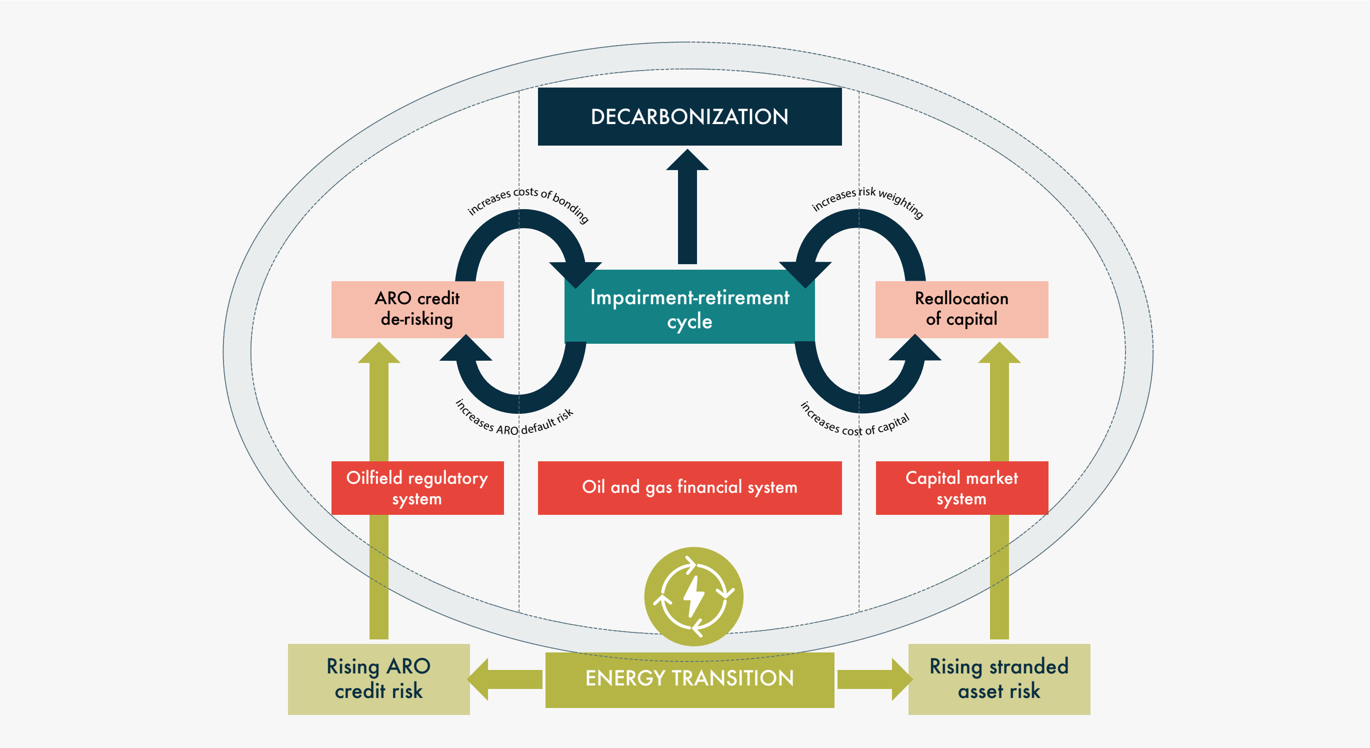
Table 1 lists examples of federal and state government actions and recommendations to mitigate ARO credit risk over the past several years.

Table 1. Government efforts to reduce ARO credit risk

Jurisdiction	Date--Action	Source
U.S. offshore	2014: update regulations and program oversight for Outer Continental Shelf (OCS) financial assurance requirements	Notice of Advanced Rulemaking
Wyoming	2015: set individual bonds at $10 per foot for all wells and increased blanket bonds from $25,000 to $100,000[9]	Legislative memorandum
U.S. offshore	2015: actions needed to better protect against billions of dollars in federal exposure to decommissioning liabilities	GAO-16-40
U.S. offshore	2016: Additional security requirements for OCS leases, pipeline rights-of-way, and rights-of-use and easement	NTL No. 2016-N01
U.S. offshore	2018: timely decommissioning of idle infrastructure on active leases	NTL No. 2018-G03
U.S. onshore	2019: BLM should address risks from insufficient bonds to reclaim wells	GAO-19-615
Alaska	2019: Increased individual bonds from $100,000 to $400,000 and blanket bonds from $200,000 to $30 million	20 AAC 25.025
North Dakota	2019: added limits on blanket bonds for wells idle more than 7 years	NDAC 43-02-03-15
South Dakota	2019: proposal to increase individual bonds from $10,000 to $50,000 and blanket bonds from $30,000 to $100,000 for shallow wells[10]	SDLRC 45-9-15

[9] https://trib.com/business/wyoming-proposes-to-increase-oil-gas-well-bonding/article_7bfb7987-aac4-560e-849c-6a8f220795e3.html.
[10] Proposed increase in bond amounts for shallow wells reported at https://rapidcityjournal.com/news/local/govt-and-politics/regulators-want-bigger-bonds-from-oil-and-gas-drillers/article_f690f105-7660-5332-8c0e-6606d282ddb9.html.

Figure 1. Oil and Gas Finance System



The oil and gas finance system is complex, non-linear and dynamic. Reinforcing feedback loops can accelerate suddenly and unexpectedly. As depicted in Figure 1, the oil and gas finance system has two subsystems – the oilfield regulatory system and the capital market system.

Higher bond levels impact oil companies via the entities that issue bonds. The sureties (i.e., those who "insure" against company default on the P&A obligation) who issue these bonds and are liable if companies cannot or will not pay, set annual premiums and collateral requirements based on the face amount of bonds and the risk of default. As bond amounts increase, so do the bond carrying costs borne by industry.

Higher bond carrying costs and regulatory fees on marginal and idle wells increase operating costs and breakeven prices. This may cause wells to become non-economic resulting in accelerated closures. For example, in its latest 10-K, California Resources Corporation reported accelerated estimated timing of ARO costs following new California idle well regulations.[11]

If retirement dates are brought forward as a result of increased regulatory costs, the combined effect of accelerated asset retirement and higher costs can impact the financial statements triggering the "impairment-retirement" cycle identified in the center of figure 1. Here's how it works.

Under U.S. accounting principles, impairment tests compare the capitalized cost of the asset (book value), which includes capitalized asset retirement costs, against expected undiscounted future cash flows, which consider bond carrying costs and fees on marginal and idle wells. Impairments losses are recognized when book values exceed expected future cash flows.

Impairments can therefore be driven by increased capitalized costs or decreased expected future cash flows, or both. Higher regulatory costs worsen both sides of the impairment equation.

Higher regulatory costs decrease expected future cash flows, as discussed above. Certain regulatory requirements (i.e., surety bonds, idle well fee payments, monitoring and reporting requirements) increase breakeven prices, resulting in lower profit margins at any given price. Lower margins cause some wells to become non-economic immediately and others to have accelerated estimated retirement dates as they age and decline in value.

Accelerating retirements have a less obvious but important reinforcing impact on impairments – it increases the book value of the assets. How? The capitalized asset retirement costs are already included in a well's book value, on a discounted basis. Bringing them forward in time unwinds the discount, which translates to higher book values. Thus, as regulatory costs increase, the useful economic lives of producing wells decrease, and the book values of those wells increase.

Recall that impairments losses are recognized when book values exceed expected future cash flows. If expected cash flows go down (due to increased regulatory costs) and book values go up (due to early asset retirement caused by increased regulatory costs), impairment is more likely.

[11] https://www.sec.gov/ix?doc=/Archives/edgar/data/1609253/000160925320000066/a2019ye10-kdocument.htm.

