Katherine Douglas Appellant References

\# 1

LATE DIST

From:	Cynthia Elkins <CElkins@biologicaldiversity.org>
Sent:	Wednesday, February 19, 2025 11:19 PM
To:	sbcob
Subject:	Vol. 5 - References in support of appeal - SYU transfers, case no. 24APL-00025
Attachments:	Vol 5_CBD References - SYU Appeal (Docs 27 - 32).pdf
Follow Up Flag:	Follow up
Flag Status:	Flagged

Volume 5 of 8 attached

Dear Supervisors and Clerk Alexander,

Please see the attached references submitted on behalf of the Center for Biological Diversity and Wishtoyo Foundation, which are submitted in support of our appeal of the Planning Commission's approval of Sable Offshore Corp.'s application to transfer the Final Development Permits for the Santa Ynez Unit, Pacific Offshore Pipeline Company Gas Plant, and Las Flores Pipeline System. Our comments were submitted under a separate cover.

Hard copies of the attached are also being sent by FedEx, and they are also available to download at the following link:

https://www.dropbox.com/scl/fo/bilsgpxu2mi3tltl4ct9u/AO88HVAbP3ZuC5KiHT3bTN0?rlkey=pq3yyzbipp074lqqe5w8x8cuh&st=uwx4ibd0&dl=0

Please include these references as part of your administrative record for this matter, and please contact me if there are any questions or problems in receiving them.

Thank you for your time and assistance, and for your consideration of our comments and concerns.

Sincerely,
Cynthia Elkins, Senior Paralegal
Center for Biological Diversity
celkins@biologicaldiversity.org
(707) 358 – 0430

REFERENCES

Volume 5
Documents 27–32

Submitted on Behalf of the Center for Biological Diversity and Wishtoyo Foundation

Case No. 24APL-00025

Carbon Tracker Initiative

June 2022

Double or Nothing

How regulators are gambling on the future self-interest of large oil and gas companies to decommission the Gulf of Mexico's aging infrastructure

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.

www.carbontracker.org | hello@carbontracker.org

About the Authors

Robert Schuwerk – Executive Director, North America

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.

Greg Rogers – Senior Adviser

Greg is a practitioner-scholar in accounting for climate change. He wrote the seminal desk book on financial reporting of environmental liabilities and risks. In addition, Greg is a Fellow and Advisor to the Master of Accounting Program at Cambridge Judge Business School. He worked as an advisor to BP and its auditors Ernst & Young on liability estimates and disclosures arising from the Deepwater Horizon disaster. He has consulted/ testified as an expert in environmental and climate-related litigation.

Stephen Greenslade – ARO Analyst

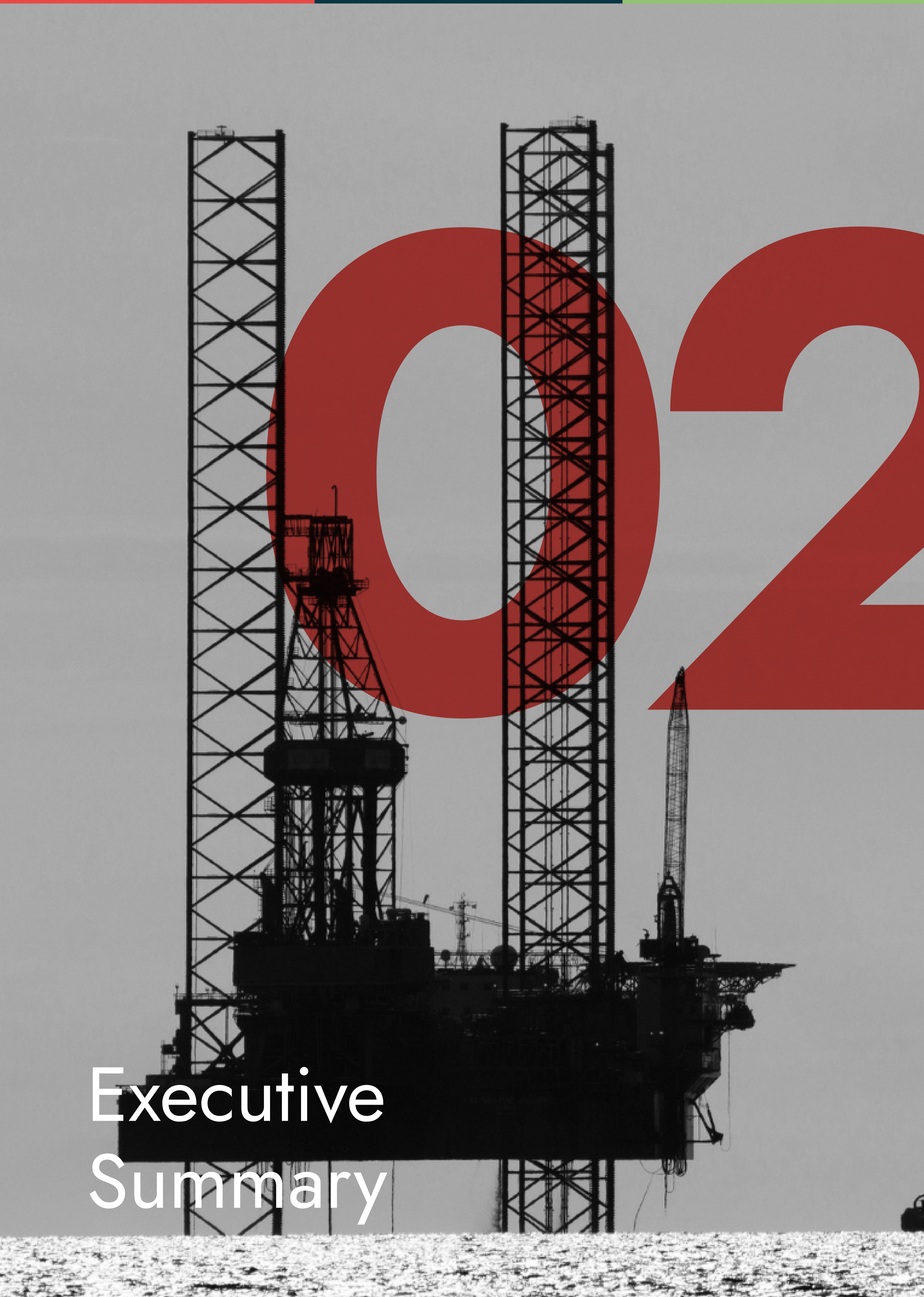
Stephen is a sustainable development specialist and analyst focused on accelerating decarbonization of the economy. At Carbon Tracker, Stephen utilises data and GIS analysis to communicate the scale and distribution of financial risks associated with decommissioning oil and gas infrastructure. In 2018, Stephen co-founded the ARO Working Group to highlight the massive unfunded costs of oilfield cleanup. He holds a Master of Urban and Regional Planning degree from Portland State University.

Table of Contents

01

Key Findings

- Production on the Outer Continental Shelf (OCS) of the Gulf of Mexico (GOM) is moving into deeper water, where development and decommissioning costs are much higher. As the energy transition progresses, the risk that companies will be unable to pay their decommissioning costs will grow.
- At best, only 10% of estimated decommissioning costs for the OCS are secured by bonds (Figure 2.1).
- Bond coverage for the largest publicly traded exploration and production (E&P) companies in the GOM is only 1%, on average.
- The problem is, parent corporations are not, as a matter of law, liable for their subsidiaries and the major operators in the GOM are all subsidiaries.
- Federal regulators are heavily reliant on the future financial strength of large publicly traded corporations to ensure decommissioning obligations are not abandoned to the public.
- The 10 largest publicly traded companies operating in the OCS, as a group, are jointly and severally liable for 78% of total OCS decommissioning costs, amounting to at least $26.7 billion (Figure 2.2).
- Due to joint and several liability, the energy transition can be expected to consolidate decommissioning obligations of weaker firms in a few "last ones standing."
- Whether parent corporations assume the decommissioning obligations of their subsidiaries, if and whencalled upon to do so, will be a matter of self-interest rather than law.
- Worsening economics combined with rising decommissioning costs will tilt the self-interest of large legacy operating groups towards avoiding decommissioning costs.
- If the last ones standing choose to back their subsidiaries, they could incur costs that are 2.3 to 6.8 times the amount of their direct liability on current leases, equivalent to billions in additional decommissioning costs for a given company. These costs are not generally reflected on balance sheets today.
- The U.S. Department of Interior should increase financial assurance requirements now to ensure that future decommissioning occurs on a timely basis at the expense of industry rather than taxpayers.



02

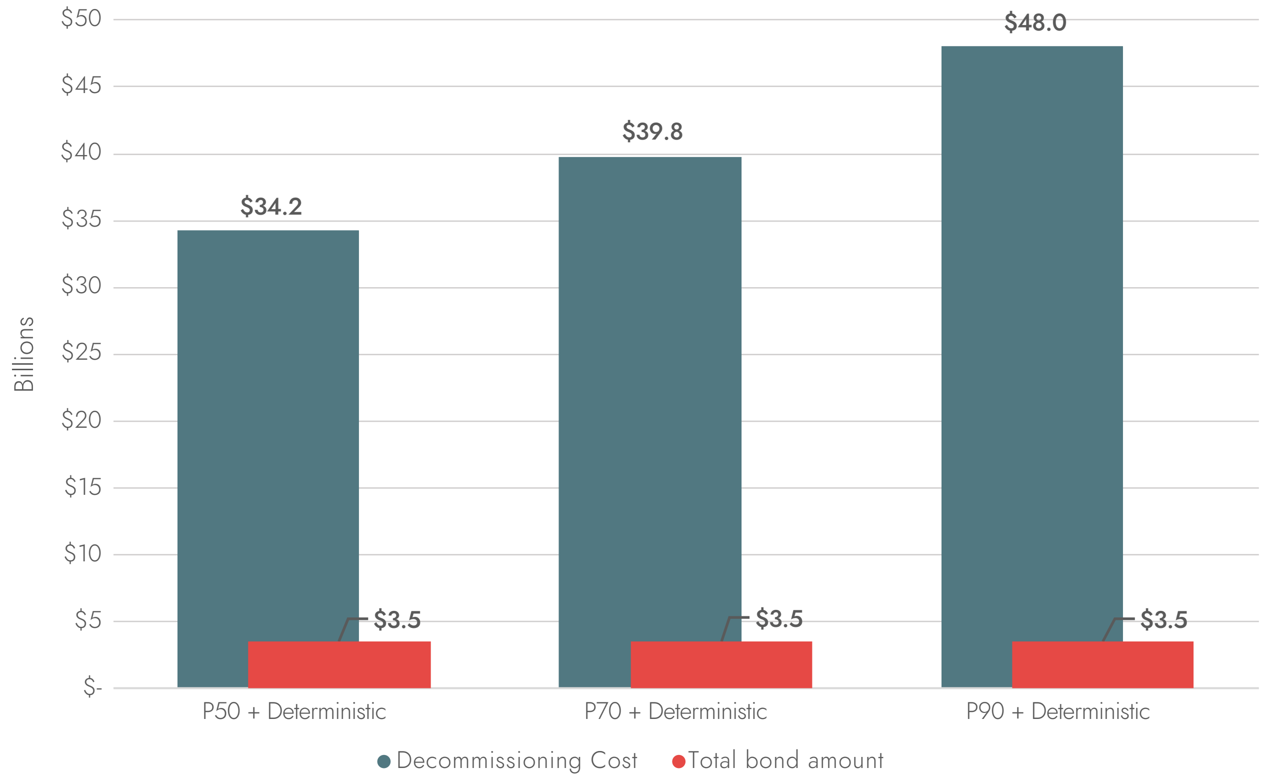
Executive Summary

The current financial assurance regime for the Outer Continental Shelf (OCS) of the Gulf of Mexico (GOM) relies on joint and several liability, under which companies can be required to pay the cost to decommission any and all infrastructure that existed during their ownership of every lease in which they own or once owned a stake. The price tag could be significant, particularly if they are the "last ones standing," and whether due to a shift in perceived self-interest or the broader impacts of the energy transition (or both), major E&P companies may not be willing or able to pay the joint and several liabilities of their GOM subsidiaries if and when the energy transition renders much of the OCS uneconomic to produce.

Gulf Trends and the Energy Transition

The GOM has long been a major oil and gas producing region for the U.S., but field depletion in shallower regions near shore has driven development into deep and ultra-deep waters, driving up the cost to develop and decommission infrastructure. Meanwhile, aging wells and platforms closer to shore — many of which are now owned by smaller operators — are increasingly marginal in value, raising the risk that they will be abandoned by their current operators.

Figure 2.1 — Total financial collateral vs. total estimated decommissioning costs, P50, P70, and P90 cost tiers.



Data: BSEE, BOEM

Notwithstanding current crisis-driven energy needs, the energy transition will continue to accelerate as market and policy forces coalesce around net-zero pathways, drawing into question the long-term viability of both old and marginal production (like OCS shallow), and new, long-horizon, high-cost production (like OCS deepwater). More than 32,000 of 55,000 wells in the OCS are permanently or temporarily abandoned, and hundreds of companies obligated to decommission production facilities have no current production. As productive assets deplete, firms may prefer to pay out shareholders rather than hold back funds to pay the costs of retiring infrastructure.

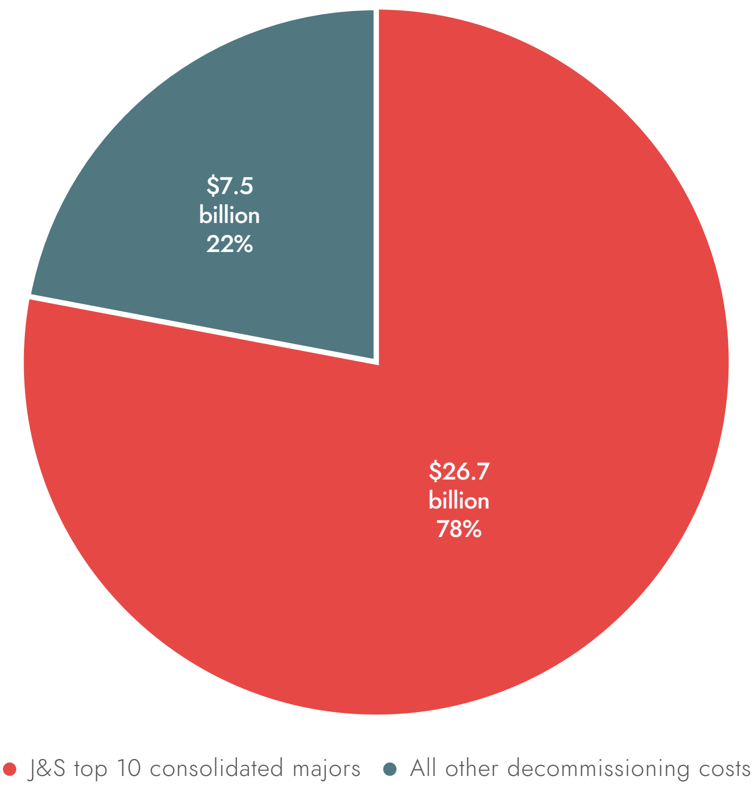
Like most oil and gas decommissioning regimes, the government is at risk since it has not required companies to save for retirement — BOEM holds bonds worth only 10% of the expected cost of decommissioning offshore infrastructure in the GOM.[1]

Joint and Several Liability

The OCS benefits from a decommissioning liability regime that is distinct from most onshore regions in the U.S.—joint and several liability—under which any co-owner or prior title or operating interest owner can be held liable for the entire cost of decommissioning a lease. BOEM's regulatory approach relies heavily on joint and several liability as a backstop for defaulting operators.

Our detailed review of DOI datasets traced joint and several liability through the chain of ownership, and reveals concerning results.

Figure 2.2 — Share of total decommissioning costs linked by past or present lease or operating rights interest to the top 10 publicly traded companies operating in the GOM.



Data: BSEE, BOEM, SEC

1. In the future, the major E&P companies with operations in the GOM may face liability not just for their own proportional share of the leases they own, but also for successors and other working interest owners. The total could range between 2.3 to 6.8 times the amount of their direct proportional liability for current leases for this group. This contingent liability is not generally reported on balance sheets today.
2. The federal government lacks adequate financial assurance for decommissioning obligations,

1 Assuming P50-tier decommissioning costs. At the P90 tier, coverage declines to 7%.

especially from the majors it will most rely upon when less creditworthy entities fail, as we saw in the recent Fieldwood Energy bankruptcy. More than three quarters of the total liability in the GOM is tied back to ten consolidated companies, but because of BOEM's assessment of their current financial strength, these companies have only been required to post surety bonds worth around 1% of their estimated direct liabilities, and nothing for contingent joint and several liability.

3. Whether the majors stand behind their GOM subsidiaries' liabilities boils down to their financial strength and self-interest when the costs are incurred, since parents are not liable for their subsidiaries absent corporate guarantees or "alter ego" theories of liability. In the ordinary course of business, we would not expect the largest E&P companies to walk away from regulatory obligations due to the real reputational and financial risks involved, but by definition, closure obligations come due when there is no longer any value in production, and the energy transition could render much of the GOM uneconomic to produce sooner than expected, which could change the calculus even for major producers.

The large E&P companies that drill offshore wells often sell their late-life assets as production declines. Those with the longest history of operations in the GOM have significant contingent joint and several liability for assets they no longer own. The potential for liability to decommission formerly owned assets to boomerang sheds a different light on the "last one standing" strategy.

Nothing Like Cash in the Bank

Our conclusion therefore is that the DOI should secure collateral (bonds or equivalent) from industry now while cash is flowing to ensure that future decommissioning occurs on a timely basis and at the expense of industry rather than taxpayers. Our findings demonstrate that this would, in the medium term, also reduce contingent exposures of co-liable parties, including the largest operators, potentially reducing the risk of chaotic joint and several liability cascades precipitated by the broader trends of the energy transition.

KEY TERMS:

P50, P70, and P90 costs are probabilistic cost estimates created by the U.S. Department of Interior (DOI) Bureau of Safety and Environmental Enforcement (BSEE) based on actual industry-reported decommissioning costs. The P50 value is the cost estimate with a 50% non-exceedance probability, i.e., there is a 50% chance actual cost will not exceed the P50 value based on BSEE's model, and so forth.

Bond coverage is the ratio of the face value of surety bonds held as security for decommissioning obligations to estimated decommissioning costs.

Deterministic costs provide a single estimate from a deterministic model rather than a probabilistic distribution. Any single facility will be assigned with either a probabilistic cost or a deterministic cost, so aggregation to the lease or company level requires adding probabilistic and deterministic estimates. For simplicity, we report combined probabilistic and deterministic cost in three tiers. For example, the P50-tier for a company is the sum of all P50 costs plus the sum of all deterministic costs assigned to that company.

Bonds/financial assurance — The report mentions bonds (or surety bonds), financial assurance, and collateral to describe liquid financial instruments held by the DOI Bureau of Ocean Energy Management (BOEM) as security against default on decommissioning obligations. There are a range of financial instruments used for decommissioning financial assurance purposes, with surety bonds being the most common. We assume that all active collaterals reported by BOEM are surety bonds or equivalent, and use the terms bonds, financial assurance, and collateral interchangeably throughout the report.

Direct liability — Direct liability is a company's proportional decommissioning liability based on (1) ownership stake in a lease and (2) BSEE's estimated decommissioning cost for existing infrastructure.

100% lease liability — This is the potential cost to a company if it were required to pay 100% of the decommissioning costs for all of the leases in which it currently owns a stake.

Joint and several liability — Joint and several liability for a given company includes 100% of the estimated cost to decommission all the infrastructure installed prior to and during their ownership on every lease for which a company owns or owned a stake or operating interest. It is the sum of 100% lease liability for current leases and 100% lease liability for obligations accrued prior to the transfer of former leases.

Limited liability principle is the legal principle that insulates a corporation's owners (its shareholders) from the debts of the corporation beyond the amount of their investment.

03

Self-Bonding: An Unreliable Strategy

The goal of the DOI for its decommissioning financial assurance program in the OCS is the protection of American taxpayers from exposure to financial loss associated with OCS development, while ensuring that the financial assurance program does not detrimentally affect offshore investment or position American offshore exploration and production companies at a competitive disadvantage globally.

As a result of the tension between these objectives, tens of billions in OCS decommissioning costs are largely "self-bonded," meaning they are secured only by the financial strength of the companies obligated to perform the work.

3.1 What Does it Cost?

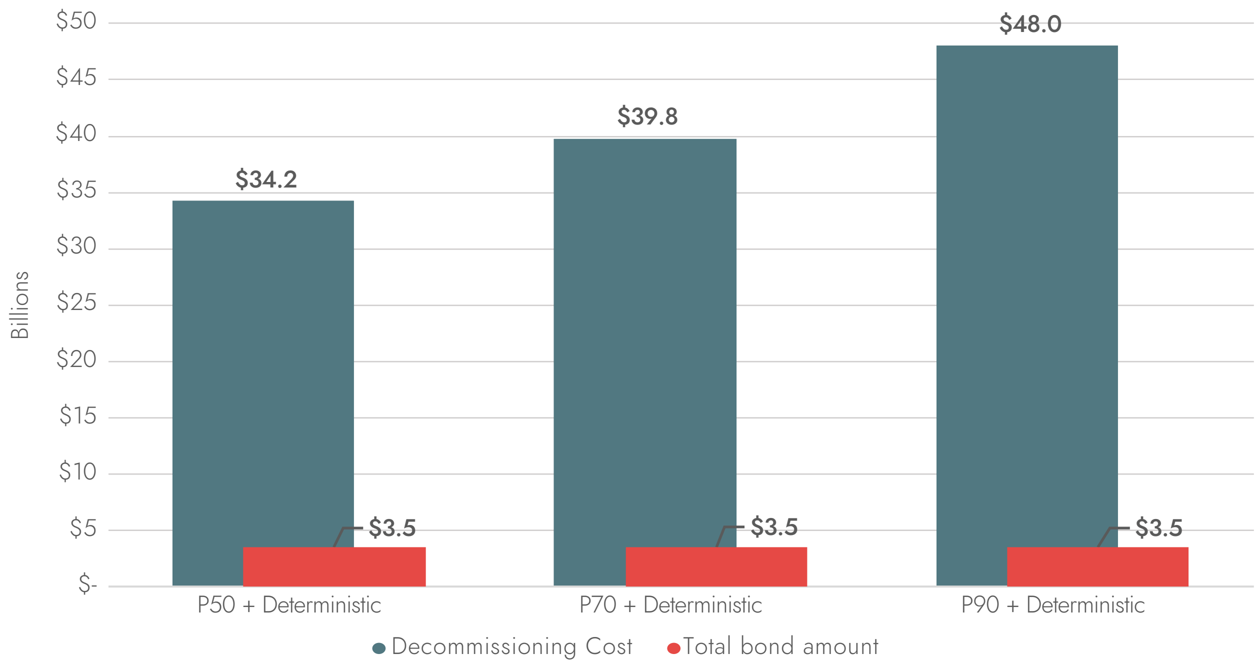
Determining the appropriate amount of financial assurance requires accurate decommissioning cost estimates. Until December 2015, the DOI's Bureau of Safety and Environmental Enforcement (BSEE) did not have a requirement for lessees to report on costs associated with decommissioning activities in the OCS. Instead, BSEE contracted studies to obtain data on decommissioning costs.[2] In 2015, BSEE issued regulations requiring lessees to report data on most, but not all, decommissioning costs.[3] This rule requires lessees and owners of operating rights to submit summaries of their actual expenditures for the decommissioning of wells and platforms, and for verification that the site is clear of obstructions. Obtaining summaries of actual decommissioning costs has enabled BSEE to build a robust database to help the bureau better estimate future decommissioning costs in the OCS.

BOEM holds $3.5 billion in active bonds that secure between $34 and $48 billion (depending on the probability tier, see Key Terms) in estimated OCS decommissioning costs for a bond coverage ratio of 7-10%, (Figure 3.1).

2 GAO-16-40, Actions Needed to Better Protect Against Billions of Dollars in Federal Exposure to Decommissioning Liabilities (December 2015).

3 Final Rule, 80 Fed. Reg. 75806 (December 4, 2015). BSEE later adopted a rule requiring companies to also submit summaries of actual expenditures for pipeline decommissioning. Final Rule, 81 Fed. Reg. 80587 (November 16, 2016).

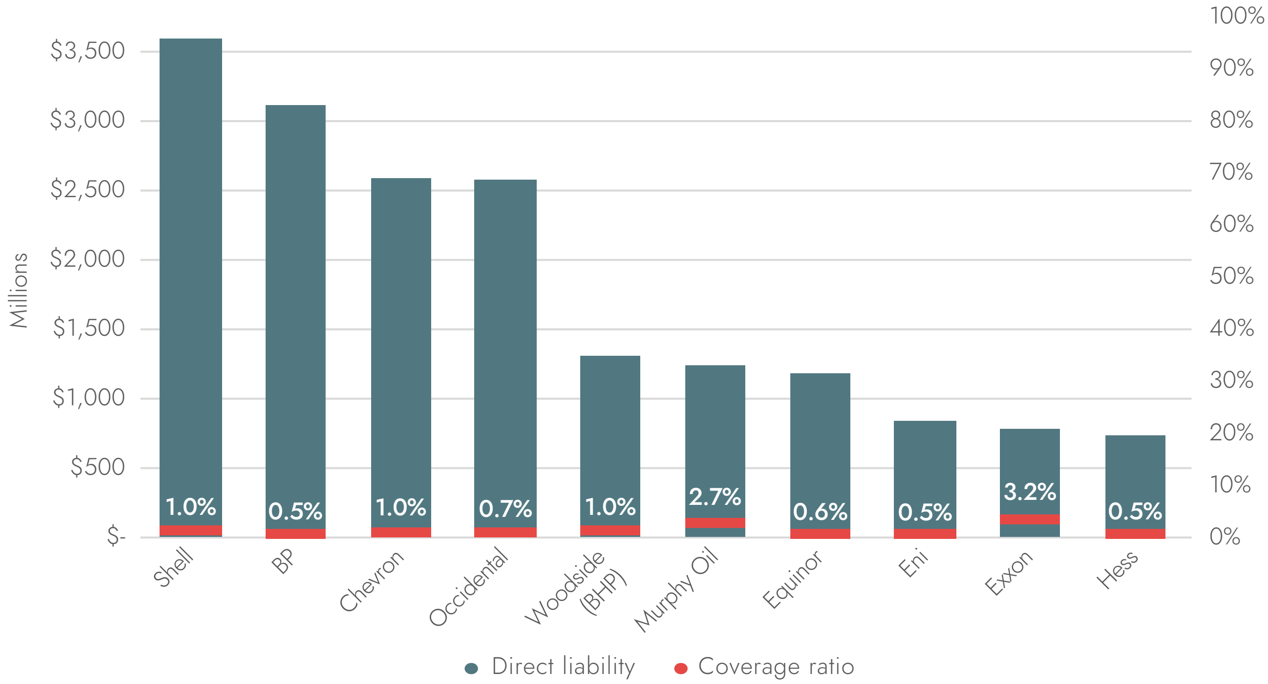
Figure 3.1 - Bond collateral compared to the full estimated cost to decommission GOM wells, platforms and pipelines at the three reported cost tiers.



Data: BSEE, BOEM

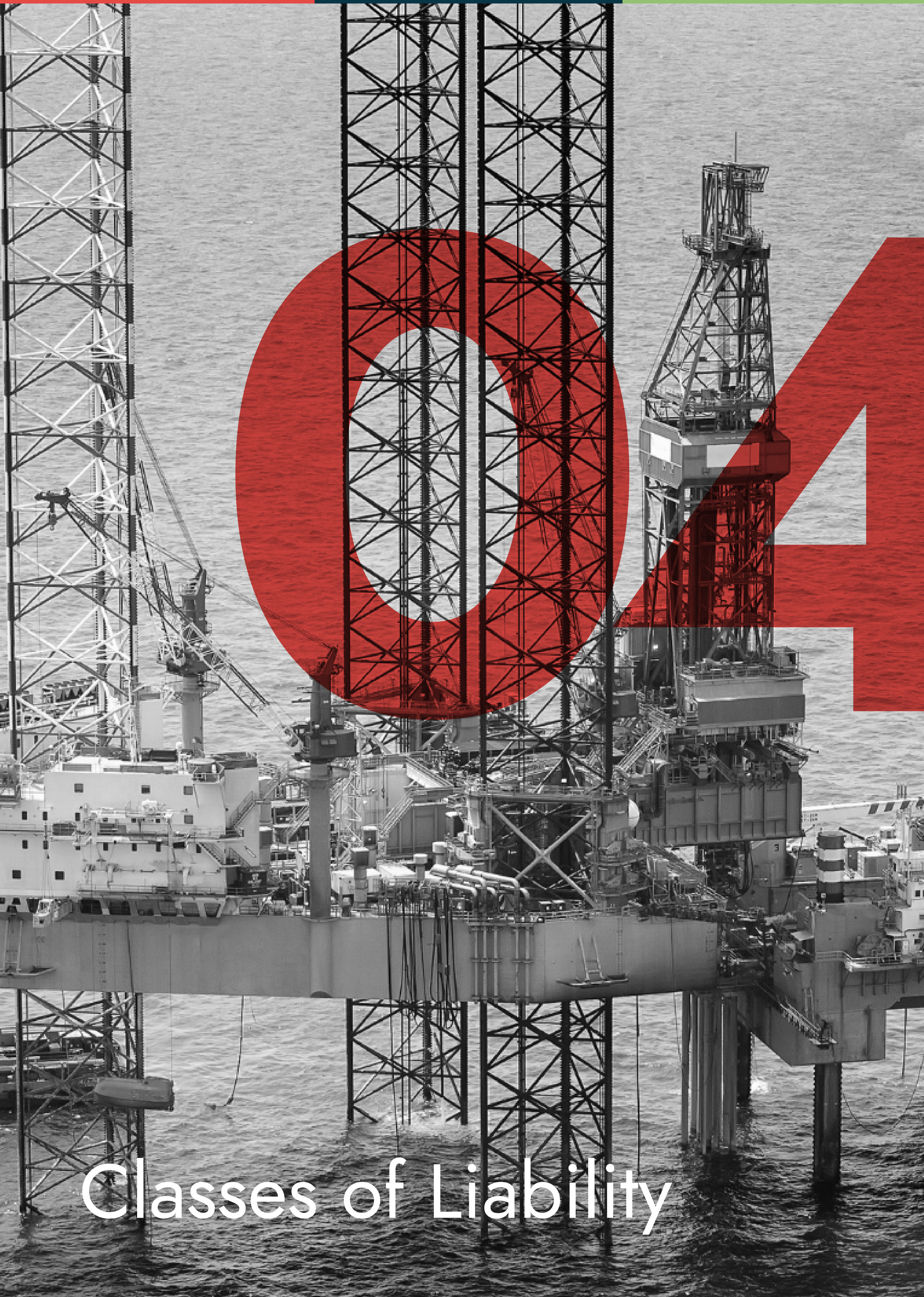
The largest operators have far lower bond coverage than the average, as shown in Figure 3.2.