In sum, increased regulatory costs accelerate asset retirement and increase the probability and severity of asset impairment losses. Rising impairment losses in turn increase ARO credit risk, giving oil producing states more reason to increase bond amounts and fees on marginal and idle wells.

2. There are feedback loops in the capital market system as well.

A similar feedback loop can be seen in the capital market system at the corporate level. Oil and gas exploration and production is capital intensive. Rising regulatory costs, mounting environmental liabilities, recurring impairment losses, and concerns about the industry's long-term viability can cause investors to impose a risk premium on the sector. Investors may de-rate the sector. Banks may charge higher interest rates. These changed expectations can negatively impact the company's weighted-average cost of capital and cash flows.

As equity financing become more expensive or unavailable, companies must borrow more money at higher interest rates to fund new projects. Financing costs are not considered in impairment testing under U.S. accounting standards because they are not expected to arise as a direct result of the use and eventual disposition of the asset. However, financing costs are a factor in determining breakeven points for developing new fields and drilling new wells (the cash flows of which were expected to be used to settle existing AROs). Rising financing costs also reduce available cash to settle asset retirement obligations. This is likely to happen at the same time revenues are suffering from lower demand and prices.

Putting the regulatory and capital market finance systems together, rising regulatory costs to mitigate ARO credit risk increase asset impairments and investment risk, which increases financing costs, which reduces asset valuations and available cash for retirement costs, which increases ARO credit risk, and so on in a downward spiral.

C. Forever is over, costs underestimated, hiding in plain sight

If ARO acceleration risk sounds unfamiliar, it's because it has not been viewed as a systemic, structural risk before now – the default assumption has been that the industry was essential to economic growth and therefore would live forever. That topline assumption began to erode with Mark Carney's 2015 Tragedy of the Horizons speech. With the onset of Covid-19, the implications are now becoming increasingly clear to other stakeholders. Even before the impact of the pandemic was widely understood, CNBC's Jim Cramer captured the emerging zeitgeist, proclaiming on air February 3, 2020 that fossil fuels are "in the death knell phase." BP's CEO would not have put it so bluntly, but his new vision for BP includes producing less oil and gas over time.

Now that the forced early retirement of the oil industry is seen as a matter of when, not if, companies, states, investors and taxpayers need to rethink their ARO exposures. Financial data and analysis on P&A costs that has not been important before is now essential.

5. True costs of retiring producing and idle wells

Oil industry experts estimate that the cost to plug and abandon a modern U.S. shale well is $33,000 per well. Industry cost data from outside the U.S. (there is no available U.S. industry cost data) indicates that actual costs may be an order of magnitude higher on average. The costs to retire thousands of ultra-deep wells and those with wellbore damage or close proximity to sensitive receptors can exceed $1 million.

It's worth repeating that there is no available U.S. industry data on P&A costs. All of the available cost data comes from state orphan well programs.

Google "average well P&A costs" and the top response is likely to be a Wikipedia page on abandonment cost stating that, "The cost of a routine abandonment of a typical well in the United States is about $5,000 (~Texas average cost in year 2000)." Add "Texas" to the search and the top response is likely to be a Well Plugging Primer published by the Railroad Commission of Texas in 2000, stating that "Based on historical well plugging charges, the average well plugging cost in the State is approximately $4,500 per well."

These statements imply that there is such a thing as a "typical well" and that the average cost to plug such a well is $4,500. This is akin to saying the typical commercial building is 50 feet high and costs $4,500 to demolish. If one lives in a small rural town, this might be a useful estimation. If one lives in Manhattan, it is not.

In their 2016 paper published by the Society for Petroleum Engineers (SPE), *Estimating Ultimate Recovery and Economic Analysis of Shale Oil Wells in Eagle Ford and Bakken* (the "SPE Paper"), a team of Baker Hughes petroleum engineers propagated the same fallacy. Based on updated Texas orphan well data, the authors projected an average cost of $33,000 per well to plug producing wells in both basins.

> **Plug and Abandonment (P&A).** This cost bucket accumulates all costs for the abandonment of a well and reclamation of the site. Very often these costs are estimated as a percentage of the drilling costs (e.g. 5% or 10%). It is reported that Texas spent $14.3 million in 2014 to plug and decontaminate 428 orphaned oil wells. This implies a mean P&A cost of $33,000 per well in Eagle Ford. The same value is adopted as the P&A cost for the wells in Bakken.[12]

[12] Darugar, Q., Heinisch, D., Lundy, B. J., Witte, P., Wu, W., & Zhou, S. (2016, November 7). Estimating Ultimate Recovery and Economic Analysis of Shale Oil Wells in Eagle Ford and Bakken. Society of Petroleum Engineers. doi:10.2118/183396-MS.

The authors implicitly assumed that tight oil shale wells in the Eagle Ford and Bakken and orphan wells in Texas are typical (having the same distinctive qualities), and therefore the costs to plug each are comparable. They are not.

There are at least two ways in which existing orphan wells and shale wells differ – depth and design. Both can significantly affect P&A costs. While we believe these issues are understood by industry, they are rarely explicitly discussed, and data is difficult to come by. This is in part because so few deep wells have been plugged and also because regulators have not required industry to report P&A cost data and estimates so that they could be studied.

A. Shale wells are deeper, making them more costly to drill and to plug

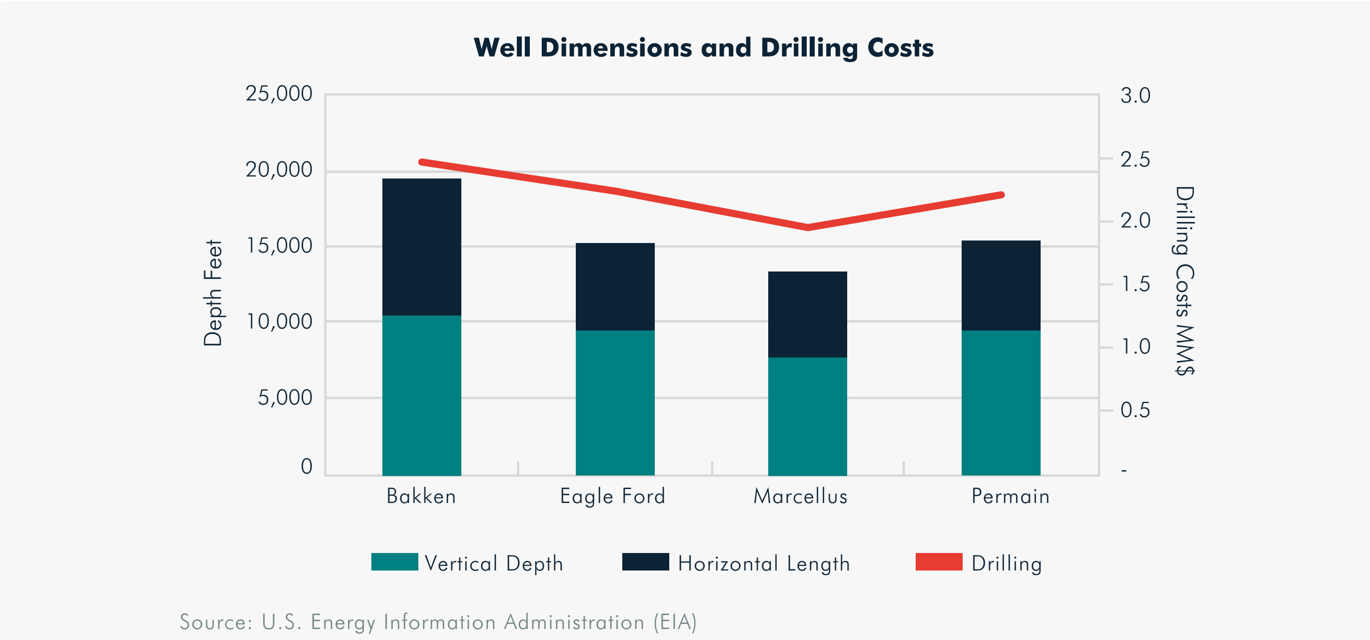
It is intuitive that it costs more to dig (and plug) a deep hole compared to a shallow hole; that depth is a cost factor is acknowledged by the Interstate Oil and Gas Compact Commission (IOGCC). It says that, "[t]he average cost to plug an orphan well varies widely depending on well depth and condition, accessibility, and other factors." The IOGCC also notes that several states set bond amounts based on well depth – an implicit recognition that plugging costs scale with depth.[13]

As a general rule, well P&A costs scale with depth. The problem is that regulators and industry (which benefits from the belief that P&A costs will be low) have too often implied that closure costs for deep wells will be in line with orphan well cost averages that are skewed downward by large numbers of low-cost shallow wells. Typical orphan wells are older and relatively shallow compared to shale wells. Most orphan wells were drilled before there was any regulatory oversight. Typically, these wells were drilled to shallow depths – often just a few hundred feet. Many do not create conduits for oil, gas, or saltwater migration and can be safely abandoned at very low cost.[14] For this and other reasons, the cost to plug the typical orphan well is not representative of the cost to plug typical shale wells.

Modern shale wells in the Western U.S. are deep, averaging 10,000 feet in vertical depth. Figure 2 shows vertical depths for shale wells in the Bakken, Eagle Ford, Marcellus, and Permian basins.[15]

[13] IOGCC. http://iogcc.ok.gov/Websites/iogcc/images/Publications/2019%2012%2031%20Idle%20and%20Orphan%20oil%20and%20gas%20wells%20-%20state%20and%20provincial%20regulatory%20strategies%20(2019).pdf
[14] IOGCC, at p 14. http://iogcc.ok.gov/Websites/iogcc/images/Publications/2019%2012%2031%20Idle%20and%20Orphan%20oil%20and%20gas%20wells%20-%20state%20and%20provincial%20regulatory%20strategies%20(2019).pdf
[15] https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf. See Figure 2-2: Depth and drilling cost by play.

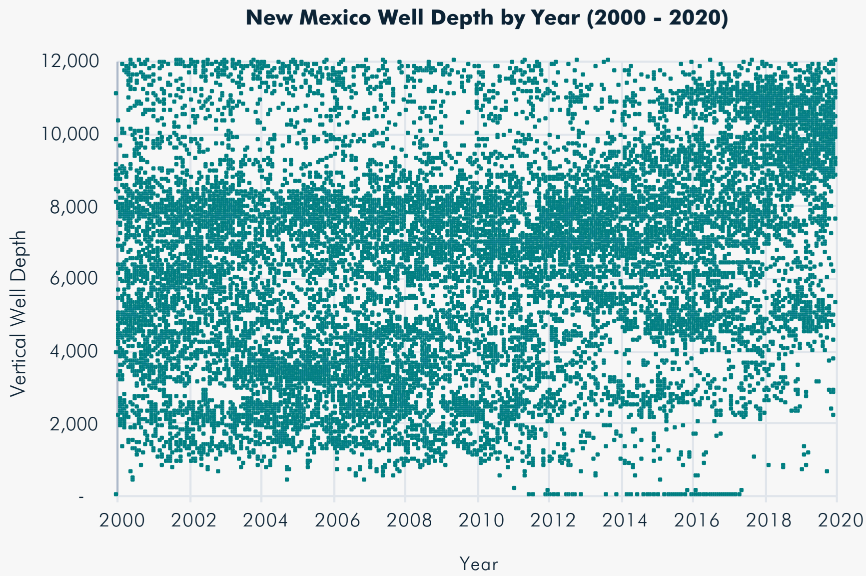
Figure 2. U.S. shale well depths



Many shale wells are even deeper, between 10,000 to 12,000 feet, and some wells go much deeper yet, approaching 20,000 feet (see Figure 6, below).[16] Average depth is increasing over time. The average depth of wells drilled in the U.S. from 1949 to 2008 was less than 5,000 feet. Figure 3 shows that oil companies in the New Mexico shale basins are steadily drilling deeper with time, moving toward 12,000 feet. Wells managed by the U.S. Bureau of Land Management have also become deeper over time.[17]

[16] https://business.okstate.edu/site-files/docs/economy/economics_of_deep_drilling.pdf. See Figure 6. Sample of Deep Wells Drilled in OK Since 2000 by County.
[17] Figure 6 at https://westernpriorities.org/wp-content/uploads/2018/02/Bonding-Report.pdf.

Figure 3. Increasing well depths in shale basins



Why is depth a factor in the cost to plug a well?

Deeper wells require more expensive rigs,[18] longer cycle times, more costly materials, and more complicated processes. These all increase average expected costs and the chance that something unexpected may go wrong and will have to be redone.

Plugging deeper wells involves higher pressures, higher temperatures and longer cycle times. According to the National Petroleum Council (NPC), deep wells may require more plugs, more expensive cement, and special cement additives. Different grades of cement are suitable for well depths up to 6,000 feet (API Class A, B and C), between 6,000 and 10,000 feet (API

[18] For example, rigs suitable for shallow wells less than 2,000 feet deep cannot service deeper wells up to 14,000 feet. See e.g., rigs available for different service depths from Continental Services, a contractor used by the Wyoming Oil and Gas Conservation Commission to plug orphan wells, at https://www.wellplugging.com/equipment/workover-rigs.

Class D), and over 10,000 feet (API Class E and F). Plugging deep wells requires long pump times to get cement to the bottom of the well. Long pump times increase the chances that the cement could harden prematurely. This requires special cement retarders to allow for adequate time to place the cement.

In addition to depth, the horizontal orientation of modern shale wells adds a layer of complexity not captured by our available cost data, which only cover vertical wells.

B. The design of horizontal wells makes obtaining a seal more difficult potentially increasing plugging costs

The shale boom began in the Barnett Shale in 2004, employing modern unconventional drilling and completion techniques such as horizontal drilling and hydraulic fracturing (fracking).[19] Most orphan wells are straight hole vertical wells that far predate the shale boom.

Horizontal drilling will be a factor in the cost to plug a well (though not one we have estimated here). According to the National Petroleum Council (NPC), horizontal shale wells, and particularly shale-gas wells, pose technical plugging challenges:

> The horizontal orientations introduce different gravitational effects compared with vertical wells. In a typical vertical well, where there is a large column of cement, some migration of the solids downward or the water upward does not cause a significant change in the cement properties. In a horizontal well, the solids migrating to the bottom of the section and the water migrating to the top can provide areas of the well that do not have a complete seal. If the water in the cement separates from the mixture before the cement is set, it can migrate to the top of the wellbore and form a channel along the top of the wellbore which can allow migration of formation fluids. If the solids in the cement mixture settle to the bottom of the cement before the cement can harden, the solids can cause the cement to not set up correctly and the weakened area along the bottom of the wellbore can fail under pressure during stimulation activities.

The NPC cautions that the eventual retirement of shale-gas wells must address plugging practices that are specific to issues affecting gas wells and especially horizontal gas wells.[20]

Significant differences in vertical depth and well design mean that average P&A costs for orphan wells in Texas do not imply an average P&A cost for shale wells.