Figure 3.2 - Direct liability for consolidated subsidiaries of the top publicly traded companies and bond coverage ratios.



Data: BSEE, BOEM, SEC

In short, DOI does not require bonds commensurate to outstanding decommissioning obligations. Instead, it relies on the financial strength of current and former lessees, particularly the corporate subsidiaries of the world's largest E&P companies, who are jointly and severally liable for the lion's share of GOM decommissioning costs.



04

Classes of Liability

4.1 Direct vs. Joint and Several Liability

Liability for OCS decommissioning obligations is joint and several among all who have accrued the liability and survives until those obligations are met.[4] Regardless of proportional ownership, lessees are liable for the entire amount of decommissioning obligations that have accrued prior to and during their ownership. This means operators are legally responsible for the decommissioning obligations of co-lessees. Former lessees also bear contingent decommissioning liability for infrastructure that they do not currently own.[5] Joint and several liability contrasts with direct liability, which we estimate as the proportional share of lease decommissioning costs based on current ownership stake. In other words, we assume that a 50% owner of a lease is directly liable for 50% of the costs.

As shown in Table 4.1, large corporate groups have contingent joint and several liability for current and former leases that is several times their direct liability for current operations.

"Large corporate groups have contingent joint and several liability for current and former leases that is several times their direct liability for current operations."

4 Joint and several liability is a common feature of offshore oil and gas regulatory regimes around the world. This is distinguished from onshore regulation, which generally does not impose joint and several liability. See Understanding decommissioning of offshore infrastructures: A legal and economic appetizer.

5 See 30 CFR § 250.146.

Table 4.1 — Joint and several liability leader board.

Direct liability as compared to the full potential joint and several liability for the top public oil company groups operating in the GOM. The spread is the difference between direct liability and joint and several liability, and the multiple is the maximum potential multiplier on direct liability if a given company was forced to incur 100% of the cost to decommission infrastructure on all current and former leases.

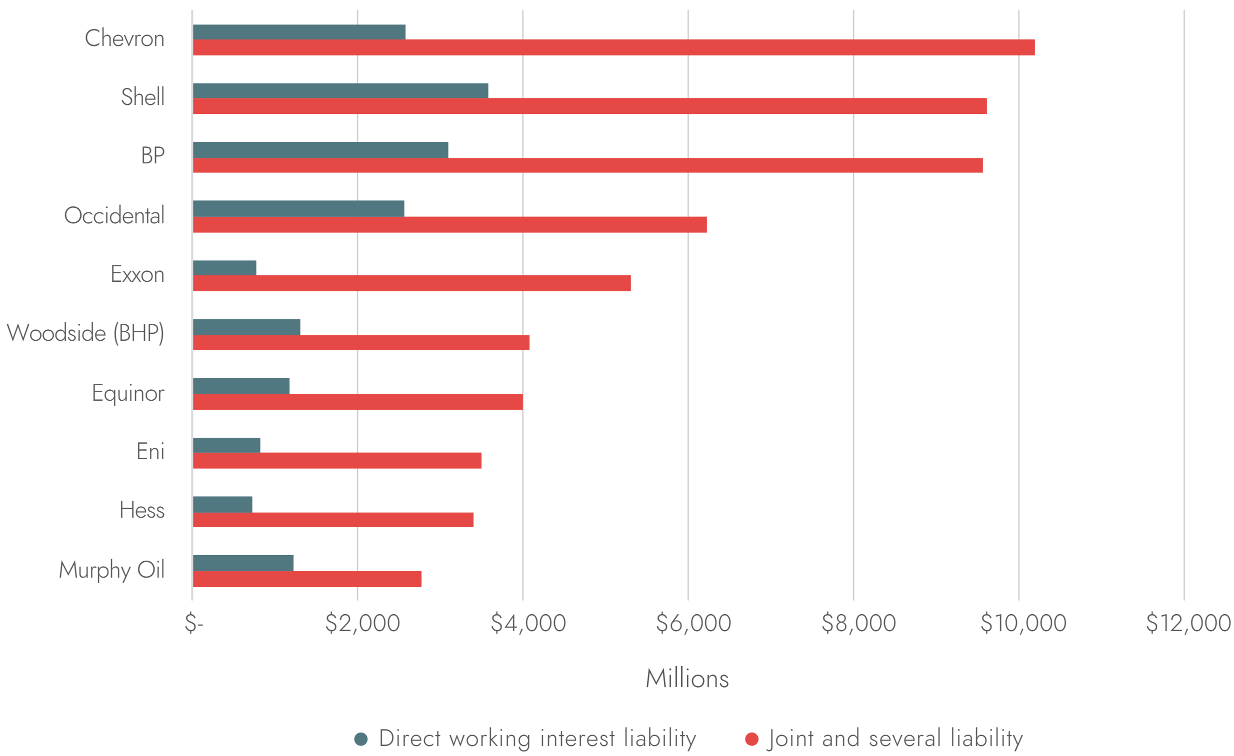
Liability Leaderboard	P50 Tier ($ millions)			
Corporation Name	**Direct liability**	**J&S Liability**	**Spread**	**Multiple**
ExxonMobil	$776	$5,357	$4,580	6.9
Hess	$731	$3,421	$2,689	4.7
Eni	$828	$3,643	$2,815	4.4
Chevron	$2,578	$10,238	$7,660	4.0
Equinor	$1,171	$3,995	$2,824	3.4
Woodside (BHP)	$1,301	$4,204	$2,904	3.2
BP	$3,098	$9,665	$6,566	3.1
Shell	$3,574	$9,669	$6,095	2.7
Occidental	$2,561	$6,301	$3,739	2.5
Murphy Oil	$1,223	$2,774	$1,551	2.3
Average Multiple				**3.71**

	P90 Tier ($ millions)			
Corporation Name	**Direct liability**	**J&S Liability**	**Spread**	**Multiple**
ExxonMobil	$1,040	$7,516	$6,476	7.2
Hess	$978	$4,665	$3,686	4.8
Chevron	$3,456	$14,846	$11,390	4.3
Eni	$1,156	$4,702	$3,546	4.1
Equinor	$1,525	$5,244	$3,719	3.4
Woodside (BHP)	$1,746	$5,561	$3,814	3.2
BP	$4,320	$13,533	$9,213	3.1
Shell	$4,829	$13,196	$8,367	2.7
Occidental	$3,303	$8,519	$5,215	2.6
Murphy Oil	$1,640	$3,795	$2,155	2.3
Average Multiple				**3.77**

Data: BSEE, BOEM, SEC

Contingent joint and several liability is on average 3.7 times greater than direct proportional liability, representing billions in potential additional decommissioning costs. The multiplier doesn't change dramatically between P50 and P90 cost estimates because both direct and joint and several liability are magnified. However, the difference between the P50 and P90 values can be greater by billions of dollars. Figure 4.1 below visualizes the difference between direct and joint and several liability for the top 10 public companies (P50 cost tier).

Figure 4.1 — Direct vs. Joint and Several liability (P50 cost tier) for the top companies operating in the Gulf of Mexico.



Data: BSEE, BOEM, SEC

4.2 Joint and Several Liability Concentrates Risk

The joint and several liability regime has the effect of concentrating risk in a handful of corporate groups with long legacies in the GOM. Ten large corporate groups bear contingent joint and several liability amounting to $27 to $35 billion total depending on the cost tier (Table 4.2), which totals over 3/4 of total estimated decommissioning costs (Figure 4.2). Low bond coverage means that the OCS joint and several liability regime is heavily reliant on the future financial strength of these corporate groups.

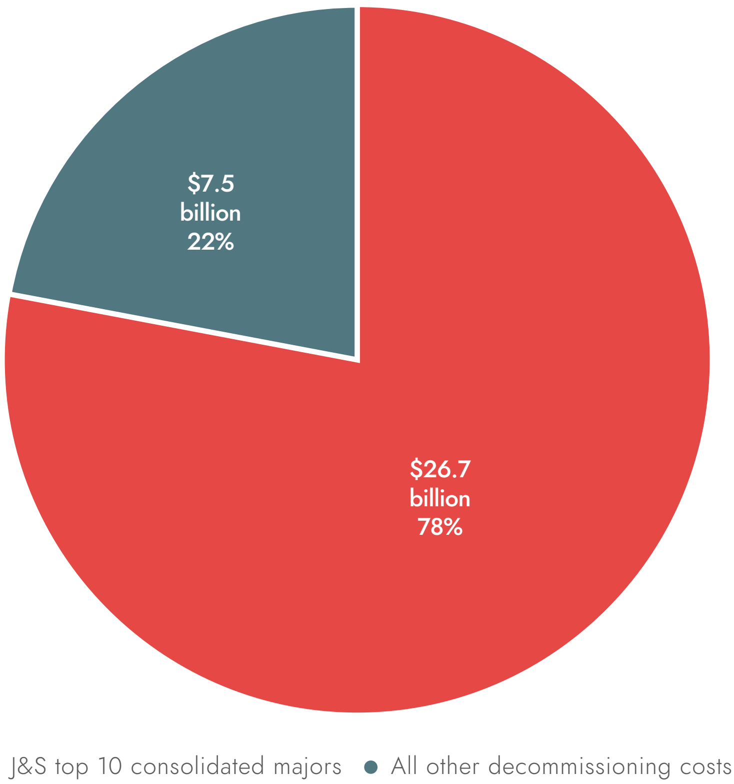
Table 4.2 - Total volume of liability that can be rolled up to the top 10 publicly traded operators in the Gulf.

GOM Costs Linked to the Top Majors ($ millions)	
P50 Tier	$26,704,517,018
P70 Tier	$31,056,279,118
P90 Tier	$37,527,250,554

Data: BSEE, SEC

These large corporate groups stand to become secondarily liable for the decommissioning obligations of smaller firms with limited production and financial resources. More than 32,000 of 55,000 wells in the OCS are permanently or temporarily abandoned.[6]

Figure 4.2 - Share of total GOM costs backstopped by joint and several liability with the top publicly traded operators.



Data: BSEE, SEC

6 Fixing Abandoned Offshore Oil Wells Can Create Jobs and Protect the Ocean (Center for American Progress, April 2022).

Hundreds of companies with decommissioning obligations for OCS production facilities have no current production.[7] Table 4.3 shows that 61% of estimated decommissioning costs attributable to OCS lessees with no production are covered by bonds, but a large portion of these bonds are "surplus" to cost estimates, i.e., BOEM holds bonds for some operators in amounts that exceed their estimated direct liability. These surplus amounts generally do not secure the obligations of other affiliated entities, and thus have no addtional 'spill-over' value as security. Accounting only for non-surplus bonds, the coverage ratio drops to 22%.[8]

Table 4.3 — Key statistics for the subset of non-midstream companies with direct liability indicated by BSEE data and no recorded production for 2021.

Companies With Direct Liaiblity and No Production in 2021 ($ millions)	
Company count	207
Direct Liability - P50 Tier	$1,154
Gross bond amounts	$698
Raw underbonded amount — P50 Tier	$456
Gross coverage ratio	61%
Adjusted underbonded amount — P50 Tier	$903
Effective coverage ratio	22%

Data: BSEE, BOEM

DOI's reliance on corporate balance sheets could prove expensive for the GOM's top operators, and if the ratio between direct and contingent liability in the OCS holds globally, the potential impact is further magnified. For example, BP reported undiscounted long-term decommissioning obligations, as of December 31, 2021, in the amount of USD $23.2 billion.[9] Using a multiplier of 3.1 (from Table 4.1) BP's global continent joint and several liability would amount to $71.9 billion.

7 We have endeavoured to remove pipeline operators from these counts due to the fact that pipeline operators can be expected to show no oil and gas production in the data, and thus lack of production does not indicate inactivity or delinquency.

8 To calculate effective bond, we removed bond coverage amounts in excess of estimated decommissioning costs from the gross bound amount for the group because overages are presumably only effective for the principal company. This doesn't make large bonds valueless——they may provide additional protection for exceptionally risky leases or companies——but that additional coverage doesn't benefit the federal government except with respect to that lease or operator.

9 BP Annual Report and Form 20-F 2021.

05

Limited Liability Principle

Although lessees are jointly and severally liable for the decommissioning obligations of co-lessees as well as successors in interest, parent corporations are not necessarily jointly and severally liable for the obligations of their corporate subsidiaries and affiliates operating in the OCS.

A central feature of corporate law is the principle of limited liability. Absent exceptional circumstances that warrant piercing the corporate veil, the limited liability principle insulates a corporation's owners (its shareholders) from the debts of the corporation beyond the amount of their investment. Limited liability extends to situations in which a corporation, rather than a natural person, is the owner of another corporation, regardless of how much stock that corporation owns.

The individual OCS operators with the largest direct and joint and several liability are all subsidiaries of multinational corporations. Our review of the largest companies by lease-allocated production reveals that they all have operated through a number of subsidiaries, each of which may hold both direct and joint and several decommissioning liability. The typical pattern, represented by BP, Shell and Chevron below, is for all production to be housed in one or two major subsidiaries, with liability and bonds distributed among the remaining subsidiaries. It is not uncommon for a subsidiary to carry close to a billion dollars in liability but produce neither oil nor gas (Table 5.1).

The key point is that the large publicly-traded E&P parent companies with subsidiary operations in the OCS are not themselves legally responsible for decommissioning. This means that at some point in the future when these liabilities are due, the parent may have the option to voluntarily assume the obligation or walk away.

Table 5.1 - BP, Shell and Chevron subsidiaries in the Gulf of Mexico. ($ millions)

BP plc

GOM subsidiaries	2021 Production+ (MMboe)	Direct liability P50	J&S liability P50*	Bond Coverage
Amoco Canyon Company	-	$ -	$ 9.0	$ -
Amoco Foundation, Inc.	-	$ -	$ 14.4	$ -
Atlantic Richfield Company	-	$ -	$ 163.9	$ 3.3
BP America Production Company	-	$ -	$ 1,231.8	$ 6.3
BP Exploration (Alaska) Inc.	-	$ -	$ -	$ -
BP Exploration & Oil Inc.	-	$ 0.2	$ 959.9	$ 3.0
BP Exploration & Production Inc.	111.7	$ 3,098.2	$ 8,306.6	$ 3.3
BP Exploration Inc.	-	$ -	$ 301.2	$ -
BP Prod. Corp.	-	$ -	$ -	$ -
The Standard Oil Company (Ohio)	-	$ -	$ -	$ -
Consolidated Total	**111.7**	**$ 3,098.4**		**$ 15.9**

Shell plc

GOM subsidiaries	2021 Production+ (MMboe)	Direct liability P50	J&S liability P50*	Bond Coverage
Shell Consolidated Energy Resources Inc.	-	$ -	$ -	$ -
Shell Deepwater Development Inc.	-	$ -	$ 533.6	$ -
Shell Deepwater Production Inc.	-	$ -	$ 317.3	$ -
Shell Energy Resources Inc.	-	$ -	$ 87.3	$ -
Shell Frontier Oil & Gas Inc.	-	$ -	$ 138.2	$ 3.3
Shell Gulf of Mexico Inc.	1.4	$ 42.0	$ 910.3	$ 3.3
Shell Land & Energy Company	-	$ -	$ -	$ -
Shell Offshore Inc.	133.4	$ 3,431.3	$ 7,888.1	$ 3.3
Shell Offshore Properties and Capital II, Inc.	-	$ -	$ 0.7	$ -
Shell Oil Company	-	$ 5.5	$ 213.7	$ 0.3
Shell Pipeline Company LP	-	$ 95.4	$ 95.6	$ 25.0
SOI Corporation	-	$ -	$ -	$ -
SOI Finance Inc.	-	$ -	$ 0.7	$ -
SWEPI LP	-	$ -	$ -	$ -
Consolidated Total	**134.7**	**$ 3,574.2**		**$ 35.2**

Chevron Corporation

GOM subsidiaries	2021 Production+ (MMboe)	Direct liability P50	J&S liability P50*	Bond Coverage
Chevron PBC, Inc.	-	$ -	$ -	$ -
Chevron Pipe Line Company	-	$ 9.4	$ 9.4	$ 10.9
Chevron U.S.A. Inc.	62.5	$ 2,054.5	$ 6,911.2	$ 3.3
Noble Drilling Exploration Company	-	$ -	$ -	$ -
Noble Energy, Inc.	-	$ 28.9	$ 877.9	$ 3.3
Texaco Exploration and Production Inc.	-	$ 1.5	$ 1,131.8	$ 3.8
Texaco Inc.	-	$ 0.0	$ 217.8	$ 0.3
Texaco Oils Inc.	-	$ -	$ -	$ -
Union Oil Company of California	18.2	$ 483.9	$ 2,911.1	$ 3.3
Unocal Exploration Corporation	-	$ -	$ 371.3	$ -
Consolidated Total	**80.7**	**$ 2,578.3**		**$ 24.9**

* J&S liability cannot be summed between subsidiaries due to the likelihood of double counting.

+ For this analysis, lease production volumes were allocated proportionally to lease title owners. This is distinct from how BSEE aggregates production for the reported production rankings, but better reflects the obligations and dynamics under inspection in this report.

Data: BSEE, BOEM, SEC

06

Double or Nothing

The odds that parent companies will walk away from the decommissioning liabilities of their corporate subsidiaries is remote when large E&P companies are repeat players, constantly cycling between retiring old infrastructure and drilling new wells. Reputational risk and the need to maintain good standing with lenders and regulators in order to continue exploration and drilling programs means that the choice to abandon a subsidiary's decommissioning liabilities could be too costly to bear. But in a fossil fuel endgame, the premise that large E&P companies will always be repeat players may no longer hold. The energy transition will change incentives, perhaps transforming repeat players into less credit worthy operators that seek to evade creditors through corporate structuring and bankruptcy.

The spectrum of self-interest of publicly-traded E&P companies operating in the OCS can be seen through the lens of two contrasting events—the 2010 Deepwater Horizon incident and the 2021 Fieldwood Energy bankruptcy.

6.1 Deepwater Horizon incident — analogous issue

On April 20, 2010, the oil drilling rig *Deepwater Horizon* exploded in the Gulf of Mexico and sank, resulting in the death of 11 workers and the largest spill of oil in the history of marine oil drilling operations.

Individuals, businesses, and state governments filed hundreds of lawsuits in state and federal courts naming as defendants BP p.l.c. ("BP"), the parent company of the British Petroleum multi-national corporation, and certain of its U.S. subsidiaries, among others.

Because BP's operations in the OCS were all conducted through subsidiary corporations, a critical issue was whether claimants could reach the assets of BP or only those of its U.S. subsidiaries. This question became moot when BP accepted responsibility under the Oil Pollution Act (OPA) and waived OPA's $75 million liability cap. BP later agreed to fund a $20 billion escrow account to facilitate payment of OPA claims.[10]

BP is one of the largest oil producers in the deepwater OCS. At the time of the Deepwater Horizon incident, 28% of of BP's global subsidiary oil production came from the OCS — BP could not avoid responsibility for damages and expect to continue business as usual in the OCS.[11] In 2010, it was in BP's self-interest to voluntarily guarantee the obligations of its U.S. subsidiaries.

6.2 Fieldwood Energy bankrupcty — liability boomerang

The 2021 bankruptcy of Fieldwood Energy LLC exemplifies a bankruptcy strategy that involves large E&P companies spinning off riskier assets—in this case offshore wells nearing the end of their productive lives—into undercapitalized companies like Fieldwood.

Fieldwood was a Houston-based, private-equity backed E&P company established in 2013. In 2021 it was the 11th biggest producer in the GOM by BOE. It began acquiring producing assets in the OCS with the acquisition of Apache Corporation's Gulf of Mexico Shelf business in 2013, followed by the acquisition of Sand Ridge's Gulf of Mexico and Gulf Coast business units.

The number of E&P companies with joint and several decommissioning liability for Fieldwood's OCS assets is large. Over 500 companies own or once owned an interest in OCS assets ultimately acquired by Fieldwood. With a few notable exceptions including Apache, ConocoPhillips, and Marathon, all appear to be subsidiaries of publicly-traded E&P companies or small special purpose limited liability entities.

Fieldwood entered bankruptcy the first time in February 2018 and emerged on April 11, 2018. The

10 BP in the Wake of the Deepwater Horizon Incident and the Bankruptcy Implications of Mounting Environmental Liabilities (Cadwalader, July 07, 2010).

11 BP Annual Report and 20-F, 2010

next day it announced the acquisition of all of Noble Energy's deepwater oil and gas assets located in the OCS.[12]

Fieldwood filed for bankruptcy again in August 2020, characterizing the decommissioning costs it shared with Apache as "among the Company's most significant liabilities."[13] In June 2021 a federal judge ordered Shell Offshore, BP Exploration & Production, ConocoPhillips, and Marathon to pay part of Fieldwood's estimated $7.2 billion liability to retire hundreds of aging wells in the OCS that they once owned and had sold to Fieldwood or its predecessor, Apache.[14]

Apache's experience with the Fieldwood bankruptcy illustrates how joint and several liability for decommissioning can boomerang back to former lessees through DOI's regulatory process. Under the terms of Fieldwood's 2013 purchase agreement with Apache, Fieldwood paid $3.75 billion in cash and assumed the obligation to decommission the acquired properties. To secure its decommissioning obligations, Fieldwood posted letters of credit in favour of Apache and established trust accounts of which Apache was a beneficiary and which were funded by two net profits interests depending on future oil prices.[15]

In September 2021, GOM Shelf LLC (listed as an affiliate of Fieldwood in the bankruptcy petition) notified BSEE that it was unable to fund its decommissioning obligations. BSEE in turn issued orders to Apache to decommission certain OCS assets included in GOM Shelf's notification to BSEE.

Apache recorded a contingent liability of $1.2 billion for estimated decommissioning costs it may be required to perform on the OCS assets sold to Fieldwood. Apache also recorded a $740 million asset, which represented the amount it expected to be reimbursed from the security provided by Fieldwood. Apache recorded a loss of $446 million ($1.2 billion minus $740 million).

The Fieldwood case illustrates several important points.

First, if bankrupt companies default on their decommissioning obligations, co-lessees and predecessors in interest may be on the hook due to joint and several liability. How much of the possibly $50 billion in offshore decommissioning liability is held by companies that are only a dragged anchor, hurricane, leaking pipeline, or oil price shock away from default?

Second, companies that bear contingent decommissioning non-performance risk when they sell offshore assets can and do take steps to protect themselves. Although it suffered a loss, Apache's loss was significantly reduced by $740 million in security obtained from Fieldwood. Based on initial cost estimates, Apache's security coverage was 62% ($740 million / $1.2 billion). Compare this ratio to BOEM's bond coverage ratio of 10% at the P50 cost level (7% at P90). If private corporations can obtain significant levels of collateralized assurance to protect themselves, why can't the government do the same?

Third, company exposure to contingent joint and several liabilities, like Apache's liability for Fieldwood's wells, often remain off-balance sheet until a default occurs; this suggests that investors are typically unaware of a group's full exposure. Apache's financial statements, for example, did not recognize a contingent decommissioning liability until it received notification from BSEE of Fieldwood's default. Even if this is permitted practice under applicable accounting standards, it is little comfort to investors who may see billions in liability appear on the balance sheet overnight.

12 Fieldwood Energy corporate web site; see also How bankruptcy lets oil and gas companies evade cleanup rules.(Grist, June 2021).
13 Dane Declaration, at 4.
14 Fieldwood Energy faces pushback to reorganization plan from oil producers (Reuters, June 2021).
15 Apache Form 10-K 2021.

07

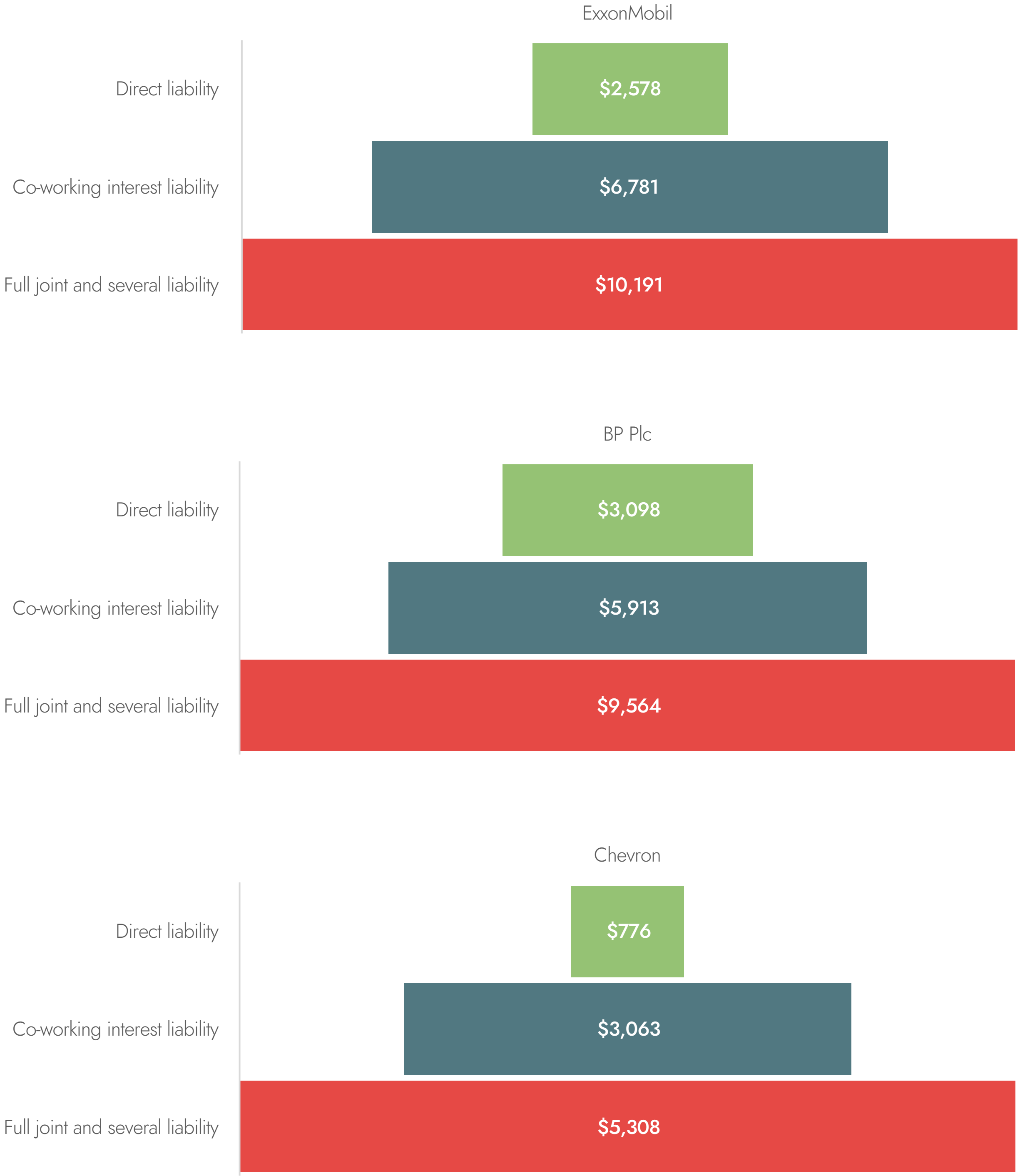
Financial Reporting

In order to assess the financial strength of E&P companies operating in the OCS relative to their liability exposure, DOI, taxpayers, lenders, and investors have an interest in knowing which companies are directly and contingently liable for what and for how much. In this regard, however, the consolidated financial statements of publicly-traded E&P companies may be misleading because they do not account for the billions in contingent joint and several liability.

Consolidated corporate financial statements may fail to fully reflect total direct and contingent decommissioning liabilities, though the impact cannot be ascertained without additional information from sources outside the financial statements.

Financial statements may understate decommissioning liabilities because reported asset retirement obligations do not account for contingent joint and several liability (in the OCS or elsewhere around the world) and therefore may significantly understate a company's total liability exposure. This is not a contravention of accounting standards, which do not require companies to record loss contingencies that are not deemed probable of resulting in cash outlays. Nonetheless, these loss exposures may be relevant from an investment standpoint. For some of the largest operators in the OCS, off-balance sheet exposure to joint and several liability appears to be material. Figure 7.2 demonstrates the relative magnitude of direct liability when compared to co-working interest liability (100% liability for current leases), and joint and several liability (100% liability for current and past leases).

Figure 7.2 — Liability tiers for ExxonMobil, BP Plc, and Chevron (P50-tier costs, $ millions)



Data: BSEE, SEC

In a technical sense, financial statements may also overstate decommissioning liabilities because they consolidate the liabilities of corporate subsidiaries for which the parent entity is not legally responsible.

In short, in an energy transition, the financial reports of the largest oil and gas companies—the expected "last ones standing"—may account for "consolidated" liabilities that are not actually secured by local regulators, yet fail to account for contingent joint and several liabilities for current and former operations.

08 Conclusion

Under the existing regulatory risk management framework, actual financial collateral is foregone in exchange for trailing liability, which inherently relies on the continued financial viability of major oil producers in the region. But the nature of decommissioning costs is that they come due after the underlying asset has been depleted, and the energy transition is likely to hasten the economic demise of the OCS oilfields.

The market forces that will strain more marginal producers will likely produce magnified impact on some large GOM operators in the form of boomerang joint and several liability for assets sold off to other companies. This could amount to billions of dollars in off-balance-sheet costs that hit alongside other business headwinds. These combined impacts will cause major operators to question whether it is financially prudent to pay large decommissioning bills in favour of ailing subsidiary companies for which the parent may not be legally liable.

Our analysis leads us to the same conclusion reached by BOEM: Existing regulations are inadequate to protect the public from potential responsibility for OCS decommissioning liabilities, especially during periods of low hydrocarbon prices. Because the energy transition can be expected to bring extended periods of low hydrocarbon prices in coming decades, and changing federal regulations can take years, current deficiencies in DOI's risk management program must be addressed proactively, while money is available, to ensure financial assurance for decommissioning is available when it is most needed.

The solution for eliminating the risk is simple: BOEM should require full bond coverage – i.e., bonds equal to 100% of estimated decommissioning costs. Current record profits make it hard for the industry to argue that it can't pay, but that's exactly what they'll say when prices fall again.

Short of that, BOEM should implement a combination of increased bonding, sinking funds, third-party guarantees, and diligent monitoring of the financial strength and creditworthiness of current and former lessees.

To the extent that BOEM relies on audited financial statements to assess a lessee's financial strength, it should implement procedures to adjust reported decommissioning obligations to better reflect the lessee's direct and contingent joint and several liability.

09

Appendices

9.1 A — Regulation of decommissioning and related financial assurance on the Outer Continental Shelf

9.1.1 Decommissioning obligations

Oil and gas companies bear the burden of plugging wells and reclaiming oil and gas infrastructure at the end of their useful life. In the OCS operators are required to plug wells, remove platforms and other facilities, decommission pipelines, and clear the seafloor of obstructions.[16] These obligations kick in after infrastructure is no longer economic, raising the concern that firms will not meet these obligations when due.