[19] EIA at https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf.
[20] NPC at https://www.npc.org/Prudent_Development-Topic_Papers/2-25_Well_Plugging_and_Abandonment_Paper.pdf.

C. P&A costs by depth

We previously referenced the SPE Paper projection of $33,000 per well (based on average costs to plug a number of orphan wells in Texas). Similar estimates are echoed and reinforced by oil companies and data providers: Diversified Gas & Oil – $28,400 per well;[21] and Rystad – $20,000 to $40,000 per well.[22] Such estimates are misguided because they fail to account for the fact that plugging costs, like drilling costs, increase with depth.

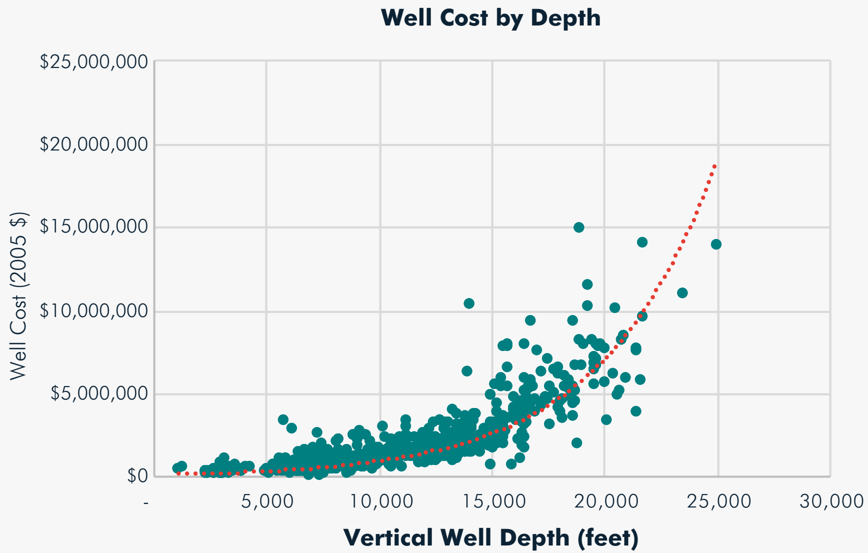
1. Drilling costs and plugging costs

A report examining the economic implications for Oklahoma of the natural gas industry's ongoing shift to deep resources, showed how drilling costs increase with depth (see Figure 4).[23]

P&A costs – like drilling costs – also scale with depth. The correlation is reflected in the industry's practice of estimating plugging costs as a percentage of drilling costs. Applying the rule of thumb referenced in the SPE Paper (estimated plugging costs are 5% to 10% of drilling costs) to the EIA's figures for average shale drilling costs ($1.8 to $2.6 million per well),[24] the industry forecast of average P&A costs for shale wells in the Eagle Ford and Bakken should range from $90,000 (5% of $1.8 million) to $260,000 (10% of $2.6 million).

[21] 2019 Diversified Gas & Oil investor presentation at: https://d1io3yog0oux5.cloudfront.net/_28d9d5529099b5877b9e19aa9798c2da/dgoc/db/557/4323/pdf/DGO+-+Investor+Presentation+-+June+2019_vFinal_updated+slide+13.pdf.
[22] https://www.rystadenergy.com/newsevents/news/press-releases/american-backyard-wells-the-flexible-11pct-of-the-us-onshore-oil-output-now-face-an-inflexible-choice/.
[23] Mark C. Snead, Ph.D., The Economics of Deep Drilling in Oklahoma (2005) at https://business.okstate.edu/site-files/docs/economy/economics_of_deep_drilling.pdf. We want to thank Professor Snead for supplying the raw data used to reproduce this graph.
[24] EIA at p.7. https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

Figure 4. Drilling costs and well depth (Oklahoma State University)



2. Overview of available P&A cost data

We reviewed available data from three data sets. These include data from state orphan well programs in Wyoming and Ohio and industry cost data for P&A well completions in Australia.[25]

While there are differences in the characteristics of each data set, what is striking is that they all demonstrate that costs scale with depth.

[25] Louisiana has reported average plugging costs of $4.76 per foot for 139 shallow onshore wells (< 3,000 feet) plugged in 2019, compared to the average cost to plug six deep onshore land wells (between 3,000 and 10,000 feet) of $35.84 per foot. However, data on individual well costs and depths were not available. http://app.lla.state.la.us/PublicReports.nsf/0/C9D7297FEA93568D86258528006BA4F8/$FILE/0001FA2E.pdf.

Key differences pertain to the party performing the work, the nature and specifications of the work performed, and the source and nature of the available documentation of costs.

The Wyoming and Ohio data sets come from orphan well programs where the state was the party contracting and paying for services. The Australian data comes from industry P&A completions contracted and paid for by oil companies.

The Wyoming data set included 452 orphan wells plugged by the Wyoming Oil and Gas Conservation Commission between 1997 and 2014. The wells were grouped into 80 contracts, some for single wells and others for as many as 83 wells. We adjusted the cost data for inflation.[26] The Wyoming data set included costs to plug a mix of coalbed methane (CBM) wells and conventional oil and gas wells. Compared to conventional wells, such as those in the Ohio and Australian data, CBM wells are relatively easy and inexpensive to plug. The prevalence of CBM wells in the Wyoming data set tends to lower average costs per well.

The Ohio data included proposals received by the Ohio Department of Natural Resources, Division of Oil & Gas Resources Management in 2019 to plug and abandon 356 orphan wells grouped into 103 contracts, some for single wells and others for as many as 33 wells.[27] Where multiple proposals were received, we used the lowest bid.

The Ohio data was accompanied by detailed contract specifications describing the work to be performed. The Wyoming and Australian data are not supported by similar contract documents. Of particular note, the Ohio contracts specify that, "The Contractor shall identify the diameter of the well bore below the surface casing and drill with a full-size bit to total depth. In any case where an obstruction is encountered, and total depth cannot be achieved, the Contractor shall immediately notify the Division." We are not aware of similar requirements in other jurisdictions. Ohio's stringent wellbore preparation requirements may result in higher costs relative to other jurisdictions.

The Australian data set was derived from Well Completion Reports submitted to state governments. These reports, which are described in an academic study, documented work performed and related costs. We did not independently review these reports.

[26] http://insideenergy.org/2015/10/01/the-rising-cost-of-cleaning-up-after-oil-and-gas/.
[27] http://oilandgas.ohiodnr.gov/regulatory-sections/orphan-well-program/scope-of-work. We allocated total costs for multi-well contracts among wells based on relative well depth.

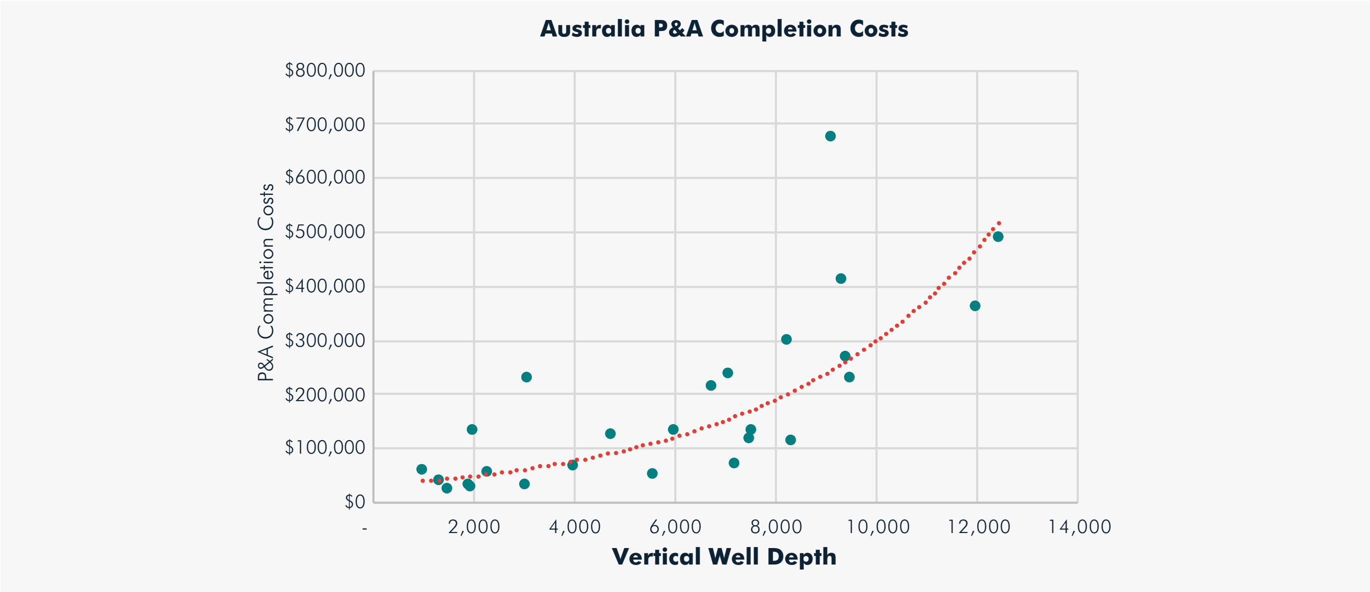
3. Australia P&A completion data

The Australian data set was prepared in connection with a master's thesis for School of Petroleum Engineering at the University of New South Wales. A key conclusion of the thesis is that the relationship between P&A completion costs and depth is exponential.[28] Unlike post-production closures, the Australian P&A completions did not include site preparation and rig mobilization costs (because the drilling rig was already on site), which can be a significant portion of total P&A costs. Although less expensive "workover rigs" are generally used for post-production P&A, the higher day rates for the more powerful drilling rigs used in the Australian P&A completions would have been offset, at least in part, by faster completion times. Separately, as these wells were being plugged immediately after being drilled, there was less risk of wellbore damage and surface contamination associated with decades of production, thereby reducing the risk of atypical costs.

When new wells are drilled, they can either be completed to produce oil and gas or, if the hole is dry, plugged and abandoned. P&A completions are single-well projects that avoid the distortion of well depth and cost averaging for multi-well contracts. Figure 5 shows P&A completion costs for 26 dry holes drilled in Australia from 1996 to 2004.[29] Costs are adjusted for inflation and shown in U.S. dollars.

[28] Leamon, at Section 6.4.4.3. https://www.unsworks.unsw.edu.au/primo-explore/fulldisplay/unsworks_1559/UNSWORKS
[29] https://www.unsworks.unsw.edu.au/primo-explore/fulldisplay/unsworks_1559/UNSWORKS

Figure 5. Australian P&A completion costs by depth



Adjusted for inflation and currency conversion, the cheapest well cost $25,515 to plug. The most expensive cost $675,604. The average cost for wells more than 10,000 feet was $424,000. These costs exclude charges for site preparation and rig mobilization, which are unnecessary in P&A completions where the drilling rig remains on site, but which are incurred when closing post-production wells.

Notably, the one outlier in the Australia data (a 9,000-foot well costing $676,000) shows that outlier deep wells can significantly exceed expected average costs (see Figure 5).

The Australian P&A completion data set offers an undistorted reflection of the correlation between plugging costs and depth. It excludes distortions from fixed costs for site preparation and rig mobilization, costs that are incurred prior to in-hole activity and are therefore largely unrelated to well depth. The single-well data set eliminates cost and depth averaging distortions for multi-well contracts and is also largely free of outlier wells with costly well-specific factors uncorrelated with depth.

The Australian P&A completion cost data indicate that expected costs for industry to plug a typical 10,000-foot straight hole well in the ordinary course of operations are in the range of $300,000, an order of magnitude higher than oft-cited average orphan well costs. The data also show that outlier deep wells can cost hundreds of thousands of dollars more to abandon than normal wells of comparable depth.

We cannot verify that P&A costs in the U.S. today will be the same as P&A costs incurred in Australia from 1996 to 2004, adjusted for currency conversion and inflation. There are also differences between P&A completions and closures of producing and idle wells that could materially affect costs for individual projects.

However, the Australian industry cost data stand strongly for the proposition that P&A costs increase exponentially with depth and that average P&A costs for deep shale wells will be much higher than average orphan well program costs dominated by shallow wells. Absent evidence to the contrary, which the U.S. oil industry is free to disclose, the Australian data stand as the best and only available proxy for expected industry costs to close deep shale wells.

4. Orphan well data

Table 2 summarizes key findings from the Wyoming and Ohio state orphan well data in comparison to the Australian P&A completion data. In addition to the aggregate Ohio data, which includes multi-well and single-well contracts, the table includes data for 25 single-well contracts.

Table 2. Summary of P&A cost data

	Wyoming		Ohio		Ohio-Single		Australia	
Vertical Depth	**#**	**$/well**	**#**	**$/well**	**#**	**$/well**	**#**	**$/well**
>10,000 ft.	3	321,785	0	-	0	-	2	$423,885
7,500 – 10,000 ft.	10	64,202	0	-	0	-	7	$304,452
5,000 – 7,500 ft.	5	59,378	10	$122,101	0	-	6	$136,690
2,500 – 5,000 ft.	15	66,873	68	$114,691	7	$139,832	4	$112,512
1,000 – 2,500 ft.	19	23,175	158	$77,737	8	$114,899	6	$51,681
<1,000 ft.	21	8,381	123	$56,619	10	$69,132	1	$57,671
All	**73**	**48,270**	**359**	**$78,737**	**25**	**$103,573**	**26**	**$177,572**

Table 2 shows that the orphan well data is dominated by wells less than 2,500 feet, that average costs tend to increase with depth, and that costs for deep wells are significantly higher than average costs for all wells.

The orphan well data also indicate that costs range widely from state to state. Ohio's average cost per well is nearly twice that of Wyoming. The Ohio data also indicate that current P&A costs in the U.S., at least for wells with depths less than 7,500 feet, are comparable to P&A completion costs in Australia. Further research is needed to understand the variance between P&A costs in Ohio and Wyoming.

That said, both the Wyoming and Ohio data indicate an exponential correlation between depth and costs. Other researchers have cited the Wyoming data for the proposition that P&A costs are correlated with depth.[30] They concluded the relationship was linear when in fact the data indicate it is exponential. We expect the exponential relationship would be even stronger if the data excluded multi-well contracts.

It is important to note that the orphan well data sets all suffer to some extent from multi-well campaign averaging that distorts the relationship of depth and cost. For example, the Wyoming data included total costs and depth per multi-well contract but not individual well depths and P&A costs. The Ohio data included individual well depths but not individual well costs for multi-well contracts. In these cases, we allocated well depths and costs ratably based on the number of wells (e.g., we allocated 20% of the total cost to each well in a 5-well contract).

The grouping of wells of widely varying depth into single contracts with an aggregate cost to plug all wells has the effect of dampening the correlation between depth and cost. For example, one of the Ohio contracts included three wells with depths of 685, 700 and 3,669 feet. Another grouped two wells with depths of 1,528 and 6,054 feet. In this case, the deepest well in the set was averaged with a much shallower well. Separate pricing for individual wells likely would have resulted in a stronger correlation between depth and cost. When total costs scale exponentially with depth, the expected average cost to plug a 1,500-foot well and a 6,000-foot well may be higher than the expected average cost to plug two 3,750-foot wells.