9.1.2 Federal regulation

Following the Deepwater Horizon incident, the Department of Interior split the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) (formerly the Minerals Management Service) into three new separate organizations: Office of Natural Resources Revenue (ONRR), Bureau of Ocean Energy Management (BOEM), and Bureau of Safety and Environmental Enforcement (BSEE).

BOEM and BSEE now share responsibility for OCS decommissioning. The decommissioning process is regulated by the BSEE. BSEE is also responsible for evaluating and making available decommissioning cost estimates.

BOEM is responsible for determining and securing the appropriate amount of financial assurance. BOEM uses BSEE's decommissioning cost estimates to set financial assurance levels in order to mitigate the potential that taxpayers will need to assume decommissioning obligations in cases such as bankruptcy.

9.1.3 Financial assurance

Federal regulations do not require minimum bonding for decommissioning of OCS infrastructure. Pursuant to BOEM's standard historical practice, a lessee or grant holder that passed established financial thresholds was waived from providing additional security to cover its decommissioning liabilities.[17]

Regardless of the status to the regulations, BSEE and BOEM's data makes clear that OCS decommissioning obligations are largely self-bonded, meaning they are secured almost entirely by the current financial strength of the companies obligated to perform the work. The degree of self-bonding is determined by decommissioning bond requirements and the estimated cost for perform decommissioning (See Figure 2.1).

BOEM acknowledges that its regulations are inadequate to protect the public from potential responsibility for OCS decommissioning liabilities, especially during periods of low hydrocarbon prices.[18] BOEM reports that from 2009 to 2020, there were 30 corporate bankruptcies of offshore oil and gas lessees involving partially unbonded offshore decommissioning liability of approximately $7.5 billion. The 2021 Fieldwood Energy bankruptcy involved decommissioning liabilities of $7.2 billion, bringing the bankruptcy total since 2009 to nearly $15 billion.

16 30 CFR § 250.1703.

17 Notice to Leaseholders (NTL) No. 2008–N07. This NTL was superseded by NTL No. 2016-N01, which BOEM later rescinded. Neither NTL is currently listed on BOEM's website.

18 Proposed Rule, 85 Fed. Reg. 65904, 65906 (Oct. 16, 2020).

Importantly, many of these bankrupt entities had financial assurance waivers from BOEM, demonstrating the weakness in BOEM's financial assurance program. ATP Oil & Gas was a mid-sized company with a financial assurance waiver under NTL No. 2008—N07 when it filed for bankruptcy in 2012. Bennu Oil & Gas also had a financial assurance waiver at the time of its bankruptcy filing. Energy XXI and Stone Energy did not lose their waivers until less than 12 months prior to filing bankruptcy.

To compound the non-performance risk, it is also the case that co-lessees are not required to provide supplemental bonding for decommissioning obligations regardless of their own financial strength, so long as one lessee is waived.[19] This means that the creditworthiness of one entity supports all parties on the lease.

Lessees can use a third-party guarantee in lieu of a supplemental bond. For example, a publicly-traded E&P company can guarantee the decommissioning obligations of a private subsidiary that cannot demonstrate financial strength with its own audited financial statements.[20] These provisions mean that less credit-worthy companies can avoid posting bonds, and it also demonstrates the key feature of the system of joint and several liability which, in theory, makes the largest, longest-standing companies act as backstops on liability.

9.1.4 Legacy of decommissioning activity

Drilling in the OCS began in shallow water, and because these are the oldest assets, most decommissioning activity has also been in shallow water. Newer deepwater assets will be more expensive to decommission. Consequently, recent cost data may not be representative of future costs.

The first structure decommissioned in the OCS was in 1973. It was not until the mid-1980s that the pace began to accelerate. From 1987-1996, 108 structures per year were decommissioned on average, increasing to 136 structures per year from 1997-2006, and nearly doubling to 208 structures per year from 2007-2016 where over 40% of all decommissioning activity to date has occurred.

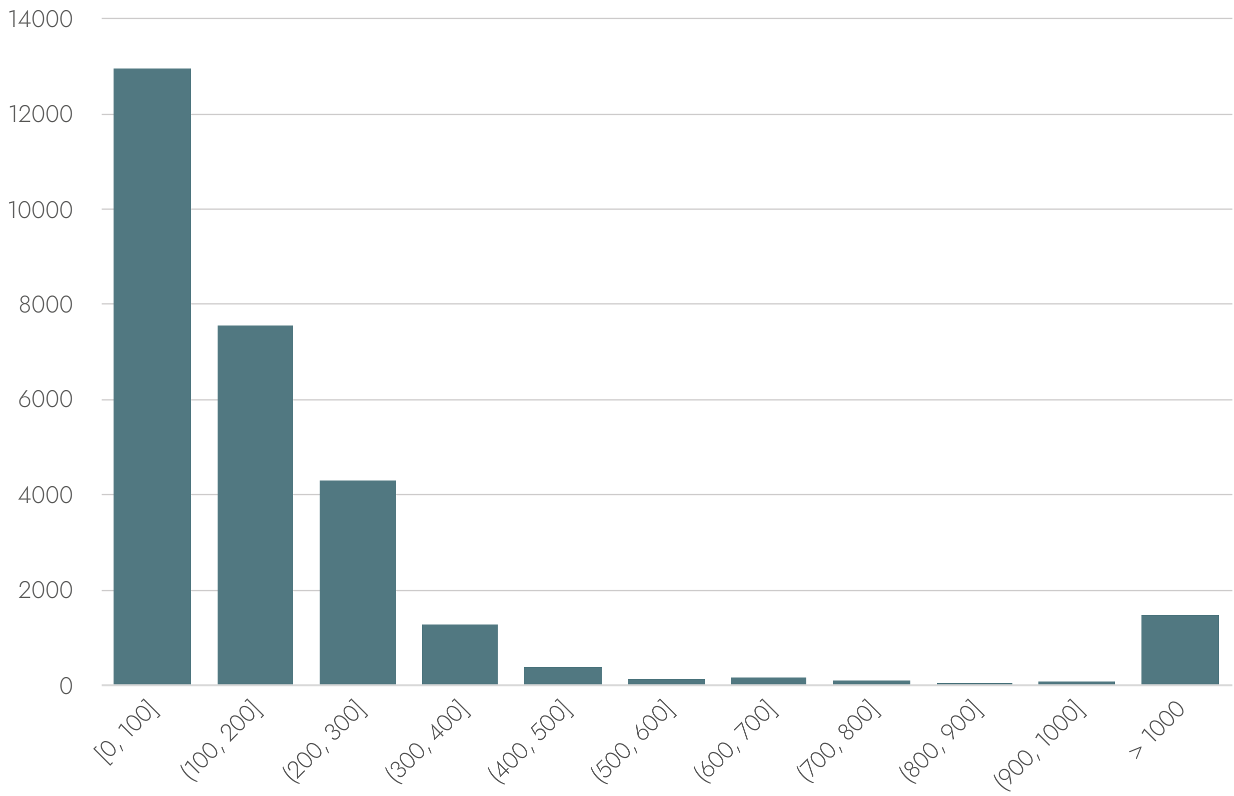
The first deepwater structure was decommissioned in 1989 and over the next twenty years only seven deepwater structures were decommissioned. Through 2017, a total of 23 deepwater structures have been decommissioned. Deepwater structures have been decommissioned every year since 2009, usually only one or two per year, with slightly higher levels of activity in 2011 and 2016.[21]

19 Current And Predecessor Lessees And Grant Holders Take Heed: BSEE And BOEM Propose Revisions In Offshore Decommissioning Obligations And Associated Financial Assurance Requirements (Vinson & Elkins, November 2020).

20 See 30 CFR § 556.905 (Using a third-party guarantee instead of a bond). To our knowledge, guarantor information on leases is not readily available from BOEM or BSEE.

21 Gulf of Mexico Decommissioning Trends and Operating Cost Estimation (BSEE, 2019).

Figure 9.1: Histogram of water depth of plugging activity. The data indicate the vast majority of plugged wells have been in very shallow water and may not be indicative of future costs.



Data: BSEE

Table 9.1 - Descriptive statistics for decommissioned OCS platforms.

Water depth of decommissioned platforms	
Total count	5,396
Count Major Structures	2,002
Median Water Depth	56
Average Water Depth	87
Max Water Depth	8,000
Min Water Depth	1

Data: BSEE

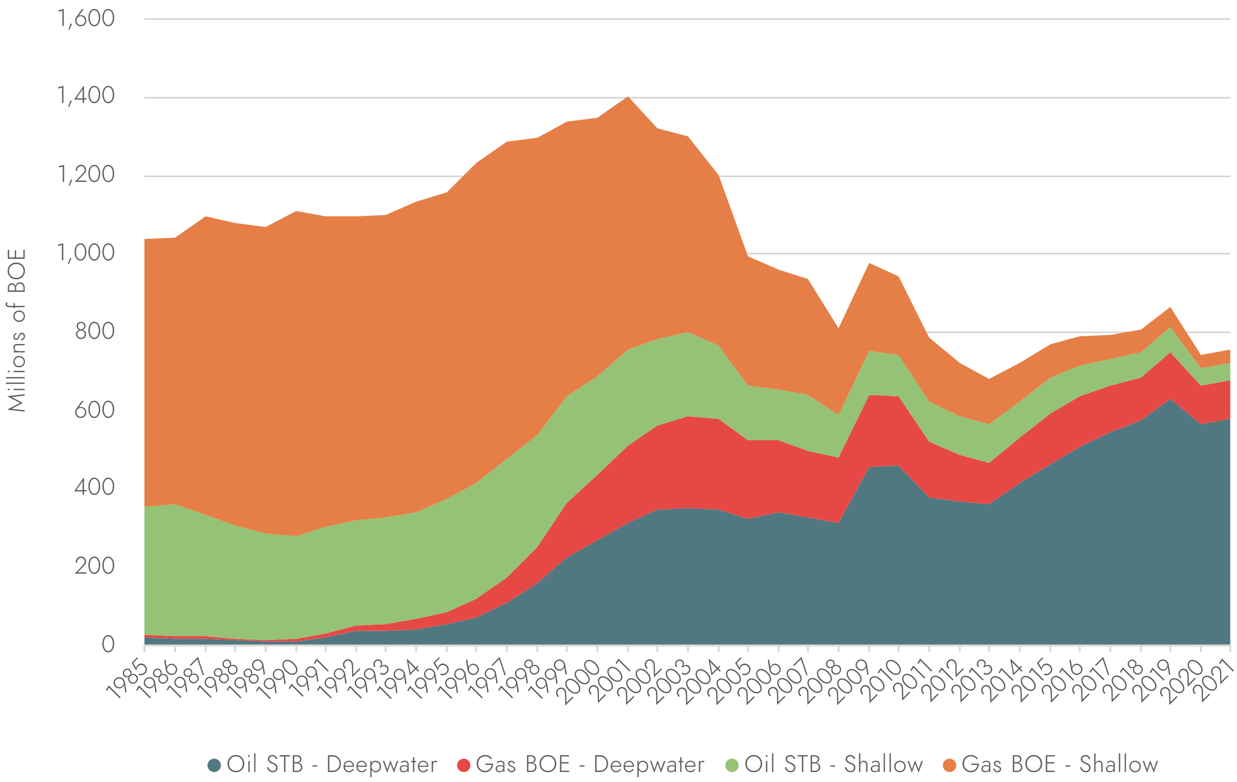
9.2 Appendix B OSC production and producing assets

Three trends in the OCS indicate rising decommissioning default risk. First, hydrocarbon production rates are declining. Second, the inventory of inactive shallow water assets is growing. Third, new exploration is taking place in deeper water where decommissioning costs will be higher.

9.2.1 Production

Total hydrocarbon production rates in the OCS are declining. Natural gas production has been declining steadily since 1997. Crude oil production in the OCS has been declining more moderately since 2019. Declining production may change the self-interest of large E&P companies operating in the OCS going forward making them more likely to abandon the liabilities of corporate subsidiaries.

Figure 9.2 - Production trend in Gulf of Mexico since 1985.



Data: BSEE

Table 9.2 - Number of operators constituting 80% of production in GOM as of last year.

19 operators account for 80.21% of production for 2021

Company name	Parent	2021 Production	2021 Production per day
Shell Offshore Inc.	Shell	133,362,675	365,377
BP Exploration & Production Inc.	BP	111,706,137	306,044
Chevron U.S.A. Inc.	Chevron	62,538,222	171,338
Anadarko US Offshore LLC	Occidental	54,490,163	149,288
Equinor Gulf of Mexico LLC	Equinor	38,371,240	105,127
BHP Billiton Petroleum (Deepwater) Inc.	BHP Billiton	31,298,489	85,749
MP Gulf of Mexico, LLC	Murphy Oil	22,211,436	60,853
Hess Corporation	Hess	18,602,245	50,965
Union Oil Company of California	Chevron	18,187,420	49,829
CNOOC Petroleum Offshore U.S.A. Inc.		16,399,816	44,931
Fieldwood Energy LLC		15,852,512	43,432
Murphy Exploration & Production Company - USA	Murphy Oil	12,757,855	34,953
Arena Energy, LLC		12,180,172	33,370
MOBIL OIL EXPLORATION & PRODUCING SOUTHEAST INC.	Exxon	12,045,783	33,002
EnVen Energy Ventures, LLC		10,929,020	29,943
Exxon Mobil Corporation	Exxon	10,019,811	27,452
Eni Petroleum US LLC	Eni	9,427,433	25,829
Talos ERT LLC		7,686,066	21,058
Walter Oil & Gas Corporation		7,640,710	20,933

Structures that are no longer producing or useful for operations are unlikely to receive the attention and maintenance of active fleets and may fall into a state of neglect and disrepair. Operators with large inventories of idle infrastructure may fall behind on maintenance from corrosion and struggle to keep up with increasing regulations and regulatory audits. Safety and environmental risks may ensue from rusting structures and require additional precautions and cost in decommissioning.[22]

The advanced age of many active pipelines might make them more susceptible to a loss of integrity, undermining production at the platforms they service. This further underscores BSEE's need to enhance its inspection requirements. Specifically, over 44 percent (about 3,780 of 8,600 miles) of active pipelines were installed prior to 2000, which, according to BSEE documentation, can increase the risk of leakage incidents due to corrosion.[23]

22 Gulf of Mexico Decommissioning Trends and Operating Cost Estimation (BSEE, 2019).
23 GAO-21-293, Updated Regulations Needed to Improve Pipeline Oversight and Decommissioning (March 2021).

9.2.2 Deepwater exploration

The gently sloping OCS allowed the offshore petroleum industry to move slowly into deeper water in the Gulf of Mexico, developing new drilling technologies as it went. As a consequence, the newest assets will be the most expensive to decommission. Existing cost data and estimates may not adequately reflect this phenomenon. Figure 1 summarizes the industry's development beginning in the 1940s.[24]

Figure 9.3 - Summary of the history of offshore oil and gas development

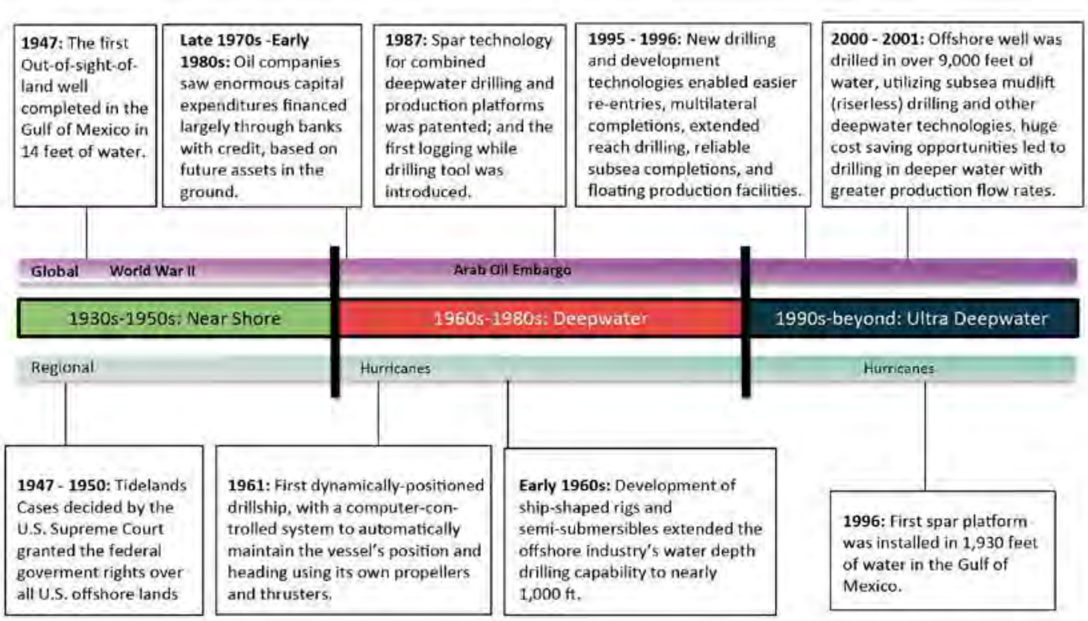
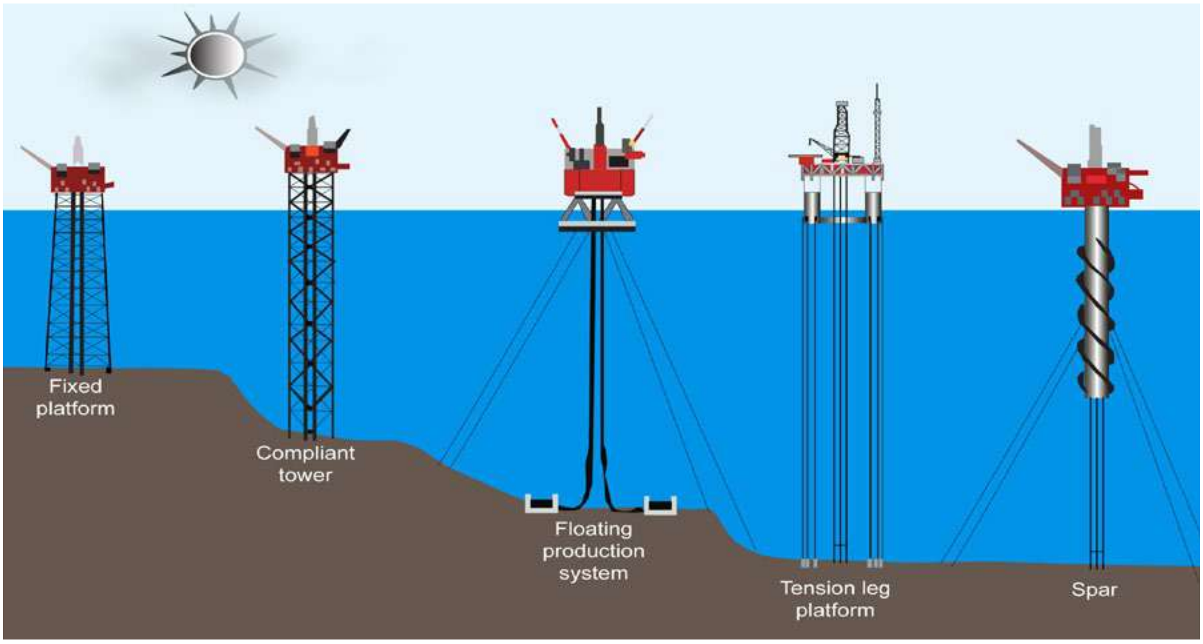


Figure 9.4 - Progression of offshore technology in the OCS



Source: GAO

This image from the GAO shows the technological progression into ever deeper water. Note that water depth is not to scale in this image, and historical shallow operations have on average been concentrated in water less than 100 feet deep while more recent projects routinely sit in thousands of feet of water.

24 The Offshore Petroleum Industry in the Gulf of Mexico: A Continuum of Activities (BOEM, 2008)

9.3 Appendix C – Methodology

9.3.1 Joint and Several Liability

To estimate joint and several liability, lease ownership history and title assignments data from BSEE were analysed to identify the chain of title for offshore leases. Spud dates and platform/pipeline installation dates were analysed to determine, for each lease assignment, which infrastructure existed at the time. For each lease assignment, all the estimated decommissioning costs were summed together to produce an estimate for decommissioning for each lease assignment. Then, the cost to decommission leases were summed by company (identified by MMS number) based on the time of ownership using pivot aggregation to remove double counts. For consolidated majors, SEC disclosures were reviewed to develop lists of subsidiaries. Companies identified as subsidiaries were assigned to their parent company and lease costs were summed using pivot aggregation to remove double counts.

9.3.2 Direct Liability

To estimate direct liability, property and collateral files published by BOEM were analysed. Costs for prospective infrastructure were removed from the lease cost totals, and lease decommissioning costs were summed by company using pivot aggregation to remove double counts.

9.3.4 Bond Coverage/Effective Bond Coverage

To determine bond coverage, property and collateral files published by BOEM were analysed to identify the total value of active collaterals listed to each operator. Effective bond coverage was estimated by determining the specific surplus value of each bond over the estimated direct liability of the listed principal and subtracting the surplus from the overall bond pool for the GOM. Surplus coverage has value, as it adds extra protection for individual companies and properties, but when comparing to aggregate estimated costs, surplus coverage on an individual lease or company may not provide additional coverage for other leases or companies.

9.3.5 Production Allocation

For this analysis, production (reported by lease) was allocated to lease title owners according to their ownership stake. For simplicity, all annual production was allocated to the last recorded owner for 2021. This is not the only way production can be allocated, and differs from BSEE's reported production rankings. However, this method better reflects the dynamics of joint and several liability as they are expressed in the Code of Federal Regulations, and avoids the issue of under-reporting production for major operators who contract out a substantal proportion of direct operations.

9.3.6 Subsidiary Lists

Subsidiary lists were compiled using a combination of BSEE and Securities and Exchange Commission data. Publicly traded companies list their significant subsidiaries and affiliates in financial filings, and these documents were examined to identify subsidiaries in the BSEE company data. Additionally, companies listed by BSEE that substantially share the branded name of the parent were added to the subsidiaries lists regardless of whether those companies are currently active in financial filings or not. Due to the complexity of identifying and attributing historical subsidiaries to current parent companies, it is possible that these lists are incomplete.

Further questions on methodology may be addressed to Stephen Greenslade: sgreenslade@carbontracker.org.

Disclaimer

To know more please visit:

www.carbontracker.org

@carbonbubble

Carbon Tracker Initiative

Why Interior could get stuck with the tab for cleaning up oil platforms

eenews.net/articles/why-interior-could-get-stuck-with-the-tab-for-cleaning-up-oil-platforms

April 12, 2024

CARPINTERIA, California — Two hulking platforms have sucked oil out of the ocean floor off this sunny local beach for nearly five decades.

The Hogan and Houchin platforms are now rusting monuments to California's once-powerful fossil fuel industry. Abandoned by their last owner, they should have been torn down years ago.

But a series of companies tied to the platforms say it's not their job — and now, they want the federal government to take on the multimillion-dollar responsibility.

The saga echoes the unfolding fight to clean up the nation's deteriorating fossil fuel infrastructure. More than 2,700 offshore oil and gas wells and 500 platforms are overdue for decommissioning in the Gulf of Mexico alone, according to a recent report from the Government Accountability Office.

The Interior Department has long struggled to ensure oil companies pay up and clean up once they've stopped pumping oil, a challenge that could only increase as decades-old infrastructure off the nation's coastlines faces retirement**.** If not maintained, old platforms and their wells can leak toxins and degrade ecosystems, becoming serious environmental hazards.

"The agency has recognized these problems for years," said John Smith, who worked on decommissioning at Interior's former Minerals Management Service (MMS). "When it comes to doing something about it, they're weak-kneed."

Interior could soon find itself on the hook for the millions of dollars required to safely remove the two California platforms. That's because the companies that once owned a stake in Hogan and Houchin — ConocoPhillips, Occidental Petroleum and Devon Energy — are appealing an order to take the platforms down, testing a federal regulation that requires former owners to ensure cleanup.

The stakes are high for Interior. Experts say its rule may not withstand opposition if oil majors take it to court, with uncertain consequences for a potentially enormous backlog of oil and gas wells, platforms and pipelines that are past their prime and owned by midsize companies more likely to go into financial distress.

In a statement, the Bureau of Ocean Energy Management said those beefed-up requirements would "ensure the taxpayer is protected from financial loss from offshore decommissioning liability."

Environmental groups are already on board with President Joe Biden's proposed rules. They look at Hogan and Houchin as a preamble to the kind of costs that could emerge during the gradual retirement of the nation's oil program due to its climate impacts.

"Without proper decommissioning, we can't really move away from our dependency on fossil fuels," said Ava Ibanez Amador, an attorney with Earthjustice. "We are just advocating for the government to actually enforce what it's supposed to enforce and to create stronger regulations so that we can protect our oceans."

But Elmer Danenberger, former chief of the engineering and operations division at MMS, said the Biden administration could miss a key lesson in Hogan and Houchin: that federal officials shouldn’t greenlight offshore energy projects from companies that show signs they can’t pay for the eventual cleanup.

That applies not just to oil infrastructure, he said, but to the emerging offshore wind industry.

“The taxpayer should not pay a dime, ever, for decommissioning,” he said.

How Hogan and Houchin were abandoned

In 1990, the Hogan and Houchin platforms were in decline. But a new company called Signal Hill Services wanted to buy the platforms from its then-owners — which included Phillips Petroleum Co. and Occidental Petroleum — and promised to revive production with horizontal drilling and by pumping water into the old reservoirs to increase pressure.

Career MMS employees were skeptical. They saw an inexperienced operator with weak financial backing.

The company had just been created by petroleum engineer Richard Carone and his brother Robert. Both had experience in the oil drilling sector, before going into finance at Chase Manhattan Bank’s global petroleum business.

They launched an oil and gas consulting business in 1984, before creating Signal Hill, their first foray into offshore drilling.

“Field people [in California] were opposed to the deal, and so were career people in headquarters,” recalled Danenberger.

Smith, who also worked at the agency during the Signal Hill takeover, echoed Danenberger’s recollection of widespread opposition to Signal Hill, as did one former BOEM employee familiar with the history who was granted anonymity due to the sensitive nature of the conflict. BOEM and the Bureau of Safety and Environmental Enforcement (BSEE) replaced MMS in 2011.

But political leadership believed an escrow account that would be filled to $17 million would cover future issues, former officials said.

“They just thought this was something to get some additional production. You know: ‘Give this company a chance. We're gonna have an escrow account. We’ll be protected, and we can fall back on Phillips,’” Danenberger said, referring to the firm that preceded ConocoPhillips.

Who ordered the green light for Signal Hill isn’t clear. But the George H.W. Bush administration — and its political appointees — were friendly toward oil and gas development.

Bush, a Republican, had built his fortune first in the West Texas oil fields and then in the Gulf of Mexico with the oil firm Zapata Offshore.

The director of MMS at the time was Barry Williamson, who would later lead the Texas Railroad Commission, which has at times been criticized for its oversight of the oil and gas industry. Bush’s Interior secretary, former New Mexico politician Manuel Lujan Jr., was jostling for more offshore development in the early 1990s, even as he juggled the fallout of the Exxon Valdez tanker oil spill off the coast of Alaska.

Lujan, who died in 2019, faced criticism from environmentalists during his tenure for his drilling stance. He framed the Exxon spill in Alaska as a problem with oil transportation and warned against blaming the nation’s offshore drillers.

"While tankers continue to spill oil into our waters, and offshore drilling continues to provide a record of environmentally sound production, why are we attacking offshore drilling?" Lujan said at the time.

The complicated question of who pays

Federal agencies did not always have strict rules to force oil and gas companies to decommission old wells and platforms. Many companies only held general bonds that covered just a portion of the ultimate cost, said Danenberger, who now runs a blog exploring offshore regulatory issues and news.

Former owners of oil and gas assets were also not expected to pay if a later owner folded. In a 1988 letter obtained by Danenberger's blog, then-MMS Director William Bettenberg told the Amoco Production Co. flatly that the Interior Department "will not proceed against" prior owners if a company is "unable to fulfill its obligations to plug and abandon wells and remove facilities."

Interior reversed that position in the 1990s.

BOEM confirmed in a statement that it can hold prior holders of a federal lease liable for decommissioning.

That’s more complicated than it sounds for the thousands of platforms off the U.S. coasts, many changing hands from company to company over decades, said Frank Rusco, director of the Government Accountability Office's natural resources and environment team.

GAO's investigation into offshore decommissioning found that BSEE — the agency tasked with forcing decommissioning — has been hesitant to "test its strength," not knowing what would happen if a legacy oil company took the bureau to court. Each decommissioning conflict so far has been solved through a mix of negotiation and light force, Rusco said.

"The way that regulations are, if you've ever held a lease, then you're responsible for decommissioning all the stuff that was on that lease at the time that you sold it, but it's not clear how far back you can go," Rusco said. "BSEE has gotten some folks to pitch in and take over previous lease owners, … but if they tried to enforce that, broadly, it would end up in the courts no doubt, and they're not sure what the outcome would be."

The question of who pays is becoming more pressing as older oil and gas operations in the Gulf of Mexico edge toward retirement, and following several high-profile bankruptcies.

In 2021, for example, the Fieldwood Energy bankruptcy resulted in roughly $7 billion worth of cleanup costs meted out in part to former owners.

The more recent Cox bankruptcy threatened to revive the issue — the company had roughly $4.5 billion in total estimated cleanup costs for Cox and Cox-affiliated offshore assets. The company avoided a crisis by selling much of its older platforms and wells.

Rahul Vashi, a partner in the Houston office of the Gibson, Dunn & Crutcher law firm, said the current assumption for most legacy oil operators is that they could be forced to cover the decommissioning of older assets.

"For assets that have been off the books for years and may have been sold at a time when producers and regulators were less focused on end-of-life decommissioning, operators have to prepare for the possibility, or perhaps likelihood, that they could be left responsible for a massive liability," he said.

The Hogan and Houchin case is challenging those assumptions.

BOEM estimated in 2020 that the platforms and infrastructure for Hogan and Houchin would cost $85.6 million to remove. But legacy owner ConocoPhillips — alongside Devon Energy and Occidental Petroleum — is fighting orders to pay it, and none of the cost is covered by supplemental bonds, according to BOEM's records.

Smith, the former MMS official, said the oil and gas industry's perspective could be that the Interior Department is the one that failed with Hogan and Houchin.

"ConocoPhillips is saying, 'No, we're not responsible for the full cost. … As an agency, you were responsible for ensuring that bond money was there, and you're negligent. So why should we cover your negligence?'" Smith said.

'Worst operators on the OCS'

When Signal Hill took over Hogan and Houchin, it was the first independent oil company to venture into those waters. All former players in the Pacific's offshore oil industry had been oil majors.

But the Carone brothers — and their engineering manager Steven Coombs — never succeeded in bringing Hogan and Houchin back to booming. Their company also fell behind financially, missing regular payments to the original decommissioning escrow account, recalled Smith.

Signal Hill also built a reputation for safety violations and poor upkeep of their facilities, validating the initial warnings from MMS officials, according to former federal officials and California state records.

"They were the worst operators on the OCS," Smith said, referring to the outer continental shelf.

By around 2010, MMS was demanding that Signal Hill fill the decommissioning account to about $67 million, its estimate of current cleanup costs, which was far more that Signal currently had in the account.

Federal officials went back and forth with Signal Hill, trying to get the company to fill the account. They were fearful, however, that demanding too much money could push the company into bankruptcy.

"We knew they were financially not that stable. So, we wanted to ensure the bond kept increasing without putting them out of business," Smith said.

The fight lasted for years, with Signal Hill filing multiple appeals to the Interior Board of Land Appeals. Finally, Interior's lawyers threatened to sue, leading to an out of court settlement that required Signal Hill to gradually contribute to the escrow account while allowing the company to use the money for decommissioning work, recalled Smith.

But Signal Hill dipped into the account for operational expenses too, draining available funds, according to a 2020 investigation from the Interior Office of Inspector General.

The OIG referred the potential fraud case to the U.S. Department of Justice, which declined to prosecute.

By this time, Signal Hill was unraveling.

Signal Hill’s final days

Signal Hill’s former executives could not be reached for this story, but their representative Bruce Cowen defended the company during a hearing in 2019 before the California State Lands Commission in San Diego.

“We've gone through a very difficult period the last five years,” he told regulators, who were weighing whether to yank the company’s right of ways for back rent. “We acknowledge we haven't paid. We want to make it right.”

Offshore oil platforms dot the horizon as a couple looks on at California’s Summerland Beach. | Heather Richards/POLITICO's E&E News

Cowen cited the company’s struggle with declining oil prices, mudslides that knocked out coastal roads to its facilities and a 2017 fire that cost the firm millions in uninsured costs.

Bucking the company’s plea, the commissioners voted to terminate the company’s leases for pipelines in state waters and slammed Signal Hill’s record of noncompliance with the state and with federal agencies.

“The fundamental issue is that [Signal Hill] had an obligation to comply with the lease terms, and they failed to do so year, after year, after year,” said State Lands Commission Executive Officer Jennifer Lucchesi at the San Diego hearing, according to a transcript of the meeting.

Without the right to pass through state waters, Hogan and Houchin could no longer produce, effectively cutting off the cash-strapped company’s source of revenue.

In October of 2020, Signal Hill relinquished its offshore lease to BOEM and dissolved. A month later, BSEE ordered legacy owners ConocoPhillips, Devon Energy and Occidental Petroleum to decommission the platforms.

Those firms — none of which would speak to E&E News for this article — have appealed that order, and the Hogan and Houchin story has disappeared into the Interior Board of Land Appeals. The board, which settles regulatory disputes for Interior's bureaus, only makes final decisions public.

BOEM does not have any money to cover decommissioning of the two platforms if the federal government were forced to take that liability.

BOEM said in an email to E&E News that it had secured an agreement with ConocoPhillips to use what financial assurance was available — a general bond for the Hogan and Houchin lease — to pay for upkeep of the platforms until decommissioning begins. The bureau did not provide details when asked for specific dollar amounts that it may require from the legacy owners.

But even if the Interior Board of Land Appeals rules against industry, the companies can still take the cleanup fight to district court.

If that happens, Interior's requirement that former companies pay to decommission abandoned oil and gas infrastructure will be put to a legal test for the first time, said Danenberger.

Companies often don't want their reputations bruised by fights over cleanup liabilities, but they could feel like it's worth the public attention given the high cost of the old Signal Hill assets.

"If you're talking $100 million plus to take down Hogan and Houchin, [they] may not be worrying so much about what the public thinks," he said.

Since 2020, ConocoPhillips has employed the Beacon West Energy Group to maintain the platforms, which were in a state of disrepair, according to state records.

Conoco declined to comment for this story given the ongoing dispute. But the company mentioned the Hogan and Houchin saga in its recent financial filings, saying it "continues to evaluate its exposure in this matter."

Escalating costs

The conflict over Hogan and Houchin is arising now partly because California decommissioning is so expensive that companies are balking.

Smith, now an offshore energy consultant, said the cost to take down offshore oil platforms in the Pacific could be many factors greater than Interior has estimated — the result of age, water depth and lack of decommissioning resources on the West Coast.

All of California's remaining oil platforms are older than the 30-year lifespan they were designed for, according to a recent decommissioning report by Smith and the consultancy firm TSB Offshore.

Hogan and Houchin weigh more than 10 million pounds each and sit in waters more than 150 feet deep. The TSB report estimates that the decommissioning cost for each platform could be two to three times higher than the $85 million estimated by Interior bureaus.

But they aren't even the most challenging of California's older infrastructure.

Heritage and Harmony, owned by Exxon Mobil, weigh between 138 million to 174 million pounds. Seven of the last California platforms are in water depths exceeding 500 feet, which is close to the world depth record for totally removing a conventional steel jacket platform from the ocean, according to TSB.

The cost for decommissioning is also high because California doesn't have ships to take down oil platforms.

U.S. heavy lift vessels of the right size are in the Gulf of Mexico, the heart of the nation's offshore oil and gas development. Ships could be brought from Asia and the North Sea at a high cost — ranging from $16 million to $66 million — but the Jones Act, a federal law to protect U.S. maritime jobs, also hampers efficient use of ships that are foreign flagged, the TSB report notes.

More light will be shed on California's decommissioning outlook as the state begins to take down the Holly platform, which was abandoned in state waters by owner Venoco in 2017.

Lucchesi said Holly's decommissioning has proved more costly than anticipated. But she noted that the high cost was partly because the state had to take over as an operator after Venoco walked away.

"That's a significant lesson that we have learned over the years," she said. "We're not just taking operators' numbers [on decommissioning costs], because that might be true for the operators. But it's not true in the worst-case scenario — where the state has to step in and take over."

New rules

The Biden administration is only the latest to try and update bonding and decommissioning rules to protect the U.S. government from picking up cleanup costs. The Trump administration began reforms but didn't finish them.

BOEM's draft rules, released last year, would bring in an additional $9.2 billion in financial assurances by forcing some companies to provide supplemental bonds. The agency has said its approach will target the companies it views as most likely to go into distress.

Danenberger, the former MMS engineering chief, was critical of BOEM's draft for nixing an earlier provision to require extra financial assurances from companies amassing violations. Missing payments and cutting safety corners is often a harbinger of financial troubles, as it was for Hogan and Houchin, he said.

BOEM said operators with more leases often have a higher number of violations, so that record is "not an accurate predictor of its financial ability to meet decommissioning obligations."

Large operators are largely supportive of the supplemental bonds idea, which could cushion them from liabilities when properties are abandoned. But midsize oil companies have balked at the Biden administration rules, warning that pressuring companies to secure new bonds could lead to more bankruptcies.

Ibanez Amador, with Earthjustice, pushed back on those concerns.

The group was one of several that issued a letter to Interior following the GAO report demanding tougher enforcement of decommissioning offshore. She said if a company faces insolvency due to complying with cleanup rules or paying penalties, it's a fair cost of doing business.

"They know from the very beginning of their operations what the penalties, what the liabilities, what the decommissioning costs, may be," she said. "None of this is a surprise."

nature energy

Analysis

https://doi.org/10.1038/s41560-023-01248-1

Financial liabilities and environmental implications of unplugged wells for the Gulf of Mexico and coastal waters

Received: 29 July 2022

Accepted: 13 March 2023

Published online: 8 May 2023

Check for updates

Mark Agerton [1] ✉, Siddhartha Narra [2], Brian Snyder [3] & Gregory B. Upton Jr. [2]

Plugging and abandoning (P&Aing) wells is a policy priority because unplugged wells present potential financial and environmental risks to the public. Offshore wells, compared with land wells, generally produce more, cost more to P&A and present different environmental risks. Here we estimate that the cost to P&A all 14,000 unplugged, non-producing wells in US Gulf of Mexico offshore waters, inland waters and wetlands is US$30 billion. Wells in shallower waters closer to shore make up 90% of inactive wells but only 25% of total P&A costs. They also present larger environmental risks. Prior owners of wells in federal waters (deeper and farther from shore) can be held liable for P&A costs if the current owner does not P&A them. We find that 88% of outstanding P&A liability in federal waters is associated with wells currently or formerly owned by one of the large, financially stable 'supermajor' companies.

The United States was the world's top oil and gas producer in 2021, and it holds the top spot for cumulative production over the past century[1]. Enverus's Drillinginfo database contains records of over 4.4 million oil and gas wells that have been drilled in the United States. Only 113,000 of these (2.5%) are offshore or in coastal waters, but these represent an outsized share of production; over the past two decades, federal offshore wells have contributed 15% of all US production, with wells in state waters adding to this share. Plugging and abandoning (P&Aing) wells is a critical part of decommissioning. P&A ensures that hydrocarbons or other gases and fluids do not escape from the wellbore. If producers face declining revenues and are unable to fulfil their P&A obligations, unplugged wells may become 'orphaned' and present increased environmental risks or financial burdens on the taxpaying public.

Previous research has assessed the P&A liability associated with onshore oil and gas wells in the United States. However, offshore wells are quite different in terms of their average production rates, investment and decommissioning costs and the environmental risks they present. Because of these differences, it is important to study offshore wells separately from onshore wells.

The epicentre of US offshore oil and gas operations is the Gulf of Mexico (GoM). In this study, we assess the outstanding financial liability associated with P&Aing all offshore oil and gas wells in the GoM and inland waters of the US Gulf Coast region. To contextualize these cost estimates, we review the environmental sciences literature on offshore oil and gas releases, existing P&A policies and the economics of decommissioning. This leads to a number of pragmatic policy suggestions.

Here we estimate the P&A costs of offshore wells in the GoM, including the federal offshore and state waters of Texas, Louisiana and Alabama. We calculate over US$30 billion in future P&A costs in the GoM. The majority of unplugged GoM wells have not produced in five years and are unlikely to re-enter production. Wells in shallow waters are much less expensive to P&A, and they also present higher environmental risks. In federal waters, 88% of P&A costs would be borne by one of the seven largest public oil companies before taxpayers assume the costs.

Plugging and abandonment background

When production of oil or gas stops, either onshore or offshore, regulations require that the site be decommissioned. One component of

[1]Department of Agricultural and Resource Economics, University of California Davis, Davis, CA, USA. [2]Center for Energy Studies, Louisiana State University, Baton Rouge, LA, USA. [3]Department of Environmental Sciences, Louisiana State University, Baton Rouge, LA, USA. ✉e-mail: mjagerton@ucdavis.edu

decommissioning involves P&Aing wells. The other involves decommissioning other infrastructure, including platforms or pipelines offshore[2].

Federal and state rules require operators to P&A wells. In federal waters, leases expire one year after production ends, and the operator is required to complete P&A and decommissioning work one year after the lease expires (30 Code of Federal Regulations §250). Thus, in federal waters, companies have two years from when production ceases to complete the cleanup work. Texas regulations consider wells that have not produced for more than 12 months as inactive. Operators of inactive offshore wells are required to plug within a year after they become inactive. Alternatively, operators may request a P&A extension. Extensions are a straightforward process and, if approved, allow operators to delay P&A activity (16 Texas Administrative Code §3.14 and §3.15). Louisiana defines inactive wells as those having no reported production or other permitted activity for six months. Operators must plug inactive wells within five years after they become inactive. In addition, if the well is inactive and not on the schedule of abandonment, the state assesses an annual US$250 fee per inactive well (Louisiana Administrative Code 43:XIX.137). Generally, Louisiana P&A deadlines can be extended if inactive wells share a lease with active wells.

All offshore wells are on government leases. Companies must comply with any requirements of an offshore lease in addition to state or federal statutes. P&A requirements of leases can be more restrictive than statutory requirements. Should a company fail to comply with a lease's P&A requirements, the government can attempt to enforce the P&A requirements as any private mineral owner would.

P&Aing wells prevents underground saltwater from polluting fresh groundwater reservoirs and it prevents leakage of hydrocarbons or other substances from the well. When a well is P&Aed, depleted reservoirs are sealed by placing cement plugs in the wellbore. The upper portion of the well adjacent to the freshwater reservoir is also cemented. Typically, the well casing is then cut six feet below the surface of the seafloor (or land for onshore wells), and the surface hole is filled with the surrounding sand or dirt. For wells drilled in water, this prevents the well from being a navigational hazard.

P&A costs increase with well depth. More cement and time are required. Reservoir temperatures and pressures generally rise with well depth, necessitating more powerful equipment to pump thicker and more expensive cement. P&A costs also increase with water depth. Wells in a marshy setting may not require diving equipment to reach, but ultra-deep-water wells are not even accessible by divers. They require expensive technologies such as remotely operated vehicles.

Companies can also temporarily plug wells, which preserves the option to resume production later. This is often done with new exploratory wells waiting on surface and subsea facilities. However, many offshore wells have been temporarily plugged or idled for years. Although improvements in market conditions (such as higher oil and gas prices) might prompt some companies to restart production from some wells, the probability of re-entry declines as time progresses. Companies have sometimes used temporary abandonment as a tactic to defer higher-cost, permanent P&A work on uneconomic wells[3].

Environmental risks of unplugged wells

Unplugged wells present environmental risks, and P&Aing them mitigate these. A number of studies assess the environmental risks of onshore unplugged and orphaned wells[4–6]. Offshore environmental risks, however, are quite different. Moreover, the environmental risk from unplugged offshore wells varies with water depth and distance from shore. The fates of leaked oil and gas are different in the shallow, near-shore versus deep-water environment, and we discuss them separately. Much of our knowledge about these processes was generated in the wake of the 2010 oil spill from BP's Macondo Prospect. Releases from improperly abandoned wells will probably be chronic and small compared with Macondo, but the underlying biochemical and ecological processes that influence the ecological impacts have many similarities.

Our analysis considers oil and gas releases with similar discharge volumes, whether in shallow or deep-water facilities. In the Gulf of Mexico, deep-water wells produce more hydrocarbons than shallow-water wells, so spills and leaks from active wells may be larger. The potential releases relevant for our context are from older and inactive wells that are likely to be depleted. These releases that could be mitigated by P&A activities are likely to be small, chronic and potentially unobserved, regardless of where they are located. Thus, we assume leaks that could be prevented by P&Aing wells are similarly sized, whether for shallow or deep-water wells.

Given similar volumes, initial toxicities and probabilities of oil spills at near-shore and far offshore sites, we would expect the environmental damages of near-shore spills to be greater than those farther from shore. A barrel of oil spilled farther from shore has more time to degrade through evaporation, photochemical reactions and bacterial respiration before it reaches the shore, and it has a greater opportunity to be diluted by ocean currents relative to a barrel of oil released closer to shore. Finch et al.[7] studied the toxicity of weathered versus fresh Macondo crude oils on shrimp and fish and found higher toxicity in the fresh oil samples, probably due to higher levels of polycyclic aromatic hydrocarbons (PAHs) in fresh oils. Stefansson et al.[8] found similar results with echinoderm and bivalve larvae. Faksness et al.[9] studied weathered and fresh Macondo oil toxicity on algae and copepods and found the fresh oil to be more toxic and to have higher concentrations of aromatics such as BTEX (benzene, toluene, ethylbenzene and xylene) along with PAHs. BTEX and PAHs are known to be mutagenic and cardiotoxic[10] and are more soluble in water than other oil compounds[11]. However, PAHs and BTEX are also relatively volatile and evaporate quickly. This evaporation is thought to reduce oil toxicity[12,13].

Relative to coastal ecosystems, the open ocean has low net primary production, biodiversity and ecosystem services per unit area; thus, all else equal, a barrel of oil spilled in a coastal system would be expected to have greater ecological impacts than the same barrel spilled some distance from shore. This is especially true for the northern Gulf Coast, which is dominated by wetlands. Wetland plants are sensitive to toxicity and smothering from crude[11,14], and salt marsh plants that form the coast of the northern GoM are especially susceptible[15]. Louisiana light crude is especially toxic due to the higher proportion of lighter and more soluble hydrocarbons[16]. As a result, allowing oils time to weather before impacting the coast lowers environmental risk.

In the case of Macondo, a significant fraction (4% to 31%) of the oil stayed in the deep-water environment[17], raining out as marine snow[18]. While this oil has had environmental impacts on deep-water ecosystems[19,20], the sequestration of oil in the deep water may have also prevented oiling of coastal systems.

There are also differences between shallow- and deep-water releases of methane, ethane and propane. During the Macondo spill, the majority of methane is thought to have remained in deep water and not reached the surface[21]. Instead, methane, along with ethane and propane were either dissolved and metabolized by bacteria[22–24] or stabilized as gas hydrates. This is likely to be even more true for low-level chronic leaks in which the methanotrophic bacterial community has time to respond to methane release. As a result, it is relatively unlikely that methane released from a deep-water wellhead will reach the surface. In contrast, methane leaks from shallow-water infrastructure, including from temporarily abandoned platforms, could be a significant emissions source. There is an emerging literature on methane leaks from offshore facilities[25–27], but to date, limited research has compared active with temporarily abandoned facilities[28]. Given that onshore abandoned and orphan wells are thought to be important methane sources[29–31], it is plausible that leaks from shallow-water wells, but not deep-water wells, would result in the release of greenhouse gases into the atmosphere.

Table 1 | Number of wells ever drilled in GoM

	Well Count
Wells by location	
State inland	31,440
State offshore	13,601
Federal shallow waters	34,517
Federal deep waters	2,699
All	82,257
Wells by status	
Active	6,502
P&A	64,373
Temporary P&A	3,544
Orphaned	752
Active injection	473
Idle, shut in or inactive	6,613
All	82,257

This table includes all documented wells spudded offshore through 2020 in the federal GoM and the state waters of Texas, Louisiana and Alabama. We include wells that have already been P&Aed. We exclude wells that are permitted but undrilled and also wells with suspended drilling operations. Note that wells in federal waters may have multiple associated wellbores.

Orphaned wells and prior studies

An unplugged well may become orphaned when there is no financially viable company liable for cleaning it up. States maintain lists of orphaned wells and have different criteria for designating specific wells as orphaned. The immediate cause of orphaning is usually bankruptcy. In such cases, the state takes on responsibility to P&A the well. There is no official orphaned-well list in federal waters offshore, but we use the term 'orphaned' broadly to describe wells for which the previous owner has abandoned operations in the area and is unlikely to have the financial means to properly P&A the well.

Policy can provide economic incentive for operators to P&A wells by either making decommissioning less expensive through subsidies or by increasing the opportunity cost of not P&Aing wells. P&Aing more wells could reduce the population of wells at risk of being orphaned one day. One potential concern with subsidies is that operators may increase overall P&A costs by drilling more sub-economic wells or changing engineering decisions. Increasing the opportunity cost of not P&Aing wells could involve penalties for idle wells.

Orphaned wells present particular challenges because they are a result of bankrupt owners. Bankruptcy presents a potential avenue for firms to avoid compliance with regulatory requirements[32]. The presence of a bankruptcy option to avoid environmental liabilities has been shown empirically to exacerbate risky behaviour by oil and gas producers[33]. A traditional solution in the oil and gas industry has been bonding requirements[34–37]. A number of studies have expressed concerns that existing bonding requirements in a variety of jurisdictions should be tightened or targeted better[38–41]. Blanket bonds, which allow a company to submit one bond to cover all of its wells, are a particular concern. Federal policy additionally combats orphaned wells by extending decommissioning liability beyond the current owners to previous owners. While this serves to limit taxpayer P&A liability, it could also increase the incentive for companies to declare bankruptcy and pass on decommissioning liabilities to prior owners.

An important difference between wells in federal and state waters is that the federal government can hold prior owners liable for P&Aing old wells if the current owner goes bankrupt (30 Code of Federal Regulations §556.710 and §556.80). In federal waters, 87% of all offshore wells were owned at one point by a 'supermajor' oil producer. We define the set of supermajors as Chevron, Shell, ExxonMobil, ConocoPhillips, BP, Total and Eni, plus their historical antecedents or acquisitions in the federal GoM, which include Exxon, Mobil, Conoco, Texaco, Union Oil Company, Atlantic Richfield and XTO. As of 1 July 2022, the supermajors had a combined market capitalization of US$1.2 trillion. These offshore producers are least likely to go bankrupt given their market capitalization, and the wells they have owned in federal waters are least likely to become orphaned. The 2021 bankruptcy proceeding for Fieldwood Energy underscores how prior owners of federal offshore wells may end up footing large P&A liabilities[42].

The Interstate Oil and Gas Compact Commission tracks onshore and offshore wells designated as orphans by 31 states[43–45]. In 2020, the commission identified 92,000 orphan wells (both onshore and offshore) across these states. Of these, we estimate around 15,000 were located within the Gulf Coast states we study (Alabama, Mississippi, Louisiana and Texas).

There is significant uncertainty about the size of total orphaned-well liabilities. Raimi et al.[46] focus on onshore orphaned and abandoned wells in the United States and estimate a wide range for the number of wells at high risk of being orphaned: several hundred thousand to 3 million. In a follow-up study, Raimi et al.[41] study a dataset of P&A costs for orphaned onshore wells that were actually paid by regulators. They find median costs are US$20 thousand per well but vary widely between states. Kang et al.[47] find at least 116,000 wells across 32 states and four Canadian provinces and territories that are operated by companies that filed for bankruptcy in the first half of 2020. The authors highlight that three in five wells ever drilled in the United States are currently inactive, but only one in three are permanently P&Aed. Boomhower et al.[48] analyses idle oil and gas wells in California, primarily onshore. Of the 107,000 oil and gas wells in California (both active and idle), they find that 5,540 wells may already have no viable operator or be at high risk of becoming orphaned in the near future. The estimated future financial liability to taxpayers for these 5,540 wells is approximately US$500 million, not counting any environmental or health damages from orphan wells. A number of other studies have focused on P&A risk in specific areas[49–54].

California Geologic Energy Management Division (CalGEM)[55] is the only study we are aware of that focuses specifically on P&Aing offshore wells. The report estimates the P&A and overall decommissioning costs for all offshore wells in California state waters. It estimates that P&A alone costs US$313–600 million. The study finds that existing surety bonds are insufficient to cover decommissioning costs. CalGEM[55] highlights that offshore wells are significantly more expensive to P&A relative to onshore wells. Although results from California are instructive for the GoM, these two regions are quite different. California wells are drilled in relatively shallow water—mostly less than 100 feet—while GoM wells can be in up to 10,000 feet of water. The GoM offshore oil and gas industry and its universe of support services are also larger and more active relative to California.

Population of GoM wells

We assembled data on the population of GoM wells from several sources. From the Bureau of Safety and Environmental Enforcement (BSEE), we obtained data on federal offshore wells and historical production, ownership histories of all federal leases and estimated P&A costs for some federal offshore wells. We obtained data on state offshore wells from individual state agencies, and we merged this with historical production data from Enverus. Our states include Louisiana, Texas, Mississippi and Alabama. We exclude Florida because offshore drilling has been prohibited in the state since 1989 (Florida Statutes 377.242(1)(a)), and attempts at offshore extraction in Florida state waters have been unsuccessful[56].

Table 1 presents the number of wells ever drilled within federal or state waters that are documented in public databases. Of the 82,000

Table 2 | Population summary statistics for unplugged GoM wells

	Mean	Median	Std. dev.	Mean	Median	Std. dev.
	(1)	(2)	(3)	(4)	(5)	(6)
	BSEE cost estimate			No BSEE cost estimate		
Federal deep water (>1,000 feet water depth)						
P50 cost per foot (US$ ft^{-1})	1,108	1,156	224			
P70 cost per foot (US$ ft^{-1})	1,341	1,366	258			
P90 cost per foot (US$ ft^{-1})	1,682	1,675	345			
Expected P&A cost (million US$)	24.14	23.80	7.49			
Water depth (ft)	4,714	4,428	1,946	3,131	2,945	1,793
Measured depth (ft)	20,580	19,965	6,170	16,875	16,471	5,824
MD imputed	11.4%			2.4%		
Measured depth, orig. or imputed (ft)	20,805	20,405	6,098	16,957	16,574	5,842
Spud year	2011	2012	7	2002	2002	9
Distance to shore (km)	148	139	80	122	111	77
Subsea completion	77.8%			34.8%		
Supermajor ownership	84%			90%		
Wellbore counts	778			1,678		
Well counts	444			761		
Federal shallow water (<1,000 feet water depth)						
P50 cost per foot (US$ ft^{-1})	60	50	66			
P70 cost per foot (US$ ft^{-1})	79	70	89			
P90 cost per foot (US$ ft^{-1})	106	98	123			
Expected P&A cost (million US$)	0.66	0.67	0.78			
Water depth (ft)	150	140	100	211	177	185
Measured depth (ft)	10,658	10,476	3,235	10,442	10,388	3,580
MD imputed	0.1%			0.6%		
Measured depth, orig. or imputed (ft)	10,658	10,477	3,235	10,450	10,411	3,575
Spud year	1990	1992	15	1988	1989	14
Distance to shore (km)	57	40	48	57	34	49
Subsea completion	0.1%			0.4%		
Supermajor ownership	88%			89%		
Wellbore counts	6,865			6,176		
Well counts	3,923			3,590		
State coastal and offshore						
Water depth (ft)				5	0	11
Measured depth (ft)				9,960	9,700	3,555
MD imputed				10.0%		
Measured depth, orig. or imputed (ft)				9,920	9,700	3,636
Spud year				1979	1977	21
Distance to shore (km)				2	0	4
Subsea completion				0.0%		
Well counts				9,166		

The table includes all documented wells spudded offshore through 2020 in the federal GoM and the state waters of Texas, Louisiana and Alabama. We exclude wells that have been P&Aed (unlike Table 4), wells that are permitted but undrilled and wells with suspended drilling operations. We list two sets of statistics for measured depth, one that includes only measured depth information recorded in well databases and one that also includes imputed measured depth information. Wells in federal waters may have multiple wellbores (boreholes) per well, and we provide counts for both. Wells in state waters have only one wellbore. We also have information on prior ownership only for federal wells, so we indicate ownership by a supermajor for those wells only. We identify a well as being owned by a supermajor if the following regular expression returns a match for any year for a given well's owner (chevron|shell|exxon|mobil|conoco|bp|texaco|total|union oil|atlantic richfield|xto|^eni) and the firm's name is not 'RBP Offshore', 'TBP Offshore Co.' or 'Mobile Mineral Corporation'. Std. dev., standard deviation; MD, measured depth; orig., original.

wells, 55% have been drilled in state waters, with the remainder in federal waters. Two-thirds of wells in state waters are in inland waters, which include bodies such as bays, estuaries and marsh and swamp wetlands. Seventy-eight percent of all wells ever drilled have been P&Aed. Only 8% are currently active. The remaining 14% are plausible candidates for P&A at this time.

https://doi.org/10.1038/s41560-023-01248-1

Table 3 | Aggregated GoM P&A cost estimates (billion US$) and well counts by jurisdiction

	Total	Federal deep	Federal shallow	State
Total P&A cost				
All	44.40	34.48	7.61	2.32
	(19,341)	*(1,617)*	*(9,166)*	*(8,558)*
P&A candidate categories				
Inactive wells (A)	30.16	22.69	5.57	1.91
	(14,097)	*(829)*	*(6,263)*	*(7,005)*
Temporary P&A (B)	9.53	7.14	2.32	0.07
	(3,672)	*(272)*	*(3,170)*	*(230)*
Inactive lease (C)	1.83	1.03	0.80	
	(1,038)	*(45)*	*(993)*	
A or B or C	30.56	22.98	5.67	1.91
	(14,316)	*(856)*	*(6,446)*	*(7,014)*
Active/recently active	13.84	11.49	1.94	0.41
	(5,025)	*(761)*	*(2,720)*	*(1,544)*
Wells in multiple categories				
A and B	9.27	6.96	2.25	0.07
	(3,517)	*(252)*	*(3,044)*	*(221)*
A and C	1.66	0.91	0.75	
	(942)	*(34)*	*(908)*	
B and C	0.87	0.44	0.43	
	(622)	*(19)*	*(603)*	
A and B and C	0.84	0.43	0.42	
	(590)	*(15)*	*(575)*	

Well counts (not wellbore counts) are listed in parentheses and italics below P&A cost (billion US$). Deep water includes all wells in water greater than 1,000 feet of water depth. Shallow-water wells are those in water less than 1,000 feet of water depth. State waters do not have inactive federal leases (category 'C'), so these spots are left blank.

We present summary statistics of wells that have not been P&Aed in Table 2. We note that for wells in federal waters, the unit of observation is a wellbore, and there can be multiple wellbores branching off a single well. Wells in state waters have only a single wellbore per well. Wellbores without estimated P&A costs from BSEE tend to be older; the median spud year is 2002 versus 2012 for wellbores with reported estimated costs. Wellbores without reported estimated costs also tend to be shallower, closer to shore and in shallower water. They are less likely to involve a subsea completion, which can significantly increase P&A costs.

For the 778 deep-water wells with BSEE-estimated costs, the mean P50 (50th percentile) P&A cost per foot is US$1,108, and there is some dispersion. We note that for all 689 deep-water wells with a recorded measured depth (versus imputed measured depth), the cost per foot is the same: US$1,156 per foot of measured depth. The P70 and P90 (70th and 90th percentile) costs are larger and exhibit more variation. We calculate the average mean cost per wellbore to be US$24 million. Finally, we note that most deep-water wells are currently or were at one point owned by a supermajor—84% of those with cost estimates and 90% of those without.

Table 2 also shows wells in federal shallow waters. BSEE provides the estimated cost for just over half of these. Shallow-water P&A costs per foot are much smaller than deep-water costs; the P50 cost per foot is US$60 versus US$1,108 for deep water. The difference in cost, while large, is not entirely surprising; unlike deep-water wells, shallow-water wells tend to be drilled to shallower depths and are closer to shore. Very few (less than 1%) involve subsea completions. We note that the average depth of federal deep-water wells is twice that of federal shallow-water wells. The average cost to P&A a wellbore in federal shallow waters is listed as US$660,000, compared with US$24 million in federal deep waters. As with the deep-water wells, a large majority of federal shallow-water wells are currently, or at one point, owned by a supermajor—88% of those with cost estimates and 89% of those without.

Wells in state waters are not in federal waters, so BSEE does not provide P&A cost estimates. Also, state records do not include ownership histories. Wells in state waters are in shallower water, closer to shore and older than those in shallow federal waters. The average depth of wells in state waters is less than the average depth of wells in federal shallow waters. Notably, water wells in state coastal and offshore areas or located in swamp and marsh areas have a median water depth of zero feet. This reflects the fact that many wells in coastal Louisiana are accessed by dredging canals to the well location. Thus, although the well is in water, the water depth in the coastal area is listed as zero feet.

Overall cost estimates

We constructed P&A cost estimates for every unplugged well in the GoM that BSEE does not provide cost estimates for. We did this by estimating the parameters of BSEE's P&A cost model and then using the estimated parameters to predict P&A costs for all wells without cost estimates (Methods). Table 3 displays aggregate P&A cost estimates. We estimate that total future P&A liabilities for both active and inactive wells are approximately US$44 billion.