For these reasons, it is important to consider the cost differences between the aggregate Ohio cost data, which includes multi-well and single-well contracts, and the cost data for the 25 single-well contracts.

D. The importance of time flexibility

The authors of the SPE Paper assumed that industry's costs to plug comparable wells of similar depth in the ordinary course of operations are the same as those incurred by state orphan well programs. This may not be true.

The conclusion that average orphan well closure costs incurred by states are a good proxy for the average costs industry will incur to retire producing and idle wells of comparable depth in the ordinary course of operations assumes that companies and state orphan well programs will pay equivalent prices for equipment and labor costs to plug a well. This is not necessarily the case.

Rig-related costs – daily rental rates and the costs to transport the rig to and from the site – are by far the largest component cost of well abandonment. The workover rigs typically used for well plugging are also used to service producing and idle wells. Demand for these rigs is largely determined by oil prices and drilling/workover activity. Rig day rates can vary widely

[30] http://insideenergy.org/2015/10/01/the-rising-cost-of-cleaning-up-after-oil-and-gas and https://westernpriorities.org/wp-content/uploads/2018/02/Bonding-Report.pdf.

over time and across regions, depending on regional supply and demand. When oil prices are high and exploration and production activity is surging, rig rates are high, and plugging is relatively expensive. When oil prices are low, and exploration and production activity is contracting, as is the case now, rig rates are low, and plugging is relatively cheap – but, of course, at such times industry has little desire to expend scare financial resources to plug idle wells.

The key to minimizing P&A costs is to minimize rig-related costs. There are several ways to do this, if the party contracting for the work has timing flexibility. Ways to minimize rig-related costs, individually or in combination, include:

- Timing projects when regional rig rates are relatively low in order to reduce rental costs
- Timing projects when rigs are available in close proximity to the well(s) to be plugged in order to reduce rig mobilization and transport costs
- Organizing campaigns to plug multiple wells in the same geographic area in order to spread rig mobilization and transport costs over multiple wells

State orphan well programs have flexibility to exploit these cost saving opportunities that operators plugging wells in the ordinary course of operations – i.e., promptly upon wells being deemed non-economic – often do not. The variation in costs can be significant.

To gauge the degree to which costs can vary depending on current market conditions, we compared multiple bids for P&A projects submitted by contractors in response to Ohio's request for proposals (RFPs). Ohio received multiple bids on 97 of 103 RFPs. For one third of the contracts the high bid was more than twice the low bid. For one contract, the high bid was 8.5 times higher than the low bid. On average, high bids exceeded low bids by 89%. The RFPs were identical in terms of scope of work, number of wells, project specifications, and timing. The large variation in quoted prices therefore appears to be attributable largely to the contractors' availability of rigs in the area at the time. The Ohio cost proposal data suggests that P&A costs can vary 200% or more depending on regional availability alone.

A key to achieving these kind of savings is time flexibility. Table 3 describes three abandonment scenarios. In the first scenario, the state plugs an orphan well after the operator defaults. In the second scenario, the operator plugs a producing or idle well following a determination that it is no longer economically beneficial and thus must be permanently abandoned according to state law. In the third scenario, the operator plugs a dry hole immediately after the well is drilled and before the drilling rig leaves the site. In this scenario, there are no rig transport and mobilization costs because the same rig used to drill the well is also used to plug it.

Table 3. Abandonment scenarios

Rig-related cost factor	Orphan well	Producing or idle well	Dry hole
Day rates	Rates for workover rigs vary widely based on regional supply and demand	Rates for workover rigs vary widely based on regional supply and demand	Rates for (more costly) drilling rigs vary widely based on regional supply and demand
Transport and set up	Varies with distance, equipment and number of wells in campaign	Varies with distance, equipment and number of wells in campaign	n/a – rig already on site; no ability to plug multiple wells in campaign
Timing flexibility	High ability to schedule work to minimize day rates and transport costs	Varying ability to schedule work to minimize day rates and transport costs	No timing flexibility as work must commence immediately following drilling
Average cost	**Lowest average cost** due to flexible timing	**Higher than orphan costs** due to less flexible timing	**Higher than orphan costs** due to low timing flexibility

The scenarios in Table 3 show that states have greater flexibility than operators to minimize P&A costs – assuming operators complete timely retirement of producing and idle wells in the ordinary course of operations in accordance with applicable law. This does not imply that states should require operators to permanently abandon wells immediately upon being shut-in. However, it does assume that bond amounts and fees on idle and marginal wells effectively incentivize operators to permanently retire wells when there is no viable potential for future profit.

E. Oil's deep hole dilemma

There are more than 900,000 active oil and gas wells in the United States, and more than 130,000 have been drilled since 2010 during the U.S. shale boom.[31] The correlation of plugging costs and depth raises an important question: how much will it cost on average to plug more than a hundred thousand deep shale wells?

[31] https://www.washingtonpost.com/graphics/national/united-states-of-oil/.

We repeat that the Australian P&A completion cost data indicate that expected costs for industry to plug a typical 10,000-foot straight hole well in the ordinary course of operations are in the range of $300,000, an order of magnitude higher than oft-cited average orphan well costs.

The average cost to plug unconventional tight-oil wells and shale-gas wells could be significantly more. We could find only one example of reported costs to retire a modern shale well. Pursuant to a regulatory order, in 2008 Cabot Oil & Gas plugged three Marcellus Shale vertical gas wells drilled the same year at a reported cost of $2,190,000. Adjusted for inflation, this is $2.9 million today, or about $1 million per well. The vertical depth of the three wells ranged from 6,950 to 7,450 feet.[32] Insufficient information is available to know whether these wells are representative of unconventional shale wells or if they are outliers due to the circumstances surrounding their retirement.

Well depth is not the only factor that determines plugging costs. As discussed above, it matters who is paying and when. Other random factors affecting P&A costs include the type of well (oil or gas), the applicable plugging standards,[33] the existence of wellbore damage, proximity to surface water, schools, homes, and businesses, the presence of hydrogen sulfide gas, access limitations, and the extent of required soil remediation and surface restoration. When present, these factors can significantly increase P&A costs above the trend line for wells of the same depth. Whereas, the average cost for industry to plug a typical 10,000-foot shale well may be $300,000, the cost to retire a problem well of the same depth could easily exceed $1 million.

Variability due to well-specific random variables will tend to push P&A costs up not down. Low probability, high severity risks mean that that the probability distribution of costs for comparable wells of the same depth will be fat-tailed and right-skewed rather than a bell curve. Stated simply, most surprises will be unpleasant.

[32] http://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/OilGasReports/Determination_Letters/EAST/CO258482-11_Redacted.pdf and http://www.cabotog.com/pdfs/ExhibitB.pdf.

[33] For example, some state regulations require oil and gas horizontal wells to be plugged at total depth, while others do not specify standards for plugging such wells. For horizontal wells, Wyoming requires a continuous cement plug to be placed from at least one hundred feet (100’) into the lateral back to one hundred feet (100’) into the vertical portion of the wellbore. https://cellartech.com/wp-content/uploads/2016/03/Wyoming-Chapter-3-Operational-Rules-Drilling-Rules.pdf.