Table 3 highlights that the majority of outstanding P&A liabilities—regardless of well P&A candidate classifications—reside in federal offshore waters, particularly deep waters. Specifically, US$42 billion of US$44 billion of the total P&A liability is associated with federal wells. Deep-water wells are especially expensive to P&A due to their complexity, size and depth, plus the costs of deep-water operations. Only 1,617 deep-water wells represent US$34.5 billion in P&A costs, while 9,166 wells in federal shallow waters represent only around US$7.6 billion in P&A costs. State wells represent a much smaller share of P&A costs—8,558 of them cost around US$2.3 billion to P&A, about 5% of outstanding offshore GoM P&A liability.

Table 3 further shows that the majority of P&A costs are also associated with wells that meet one of our three criteria for identifying P&A candidates: inactive wells (A), temporarily P&Aed wells (B) or inactive federal leases (C) as defined in Methods. Overall, only 31% of P&A liability—US$13.8 billion of US$44.3 billion—is associated with active wells. Specifically, for federal deep water, 33% of P&A liability is associated with active wells. This share drops to 25% in federal shallow water and to just 17% in state water. The fact that a larger share of P&A liability in state waters is associated with inactive wells could reflect differences in regulation between state and federal wells and the fact that wells in state waters tend to be older than wells in federal waters (Table 2).

Table 3 shows P&A costs and well counts for wells that meet multiple criteria. These wells are perhaps the most likely to be orphaned at some point. Most wells that are classified as inactive (A) do not fall into multiple categories. Of the temporarily P&Aed wells (B), 96% are also inactive (A).

Cost estimates by supermajor ownership

While 95% of outstanding P&A liabilities in the GoM are associated with federal waters, the fact that P&A liability in federal waters reverts to prior owners may limit federal orphan well risk relative to state risk. Table 4 splits P&A liability and well counts in federal deep and shallow waters by whether the well was ever owned by a supermajor. Summing across the supermajor-associated P&A costs and well counts, 87% of wells (9,381 wells) and 88% of P&A liability ($36.9 billion) in the federal GoM is associated with a supermajor. Even though around two-thirds of the total outstanding P&A liability in the federal GoM is associated

 https://doi.org/10.1038/s41560-023-01248-1

Table 4 | Aggregated federal GoM P&A cost estimates (billion US$) and well counts by supermajor ownership

		Deep water		Shallow waters	
	Total	Supermajor	Non-supermajor	Supermajor	Non-supermajor
Total P&A cost					
All	42.08	30.29	4.19	6.57	0.99
	(10,783)	*(1,405)*	*(212)*	*(7,976)*	*(1,066)*
P&A candidate categories					
Inactive wells (A)	28.26	20.03	2.66	4.88	0.64
	(7,092)	*(724)*	*(105)*	*(5,520)*	*(631)*
Temporary P&A (B)	9.46	5.83	1.31	2.06	0.25
	(3,442)	*(226)*	*(46)*	*(2,838)*	*(313)*
Inactive lease (C)	1.83	1.02	0.02	0.61	0.16
	(1,038)	*(43)*	*(2)*	*(776)*	*(176)*
Active/recently active	13.43	9.99	1.50	1.61	0.32
	(3,481)	*(657)*	*(104)*	*(2,318)*	*(392)*

Well counts are listed in parentheses and italics below P&A cost (billion US$). Deep water includes all wells in water greater than 1,000 feet of water depth. Shallow-water wells includes wells in water less than 1,000 feet of water depth. We identify a well as being owned by a supermajor if the following regular expression returns a match for any year for a given well's owner (chevron|shell|exxon|mobil|conoco|bp|texaco|total|union oil|atlantic richfield|xto|^eni) and the firm's name is not 'RBP Offshore', 'TBP Offshore Co.' or 'Mobile Mineral Corporation'.

Table 5 | Aggregated P&A cost estimates (million US$) and well counts in state waters

		Alabama	Louisiana		Texas	
	Total	Offshore	Inland water	Offshore	Inland water	Offshore
Total P&A cost						
All	2,319	19	1,308	755	120	117
	(8,558)	*(27)*	*(4,971)*	*(2,612)*	*(552)*	*(396)*
P&A candidate categories						
Inactive wells (A)	1,906	6	1,086	636	85	92
	(7,005)	*(8)*	*(4,131)*	*(2,198)*	*(368)*	*(300)*
Temporary P&A (B)	72	4	18	50	0	0
	(230)	*(5)*	*(56)*	*(166)*	*(2)*	*(1)*
Active/recently active	410	13	221	116	35	25
	(1,544)	*(19)*	*(840)*	*(405)*	*(184)*	*(96)*
A or B	1,909	6	1,086	639	85	92
	(7,014)	*(8)*	*(4,131)*	*(2,207)*	*(368)*	*(300)*
Wells in multiple categories						
A and B	68	4	18	47	0	0
	(221)	*(5)*	*(56)*	*(157)*	*(2)*	*(1)*

Well counts are listed in parentheses and italics below P&A cost (million US$). Table includes wells in offshore state waters and inland waters. Inland waters are defined as water bodies that are inland from the state shoreline and wetlands in the state coastal zone. State offshore waters are defined as waters between the state coastline and the federal–state boundary.

with inactive wells (category A), most of these P&A liabilities are backstopped by the largest public oil and gas companies in the world.

State waters

Table 5 breaks down results by the three Gulf Coast states with significant offshore oil and gas activity: Louisiana, Texas and Alabama and whether the wells are located in inland waters or offshore (Methods provide definition of state waters). The majority of P&A liability and wells are in Louisiana: around US$2 billion in P&A liability from about 7,500 wells. P&A liability in Texas is an order of magnitude smaller: around US$240 million associated with 1,000 wells. Alabama is another order of magnitude smaller: 27 wells associated with US$16 million in P&A liability. In Louisiana and Texas, only 16% and 25% of outstanding P&A liability is associated with active wells, while in Alabama, active wells contribute around 70% of P&A liability. Table 5 also shows that in Louisiana and Texas, around two-thirds of the wells and half of the P&A liability are concentrated in inland waters inside the official US coastline versus offshore, outside of the coastline.

Table 5 also shows that much of the outstanding P&A liability is associated with non-producing wells (category A): 84% in Louisiana and 75% in Texas. In all three states and especially Texas and Louisiana, the number of temporarily P&Aed wells (category B) and their associated costs are one—and even two—orders of magnitude smaller than the figure for inactive, non-producing wells (category A). Further comparing these two categories with their intersection (A and B) demonstrates that almost all temporarily P&Aed wells are inactive, but very few inactive wells are temporarily abandoned.

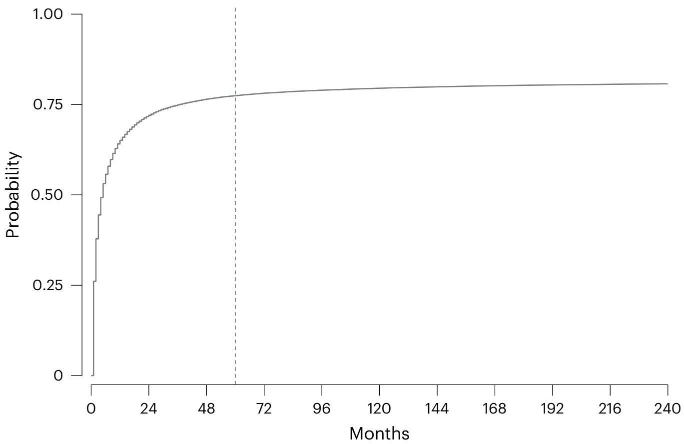


Fig. 1 | Cumulative probability well resumes production within *s* months after pausing production. The line represents the estimated probability a well in federal waters resumes production within a given time conditional on production having not yet restarted. This is estimated using a Kaplan–Meier[67] failure function. The pointwise 95% confidence interval is visually indistinguishable from the point estimate. The vertical dashed line marks our five-year (60 month) threshold identifying inactive wells.

Discussion

We identify a few policy takeaways from our analysis of the environmental and financial liabilities associated with unplugged wells in the GoM and Gulf Coast inland waters.

Although approximately 78% of all wells ever drilled in our sample have been P&Aed, there are currently over 14,000 non-producing wells that have also not been permanently P&Aed. In fact, there are more inactive, non-producing wells that have not been P&Aed than currently active wells. This is particularly true for Louisiana and Texas, where only 17% and 25% of P&A liability is associated with active wells. In federal waters, after five years of no reported production, inactive wells have less than a 4% chance or re-entering production in the future (see Methods and Fig. 1). Qualitatively similar results are likely to hold for wells in state waters. Many inactive wells in state waters might therefore be at risk of being orphaned in the future. A review of the environmental sciences literature also reveals that the environmental damages of near-shore spills is likely greater than those farther from shore.

Wells in shallow waters are significantly less expensive to P&A compared with wells in deep waters. There are around 13,000 inactive wells in state plus shallow federal waters. P&Aing these would cost approximately US$7 billion. Also including inactive deep-water wells adds only about 1,000 wells, but it increases total P&A costs to US$30 billion. Thus, over 90% of the inactive wells could be plugged for about 25% of the total cost. Because these shallower wells that are closer to shore also present larger environmental risks, P&Aing wells in state and shallow federal waters is likely to provide more environmental benefits per dollar of P&A spending relative to P&Aing more expensive, deep-water wells.

Most (88%) of the P&A liability in federal waters is associated with wells currently or previously owned by a supermajor (87% of federal offshore wells). Federal policy requires that a well's previous owner P&A it in the event that the current owner goes bankrupt. Given this policy and the large market capitalization of the supermajors, the P&A costs associated with these wells are less likely to fall on taxpayers compared with wells in state waters, where the state may not be able to compel prior owners to assume P&A liabilities. Thus, to reduce taxpayer P&A liability, policymakers might consider focusing P&A efforts on wells in state waters.

Methods

Identification of offshore wells

We first identify the universe of GoM wells that have yet to be P&Aed. We start by compiling a comprehensive dataset of offshore wells in the federal GoM and the state waters in these four states.

Our definition of state waters includes both inland and offshore waters. We define inland waters as those that lie within a state's coastal zone. Our definition of inland waters includes areas in open water and areas such as wetlands. We define offshore waters as state waters outside of the official US coastline and inside the federal–state water boundary. In Louisiana and Alabama, the federal–state water boundary is around 5.5 km (3 nautical miles) from the coastline, while in Texas the boundary is at around 16.7 km (9 nautical miles).

As we discuss above, the depth of a well is a key determinant of its P&A cost. However, public records do not provide a measured depth for a few wells, especially older ones. Measured depth is the total distance from the top of the wellbore to the bottom hole. Measured depth is missing in less than 1% of wells. We impute missing well depths with the measured depth of the closest neighbour well. In 95% of cases, the neighbour well is less than 1 km away, and in half of cases, it is less than 0.01 km away. In addition, many federal wells have secondary wellbores called sidetracks. Sidetracks are additional wellbores that branch off the initial well, often several thousand feet down. Thus, one well can have multiple wellbores (also referred to as boreholes). A well is identified by a ten-digit API (application programming interface) number, while a wellbore (borehole) is identified by a 12-digit API number. Note that in state waters, data are available only at the ten-digit API number level, that is, for each well. Thus, the distinction between wells and wellbores is only in federal waters. API numbers are unique numbers assigned to every oil and gas well in the United States.

In federal waters, measured depth is reported for each sidetrack. Summing the measured depth of each sidetrack within a well will double count the shallower portion of the well and significantly overestimate the number of feet that must be P&Aed. To avoid double counting P&A costs for wells with multiple wellbores, we consider only the incremental length that a sidetrack adds to a well when modelling P&A costs. We measure this incremental distance as a sidetrack's measured depth less its kick-off point. The kick-off point is the location at a given depth below the surface where the sidetrack deviates from the original wellbore. We find that on average, the incremental distance of a sidetrack is approximately 39% of its full measured depth. On the basis of this, we assume that the length of the sidetrack is 39% of the listed measured depth in instances where a sidetrack's kick-off point is not reported.

As discussed above, state governments have programmes that pay to P&A wells that the state determines are orphaned. We obtained records on the actual costs incurred to P&A orphaned wells from the relevant government agencies in Louisiana and Texas. However, very few of the wells that had been P&Aed were offshore. Wells in Louisiana state waters make up the majority of GoM wells in state waters, yet only four offshore wells were P&Aed with the state's orphan well fund. Because so little P&A cost data are available for wells in state waters, we choose to use state orphan well P&A cost records as external validity checks on our cost estimates rather than using them to estimate P&A costs.

We note that our analysis focuses exclusively on documented wells that are catalogued in state and federal databases. It is possible that undocumented, unplugged offshore wells exist. We also note that records for older wells are more likely to be missing key pieces of information, such as measured depth. Given these caveats, we interpret our statistics as estimates—not a complete census. Nevertheless, we believe that the data we assemble are sufficient for obtaining a reasonable estimate of the aggregate P&A liability.

Estimating costs

BSEE uses a P&A cost model to estimate P&A costs for a subset of federal wells. The agency shares cost estimates in a public database, but not the underlying model. Under Notice to Lessees and Operators 2016-N03, BSEE requires offshore operators to report all decommissioning costs to the agency, ostensibly so that the agency can use actual costs to improve its cost-estimation methods[57]. Our empirical strategy is to extrapolate BSEE's P&A cost model to wells in federal and state waters without cost estimates and then sum these costs for subsets of wells. Because BSEE does not make its cost-estimation process public, we estimate the parameters of BSEE's cost model by regressing BSEE's estimated costs on well characteristics. Our strategy relies on two major assumptions. First, we assume that after conditioning on observable well characteristics, the wells BSEE provides a cost estimate for are similar to the wells that it does not. Second, we assume that BSEE's cost estimates are indeed unbiased estimates of mean P&A costs per well.

Our empirical approach is most similar to the one taken by Ho et al.[39] and Raimi et al.[41], who regress onshore orphan well P&A costs on well characteristics. The P&A cost data in these studies are public records from state orphaned-well P&A programmes. Only a smattering of orphaned wells in state waters have been P&Aed with state dollars, however, and none in federal waters. This means that we cannot estimate an offshore P&A cost function with public data on actual P&A costs, and we cannot see how these costs have changed over time with changes in factor prices such as rig day rates. Instead, we use BSEE's estimated P&A costs to reverse engineer the agency's cost model.

Though we do use regression analysis, we choose not to provide measures of statistical uncertainty around our estimates. The underlying data-generating process we model is a deterministic cost model used by BSEE, not a statistical process with sampling variation. The true source of uncertainty in our estimates is the accuracy of BSEE's cost model, and we do not have a good way to quantitatively assess the uncertainty associated with this. Providing statistical confidence intervals that describe statistical risk would thus be misleading.

Our cost models (and therefore BSEE's cost models) are simple and elide many differences between wells—such as well age and whether a rig is required. These factors may affect P&A costs for individual wells. This means our model is not appropriate for making precise cost estimates at the level of an individual well. However, under the two assumptions above—that the wells with BSEE cost estimates are representative of the broader population and that the BSEE estimates are unbiased—our model is well-suited for making aggregate, population-level cost estimates.

Engineering and operations research studies have taken a different approach to estimating P&A costs. Previous studies have considered the cost of different plugging techniques and capital equipment rental (rigs) and then summed these individual inputs to estimate P&A costs[58–62]. More detailed operations-research models can also accommodate cost efficiencies from efficient sequencing of P&A operations and learning-by-doing effects[63,64]. Regulators appear to recognize that P&Aing several wells at once is more cost effective than one-off P&A operations and take advantage of this[41]. Firms' engineering and operational choices are important P&A cost drivers, but we choose to abstract away from these operational choices that we cannot observe and focus on how the well characteristics that we can observe translate to aggregate P&A costs. An important factor in P&A costs is the day rate for capital equipment such as rigs. Rig day rates are procyclical[65], so P&A costs are likely to rise and fall with oil and gas prices. Because we do not observe how offshore P&A costs have evolved over time, we are unable to quantitatively assess how much P&A costs vary with rig day rates. However, we conjecture that regulators could take advantage of this cyclicality and hold P&A campaigns during industry downturns. This could lower costs and offset industry job losses[46].

We also note that our estimates do not include decommissioning of platforms or subsurface equipment. The cost for decommissioning this infrastructure can be sizable; in the sample of cost data he analyses, Kaiser[66] finds that platform costs are S$0.16M–10.8 M for platforms in 25–350 feet of water, while average P&A costs are US$0.14 million per well for day-rate contracts and US$0.28 million per well for turn-key contracts. The CalGEM[55] report estimates that P&Aing 1,492 offshore wells in California state waters would cost US$313–599 million and that adding in facility decommissioning would increase the cost to US$718–928 million (assuming that artificial islands are left intact).

When BSEE provides cost estimates, they are for the P50, P70 and P90 quantiles. We assume that P&A costs have a right-tailed distribution so that the expected cost is higher than the median (that is, P50) cost. This reflects the fact that costs are bounded below by zero and the possibility of cost overruns. To calculate expected P&A costs (versus the P50 cost), we fit a separate log-normal distribution to each set of P50, P70 and P90 cost estimates and calculate the implied expected cost. Specifically, we find the location and scale parameters that minimize the Euclidean distance between the P50, P70 and P90 costs and the corresponding quantiles of the log-normal distribution. The distribution of P&A costs should be truncated on the left at zero because P&A costs can't be less than zero. This naturally suggests using a right-tailed distribution. This assumption of a right-tailed distribution of well P&A costs is also consistent with other P&A cost estimates[39,41,55] and feedback received from both industry and regulators. The expected P&A cost that we calculate is approximately 6% larger than the P50 cost. We normalize expected costs by each well's depth.

Our next step is to use regression analysis to estimate how BSEE cost estimates depend on observable wellbore characteristics. As shown in Table 2, the characteristics and costs of wells in federal deep water, federal shallow water and state waters are quite different. Because these populations of wells are different, we estimate separate regression models for all three groups. We then use our estimated regression parameters to predict costs for the wellbores in federal and state waters that lack cost estimates. For federal wells with sidetracks, we also remove the double-counted portion of each sidetrack's measured depth above the kick-off point.

For the 689 deep-water wells with a BSEE cost estimate and a recorded measured depth, BSEE estimates that the P50 cost to P&A any federal deep-water well is exactly US$1,156 per foot of measured well depth. Approximately 11% of federal wells with BSEE cost estimates lacked a recorded measured depth and had to be imputed (Table 2). Among the 689 wells with a BSEE cost estimate, there is variation in water depth, distance to shore and whether the well involved a subsea completion. However, there is no variation in the P50 P&A costs. Well characteristics are likely to impact the P&A cost per foot but are apparently not taken into account in BSEE's P50 cost-estimation methodology. While there is some variation in the estimated P70 and P90 costs per foot, we were unable to detect systematic relationships between well characteristics available in the public BSEE databases and these costs. The mean of the expected P&A cost for federal deep-water wells with recorded measured depths is US$1,230 per foot. To calculate expected P&A costs for wellbores without cost estimates, we simply find the total length of the wellbore (adjusting sidetrack depths to avoid double counting) and multiply by our average expected cost of US$1,230 per foot.

For wells in shallow federal waters, we use equation (1) to estimate the P&A cost. We assume that for well i, the cost per measured depth (c_i) depends on the water depth (WD_i) and a binary indicator variable representing whether the well involves a subsea completion (subsea_i):

$$c_i = \alpha + \beta \mathrm{WD}_i + \gamma \mathrm{subsea}_i + \varepsilon_i. \quad (1)$$

Equation (1) is parsimonious. However, including other well characteristics such as distance to shore does not improve model fit or make a statistically significant difference in cost estimates. There are certainly many other engineering considerations that affect P&A costs

 https://doi.org/10.1038/s41560-023-01248-1

that are left out of equation (1), but these factors do not appear to enter BSEE's P&A cost function.

We estimate the parameters in equation (1) using the expected BSEE P&A cost for all 6,865 wellbores listed in Table 2 (including the 0.1% for which we had to impute a measured depth). Our estimates imply that the cost per foot at a water depth of zero is US$18.59 ($\alpha = 18.59$). For every 100 feet of additional water depth, cost per foot rises by US$32 ($\beta = 0.3217$). Wells with subsea completions are significantly more expensive, adding an additional US$870 per foot ($\gamma = 869.59$). Reported standard errors were small and imply that coefficients are statistically different from zero at the $p = 0.01$ level, and the R^2 was 40%. We take this not as a measure of statistical uncertainty but as a test of goodness of fit that we have accurately and precisely recovered the parameters of BSEE's cost model. We set the shallow-to-deep water cut-off at 1,000 feet. Our estimates imply that at 1,000 feet of water depth, a federal 'shallow' water well with subsea completion would cost US$1,210 per foot to P&A, which is close to our estimated deep-water cost of US$1,230 per foot. The shallow- and deep-water cost functions intersect at 1,060 feet of water depth, which is close to our cut-off. Using these estimated regression coefficients and data on well characteristics, we predict expected P&A costs for the 6,176 out-of-sample wellbores in federal shallow waters that lack P&A cost estimates.

We assume that P&A costs for wells in state waters are generated by the model in equation (2). The model is very similar to the one used in federal shallow waters.

$$c_i = \alpha + \beta \mathrm{WD}_i + \varepsilon_i. \tag{2}$$

The most important difference with the prior equation (1) is that we estimate the state waters in equation (2) using only wellbores in federal waters that are less than 15 km from shore and do not have subsea completions. Recall that in Louisiana, Mississippi and Alabama, the federal–state water boundary is around 5.5 km (3 nautical miles), while in Texas, the boundary is at around 16.7 km (9 nautical miles). Removing wells greater than 15 km from shore leaves 1,708 wellbores in shallow federal waters with BSEE cost estimates. Three wells with costs per foot that are clearly outliers are also removed. Effectively, this means we are extrapolating federal shallow-water P&A costs into state waters with shallower wells.

One concern is with extrapolating costs for federal shallow waters to state waters is that wells in state waters might have a different P&A cost function compared with wells in federal waters. The two main variables in our cost model are measured depth and water depth, so we examine these two distributions more closely to see how they compare. Supplementary Fig. 1 is a set of stacked histograms. These show that the measured depths of wells in Texas and Louisiana are similar to the wells in federal shallow waters with estimated P&A costs, while the 27 wells in Alabama are substantially deeper. Supplementary Fig. 2 is a set of stacked histograms of water depths. The histograms make clear that even though the measured depths of state wells are generally comparable to measured depths of wells in federal shallow waters, the water depths are not. This is not entirely surprising because federal waters begin 3 miles from the Louisiana coast and 9 miles from the Texas coast, and water depth is correlated with distance from shore. Supplementary Table 1 provides further detail on these distributions. The right-most two columns show what share of the federal shallow estimation sample has water depth deeper than the (1) deepest (maximum) and (2) 90% quantile water depth for a set of state wells. The table further clarifies that there is minimal overlap in water depth between wells in inland state waters and wells in federal shallow waters and a bit more for state offshore wells. Fully 25% of wells in federal shallow waters are shallower than the 90th percentile Texas offshore well, but only 3% of wells in federal shallow waters are shallower than the 90th percentile Louisiana offshore well. Our state waters equation (2) also differs from equation (1) in that it omits the indicator variable for subsea completions. We do not actually observe whether wells in state waters involve subsea completions; however, we believe that it is unlikely that they do. Less than 1% of federal shallow-water wells have subsea completions.

Our estimates for equation (2) imply that the P&A cost per foot starts at US$25.8 per foot ($\alpha = 25.8$) and increases by US$26.47 for every 100 feet of water depth ($\beta = 0.2647$). As with our equation (1) estimates, the standard errors are tight, implying that p values are less than 0.01, and the R^2 was also 40%. Again, we interpret this not as a sign of statistical certainty but that we have done a good job of recovering the parameters of BSEE's P&A cost model.

The four orphaned wells that the state of Louisiana paid to P&A cost between US$25 per foot to US$55 per foot, with an average of US$34 per foot. These costs incurred by the state of Louisiana to P&A specific orphaned wells are in the range of our estimates.

Identifying P&A priorities

For policy purposes, the relevant quantities of interest are likely to be the aggregate cost for sets of wells with particular characteristics that make them relevant to the public. We identify two such sets of wells—first, wells that are not producing and are unlikely to produce in the future, and second, federal wells that were ever owned by a 'supermajor' oil and gas company that could serve as a backstop for P&A liability.

The first group of wells that may be of interest to policymakers is the set of non-producing wells that are unlikely to begin production again. A key opportunity cost of P&Aing a non-producing well (besides the expense of doing so) is the loss of a real option to restart production from that well in the future[3]. The value of this option is smallest for wells that are not very profitable and therefore unlikely to re-enter production. Some of these wells, in fact, may have negative values to the company and represent future financial liabilities without revenue. It is profit maximizing for the owners of these wells to defer P&Aing them because this reduces the present value of P&A costs. P&Aing these wells is unlikely to reduce the supply of oil and gas because they are not currently producing.

We identify three factors that suggest a non-producing well is unlikely to resume production in the future: (1) the well is listed as idle or has not reported production in five years, (2) the well has been temporarily plugged and (3) the well is on a federal lease that has expired. These factors are not mutually exclusive. We discuss each factor separately, but we hypothesize that wells with multiple factors are unlikely to produce meaningful quantities in the future.

First, we identify wells that are not yet P&Aed but are currently listed as inactive, idle or shut in or have not reported production in five years. We note that well status codes differ across states and were harmonized. We also note that in federal waters, some wellbores (that is, API-12) are listed as inactive, but another wellbore within that well (that is, API-10) is listed as either P&Aed or currently producing oil and gas. If an individual wellbore is listed as active or P&Aed within a federal well, we apply that status to all wellbores in the well.

'Inactive', 'idle' and 'shut in' are status codes identified in federal and state well databases. Restarting production involves a one-time cost in addition to the ongoing cost to maintain a producing well. Profitable wells sometimes temporarily shut in for operational or safety reasons (such as a hurricane) but restart quickly once the event subsides because production revenue is larger than the cost to restart. Other wells will not be restarted if the company decides that the costs associated with restarting are higher than the projected revenues.

To choose what length of time a well needs to be inactive to be classified as a P&A candidate, we estimate the probability that a non-producing well restarts production as a function of the time it has not produced. Economic theory suggests that the more time a well does not produce, the more likely it is that the well is unprofitable and the lower the probability it will restart in the future. Using data on all federal GoM production from 1947 to November 2021 and statistical survival analysis techniques, we estimate the probability that a well restarts production in s months or less after stopping production. To do so, we aggregate production data to the API-10 level. We then identify all production gaps in which a well produces nothing for at least one month. Each observation is then an s month gap in production. For example, if a well produces in January 1996 (month $t = -1$), does not produce February–March 1996 (months $t \in \{0, 1\}$) and produces again starting in April 1996 (month $t = 2$), we record a two-month production gap. Some wells stop producing and never produce again. We retain these observations, assuming that the well remains at risk of restarting production and define November 2021 as a censoring date. Using these data, we estimate $\text{Probability}(\text{restart by } t \pm s | \text{produced in } t-1 \text{ but not } t)$ with a Kaplan–Meier[67] estimator. This is similar to a time-to-failure analysis that allows for time-varying failure rates. The failure rates decline over time as high-productivity wells reactivate early (fail) and leave the sample.

Figure 1 plots an estimate of this probability. The estimate shows that most wells that restart production do so within the first couple of years. After three years of no reported production, a well has a 5.8% chance of reporting production in the following 17 years. After five years of no reported production, a well has a 3.3% chance of reporting production in the following 17 years. These results suggest that after five years of no reported production, a well has less than a 4% chance of producing oil and/or gas in the future.

Second, we identify wells that have been temporarily plugged. There are two common situations where a well may be temporarily plugged. First, firms drill exploratory wells while the economic potential of a location is uncertain. If an exploratory well is successful, the firm is likely to develop the field. The firm may temporarily plug the well while waiting on additional drilling and additional infrastructure to bring hydrocarbons to market. Second, a firm may temporarily P&A wells, mothballing them, instead of permanently P&Aing them. This preserves the option of producing the well again when prices are higher or P&A costs are lower. It is possible that P&A costs per well may be lower if the firm can simultaneously P&A several nearby wells.

Third, we identify wells in federal waters that are on inactive leases. Federal leases expire one year after production has ceased. Thus, we consider a lease expired after one year has passed with no reported oil and gas production. There can be many wells on one lease, and so if any individual well is still producing, the lease is held by production. The federal government does not require that the operator P&A wells or remove unused equipment as long as the lease is held by production. One year after the last well on a lease has halted production, the lease is terminated, and the operator is obligated to decommission platforms and P&A wells within 12 months. Thus, wells that have not been P&Aed within one year after a lease becomes inactive are not in compliance with BSEE regulations.

Supermajor ownership

Some wellbores (that is, API-10) have multiple sidetracks (that is, API-12). In some cases, for a well with multiple sidetracks, some sidetracks were drilled after ownership was transferred from a supermajor to a smaller company. In these instances, some share of the P&A cost is allocated to prior supermajor ownership, while the residual is not. The share is calculated based on the share of measured depth from the wellbore beyond the sidetrack's kick-off point. In these instances, the API-10 for tabulating well counts is included in both categories.

Data availability

With the exception of data from Enverus, all data are publicly available via Harvard Dataverse (https://doi.org/10.7910/DVN/EE4SLR). Commercial Enverus data were made available to us through Enverus' academic programme.

Code availability

Replication code and data are available at Harvard Dataverse (https://doi.org/10.7910/DVN/EE4SLR).