F. Summing it up

In summary, here is what we know with reasonable certainty and what we don't know about the industry's expected costs for oilfield retirement:

- The average depth of modern shale wells approaches 10,000 feet and many existing, producing and idle wells are much deeper.
- On average P&A costs increase exponentially with depth. The expected cost for industry to plug a 10,000-foot vertical straight hole well based on the most relevant available data is in the proximity of $300,000, an order of magnitude higher than forecasts of $20,000 to $40,000, based on average orphan well costs.
- Industry data is unavailable to confirm whether the costs for U.S. companies to retire producing and idle wells in the ordinary course of operations will align closely with the Australian P&A completion data. Actual costs may be higher or lower.
- The only known example of documented costs to plug a modern vertical shale well is $2.9 million (adjusted for inflation) reportedly spent to plug the three Cabot wells in 2008. The average cost to plug horizontal shale wells may significantly exceed the average cost to plug vertical shale wells of the same depth.
- Conditions unrelated to depth can increase the costs to plug individual wells by an order of magnitude, raising the prospect of million dollar orphans. Data is not available to determine the frequency of such conditions.

Appendix 1. Characteristics of oilfield AROs

Asset retirement obligations (AROs) are legal obligations to perform retirement activities when a long-lived tangible asset, such as an oil well, offshore platform, pipeline, or terminal, is permanently retired from service. In this paper, we focus exclusively on AROs associated with oilfield assets – oil and gas production wells, wastewater injection wells, offshore platforms, gathering lines, and related infrastructure.

The most common type of oilfield ARO is the legal requirement to plug and abandon (P&A) and reclaim oil and gas wells at the end of their useful life.[34] Federal and state laws and regulations require that following a determination that a well is no longer usable for beneficial purposes operators are required to plug the well in a manner that permanently confines all oil, gas and water in the separate strata in which they are originally found, and take other measures necessary to restore the location to a safe and clean condition.[35]

As the demand for energy and the complexity of wells, particularly offshore wells, increased over time the term "decommissioning" became used to include the myriad list of tasks necessary to reclaim the land or sea to its condition prior to drilling. Throughout this paper, we use the term "oilfield AROs" to encompass the full range of legally mandated oilfield asset retirement activities, including reclamation and remediation of the surrounding environment.

Although not addressed by this report, midstream and downstream AROs pose additional financial risks. For example, an analysis prepared for the State of Michigan on matters related to the pipeline operations of Enbridge found that at an estimated cost of $855 per foot to remove pipelines from the ground, it would cost $23 billion to remove all of Enbridge's buried pipes in the U.S. alone. The oil industry generally does not report the estimated value of midstream and downstream AROs on the basis that they are expected to operate indefinitely and therefore have "indeterminate useful lives." Companies are not required to report retirement costs for such assets. For this reason, the current analysis addresses just a portion of the industry's total ARO liability.

Oilfield AROs are regulated by each of the 33 oil and gas producing states in the U.S. State roles in regulating oil and gas drilling and production were formalized by the Interstate Oil & Gas Compact Commission (IOGCC), which formed in 1935 to set standards for oil and gas drilling and develop production regulations that the states agreed to enact.[36]

[34] https://www.osha.gov/SLTC/etools/oilandgas/abandoning_well/abandoning.html.
[35] New Mexico Administrative Code at NMAC 19.15.25.
[36] https://www.americangeosciences.org/geoscience-currents/us-regulation-oil-and-gas-operations

Appendix 2. Financing oilfield AROs

Oilfield companies finance oilfield retirement costs from current earnings and cashflows on a pay-as-you-go basis. When they "provision" for AROs by recognizing an accrued liability on the balance sheet, they do not at the same time set aside funds to settle these obligations and typically there is minimal reporting requirements for anticipated well closures aside from regimes to identify active and idled (or "temporarily abandoned") wells. This lies in contrast with nuclear power companies, which establish sinking funds to cover retirement costs and which provide decommissioning funding status reports to the U.S. Nuclear Regulatory Commission on multi-year and annual bases.[37]

Because these liabilities are not due until wells are closed – long after they are drilled – states often require companies to post bonds. Such bonds are not often rationally related to the actual costs of plugging the wells.

A. Bonding

The objective of state bonding regimes is to ensure that taxpayers are not left picking up retirement costs when operators default. These typically require companies to post surety bonds to assure fulfillment of AROs as they come due. Bond amounts are typically set on a per well and blanket basis, as shown in Table 4 (overleaf).

[37] For information on financial assurance requirements for nuclear power plants, see https://www.nrc.gov/waste/decommissioning/finan-assur.html.

Table 4. Oilfield ARO bonding regimes

State	Bonding - Single Well	Bonding - Blanket
Alaska[38]	$400,000	$400,000 (1-10 wells) $6,000,000 (10-40 wells) $10,000,000 (40-100 wells) $20,000,000 (100-1,000 wells) $30,000,000 (>1,000 wells)
California[39]	$25,000 (<10,000’) $40,000 (>10,000’)	$200,000 (1-50 wells) $400,000 (50-500 wells) $2,000,000 (500-10,000 wells) $3,000,000 (>10,000 wells)
Colorado[40]	$10,000 (<3,000’) $20,000 (>3,000’)	$60,000 (<100 wells) $100,000 (>100 wells)
Idaho[41]	$10,000 + $1/ft	$50,000 (1-10 wells) $100,000 (10-30 wells) $150,000 (>30 wells)

Table continued overleaf

State	Bonding - Single Well	Bonding - Blanket
Montana[42]	$1,500 (<2,000') $5,000 (>2,000'<3500') $10,000 (>3500')	$50,000 (unlimited)
New Mexico[43]	$25,000 plus $2/ft	$50,000 (1-10 wells) $75,000 (10-50 wells) $125,000 (50-100 wells) $250,000 (>100 wells)
North Dakota[44]	$50,000	$100,000 (unlimited)
Oregon[45]	$25,000 (<10,000') $50,000 (>10,000')	Sum of individual bonds (minimum $150,000)
South Dakota[46]	$10,000 (<5,500') $50,000 (>5,500')	$30,000 (unlimited wells <5,500') $100,000 (unlimited wells >5,500')
Texas[47]	$2/ft depth for onshore wells $60,000 for bay wells $100,000 for offshore wells	$25,000 (1-10 wells) $50,000 (10-100 wells) $250,000 (>100 wells)

Table continued overleaf

State	Bonding - Single Well	Bonding - Blanket
Utah[48]	$1,500 (<1,000’) $15,000 (1,000’-3,000’) $30,000 (3,000’-10,000’) $60,000 (>10,000’)	$15,000 (unlimited wells <1,000’) $120,000 (unlimited wells >1,000’)
Wyoming[49]	$10,000 (<2,000’) $20,000 (>2,000’)	$75,000 (unlimited wells of any depth)
BLM[50]	$10,000	**Statewide:** $25,000 **Nationwide:** $150,000

[38] https://casetext.com/regulation/alaska-administrative-code/title-20-miscellaneous-boards-and-commissions/chapter-25-alaska-oil-and-gas-conservation-commission/article-1-drilling/section-20-aac-25025-bonding.

[39] https://www.conservation.ca.gov/index/Documents/DOGGR%20Statutes%202018%20%20updated%204-4.pdf.

[40] https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=7546&fileName=2%20CCR%20404-1.

[41] https://adminrules.idaho.gov/rules/current/20/200702.pdf.

[42] http://www.mtrules.org/gateway/ruleno.asp?RN=36%2E22%2E1308.

[43] https://casetext.com/regulation/new-mexico-administrative-code/title-19-natural-resources-and-wildlife/chapter-15-oil-and-gas/part-8-financial-assurance/section-191589-categories-and-amounts-of-financial-assurance-for-well-plugging.

[44] https://www.legis.nd.gov/information/acdata/pdf/43-02-03.pdf.

[45] https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=2886.

[46] https://sdlegislature.gov/Statutes/Codified_Laws/DisplayStatute.aspx?Type=Statute&Statute=45-9-15.

47 https://www.rrc.state.tx.us/media/8216/bondi.pdf.

[48] https://rules.utah.gov/publicat/code/r649/r649-003.htm#T1.

[49] https://cellartech.com/wp-content/uploads/2016/03/Wyoming-Chapter-3-Operational-Rules-Drilling-Rules.pdf.

[50] 43 Code of Federal Regulations §§ 3104.1 to 3104.3 at https://www.law.cornell.edu/cfr/text/43/3104.1.

In a 2019 report, the U.S. Government Accountability Office (GAO) found that the average value of bonds held by the Bureau of Land Management (BLM) for oil and gas wells in 2018 was only $2,122 on a per well basis. GAO stated:

> Bonds generally do not reflect reclamation costs because most bonds are set at their regulatory minimum values, and these minimums have not been adjusted since the 1950s and 1960s to account for inflation. Additionally, these minimums do not account for variables such as number of wells they cover or other characteristics that affect reclamation costs, such as well depth. Without taking steps to adjust bond levels to more closely reflect expected reclamation costs, BLM faces ongoing risks that not all wells will be completely and timely reclaimed, as required by law.

The GAO findings are broadly similar to those from a 2020 report prepared by the California Council on Science and Technology (CCST). The CCST found that the state held only $107 million in bonds for estimated ARO costs of $9.2 billion to retire 106,687 wells, leaving the state exposed to $9.1 in ARO credit risk. This means that the liabilities are substantially underfunded.

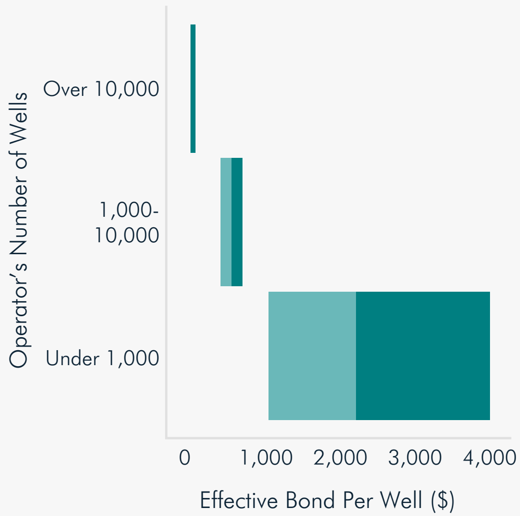
B. Self-bonding

Where there is no collateral set aside to cover P&A costs, oil and gas companies effectively 'self-bond' the difference between the estimated costs to complete retirement activities and the value of bonds held by the regulator. Figure 6 from the CCST report shows how blanket bonds increase California's ARO credit risk exposure by concentrating self-bonded ARO credit in those companies operating a large number of wells. The implicit assumption is that companies with a large number of wells are inherently low credit risks. However, regulators have no procedures like those used by credit ratings agencies to assess credit worthiness, either at the time of initial permitting, at the time of permit transfer, or periodically during the life cycle of a field or well.

The assumption that companies with a large number of wells are inherently low credit risks is also undermined by the industry's practice of large companies selling late-life, low production wells to smaller, less well capitalized companies. To mitigate this risk, North Dakota in 2019 limited blanket bonds to include no more than six of the following in aggregate: unplugged or improperly properly dry holes; plugged wells where the site has not been properly reclaimed; abandoned wells not properly plugged and reclaimed; and wells temporarily abandoned for more than seven years.[51]

[51] https://www.legis.nd.gov/information/acdata/pdf/43-02-03.pdf.

Figure 6. Available California bond funds per well, by size of operator



This figure shows the median, 25th percentile, and 75th percentile of effective bond amount for wells with operators of different sizes. Effective bond amount is calculated by dividing each operator's total bond amount by the operator's total number of active and idle wells.

Source: California Council on Science and Technology (CCST)

Bonding at the state and federal level is insufficient to prevent wells being "orphaned" to the state.[52] Indeed, the failure to require full bonding presents a moral hazard. Companies with good credit are incentivized to transfer assets to those with worse credit in order to avoid these liabilities. Those companies with worse credit are less likely to ultimately have to actually pay for reclamation and will more heavily discount the value of the liability and will therefore be willing to pay a higher amount for the remaining cash flows from the well. This phenomena helps explain the growth in orphaned wells.

[52] https://www.gao.gov/assets/710/701450.pdf.

C. Orphan well programs

To pay for cleanup of abandoned unplugged wells, most oil producing states have created orphan well funds financed by taxes, fees and penalties charged to companies.[53] In the past, dealing with orphan wells has been a cyclical issue – more wells become the state's responsibility after a downturn – but it's getting worse over time, as states struggle with a backlog of wells that dates back decades. Moreover, in aging fields, the rate of abandonment may be increasing.

For example, in Texas the agency responsible for plugging orphaned wells can't close them as quickly as they're being abandoned. According to the agency, "We have 440,000 wells in the state of Texas today and we have about 130,000 that aren't producing." That means "you have a lot of old vertical wells that will get abandoned. … They're going to be coming in greater and greater numbers."[54]

Before wells become orphaned, they often sit idle for long periods. Growing inventories of idle wells therefore may foreshadow future growth in orphaned wells. Warning signs are flashing. For example, California Resources Corporation saw an increase from 4,742 onshore idle wells in 2017 to 5,897 idle wells in 2018 (a year over year increase of 24%) to 7,100 idle wells to 7,100 idle wells in 2019 (a year over year increase of 20%).

D. Bond premiums and collateral

When governments require companies to post bonds rather than allowing them to self-bond, they shift responsibility for pricing ARO credit risk to the financial markets. Bond sureties price ARO credit risk in two ways – annual bond premiums and collateral requirements. Both annual premiums and collateral requirements are subject to change on outstanding bonds to reflect changes in credit risk.

A typical bond indemnity agreement contains the following terms relating to premiums and collateral:

> **Premiums.** The Indemnitors agree to pay to Surety all premiums, renewal premiums, costs and charges due for any Bonds requested from and/or issued by Surety, until Surety, in its sole discretion, shall receive satisfactory evidence of its discharge or release from all liability under any Bonds. It is agreed that all premium is fully earned upon issuance of the Bond and is not refundable.

[53] http://iogcc.ok.gov/Websites/iogcc/images/Publications/2019%2012%2031%20Idle%20and%20Orphan%20oil%20and%20gas%20wells%20-%20state%20and%20provincial%20regulatory%20strategies%20(2019).pdf.
[54] https://www.kut.org/post/texas-isnt-plugging-abandoned-oil-and-gas-wells-fast-enough.

Collateral Security. Immediately upon demand by Surety, the Indemnitors shall deposit with Surety funds, as collateral security, in an amount Surety, in its sole and absolute discretion, deems necessary at the time of said demand to protect Surety from actual or anticipated Loss. Surety shall have no duty to invest, or provide interest on, any collateral security. The Indemnitors acknowledge and agree that their failure to immediately deposit with Surety any sums demanded under this section shall cause irreparable harm to Surety for which it has no adequate remedy at law.[55]

While information on the cost of oil and gas closure bonds is hard to come by, during the bankruptcy proceedings of coal companies like Peabody, Arch and Cloud Peak, the debtors were forced to provide such information to the bankruptcy court, revealing annual premium payments in the range of 1% of the bond face value. In addition, the bankruptcy filings revealed that the coal companies were required to post collateral ranging from 9%-50% (as a percentage of the face value of the bonds). On average Peabody's sureties required 35.3% of the face value of its bonds in collateral, Arch's sureties required 23.7% on average, and Cloud Peak's sureties a mere 15%.

[55] http://www.colonialsurety.com/wp-content/uploads/2017/03/Short-Form-Indemnity-Agreement-Specimen.pdf.

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