References

1. *Statistical Review of World Energy* (BP, 2022).
2. Kaiser, M. J. & Pulsipher, A. G. *Idle Iron in the Gulf of Mexico* (US Department of the Interior, Minerals Management Service, 2007).
3. Muehlenbachs, L. A dynamic model of cleanup: estimating sunk costs in oil and gas production. *Int. Econ. Rev.* **56**, 155–185 (2015).
4. Alboiu, V. & Walker, T. R. Pollution, management, and mitigation of idle and orphaned oil and gas wells in Alberta, Canada. *Environ. Monit. Assess.* **191**, 611 (2019).
5. Ide, S. T., Friedmann, S. J. & Herzog, H. J. CO_2 leakage through existing wells: current technology and regulations. In *8th International Conference on Greenhouse Gas Control Technologies* 19–22 (International Energy Agency Greenhouse Gas R&D Programme, 2006).
6. Pekney, N. J. et al. Measurement of methane emissions from abandoned oil and gas wells in Hillman State Park, Pennsylvania. *Carbon Manage.* **9**, 165–175 (2018).
7. Finch, B. E., Marzooghi, S., Toro, D. M. D. & Stubblefield, W. A. Phototoxic potential of undispersed and dispersed fresh and weathered Macondo crude oils to Gulf of Mexico marine organisms. *Environ. Toxicol. Chem.* **36**, 2640–2650 (2017).
8. Stefansson, E. S. et al. Acute effects of non-weathered and weathered crude oil and dispersant associated with the Deepwater Horizon incident on the development of marine bivalve and echinoderm larvae. *Environ. Toxicol. Chem.* **35**, 2016–2028 (2016).
9. Faksness, L.-G., Altin, D., Nordtug, T., Daling, P. S. & Hansen, B. H. Chemical comparison and acute toxicity of water accommodated fraction (WAF) of source and field collected Macondo oils from the Deepwater Horizon spill. *Mar. Pollut. Bull.* **91**, 222–229 (2015).
10. Martínez-Gómez, C. et al. A guide to toxicity assessment and monitoring effects at lower levels of biological organization following marine oil spills in European waters. *ICES J. Mar. Sci.* **67**, 1105–1118 (2010).
11. Lin, Q. & Mendelssohn, I. A. Impacts and recovery of the Deepwater Horizon oil spill on vegetation structure and function of coastal salt marshes in the northern Gulf of Mexico. *Environ. Sci. Technol.* **46**, 3737–3743 (2012).
12. Esbaugh, A. J. et al. The effects of weathering and chemical dispersion on Deepwater Horizon crude oil toxicity to mahi-mahi (*Coryphaena hippurus*) early life stages. *Sci. Total Environ.* **543**, 644–651 (2016).
13. Heintz, R. A., Short, J. W. & Rice, S. D. Sensitivity of fish embryos to weathered crude oil: part II. Increased mortality of pink salmon (*Oncorhynchus gorbuscha*) embryos incubating downstream from weathered Exxon Valdez crude oil. *Environ. Toxicol. Chem.* **18**, 494–503 (1999).
14. Anderson, C. J. & Hess, T. A. The effects of oil exposure and weathering on black-needle rush (*Juncus roemerianus*) marshes along the Gulf of Mexico. *Mar. Pollut. Bull.* **64**, 2749–2755 (2012).
15. Pezeshki, S. R. & Delaune, R. D. United States Gulf of Mexico coastal marsh vegetation responses and sensitivities to oil spill: a review. *Environments* **2**, 586–607 (2015).
16. Mendelssohn, I. A. et al. Oil impacts on coastal wetlands: implications for the Mississippi River Delta ecosystem after the Deepwater Horizon oil spill. *BioScience* **62**, 562–574 (2012).
17. Valentine, D. L. et al. Fallout plume of submerged oil from Deepwater Horizon. *Proc. Natl Acad. Sci. USA* **111**, 15906–15911 (2014).

https://doi.org/10.1038/s41560-023-01248-1

18. Passow, U. & Stout, S. A. Character and sedimentation of "lingering" Macondo oil to the deep-sea after the Deepwater Horizon oil spill. *Mar. Chem.* **218**, 103733 (2020).
19. Montagna, P. A. et al. Deep-sea benthic footprint of the Deepwater Horizon blowout. *PLoS ONE* **8**, e70540 (2013).
20. White, H. K. et al. Impact of the Deepwater Horizon oil spill on a deep-water coral community in the Gulf of Mexico. *Proc. Natl Acad. Sci. USA* **109**, 20303–20308 (2012).
21. Joye, S. B., Teske, A. P. & Kostka, J. E. Microbial dynamics following the Macondo oil well blowout across Gulf of Mexico environments. *Bioscience* **64**, 766–777 (2014).
22. Crespo-Medina, M. et al. The rise and fall of methanotrophy following a deepwater oil-well blowout. *Nat. Geosci.* **7**, 423–427 (2014).
23. Römer, M. et al. Amount and fate of gas and oil discharged at 3,400 m water depth from a natural seep site in the southern Gulf of Mexico. *Front. Mar. Sci.* **6**, 700 (2019).
24. Valentine, D. L. et al. Propane respiration jump-starts microbial response to a deep oil spill. *Science* **330**, 208–211 (2010).
25. Negron, A. M. G., Kort, E. A., Conley, S. A. & Smith, M. L. Airborne assessment of methane emissions from offshore platforms in the U.S. Gulf of Mexico. *Environ. Sci. Technol.* **54**, 5112–5120 (2020).
26. Yacovitch, T. I., Daube, C. & Herndon, S. C. Methane emissions from offshore oil and gas platforms in the Gulf of Mexico. *Environ. Sci. Technol.* **54**, 3530–3538 (2020).
27. Ayasse, A. K. et al. Methane remote sensing and emission quantification of offshore shallow water oil and gas platforms in the Gulf of Mexico. *Environ. Res. Lett.* **17**, 084039 (2022).
28. Böttner, C. et al. Greenhouse gas emissions from marine decommissioned hydrocarbon wells: leakage detection, monitoring and mitigation strategies. *Int. J. Greenhouse Gas Control* **100**, 103119 (2020).
29. Kang, M. et al. Direct measurements of methane emissions from abandoned oil and gas wells in Pennsylvania. *Proc. Natl Acad. Sci. USA* **111**, 18173–18177 (2014).
30. Lebel, E. D. et al. Methane emissions from abandoned oil and gas wells in California. *Environ. Sci. Technol.* **54**, 14617–14626 (2020).
31. Williams, J. P., Regehr, A. & Kang, M. Methane emissions from abandoned oil and gas wells in Canada and the United States. *Environ. Sci. Technol.* **55**, 563–570 (2021).
32. Shavell, S. The judgment proof problem. *Int. Rev. Law Econ.* **6**, 45–58 (1986).
33. Boomhower, J. Drilling like there's no tomorrow: bankruptcy, insurance, and environmental risk. *Am. Econ. Rev.* **109**, 391–426 (2019).
34. Boyd, J. Financial responsibility for environmental obligations: are bonding and assurance rules fulfilling their promise? Preprint at *SSRN* https://doi.org/10.2139/ssrn.286914 (2001).
35. Davis, L. W. Bonding requirements for U.S. natural gas producers. *Rev. Environ. Econ. Policy* **9**, 128–144 (2015).
36. Gerard, D. The law and economics of reclamation bonds. *Resour. Policy* **26**, 189–197. (2000).
37. Shogren, J. F., Herriges, J. A. & Govindasamy, R. Limits to environmental bonds. *Ecol. Econ.* **8**, 109–133 (1993).
38. *Oil and Gas: Bureau of Land Management Should Address Risks from Insufficient Bonds to Reclaim Wells* (GAO, 2019).
39. Ho, J. S., Shih, J.-S., Muehlenbachs, L. A., Munnings, C. & Krupnick, A. J. Managing environmental liability: an evaluation of bonding requirements for oil and gas wells in the United States. *Environ. Sci. Technol.* **52**, 3908–3916. (2018).
40. Purpera, D. G. Performance Audit. Audit Control #40120061. *Office of Conservation, Department of Natural Resources Oil and Gas Regulation and Orphaned Wells* (Louisiana Legislative Auditor, 2014); https://app.lla.la.gov/PublicReports.nsf/D6A0EBE279B83B9F86257CE700506EAD/$FILE/000010BC.pdf
41. Raimi, D., Krupnick, A. J., Shah, J.-S. & Thompson, A. Decommissioning orphaned and abandoned oil and gas wells: new estimates and cost drivers. *Environ. Sci. Technol.* **55**, 10224–10230 (2021).
42. Isgur, M. *Fieldwood Energy LLC and The Official Committee of Unsecured Creditors*. Case No. 20-33948 (United States Bankruptcy Court for the Southern District of Texas, 2021).
43. *Idle and Orphan Oil and Gas Wells: State and Provincial Strategies* (IOGCC, 2019).
44. *Idle and Orphan Oil and Gas Wells: State and Provincial Strategies Supplemental Information* (IOGCC, 2020).
45. *Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies 2021* (IOGCC, 2021).
46. Raimi, D., Nerurkar, N. & Bordoff, J. *Green Stimulus for Oil and Gas Workers: Considering a Major Federal Effort to Plug Orphaned and Abandoned Wells* (Resources for the Future and Center for Energy Policy at Columbia University, 2020).
47. Kang, M. et al. Orphaned oil and gas well stimulus—maximizing economic and environmental benefits. *Elem. Sci. Anth.* **9**, 00161 (2021).
48. Boomhower, J. *Orphan Wells in California: An Initial Assessment of the State's Potential Liabilities to Plug and Decommission Orphan Oil and Gas Wells* (California Council on Science and Technology, 2018). https://ccst.us/wp-content/uploads/CCST-Orphan-Wells-in-California-An-Initial-Assessment.pdf
49. Andersen, M. & Coupal, R. Economic issues and policies affecting reclamation in Wyoming's oil and gas industry. *J. Am. Soc. Min. Reclam.* **2009**, 1–17 (2009).
50. Cook, K. A. *An "Inescapable Obligation"–The Treatment of Well Decommissioning Liability in Recent Oil and Gas Bankruptcies*. MSc thesis, Univ. of Texas at Austin (2019).
51. Dachis, B., Shaffer, B. & Thivierge, V. *All's Well That Ends Well: Addressing End-of-Life Liabilities for Oil and Gas Wells* (C.D. Howe Institute, 2017).
52. Gardner, G. *Inactive Oil and Gas Wells on Federal Lands and Minerals: Potential Costs and Conflicts* (The National Wildlife Federation and Public Land Solutions, 2021).
53. Kang, M. et al. Identification and characterization of high methane-emitting abandoned oil and gas wells. *Proc. Natl Acad. Sci. USA* **113**, 13636–13641 (2016).
54. Kang, M., Mauzerall, D. L., Ma, D. Z. & Celia, M. A. Reducing methane emissions from abandoned oil and gas wells: strategies and costs. *Energy Policy* **132**, 594–601 (2019).
55. CalGem *SB 1147 Report: Offshore Oil & Gas Operations Abandonment* (California Geologic Energy Management Division, 2022).
56. Braslow, L. D. Coastal petroleum's fight to drill off Florida's Gulf Coast. *J. Land Use Environ. Law* **12**, 343–381 (1997).
57. *Reporting Requirements for Decommissioning Expenditures on the OCS* (BSEE, 2016).
58. Kaiser, M. J. Rigless well abandonment remediation in the shallow water U.S. Gulf of Mexico. *J. Pet. Sci. Eng.* **151**, 94–115 (2017).
59. Moeinikia, F., Fjelde, K. K., Saasen, A. & Vrålstad, T. An investigation of different approaches for probabilistic cost and time estimation of rigless P&A in subsea multi-well campaign. In *SPE Bergen One Day Seminar* (OnePetro, 2014).
60. Moeinikia, F., Fjelde, K. K., Sørbø, J., Saasen, A. & Vrålstad, T. A study of possible solutions for cost efficient subsea well abandonment. In *ASME 2015 34th International Conference on Ocean, Offshore and Arctic Engineering* (American Society of Mechanical Engineers Digital Collection, 2015).
61. Øia, T. M., Aarlott, M. M. & Vrålstad, T. Innovative approaches for full subsea P&A create new opportunities and cost benefits. In *SPE Norway One Day Seminar* (OnePetro, 2018).
62. Vrålstad, T. et al. Plug & abandonment of offshore wells: ensuring long-term well integrity and cost-efficiency. *J. Pet. Sci. Eng.* **173**, 478–491 (2019).

https://doi.org/10.1038/s41560-023-01248-1

63. Bakker, S., Vrålstad, T. & Tomasgard, A. An optimization model for the planning of offshore plug and abandonment campaigns. *J. Pet. Sci. Eng.* **180**, 369–379 (2019).
64. Bakker, S. J., Wang, A. & Gounaris, C. E. Vehicle routing with endogenous learning: application to offshore plug and abandonment campaign planning. *Eur. J. Oper. Res.* **289**, 93–106 (2021).
65. Vreugdenhil, N. *Booms, Busts, and Mismatch in Capital Markets: Evidence from the Offshore Oil and Gas Industry* (2020). https://nvreug.github.io/paper/bbm.pdf
66. Kaiser, M. J. Offshore decommissioning cost estimation in the Gulf of Mexico. *J. Constr. Eng. Manage.* **132**, 249–258 (2006).
67. Kaplan, E. L. & Meier, P. Nonparametric estimation from incomplete observations. *J. Am. Stat. Assoc.* **53**, 457–481 (1958).

Acknowledgements
We thank the Center for Global Energy Policy at Columbia University for supporting this work.

Author contributions
M.A. and G.B.U. conceived the paper, analysed data and wrote the manuscript. B.S. wrote the manuscript. S.N. analysed data and wrote the manuscript.

Competing interests
The authors declare no competing interests.

Additional information
Supplementary information The online version contains supplementary material available at https://doi.org/10.1038/s41560-023-01248-1.

Correspondence and requests for materials should be addressed to Mark Agerton.

Peer review information *Nature Energy* thanks Steffen Bakker, Charles Mason, Daniel Raimi and the other, anonymous, reviewer(s) for their contribution to the peer review of this work.

Reprints and permissions information is available at www.nature.com/reprints.

Publisher's note Springer Nature remains neutral with regard to jurisdictional claims in published maps and institutional affiliations.

Protecting the Ocean and Taxpayers by Strengthening Standards for

OFFSHORE OIL AND GAS DECOMMISSIONING

Ocean Conservancy®

KEY TAKEAWAYS

- To protect the ocean, its ecosystems, and the communities that rely on them, a complete transition away from harmful fossil fuels is needed.
- This transition must include the responsible cleanup of all offshore oil and gas facilities, a process called decommissioning.
- Decommissioning requires permanently plugging offshore wells and properly dismantling and disposing of structures such as platforms, pipelines, and other equipment.
- The oil and gas industry is evading its obligation to decommission nonproductive offshore infrastructure, with more than 75% of idle or end-of-life oil wells and platforms in the Gulf of Mexico overdue for decommissioning as of June 2023.
- Idle infrastructure in the ocean is a growing risk to the environment and wildlife, and a growing risk to taxpayers if the government is forced to pay cleanup costs.
- The regulatory system that governs oil and gas decommissioning in U.S. federal waters is weak and lacks the oversight and enforcement tools needed to hold offshore oil and gas operators accountable.
- Targeted policy changes and better government oversight can ensure that oil and gas companies meet their obligation to promptly and properly clean up offshore facilities and equipment that have reached the end of their useful life.

Introduction

Climate change is the single most urgent and existential threat to the health of the ocean. Climate change is making the ocean hotter; increasing the acidity of its waters; decreasing seasonal sea ice; and contributing to destructive storms, sea level rise, and coastal erosion. These changes are taking a toll on marine life—from coral reefs in the tropics to marine mammals in the Arctic—as well as harming people who live and work in coastal communities.

To protect the ocean, its marine ecosystems, and the people who depend on them, we must address the root cause of climate change: fossil fuels. The combustion of fossil fuels is responsible for the overwhelming majority of human-caused greenhouse gas emissions in the atmosphere,[1] with the ocean absorbing about 90% of the heat caused by these emissions.[2] The is the world's top producer of one of these fossil fuels: oil.[3] Roughly 15% of U.S. oil production comes from offshore operations in federal waters,[4] and 97% of all federal offshore oil production comes from the Gulf of Mexico.[5]

To address climate change, it is time to transition away from harmful fossil fuels—including offshore oil—and toward renewable power from wind, solar, and other clean energy sources.

The transition away from harmful fossil fuels requires a comprehensive effort. To begin, the U.S. must stop new offshore oil and gas lease sales, because once a lease is sold and starts producing oil or gas, operations can endure for decades into the future. Additionally, the federal government must oversee a managed phaseout of the more than 12 million acres of existing federal offshore leases and must do away with subsidies that prop up the fossil fuel industry.

Finally, the federal government must oversee an effective cleanup of all end-of-life offshore facilities and equipment, a process known as decommissioning. The government must ensure that oil and gas operators decommission their offshore equipment in a thorough and responsible manner, and that they pay the full cost of doing so.

Presently, oversight and enforcement of offshore decommissioning in U.S. waters is weak, and oil companies often fail to meet their obligations to clean up their offshore infrastructure. Offshore oil and gas operators regularly leave unused oil wells unplugged, miss cleanup deadlines, and leave old pipelines on the bottom of the ocean. In some cases, offshore oil companies fall into financial trouble and are unable to cover the costs of decommissioning, leaving taxpayers to pay cleanup costs. Government regulators are complicit in these failures due to a combination of anemic oversight, poor enforcement, and inadequate regulatory tools. This dysfunctional cycle leaves oil and gas infrastructure in the ocean—often with limited maintenance—for too long, posing risks to the environment and people. To achieve a successful transition to clean ocean energy, we need to ensure that offshore oil operators are held accountable for cleaning up after themselves.

Ocean Conservancy supports a transition to 100% clean ocean energy by the year 2050. Now is the time to phase out risky and dirty offshore oil and gas drilling and replace it with responsibly developed clean, renewable energy. Making the transition to clean ocean energy will help protect the ocean and its ecosystems from many of the future impacts of climate change.

Ocean Conservancy is boldly leading efforts to change course on offshore oil and gas drilling and support clean ocean energy. Through targeted policy changes and better government oversight, we can ensure that oil and gas companies are held responsible for phasing out their offshore operations as we simultaneously ramp up responsible renewable energy.

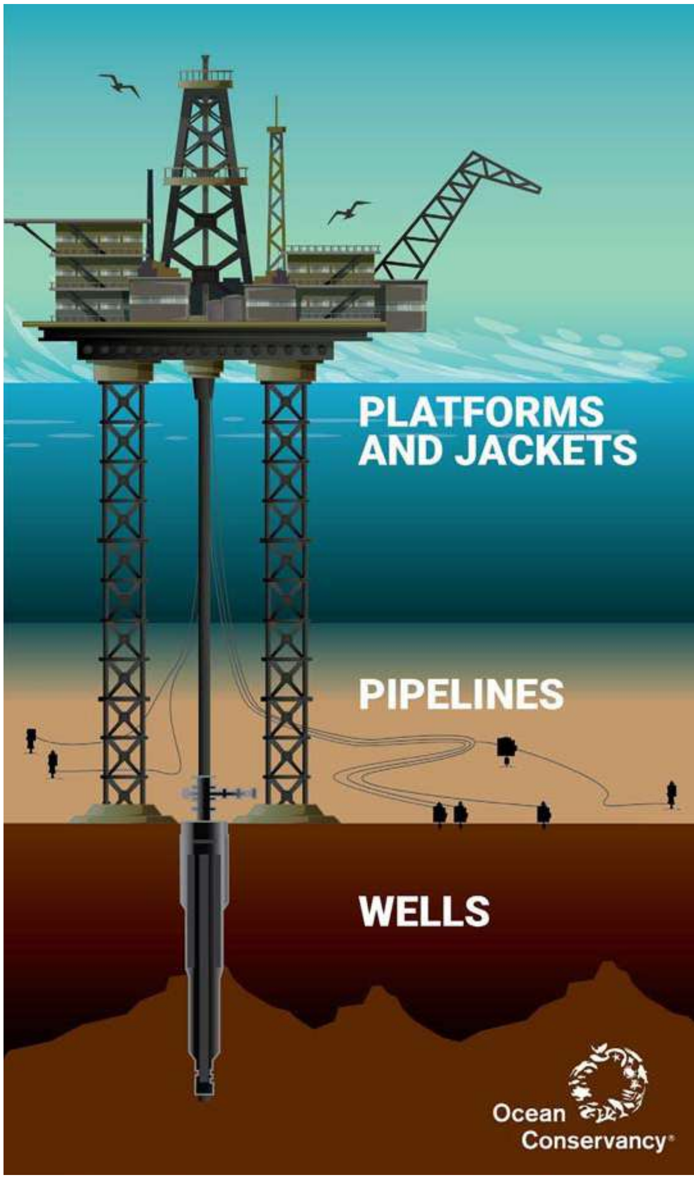
What is Decommissioning?

When offshore oil and gas infrastructure reaches the end of its productive life, operators must "decommission" that infrastructure. The decommissioning process includes permanently plugging offshore wells and properly dismantling and disposing of structures such as platforms, pipelines, and other equipment.[6] More specifically:

Platforms and Jackets: Offshore oil platforms consist of "topside" structures—the operational facilities located above the ocean's surface—as well as supporting substructures from the water's surface down to the seafloor.[7] In most cases, owners must remove platforms from the water at the end of their useful life.[8] In some cases, owners can obtain authorization to topple a platform's subsea supports or leave them partially in place for conversion to another use, such as an artificial reef.[9]

Pipelines: Subsea pipelines connect various production and processing facilities and carry oil, gas, and other products from one location to another. When a pipeline is no longer used for operations, it must be decommissioned.[12] Generally, regulations require owners to remove inactive pipelines from the ocean floor.[13] However, most operators take advantage of a regulatory exception that allows them to simply leave pipelines on the seafloor.[14]

Wells: Wells are holes that penetrate the seafloor and underlying geology, providing access to oil and gas deposits. Oil rigs can drill wells more than 10,000 feet below the surface of the ocean and to depths greater than 28,000 feet below the seafloor.[10] When these wells stop producing oil, companies must permanently seal them, usually with multiple cement barriers.[11]



Decommissioning is required by law. All oil and gas companies that acquire a federal lease on the Outer Continental Shelf (OCS) in U.S. waters take on an obligation to decommission any infrastructure they build or use on that lease, and to pay the cost of removing that infrastructure. Decommissioning liabilities are a type of "asset retirement obligation," and they are part of the legal agreement oil companies make with the federal government.[15]

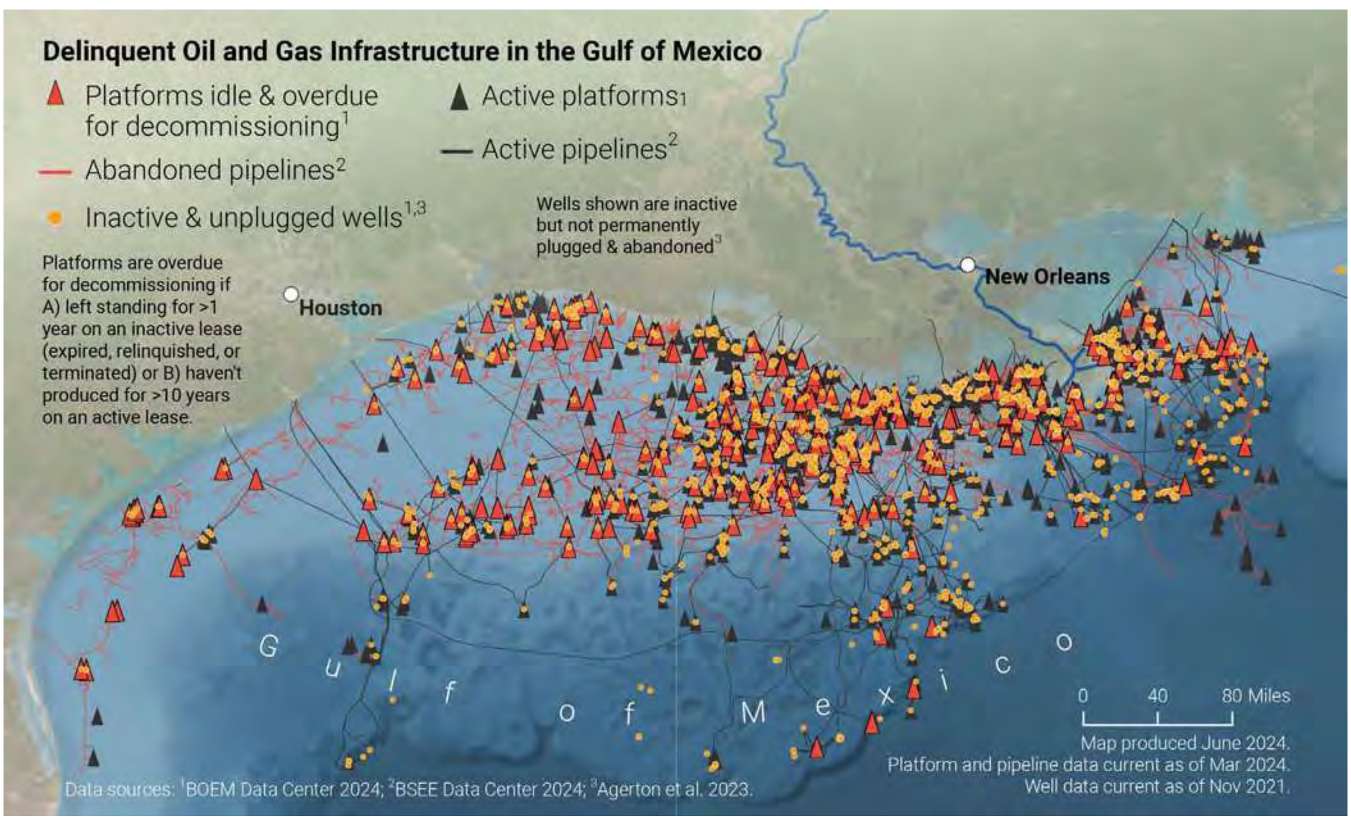
Offshore Decommissioning is a Growing and Expensive Issue in the Gulf of Mexico

While offshore oil and gas drilling has taken place in other regions of the United States, the Gulf of Mexico is home to the vast majority of U.S. offshore oil operations. Offshore oil production in the Gulf of Mexico dates back more than 80 years. In that time, operators have drilled more than 55,000 wells in the seafloor and have built more than 7,000 structures in the water.[16]

While many of the wells have been plugged and many of the structures have been removed over time, an enormous amount of unproductive infrastructure remains—and the backlog is likely to grow as offshore lessees continue to defer cleanup operations and miss decommissioning deadlines.

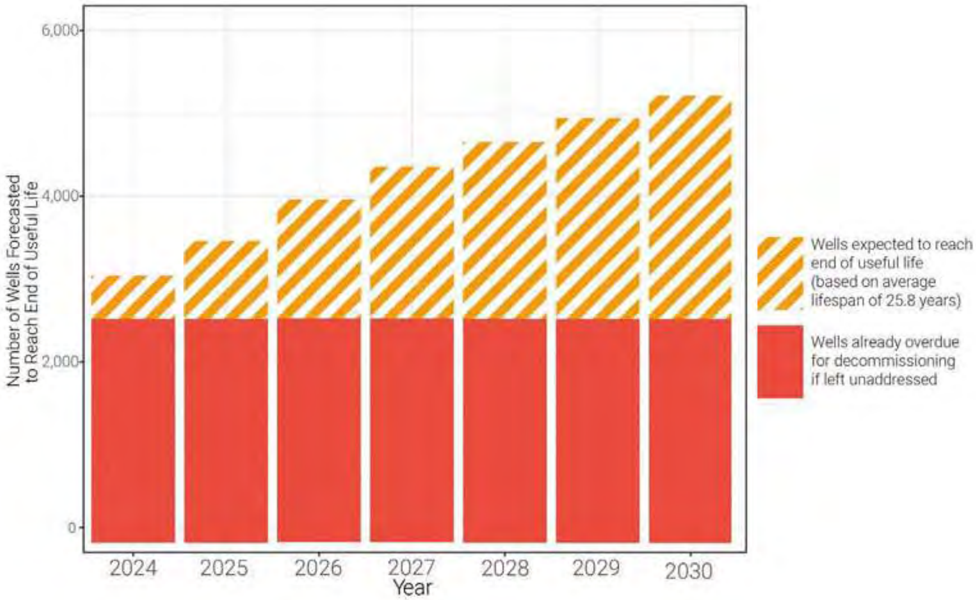
A 2024 report from the Governmental Accountability Office (GAO)—an independent, nonpartisan agency—found that as of June 2023, the federal waters of the Gulf of Mexico contained roughly 8,000 wells and about 1,600 oil and gas platforms. Of these, a total of about 2,700 wells and 500 platforms were overdue for decommissioning and considered delinquent (Figure 1).[17]

Figure 1



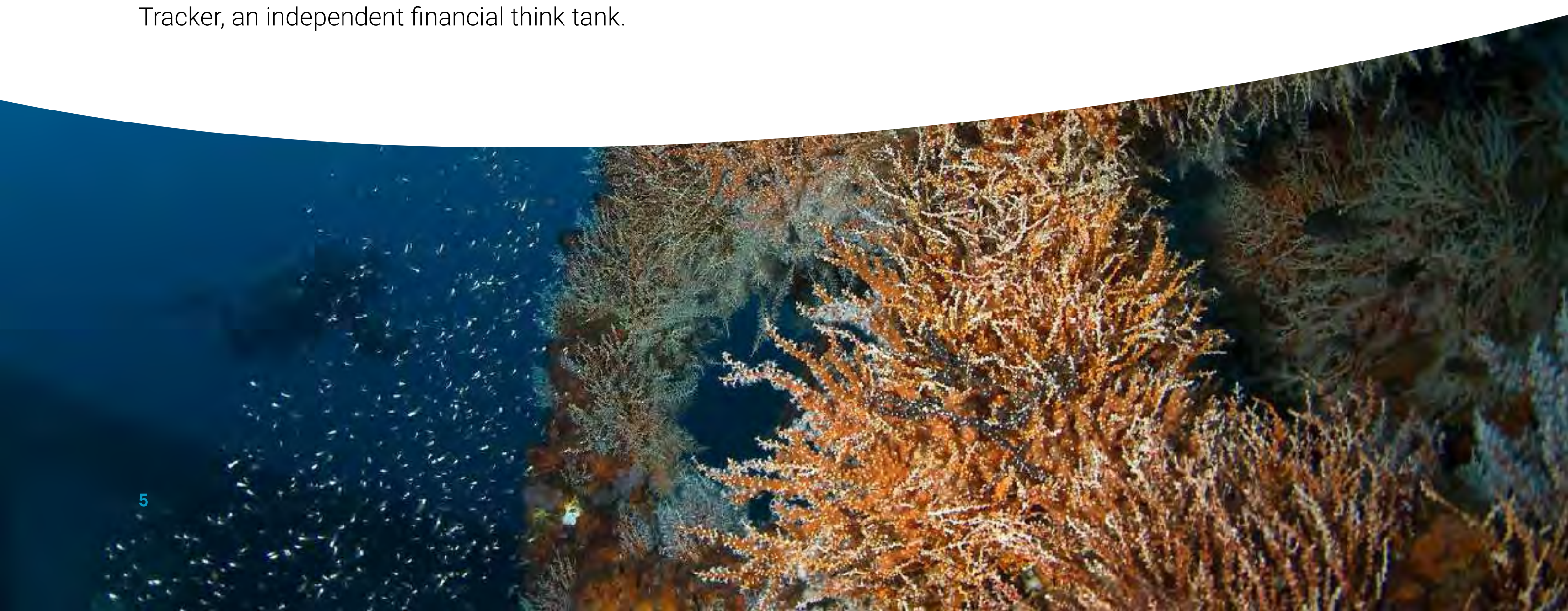
In addition to this backlog, the GAO found that almost half of the remaining active wells "are approaching or past the end of their useful life."[18] These numbers are expected to increase as the U.S. shifts to more renewable energy sources and as older, shallow-water wells continue to decline in productivity and profitability.[19] In fact, an Ocean Conservancy analysis found that if the challenges with decommissioning policy are not fixed and the backlog is not addressed, by 2030 the amount of overdue wells in need of decommissioning could nearly double, ballooning to more than 5,000 wells (Figure 2).[20]

Figure 2



Several analyses have been conducted to estimate the costs of decommissioning offshore oil infrastructure in the Gulf of Mexico. The GAO observed that the total decommissioning costs for all wells and platforms (both active and defunct) in federal waters would likely range from $40 billion to $70 billion.[21] A separate 2022 academic analysis estimated that it would cost more than $40 billion to decommission just the wells—not the platforms or pipelines—in federal waters in the Gulf of Mexico.[22]

Many oil wells in the Gulf of Mexico are located in the relatively shallow waters of the continental shelf. When production revenues from shallow water wells no longer exceed operating costs, the wells are usually abandoned, and the platforms are slated for removal or decommissioning.[23] Most of these shallow-water wells were initially developed years ago by large, well-resourced oil companies ("majors" or "supermajors"). However, many of the wells have since been sold to smaller independent operators who in turn may have sold the wells to even smaller companies.[24] As a result, older shallow-water wells and associated infrastructure are often owned by relatively small companies that lack the financial resources of major oil companies.[25] These shallow-water wells "are increasingly marginal in value, raising the risk that they will be abandoned by their current operators"[26] according to Carbon Tracker, an independent financial think tank.



Oil wells in deeper waters—greater than 1,000 feet of water—present their own challenges. While deepwater wells are generally newer than their shallow-water counterparts, they are also bigger, deeper, and more complex than shallow-water wells.[27] As a result, when these wells reach the end of their useful lives, they will be more costly to decommission than shallow-water wells. The average cost to decommission a deepwater well is $24 million, compared to $660,000 to decommission a shallow-water well in federal waters.[28] With more than 1,600 active deepwater wells in the Gulf of Mexico, decommissioning costs for these wells alone is projected to exceed $34 billion.[29] That does not include the cost of decommissioning deepwater platforms and other associated infrastructure.

The disposal of subsea pipelines is another piece of the decommissioning puzzle. Although federal rules generally require oil companies to remove pipelines from the seafloor, the rules contain an exception that allows companies to seek authorization to leave their pipelines on the seafloor if specific criteria are met. Oil and gas companies have taken full advantage of this exception. As of 2021, they had left nearly 18,000 miles of discarded pipeline sitting on the bottom of the ocean.[30] The cost to remove these pipelines has not been estimated, but is likely to have similar extremely high costs.

DECOMMISSIONING AS AN ECONOMIC OPPORTUNITY

While addressing offshore oil and gas decommissioning issues presents significant challenges, it also creates opportunities. As traditional oil and gas sector jobs decline,[31] decommissioning may offer job opportunities for displaced oil and gas workers and other skilled workers. A 2022 study estimated that decommissioning offshore wells in federal and state shallow waters of the Gulf of Mexico "would require 5,265 jobs per year … including direct workers, contractors, and suppliers" and more broadly would be associated with more than 10,500 jobs per year across the economy as a whole.[32] Another analysis that considered onshore as well as offshore oilfield work characterized decommissioning and pipeline removal—including offshore decommissioning—as an opportunity for "significant and long-term oil and gas related employment."[33]

Photo Credit: USGC

Increasing Risks From Failure to Decommission Offshore Oil and Gas Infrastructure

Aside from costs, failure to decommission offshore oil and gas infrastructure on time and in compliance with requirements poses safety, environmental, and financial risks.

SAFETY RISKS

When offshore oil structures are left idle and unused, the structures can degrade and become safety risks to employees and regulators who visit the site. Unmaintained materials and structures can deteriorate or fail, causing injury to personnel. For instance, workers or site inspectors can fall through eroded walkways or handrails.[34] Failure to maintain these structures can be so severe that they can restrict access to the structure's platform, requiring expensive repairs and contributing to additional delays in decommissioning operations.[35] Poorly maintained offshore oil platforms can pose a hazard to other ocean users, as well. For instance, if a platform lacks properly functioning lighting, it can become a navigational hazard to ships operating in the area.[36]

FINANCIAL RISKS

Decommissioning delays or noncompliance with decommissioning requirements can signal or create financial risks to the U.S. government and taxpayers. When an offshore oil operator fails to meet decommissioning deadlines, it can be a sign that the operator will not or cannot meet its financial obligations and that the government, via taxpayer dollars, may have to pay for decommissioning.[37]

From 2009 to January 2024, 37 offshore oil and gas operators filed for bankruptcy, including some operators with billions of dollars in decommissioning liabilities.[38] Some bankruptcies have "resulted in companies being unable to cover their decommissioning liabilities, leading to orphaned wells and idle infrastructure."[39] When a current lease-holder is unwilling or unable to pay decommissioning costs, federal regulators can, under a system known as "joint and several liability,"[40] require any or all co-owners or previous lease-holders to pay the decommissioning costs for that infrastructure.[41] For big oil companies with operations in the Gulf of Mexico, these "contingent liabilities" could amount to two to six times the amount of their direct decommissioning liabilities.[42] Oil companies often do not report these contingent liabilities on their balance sheets.[43]

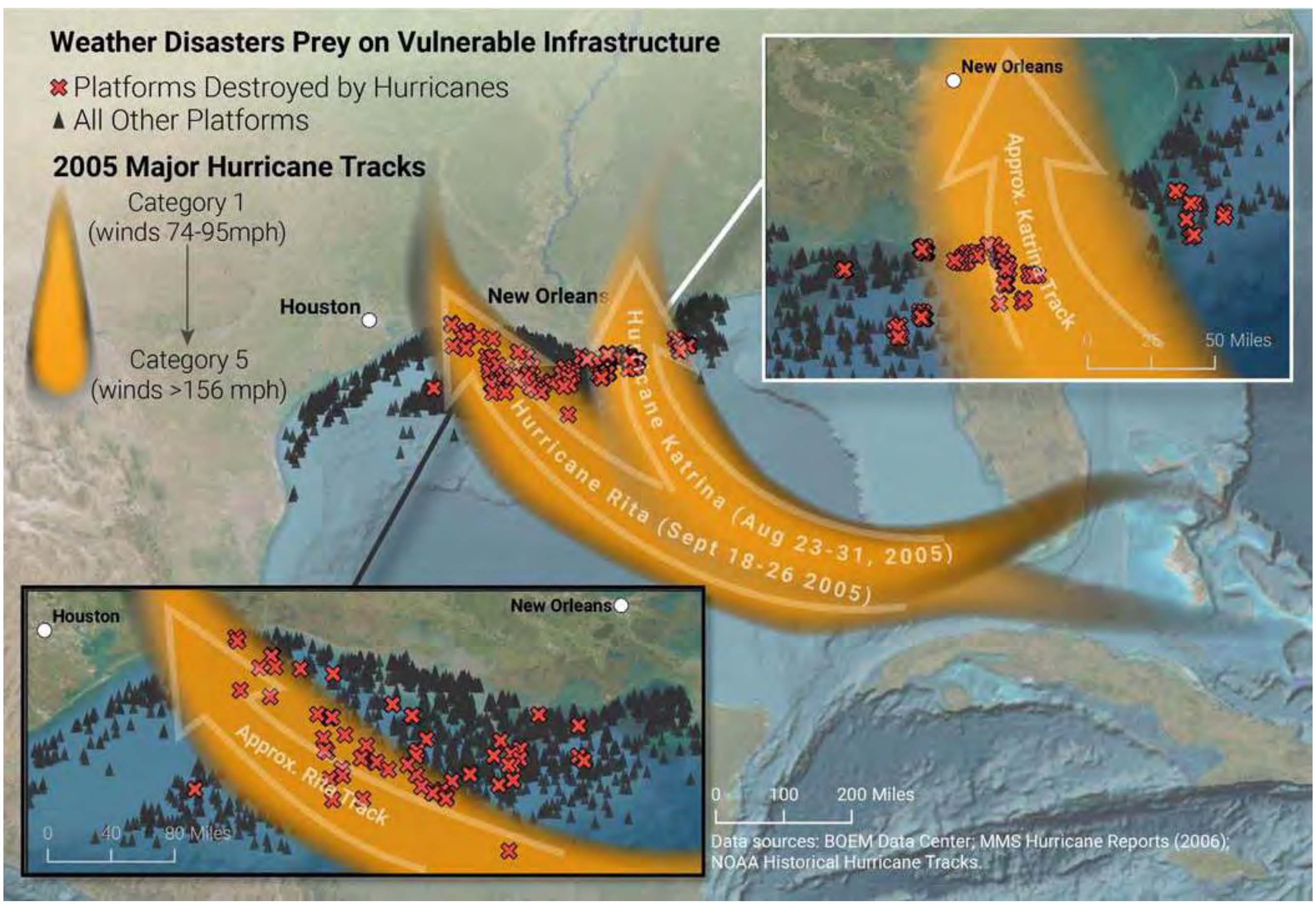
So far, most post-bankruptcy decommissioning liabilities in federal waters have been met by co-owners, previous owners, or new owners. But in some instances, the government has had to use taxpayer dollars to pay the costs of cleaning up after delinquent oil companies.[44] This could be a sign of things to come, and federal regulators have warned that "previously low losses to the government are not a reliable indicator for future losses."[45] Some observers have voiced concern and doubt about the strength of federal "joint and several liability" regulations and the government's ability to force previous lease-holders to pay decommissioning costs as more offshore oil and gas facilities reach the end of their productive lives.[46]

ENVIRONMENTAL RISKS

Idle oil and gas infrastructure in the Gulf of Mexico can become a source of pollution. Unmaintained structures are vulnerable to deterioration and decay that can cause tanks or pipelines to fail, leading to oil spills.[47] Platforms can release corroded metal into the water, causing chronic pollution.[48] Offshore wells that are unplugged or improperly plugged can also become a source of pollution.[49] Methane emitted from temporarily abandoned platforms or leaky shallow-water wells could be significant sources of greenhouse gas emissions.[50]

Deteriorated idle infrastructure can be weaker than active, maintained platforms, making them more vulnerable to hurricanes and other major weather events, which have been increasing in frequency and intensity due to climate change.[51] The Gulf of Mexico is subject to powerful hurricanes that can destroy equipment such as oil storage tanks, move subsea pipelines, or even topple entire platforms.[52] Any of these events can trigger oil spills, either directly from the damaged equipment or via impacts to connecting or adjacent facilities.[53] For example, in 2021, Hurricane Ida damaged active as well as abandoned oil and gas infrastructure.[54] In the wake of the storm, oil slicks appeared on the water and the Coast Guard evaluated more than 1,500 pollution reports.[55] Similarly, in 2005, hurricanes Katrina and Rita destroyed 113 offshore platforms, damaged more than 450 pipelines, and led to six oil spills, each of 1,000 barrels or more.[56] In 2004, a Gulf of Mexico hurricane triggered a subsea mudslide that destroyed an active oil production platform and initiated the ongoing 2004 Taylor Energy oil spill, which to date is the longest-running oil spill in U.S. history.[57] While oil spills from idle or unused oil and gas infrastructure are unlikely to discharge high volumes of material, even small amounts of oil are toxic to marine organisms—from plankton to marine mammals—and can cause adverse impacts to their health or their ability to reproduce.[58]

Figure 3



Regulation, Oversight and Enforcement of Decommissioning are Weak and Ineffective

The federal government oversees decommissioning of oil and gas facilities on the OCS, but federal oversight and enforcement are plagued by widespread and substantial shortcomings.

FAILURE TO ENFORCE DECOMMISSIONING DEADLINES FOR WELLS AND PLATFORMS LOCATED ON EXPIRED LEASES

Once a federal offshore oil and gas lease has expired (or has been relinquished or terminated), the lease-holder or operator has one year to decommission any wells and platforms on that lease.[59] Even though offshore oil operators know of this regulatory mandate from the moment they sign a lease, a recent GAO analysis that considered Gulf of Mexico leases that ended between 2010 to 2022 found that offshore operators failed to meet the one-year deadline for more than 40% of wells and more than 50% of platforms.[60]

The GAO also found operator noncompliance with decommissioning deadlines has accumulated over time to create a substantial backlog. As of June 2023, "more than 1,700 end-of-lease wells and nearly 400 end-of-lease platforms in the Gulf of Mexico were overdue for decommissioning" and considered delinquent.[61] The backlog of overdue infrastructure accounts for 75% of all end-of-lease wells and platforms due for decommissioning.[62] Of the 1,700 delinquent wells, the GAO found that more than 700 had not even been temporarily plugged to prevent leaks.[63]

The federal agency tasked with overseeing end-of-lease decommissioning—the Bureau of Safety and Environmental Enforcement (BSEE)—has been ineffective at enforcing compliance from operators. When an operator misses a decommissioning deadline for end-of-lease infrastructure, BSEE may issue a citation to the operator.[64] Unfortunately, operators largely ignore these citations.[65] In theory, BSEE can employ tougher sanctions against noncompliant owners and operators, such as imposing civil penalties, ordering operators to suspend operations, or disqualifying operators.[66] In practice, the agency rarely pursues these penalties.[67] BSEE's reluctance to impose sanctions stems in part from government concerns that compelling compliance with mandatory decommissioning deadlines will force operators into bankruptcy.[68]

Additionally, BSEE's decommissioning regulations for wells are incomplete and inadequate. They contain no requirement for operators to monitor and report on the structural integrity of well plugs over time. In the absence of ongoing monitoring and reporting requirements, there is little chance that BSEE will be effective in discovering leaking wells or ordering lessees to go back and re-plug wells whose plugs have deteriorated.

LACK OF REGULATIONS AND WEAK GUIDANCE FOR IDLE WELLS AND PLATFORMS LOCATED ON ACTIVE LEASES

In addition to the mandate to decommission offshore oil and gas infrastructure on *expired* leases, operators are also required to decommission equipment located on *active* leases when that equipment is "no longer useful for operations."[69] However, BSEE has neither developed nor issued formal rules to establish deadlines and parameters for decommissioning idle wells and platforms on active offshore oil and gas leases.[70]

Presently, BSEE relies on a guidance document called a "Notice to Lessees," or "NTL." The NTL sets forth deadlines by which operators should decommission infrastructure on active leases, but the NTL is not a formal agency regulation.[71] BSEE itself has expressed concern about its ability to enforce any deadlines on active leases, given that the deadlines in the NTL are not codified in regulation.[72] A 2019 report from the Department of the Interior's Office of Inspector General noted a concern by BSEE managers that enforcing decommissioning regulations on active leases would push operators into bankruptcy.[73] The report stated that BSEE's Gulf of Mexico staff "did not believe that BSEE had the authority to enforce decommissioning regulations" despite BSEE's role as an enforcement agency.[74]

Even if BSEE's Gulf of Mexico staff had full faith in their enforcement authority and pursued that authority rigorously, the decommissioning deadlines set forth in BSEE's guidance document are unacceptably weak. For instance, BSEE does not consider a platform on an active lease to be "no longer useful for operations" until the structure has been sitting unused for five years.[75] After that, an operator has up to an additional five years to decommission the platform.[76] In total, a platform on an active lease can be idle for 10 years before it becomes overdue for decommissioning under existing BSEE guidance. The guidance governing decommissioning for wells on active leases is also ineffective. A well on an active lease can be idle for eight years before it becomes overdue for decommissioning.[77]

BSEE has been unwilling or unable to enforce operators to comply with even these generous deadlines. On active leases in the Gulf of Mexico, more than 1,000 idle wells and more than 100 idle platforms were overdue for decommissioning and considered delinquent as of June 2023.[78] More than 800 of those wells had not produced oil in at least ten years, and nearly 600 had not even been temporarily plugged.[79]

Some operators avoid decommissioning requirements and costs by asserting that their idle equipment may be valuable for future use, a loophole allowed under BSEE guidance.[80] However, research has shown, that "[i]n federal waters, after five years of no reported production, inactive wells have less than a 4% chance of re-entering production in the future."[81]

GAPS AND LOOPHOLES IN REGULATIONS GOVERNING DECOMMISSIONING OF SUBSEA PIPELINES

Under current BSEE regulations, subsea pipelines that are no longer in use are considered "obstructions."[82] The general requirements for pipeline decommissioning require operators to "clear the seafloor of all obstructions."[83] However, the regulations contain an exception: if BSEE staff determine a pipeline will not interfere with other uses and will not have adverse environmental impacts, operators may "decommission a pipeline in place"—i.e., clear the inside of the pipeline, secure its ends, and leave it on the seafloor.[84]

This exception has grown to swallow the rule. In a 2021 report, the GAO found that BSEE had allowed offshore lessees and operators to leave more than 97% of disused pipelines on the ocean floor.[85] As of 2021, the GAO calculated that operators had left nearly 18,000 miles of disused pipeline at the bottom of the Gulf of Mexico.[86] Given that BSEE has not changed its regulations or practices since that report, this number has likely grown.[87]

If a decommissioned-in-place pipeline eventually becomes an obstruction, BSEE can—in theory—require the removal of that pipeline.[88] However, there is no funding mandate for removal, and BSEE's efforts to require pipeline removal in these cases have been "largely unsuccessful."[89]

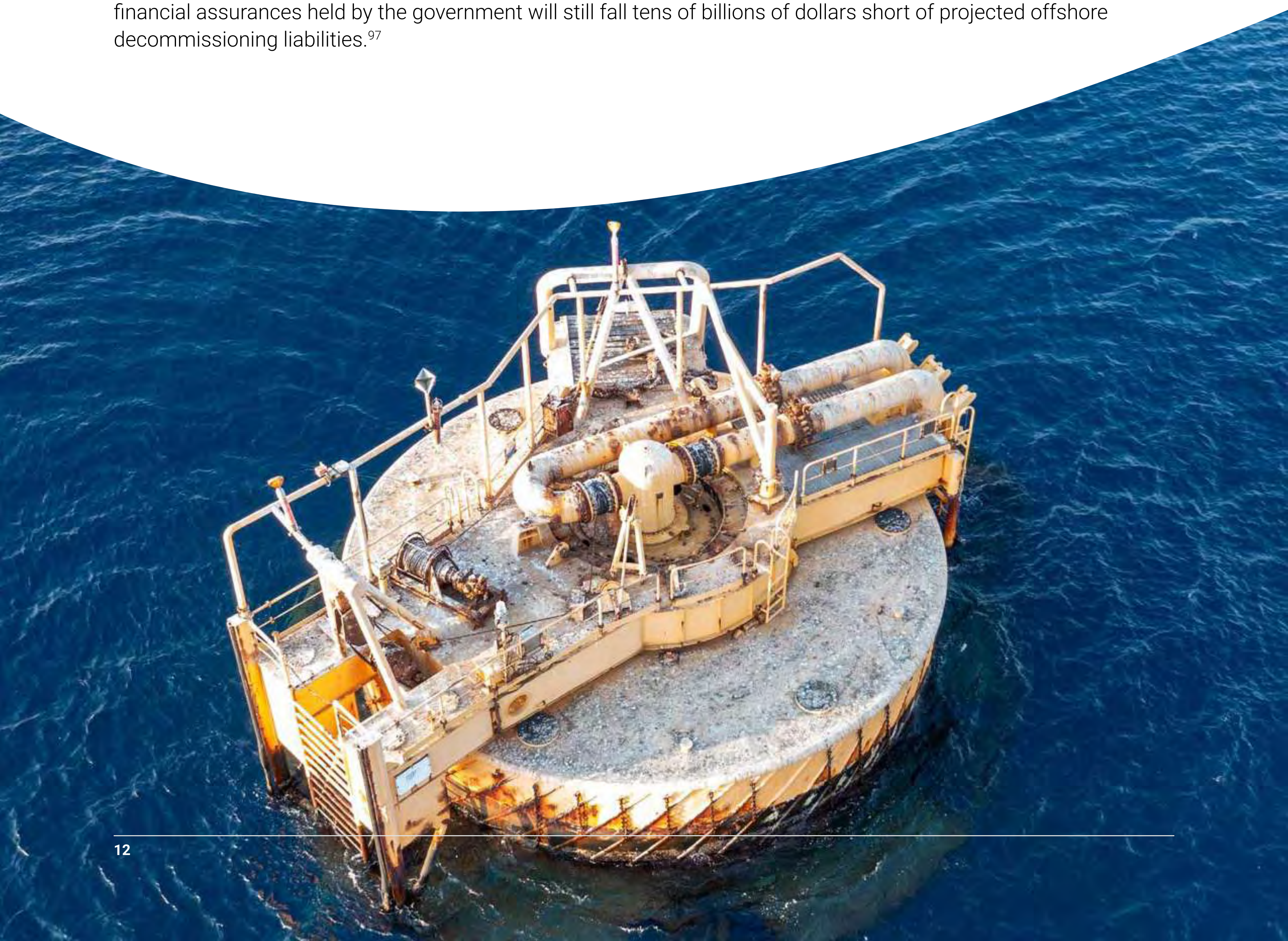
In addition to the regulatory exception that allows oil companies to leave discarded pipelines on the seafloor, BSEE's pipeline decommissioning regulations suffer from other flaws, as well. For instance, existing regulations do not specify any deadlines by which operators must complete the pipeline decommissioning process. Nor do regulations require operators to verify that decommissioned pipeline sites are clear of obstructions (something that is required when decommissioning wells and platforms).[90] Similarly, BSEE regulations do not require operators to monitor and report on decommissioned-in-place pipelines, nor does BSEE itself monitor decommissioned-in-place pipelines.[91] Given BSEE's minimal oversight and enforcement of pipeline decommissioning requirements, there is little data on the extent to which the industry is complying with—or flouting—agency regulations on subsea pipeline decommissioning.[92]

ONGOING WEAKNESS IN REGULATIONS GOVERNING SUPPLEMENTAL FINANCIAL ASSURANCE

BSEE is not the only federal agency with regulatory authority over the decommissioning of offshore oil and gas facilities. The Bureau of Ocean Energy Management (BOEM) is, among other duties, responsible for ensuring oil and gas companies that obtain leases have the financial capacity to meet their decommissioning obligations. Under this authority, BOEM requires OCS oil and gas lessees to provide "supplemental financial assurance" to ensure they can faithfully cover the cost of decommissioning their offshore infrastructure.

In practice, BOEM waives supplemental financial assurance requirements when lease owners pass a financial strength test. As a result, the GAO found that as of June 2023, federal regulators "had collected supplemental bonds to cover less than 9% of estimated decommissioning costs," or about $3.5 billion, despite $40 billion to $70 billion in predicted decommissioning costs.[93] If offshore oil and gas lessees are unable or unwilling to meet their decommissioning obligations—which is a real risk, given the significant gap between the total amount held in bonds and the total expected decommissioning costs—the U.S. government could be left to foot the bill. In fact, this scenario is already unfolding. In fiscal year 2024, BSEE requested $30 million from Congress to decommission orphaned offshore infrastructure in the Gulf of Mexico.[94] In other words, U.S. taxpayers are paying to clean up after offshore oil and gas operators.

In 2024, BOEM finalized an updated rule intended to strengthen supplemental financial assurance requirements.[95] BOEM estimates that the new rule will require offshore operators to provide a total of an additional $6.9 billion in supplemental financial assurance.[96] However, even under the new rule, many offshore oil and gas companies are still exempt from the requirement to provide supplemental financial assurance, which means that supplemental financial assurances held by the government will still fall tens of billions of dollars short of projected offshore decommissioning liabilities.[97]



INADEQUATE OR NONEXISTENT QUALIFICATION STANDARDS FOR OFFSHORE OPERATORS

Federal regulations allow BOEM and BSEE to disqualify from future operations offshore oil and gas companies whose performance—including their decommissioning performance—is unacceptable.[98] However, the agencies do not actively exercise this authority. In a 2021 report, the Department of the Interior admitted that "companies with poor environmental, safety, or reclamation histories are still allowed to bid for [offshore oil and gas] leases or acquire them from other companies."[99] The 2024 GAO report reached a similar conclusion, confirming that BOEM and BSEE have never disqualified an operator solely because it failed to meet its decommissioning obligations.[100]

Even if regulators did disqualify an offshore lessee for failure to meet decommissioning obligations, an operator could simply requalify because existing regulations astoundingly do not allow the government to deny a new qualification "regardless of the operator's performance history."[101]

In 2021, the Department of the Interior claimed that BOEM would address these shortcomings by the agency developing a "fitness to operate" standard that would "establish criteria that companies would need to meet in order to operate on the U.S. OCS."[102] More recently, BOEM officials told the GAO that BOEM and BSEE were coordinating to develop new "operator fitness criteria."[103] However, in its 2024 report, the GAO observed that the effort has yielded "limited progress," in part due to "uncertainty about how to develop and operationalize such criteria."[104] As a result, operators with poor performance records—including those who flout decommissioning requirements—can continue to hold their existing OCS leases and even obtain new ones.[105]

LACK OF TRANSPARENCY ON DECOMMISSIONING ACTIVITIES

One broader concern about the decommissioning of offshore oil and gas infrastructure relates to transparency and public accountability. To its credit, BSEE maintains an "Offshore Infrastructure Dashboard" online intended to provide user-friendly basic information about oil platforms and other structures in federal waters.[106] BOEM and BSEE also maintain a full data center that allows users to download and independently aggregate information on federal offshore leases, wells, platforms, and pipelines.[107] While these resources provide access to valuable information about decommissioning operations, they do not present the whole picture. The dashboard, for instance, only provides data about platforms and structures; the dashboard does not provide data about offshore wells or pipelines. While the data center provides public access to a broader suite of information, the data's complexity combined with incomplete explanations of terminology hinder many from being able to use it. Similarly, the agencies provide only limited information on offshore enforcement actions via either the dashboard or the data center.[108] Overall, the lack of easily accessible information makes it difficult for the public to monitor offshore oil and gas decommissioning and enforcement activities.

Policy Recommendations

The system that governs the decommissioning of oil and gas infrastructure in federal waters creates risks to the ocean and U.S. taxpayers. This system is leading to a growing backlog of disused wells and platforms and a Gulf of Mexico seafloor littered with thousands of miles of discarded pipelines. Government enforcement efforts are feeble and regulatory tools are weak.

Going forward, this already-failing system will come under even more strain. Offshore decommissioning activity will need to grow to keep pace as an increasing number of shallow-water wells reach the end of their productive lives. Additionally, as the climate crisis accelerates the transition toward renewable energy and away from fossil fuels, offshore oil and gas operators will need to shift their focus—and their finances—from drilling and production to the responsible cleanup of thousands of wells and platforms.

Addressing the challenges associated with offshore oil and gas decommissioning with targeted policy changes can set the stage for success in the long-term. Ocean Conservancy recommends the following actions:

Strengthen oversight and enforcement for the decommissioning of wells and platforms located on expired, terminated, or relinquished leases: Working in conjunction with operators that have a backlog of offshore facilities that are past-due for decommissioning, BSEE should develop mandatory decommissioning plans. Under those plans, operators should be required to clear their decommissioning backlog within a set timeframe (e.g., five years). At the same time, BSEE must more effectively enforce decommissioning deadlines moving forward for offshore wells and platforms located on expired, terminated, or relinquished leases. Because the agency's use of citations has proven ineffective, BSEE must increase its use of more severe sanctions, including civil penalties, suspensions of operations, operator disqualifications, and closing the loophole on requalification. To the extent that there is uncertainty about the enforceability of BSEE sanctions, the agency should issue clarifying guidance or—if necessary—promulgate new or revised regulations. Ultimately, BSEE must ensure it has viable and effective methods to force operator compliance with decommissioning deadlines. BSEE should also update its regulations to require operators to monitor and report on the integrity of decommissioned wells to ensure the ongoing structural integrity of well plugs.

All of the above will require a substantial increase in BSEE staff time and resources dedicated to decommissioning, which Congress should fund through the annual appropriations process. Finally, BSEE should not allow concerns about possible financial impacts to operators to impede its enforcement of decommissioning deadlines. If offshore oil companies are in such a precarious financial position that they cannot meet their mandatory decommissioning obligations, they have no business operating in federal waters. The failure to enforce decommissioning deadlines now will only exacerbate the problem.

Strengthen oversight and enforcement for the decommissioning of idle wells and platforms located on active leases: BSEE's deadlines for decommissioning idle wells and platforms located on active leases exist only in policy guidance, not in regulation. BSEE should promulgate regulations to codify its decommissioning deadlines for infrastructure on active leases. While doing so, BSEE should shorten the deadlines to ensure idle wells and platforms are cleaned up promptly. For instance, BSEE should consider any well and platform that has been inactive for two years to be "no longer useful for operations." After that, BSEE should require lessees to decommission those wells and platforms within one year, just as it does for infrastructure on expired leases. In addition, BSEE should be much more restrictive in granting decommissioning waivers for potential future use of wells or platforms; BSEE must not allow operators to defer decommissioning costs based on the pretense of future use. In cases where BSEE does grant a future use waiver, the agency should require operators to provide supplemental financial assurance that will cover the full cost of decommissioning. As noted above, BSEE should increase its use of sanctions such as civil penalties, suspensions, and disqualifications to compel compliance with decommissioning deadlines.

Strengthen decommissioning requirements for subsea pipelines: BSEE should revise its regulations to remove or substantially restrict existing language that allows the agency to approve "decommissioning in place" for subsea pipelines. When a pipeline no longer serves a useful purpose, BSEE should require its owner to remove it from the seabed. The agency should permit decommissioning in place only in rare circumstances. In those rare cases, BSEE should require operators to monitor the condition and location of the pipeline over time to ensure it remains secure, and the agency also should require operators to pay a fee to offset the ongoing impact of the discarded pipeline.

BSEE should also make greater use of its regulatory authority to require the removal of previously discarded pipeline that constitutes an obstruction, especially when the discarded pipeline interferes with alternative ocean uses or poses a hazard. In addition, BSEE should develop and codify stringent deadlines for pipeline decommissioning to ensure operators remove disused pipeline in a timely fashion. These deadlines could be congruent with new and more stringent deadlines for well and platform decommissioning recommended above. BSEE should also require operators to perform site clearance activities for pipelines, just as it does for wells, platforms, and other facilities. In addition, BSEE should step up its observation, inspection, and verification of pipeline decommissioning so that the agency is not as reliant on self-reporting by operators.

Strengthen requirements for supplemental financial assurance: BOEM, as of April 2024, updated and strengthened its regulations on supplemental financial assurance. If the agency revisits these regulations, it should do away with financial strength thresholds, via its financial strength test, and instead require all lessees or operators to provide supplemental financial assurance in an amount sufficient to cover the full cost of decommissioning.[109] BOEM should also consider implementing a system that would require each lessee to establish a dedicated account, into which the lessee would invest funds sufficient to satisfy estimated decommissioning obligations.[110] Under such a system, if a lessee made an upfront payment in the full amount, the lessee could forego any bonding requirements. Otherwise, a lessee would make regular payments into the dedicated decommissioning account while also providing a bond sufficient to cover the difference between the amount in the dedicated account and the estimated decommissioning costs. In the event of a default, BSEE would receive the funds in the decommissioning account. Otherwise, the funds would be available to the lessee to pay decommissioning costs when lease operations conclude. Ultimately, BOEM should do everything in its power to reduce U.S. taxpayer exposure to decommissioning liabilities. Taxpayers should never have to pay to clean up the messes made by offshore oil companies.

Develop and implement enforceable qualification standards of offshore operators: BOEM and BSEE should move forward with their plans to establish "fitness to operate" standards that ensure lessees and operators are qualified to conduct business on federal offshore oil and gas leases. These standards should consider past compliance with federal regulations, agency guidance, and lease and permit terms—including those that concern safety, environmental protection, decommissioning, and site reclamation. Qualification standards should also consider the financial health of lessees and operators. BOEM and BSEE should undertake a formal rulemaking process to codify fitness to operate standards and ensure the standards are enforceable. In doing so, the agencies must ensure they can disqualify existing or potential lessees or operators that fail to meet fitness to operate standards.

Remedy the lack of transparency with respect to decommissioning data: BOEM and BSEE should increase their commitments to transparency and data sharing with respect to offshore oil and gas decommissioning operations. In general, BOEM and BSEE should strive to make publicly available data as accessible and understandable as possible. To that end, BSEE should expand its existing "Offshore Infrastructure Dashboard" to incorporate information about wells and pipelines, including details on status and ownership. The dashboard could also add more details about the disposition of structures, including the reuse of platforms (such as how they are being reused, and by whom) and rigs-to-reefs status (including whether structures been left in place or removed to a designated area). In addition, the dashboard could disclose estimated and final costs for decommissioning activities. Ideally, BSEE's dashboard would also allow users to download aggregate information that could be tracked over time. BOEM's data center offers some of these capabilities but is difficult to use. BOEM could advance transparency and public access to data by improving the user-friendliness of the data center, including by offering more extensive explanations of the terminology it uses to describe OCS oil and gas operations. BOEM and BSEE should also expand the dashboard and data center to include expanded information about civil penalties, as well as other agency enforcement actions such as information on citations, incidents or notices of noncompliance, suspensions, and disqualifications.

Photo Credit: Cheryl Gerber

Photo Credit: Gabriel Barathieu

Consider opportunities for congressional action: The previous policy recommendations focus on solutions that can be implemented by executive branch agencies, such as BSEE and BOEM. However, it is also possible for Congress to pass legislation to strengthen government oversight and enforcement of offshore oil and gas decommissioning activities.

For example, the GAO has suggested that Congress "consider implementing an oversight mechanism—such as requiring annual reporting on the status of decommissioning enforcement efforts and associated liabilities."[111] In July 2024, U.S. Representatives Katie Porter and Tim Kennedy followed up on the GAO's suggestion by introducing the Plug Offshore Wells Act (POW Act), which would require a yearly "public report on the decommissioning of offshore oil and gas wells, platforms, and pipelines."[112]

In addition, Congress could also go further and pass legislation mandating any of the policy solutions discussed above. For instance, Congress could pass legislation to:

- Require shorter decommissioning deadlines for idle wells and platforms on active leases;
- Prohibit the use of decommissioning-in-place for subsea pipelines;
- Create stronger enforcement mechanisms to compel operator compliance with decommissioning regulations; and
- Create more stringent supplemental financial assurance requirements than the regulations that BOEM finalized in 2024.

Congress can also pass legislation to achieve outcomes that are arguably beyond the existing authority of administrative agencies. It could, for example, create a trust fund to pay for the decommissioning of orphaned wells and infrastructure, paid for by fees imposed on oil and gas operators. Congress could also set up programs to facilitate job training for offshore oil and gas workers who are interested in transitioning to offshore decommissioning work or work on offshore renewable energy projects.

Conclusion

To protect the ocean, marine ecosystems, and the people who depend on them, we must address the root cause of climate change. This means we must phase out fossil fuels—including dirty and dangerous offshore oil and gas operations—as part of a responsible, rapid, and just transition to 100% clean ocean energy.

Proper and timely decommissioning of offshore wells, platforms, and pipelines is a critical part of the energy transition, but the existing regulatory system is not working. If the energy transition is going to be successful, we must act now to improve government oversight and enforcement, strengthen policy and regulations, and ensure offshore oil and gas operators are held accountable for cleaning up the equipment they use to develop and produce oil and gas.

To learn more about this and other clean ocean energy solutions, visit cleanoceanenergy.org.

Report Author: Andrew Hartsig
With Contributions From: Anna-Marie Laura, Ben Sullender, Elizabeth Greener

REFERENCES

1 U.S. Energy Information Administration. (2024, June 18). *Energy and the environment explained: Where greenhouse gases come from.* Retrieved June 18, 2024 from https://www.eia.gov/energyexplained/energy-and-the-environment/where-greenhouse-gases-come-from.php

2 National Oceanic and Atmospheric Administration. (2023, September 6). *Climate change: Ocean heat content.* Retrieved from https://www.climate.gov/news-features/understanding-climate/climate-change-ocean-heat-content

3 U.S. Energy Information Administration. (2024, March 11). *In-Brief analysis: United States produces more crude oil than any country, ever.* Retrieved from https://www.eia.gov/todayinenergy/detail.php?id=61545

4 Bureau of Ocean Energy Management. (n.d.). *Oil and gas energy: Facilitating the responsible development of oil and gas resources on the OCS.* Retrieved from https://www.boem.gov/oil-and-gas-energy

5 Bureau of Ocean Energy Management. (n.d.). *Oil and gas - Gulf of Mexico.* Retrieved from https://www.boem.gov/regions/gulf-mexico-ocs-region/oil-and-gas-gulf-mexico

6 See, e.g., What do the terms "decommissioning," "obstructions," "facility," and "predecessor" mean in this subpart?, 30 C.F.R. § 250.1700 (2024). https://www.ecfr.gov/current/title-30/section-250.1700; What are the general requirements for decommissioning?, (2024). 30 C.F.R. § 250.1703 https://www.ecfr.gov/current/title-30/section-250.1703

7 Bureau of Safety and Environmental Enforcement. (n.d.). *Decommissioning*. Retrieved from https://www.bsee.gov/decommissioning

8 *What are the general requirements for decommissioning*?, 30 C.F.R. § 250.1703(c) (2024). https://www.ecfr.gov/current/title-30/section-250.1703; *When do I have to remove platforms and other facilities?*, 30 C.F.R. § 250.1725(a) (2024). https://www.ecfr.gov/current/title-30/section-250.1725

9 *When do I have to remove platforms and other facilities?,* 30 C.F.R. § § 250.1725(a) (2024). https://www.ecfr.gov/current/title-30/section-250.1725; *What are the general requirements for decommissioning?*, 30 C.F.R. § 250.1730 (2024). https://www.ecfr.gov/current/title-30/section-250.1703

10 Institute for Energy Research. (2020, September 21). History of U.S. offshore oil drilling. Retrieved from https://www.instituteforenergyresearch.org/fossil-fuels/gas-and-oil/history-of-u-s-offshore-oil-drilling/

11 *What are the general requirements for decommissioning?*, 30 C.F.R. § 250.1703(b). https://www.ecfr.gov/current/title-30/section-250.1703 (2024).

12 *What are the general requirements for decommissioning?*, 30 C.F.R. § § 250.1703(d) (2024). https://www.ecfr.gov/current/title-30/section-250.1703

13 *What are the general requirements for decommissioning?*, 30 C.F.R. § § 250.1703(e) (2024). https://www.ecfr.gov/current/title-30/section-250.1703; *What do the terms "decommissioning," "obstructions," "facility," and "predecessor" mean in this subpart?*, 30 C.F.R. § § 250.1700(b) (2024). https://www.ecfr.gov/current/title-30/section-250.1700

14 *When may I decommission a pipeline in place?*, 30 C.F.R. § § 250.1750 (2024). https://www.ecfr.gov/current/title-30/section-250.1750; *How do I decommission a pipeline in place?*, 30 C.F.R. § 250.1751 (2024). https://www.ecfr.gov/current/title-30/section-250.1751

15 See, e.g., Publish What You Pay – United States. (2023 June). *Publish your plans: The disclosures needed to support a managed decline of oil and gas production and an informed energy transition* (p. 22, describing asset retirement obligations). Retrieved from https://pwyp.org/wp-content/uploads/2023/09/PWYP-US-PYP-HANDBOOK_SHORT.pdf

16 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 1). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

17 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (pp. 14 (expired) & 19 (idle)). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

18 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 1). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdfId.

19 In a 2019 report, federal regulators characterized the shallow-water portion of the U.S. Gulf of Mexico as a province "in sharp decline." Bureau of Safety and Environmental Enforcement and Bureau of Ocean Energy Management. (2019, November 19). *Information/briefing report: Gulf of Mexico data and analysis/leasing, drilling and production, Gulf of Mexico shallow water potential stranded assets* (p. 1).

20 Historically, shallow-water wells (<200m) have had an average useful life of 25.8 years (from spud date to abandonment). Assuming active wells last 25.8 years, an additional 2,511 wells would reach the end of their useful lives by 2030 (shown in hatching). According to the 2024 GAO report, more than 2,700 wells are already overdue for decommissioning (shown in solid).

21 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 26). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

22 Agerton, M., Narra, S., Snyder, B., & Upton, Jr., G. B. (2023, May 8). *Financial liabilities and environmental implications of unplugged wells for Gulf of Mexico and coastal waters.* Nature Energy 8, 536–547. Retrieved from https://www.nature.com/articles/s41560-023-01248-1

23 Bureau of Safety and Environmental Enforcement and Bureau of Ocean Energy Management. (2019, November 19). *Information/briefing report: Gulf of Mexico data and analysis/leasing, drilling and production, Gulf of Mexico shallow water potential stranded assets* (p. 5).

24 Bureau of Safety and Environmental Enforcement and Bureau of Ocean Energy Management. (2019, November 19). *Information/briefing report: Gulf of Mexico data and analysis/leasing, drilling and production, Gulf of Mexico shallow water potential stranded assets* (p. 4) (describing historical transition of Gulf of Mexico assets from majors to independents to smaller companies).

25 Bureau of Safety and Environmental Enforcement and Bureau of Ocean Energy Management. (2019, November 19). *Information/briefing report: Gulf of Mexico data and analysis/leasing, drilling and production, Gulf of Mexico shallow water potential stranded assets* (p. 5, Figure 1). (lease ownership map showing "non-major" oil companies holding most shallow-water leases in the Gulf of Mexico). Retrieved from https://www.bsee.gov/sites/default/files/reports//shallow-water-report-01.pdf

26 Carbon Tracker Initiative. (2022, June 9). *Double or nothing: How regulators are gambling on the future self-interest of large oil and gas companies to decommission the Gulf of Mexico's aging infrastructure* (p. 8). Retrieved from https://carbontracker.org/reports/double-or-nothingId.

27 Agerton, M., Narra, S., Snyder, B., & Upton, Jr., G. B. (2023, May 8). *Financial liabilities and environmental implications of unplugged wells for Gulf of Mexico and coastal waters.* Nature Energy 8, 536–547. Retrieved from https://www.nature.com/articles/s41560-023-01248-1 (p. 537).

28 Agerton, M., Narra, S., Snyder, B., & Upton, Jr., G. B. (2023, May 8). *Financial liabilities and environmental implications of unplugged wells for Gulf of Mexico and coastal waters.* Nature Energy 8, 536–547. Retrieved from https://www.nature.com/articles/s41560-023-01248-1 (p. 540).

29 Agerton, M., Narra, S., Snyder, B., & Upton, Jr., G. B. (2023, May 8). *Financial liabilities and environmental implications of unplugged wells for Gulf of Mexico and coastal waters.* Nature Energy 8, 536–547. Retrieved from https://www.nature.com/articles/s41560-023-01248-1

30 Government Accountability Office. (2021, March 19). *Offshore oil and gas, Updated regulations needed to improve pipeline oversight and decommissioning* (p. 12). Retrieved from https://www.gao.gov/products/gao-21-293

31 See, e.g., Biven, M. M. & Lindner, L. (2023, March). *The future of energy & work in the United States: The American oil & gas worker survey.* True Transition, (p. 4, noting the oil and gas industry had fired more than 118,000 American oil and gas workers by 2020 and had let go more than a quarter of the total workforce between 2025 and 2019). Retrieved from https://www.truetransition.org/research-reports

32 Agerton, Narra, S., Snyder, B., & Upton, Jr., G. B. (2022, April 18). *Considering a federal program to permanently plug and abandon offshore oil and gas wells*, Center on Global Energy Policy at Columbia University's School of International and Public Affairs (p. 27). Retrieved from https://www.energypolicy.columbia.edu/publications/considering-federal-program-permanently-plug-and-abandon-offshore-oil-and-gas-wells/

33 Biven, M. M. & Lindner, L. (2023, March). *The future of energy & work in the United States: The American oil & gas worker survey.* True Transition, (p. 62).

34 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 8). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

35 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 8). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

36 35Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related* risks (p. 8). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

37 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 10). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

38 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p.27). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

39 Department of the Interior. (2021, November) *Report on the federal oil and Gas Leasing Program: Prepared in response to executive order 14008* (p. 11. Retrieved from https://www.doi.gov/sites/doi.gov/files/report-on-the-federal-oil-and-gas-leasing-program-doi-eo-14008.pdf

40 See *Who is responsible for fulfilling leasehold obligations?*, 30 C.F.R. § 250.146 (2024). https://www.ecfr.gov/current/title-30/section-250.146 and *Who must meet the decommissioning obligations in this subpart?* (2024). https://www.ecfr.gov/current/title-30/section-250.1701; *What are my rights and obligations as a record title owner?* 30 C.F.R § 556.604 (2024) https://www.ecfr.gov/current/title-30/section-556.604

41 Carbon Tracker Initiative. (2022, June 9). *Double or nothing: How regulators are gambling on the future self-interest of large oil and gas companies to decommission the Gulf of Mexico's aging infrastructure* (p. 8). Retrieved from https://carbontracker.org/reports/double-or-nothing/

42 Carbon Tracker Initiative. (2022, June 9). *Double or nothing: How regulators are gambling on the future self-interest of large oil and gas companies to decommission the Gulf of Mexico's aging infrastructure* (p. 8). Retrieved from https://carbontracker.org/reports/double-or-nothing

43 Carbon Tracker Initiative. (2022, June 9). *Double or nothing: How regulators are gambling on the future self-interest of large oil and gas companies to decommission the Gulf of Mexico's aging infrastructure* (p. 8). Retrieved from https://carbontracker.org/reports/double-or-nothing

44 See, e.g., Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks*, at 27, note 56 (describing Congressional allocation of funds to support decommissioning services for 15 orphaned wells and nine orphaned platforms in the Gulf of Mexico). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

45 Bureau of Ocean Energy Management. (2024, April 24). *Risk management and financial assurance for OCS lease and grant obligations*, 89 Fed. Reg. 31,544, 31,548. Retrieved from https://www.federalregister.gov/documents/2024/04/24/2024-08309/risk-management-and-financial-assurance-for-ocs-lease-and-grant-obligations

46 See, e.g., Carbon Tracker Initiative. (2022, June 9). *Double or nothing: How regulators are gambling on the future self-interest of large oil and gas companies to decommission the Gulf of Mexico's aging infrastructure* (p. 9, noting that in the future, parent companies may no longer be willing to pay decommissioning liabilities incurred by subsidiaries). Retrieved from https://carbontracker.org/reports/double-or-nothing); see also Richards, H. (2024, April 12). Why Interior could get stuck with the tab for cleaning up oil platforms. Energywire, (noting challenges to federal regulations and uncertainties about whether courts will uphold those regulations).

47 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 9). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

48 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 9). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

49 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (pp. 9-10). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

50 Agerton, M., Narra, S., Snyder, B., & Upton, Jr., G. B. (2023, May 8). *Financial liabilities and environmental implications of unplugged wells for Gulf of Mexico and coastal waters. Nature Energy* 8, 536–547 (p. 537). Retrieved from https://www.nature.com/articles/s41560-023-01248-1

51 See, e.g., Pacific Northwest National Laboratory (2023, April 7). *More frequent hurricanes raise risk to U.S. east and gulf coasts* [Press release]. (noting that warming waters can "both strengthen and push hurricanes to the U.S. East and Gulf coasts more often, boosting hurricane frequency by a third compared to current levels"). Retrieved from https://www.pnnl.gov/news-media/more-frequent-hurricanes-raise-risk-us-east-and-gulf-coasts

52 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 9). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdfId

53 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 9). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

54 National Aeronautics and Space Administration Earth Observatory. (2021, September 3) *Hurricane Ida leaves a trail of oil.* Retrieved from https://earthobservatory.nasa.gov/images/148820/hurricane-ida-leaves-a-trail-of-oil

55 National Aeronautics and Space Administration Earth Observatory. (2021, September 3) *Hurricane Ida leaves a trail of oil.* Retrieved from https://earthobservatory.nasa.gov/images/148820/hurricane-ida-leaves-a-trail-of-oil

56 Minerals Management Service. (2006, May 1). *MMS updates hurricanes Katrina and Rita damage.* Retrieved from https://www.boem.gov/sites/default/files/boem-newsroom/Press-Releases/2006/press0501.pdf

57 U.S. Fish and Wildlife Service. (2022, April 26). *Settlement reached on Taylor Energy 0il spill—the largest oil spill you never heard of* (April 26, 2022), available at https://www.doi.gov/restoration/settlement-reached-taylor-energy-oil-spill-largest-oil-spill-you-never-heard

58 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 9). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

59 See When must I permanently plug all wells on a lease?, 30 C.F.R. § 250.1710 (2024). https://www.ecfr.gov/current/title-30/section-250.1710 ; When do I have to remove platforms and other facilities??, 30 C.F.R. § 250.1725 (2024).https://www.ecfr.gov/current/title-30/section-250.1725

60 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p.13). Retrieved from https://www.gao.gov/products/gao-24-106229 OR https://www.gao.gov/assets/gao-24-106229.pdf

61 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 14). Retrieved from https://www.gao.gov/products/gao-24-106229 OR https://www.gao.gov/assets/gao-24-106229.pdf

62 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* at 14. Retrieved from https://www.gao.gov/products/gao-24-106229 OR https://www.gao.gov/assets/gao-24-106229.pdf

63 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 14). Retrieved from https://www.gao.gov/products/gao-24-106229 OR https://www.gao.gov/assets/gao-24-106229.pdf

64 *How will BSEE enforce accrued decommissioning obligations against predecessors?*, 30 C.F.R. § 250.1708(b) (2024.) https://www.ecfr.gov/current/title-30/section-250.1708

65 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 16, noting owners of delinquent wells and platforms failed to decommission even though they had received citations for roughly 94% of wells and 96% of platforms). Retrieved from https://www.gao.gov/products/gao-24-106229 OR https://www.gao.gov/assets/gao-24-106229.pdf

66 *How will BSEE enforce accrued decommissioning obligations against predecessors?*, 30 C.F.R. § 250.1708(b).) (2024.) https://www.ecfr.gov/current/title-30/section-250.1708; see also When may the Regional Supervisor direct an SOO or SOP?, 30 C.F.R. § 250.173(a), (2024). https://www.ecfr.gov/current/title-30/section-250.173

67 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (pp. 17-18). Retrieved from https://www.gao.gov/products/gao-24-106229 OR https://www.gao.gov/assets/gao-24-106229.pdf

68 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (pp. 17-18). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

69 *What are the general requirements for decommissioning?*, 30 C.F.R. § 250.1703 (2024). https://www.ecfr.gov/current/title-30/section-250.1703; See also *When will BSEE order me to permanently plug a well?,* 30 C.F.R. § 250.1711 (2024). https://www.ecfr.gov/current/title-30/section-250.1711

70 U.S. Department of the Interior, Bureau of Safety and Environmental Enforcement. (2018, December 11). *NTL No. 2018-G03: Notice to lessees and operators of federal oil and gas leases and pipeline right-of-way holders in the outer continental shelf, Gulf of Mexico OCS region: Idle iron decommissioning guidance for wells and platforms* (p. 2, (noting that agency "regulations do not expressly prescribe the time frame for decommissioning idle wells and platforms when no longer useful for operations"). Retrieved from https://www.bsee.gov/sites/bsee.gov/files/notices-to-lessees-ntl/ntl-2018-g03.pdf

71 U.S. Department of the Interior, Bureau of Safety and Environmental Enforcement. (2018, December 11). *NTL No. 2018-G03: Notice to lessees and operators of federal oil and gas leases and pipeline right-of-way holders in the outer continental shelf, Gulf of Mexico OCS region: Idle iron decommissioning guidance for wells and platforms.* This guidance document applies only to the Gulf of Mexico OCS Region.

72 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 20). Retrieved from https://www.gao.gov/products/gao-24-106229 OR https://www.gao.gov/assets/gao-24-106229.pdf

73 Department of the Interior, Office of Inspector General. (2019, March 26). *Closeout memorandum—The Bureau of Safety and Environmental Enforcement's decommissioning program*, assignment No. 2016-EAU-063 (p. 1). Retrieved from https://www.oversight.gov/sites/default/files/oig-reports/CloseoutMemo_BSEEDecomissioning_032619.pdf

74 Department of the Interior, Office of Inspector General. (2019, March 26). *Closeout memorandum—The Bureau of Safety and Environmental Enforcement's decommissioning program*, assignment No. 2016-EAU-063 (p. 1). Retrieved from https://www.oversight.gov/sites/default/files/oig-reports/CloseoutMemo_BSEEDecomissioning_032619.pdf

75 U.S. Department of the Interior, Bureau of Safety and Environmental Enforcement. (2018, December 11). *NTL No. 2018-G03: Notice to lessees and operators of federal oil and gas leases and pipeline right-of-way holders in the outer continental shelf, Gulf of Mexico OCS region: Idle iron decommissioning guidance for wells and platforms* (p. 2).The guidance also provides that platforms on active leases are "no longer useful for operations" if they have been toppled or otherwise destroyed.

76 U.S. Department of the Interior, Bureau of Safety and Environmental Enforcement. (2018, December 11). *NTL No. 2018-G03: Notice to lessees and operators of federal oil and gas leases and pipeline right-of-way holders in the outer continental shelf, Gulf of Mexico OCS region: Idle iron decommissioning guidance for wells and platforms* (p. 4).

77 U.S. Department of the Interior, Bureau of Safety and Environmental Enforcement. (2018, December 11). *NTL No. 2018-G03: Notice to lessees and operators of federal oil and gas leases and pipeline right-of-way holders in the outer continental shelf, Gulf of Mexico OCS region: Idle iron decommissioning guidance for wells and platforms* (pp. 2–3, providing that wells on active leases can be idle for five years before they are considered "no longer useful for operations," and allowing up to an addition three years for decommissioning).

78 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 19). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

79 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 19). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

80 See, e.g., *When do I have to remove platforms and other facilities?*, 30 C.F.R. § 250.1725(a) (2024.) https://www.ecfr.gov/current/title-30/section-250.1725; see also Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 19, note 41, observing that the Bureau of Safety and Environmental Enforcement granted "potential future use" exceptions for about 60 wells and 30 platforms). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

81 Agerton, M., Narra, S., Snyder, B., & Upton, Jr., G. B. (2023, May 8). *Financial liabilities and environmental implications of unplugged wells for Gulf of Mexico and coastal waters*. Nature Energy 8, 536–547. Retrieved from https://www.nature.com/articles/s41560-023-01248-1 (p. 542).

82 *What do the terms "decommissioning," "obstructions," "facility," and "predecessor" mean in this subpart?*, 30 C.F.R. § 250.1700(b) (2004). https://www.ecfr.gov/current/title-30/section-250.1700

83 *What are the general requirements for decommissioning?*, 30 C.F.R. § 250.1703(e) (2024). https://www.ecfr.gov/current/title-30/section-250.1703

84 *When may I decommission a pipeline in place?*, 30 C.F.R. § 250.1750 (2024). https://www.ecfr.gov/current/title-30/section-250.1750

85 Government Accountability Office. (2021, March 19). *Offshore oil and gas, Updated regulations needed to improve pipeline oversight and decommissioning* (p.12). Retrieved from https://www.gao.gov/products/gao-21-293

86 Government Accountability Office. (2021, March 19). *Offshore oil and gas, Updated regulations needed to improve pipeline oversight and decommissioning* (p.12). Retrieved from https://www.gao.gov/products/gao-21-293

87 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 1). Retrieved from https://www.gao.gov/assets/gao-24-106229.pdf

88 *When must I remove a pipeline decommissioned in place?*, 30 C.F.R. § 250.1754 (2024). https://www.ecfr.gov/current/title-30/section-250.1754

89 Government Accountability Office. (2021, March 19). *Offshore oil and gas, Updated regulations needed to improve pipeline oversight and decommissioning* (pp. 21-22). Retrieved from https://www.gao.gov/products/gao-21-293

90 Government Accountability Office. (2021, March 19). *Offshore oil and gas, Updated regulations needed to improve pipeline oversight and decommissioning* (p. 20). Retrieved from https://www.gao.gov/products/gao-21-2932021

91 Government Accountability Office. (2021, March 19). *Offshore oil and gas, Updated regulations needed to improve pipeline oversight and decommissioning* (p. 21). Retrieved from https://www.gao.gov/products/gao-21-2932021

92 Government Accountability Office. (2021, March 19). *Offshore oil and gas, Updated regulations needed to improve pipeline oversight and decommissioning* (p. 19). Retrieved from https://www.gao.gov/products/gao-21-2932021

93 Government Accountability Office. (2021, March 19). *Offshore oil and gas, Updated regulations needed to improve pipeline oversight and decommissioning* (p. 26). Retrieved from https://www.gao.gov/products/gao-21-2932021

94 Government Accountability Office. (2021, March 19). *Offshore oil and gas, Updated regulations needed to improve pipeline oversight and decommissioning* (p. 27, note 56). Retrieved from https://www.gao.gov/products/gao-21-2932021

95 Ocean Energy Management Bureau. (2024, April 24). *Risk Management and Financial Assurance for OCS Lease and Grant Obligations*, 89 Fed. Reg. 31,544. Retrieved from https://www.federalregister.gov/documents/2024/04/24/2024-08309/risk-management-and-financial-assurance-for-ocs-lease-and-grant-obligations

96 Ocean Energy Management Bureau, . (2024, April 24). *Risk Management and Financial Assurance for OCS Lease and Grant Obligations*, 89 Fed. Reg. 31,544 (Apr. 24, 2024). Retrieved from https://www.federalregister.gov/documents/2024/04/24/2024-08309/risk-management-and-financial-assurance-for-ocs-lease-and-grant-obligations

97 Ocean Energy Management Bureau, . (2024, April 24). *Risk Management and Financial Assurance for OCS Lease and Grant Obligations*, 89 Fed. Reg. 31,545 (noting lessees will not have to provide supplemental financial assurance if they meet certain conditions); and 89 Fed. Reg. 31,548 (noting that waiving supplemental bond requirements has resulted in a coverage gap of nearly $40 billion). Retrieved from https://www.federalregister.gov/documents/2024/04/24/2024-08309/risk-management-and-financial-assurance-for-ocs-lease-and-grant-obligations

98 *How will BSEE enforce accrued decommissioning obligations against predecessors?*, 30 C.F.R. § 250.1708(b(2024). https://www.ecfr.gov/current/title-30/section-250.1708; *What will BSEE do if my operating performance is unacceptable?*, 250.135 (2024). https://www.ecfr.gov/current/title-30/section-250.135; *How will BSEE determine if my operating performance is unacceptable?*, 30 C.F.R. §§ 250.136 (2024). https://www.ecfr.gov/current/title-30/section-250.136; *What will BOEM do if my operating performance is unacceptable?*, 30 C.F.R. § 550.135 (2024). https://www.ecfr.gov/current/title-30/section-550.135and *How will BOEM determine if my performance is unacceptable?*. 30 C.F.R. § 550.136 (2024). https://www.ecfr.gov/current/title-30/section-550.136

99 Department of the Interior. (2021, November). *Report on the federal oil and gas leasing program: Prepared in response to executive order 14008* (p. 12). Retrieved from https://www.doi.gov/sites/doi.gov/files/report-on-the-federal-oil-and-gas-leasing-program-doi-eo-14008.pdf

100 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 31). Retrieved from https://www.gao.gov/products/gao-24-106229 OR https://www.gao.gov/assets/gao-24-106229.pdf

101 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 31). Retrieved from https://www.gao.gov/products/gao-24-106229 OR https://www.gao.gov/assets/gao-24-106229.pdf2024 GAO Report at 31.

102 Department of the Interior (2021, November). *Report on the federal oil and gas leasing program: Prepared in response to executive order 14008* (p. 12). Retrieved from https://www.doi.gov/sites/doi.gov/files/report-on-the-federal-oil-and-gas-leasing-program-doi-eo-14008.pdf

103 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 32). Retrieved from https://www.gao.gov/products/gao-24-106229 OR https://www.gao.gov/assets/gao-24-106229.pdf

104 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 32). Retrieved from https://www.gao.gov/products/gao-24-106229 OR https://www.gao.gov/assets/gao-24-106229.pdf

105 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 33). Retrieved from https://www.gao.gov/products/gao-24-106229 OR https://www.gao.gov/assets/gao-24-106229.pdf2024 GAO Report at 32.

106 Bureau of Safety and Environmental Enforcement. (n.d.). *Offshore Infrastructure Dashboard. Retrieved from https://www.bsee.gov/offshore-infrastructure-dashboard* (describing the dashboard as a "tool to identify oil and gas platforms eligible for the Rigs-to-Reefs program").

107 See *Bureau of Ocean Energy Management.* (n.d.). BOEM Data Center. Retrieved from https://www.data.boem.gov

108 The Bureau of Safety and Environmental Enforcement's website provides some access to information about civil penalties. See *Bureau of Safety and Environmental Enforcement*. (n.d.). Civil Penalties Program. Retrieved from https://www.bsee.gov/what-we-do/safety-enforcement/civil-penalties-program These publicly available data could be expanded upon and included in the agencies' dashboard or data center.

109 The Bureau of Ocean Energy Management should also strengthen the supplemental financial assurance requirements by using the Bureau of Safety and Environmental Enforcement's P90 cost probabilities instead of its P70 probabilities.

110 For a more robust description of this recommendation, see Biven, M. M. (2022, October). *Comments on proposed program for the national outer continental shelf oil and gas leasing program (national OCS program) for years 2023-2028* True Transition. Retrieved from https://www.regulations.gov/comment/BOEM-2022-0031-6387

111 Government Accountability Office. (2024, January 25). *Offshore oil and gas, Interior needs to improve decommissioning enforcement and mitigate related risks* (p. 35). Retrieved from https://www.gao.gov/products/gao-24-106229 OR https://www.gao.gov/assets/gao-24-106229.pdf

112 H.R. 9168, 118th Congress (2024). See also Rep. Katie Porter. (2024, July 25). *Rep. Porter introduces bill to hold big oil accountable for cleaning up offshore wells* [Press release]. Retrieved from https://porter.house.gov/news/documentsingle.aspx?DocumentID=661

Overlooked: Why oil and gas decommissioning liabilities pose overlooked financial stability risk

Greg Rogers and Rob Schuwerk

Carbon Tracker Initiative

Analyst Report | December 2023

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.

www.carbontracker.org | **hello@carbontracker.org**

Contributors and Special Thanks

The authors would like to thank Charlotte Gardes-Landolfini, Mozes Wilhelm and Javier Solana as external experts, and Maeve O'Connor, Mike Coffin, Lee Ray of Carbon Tracker of Carbon Tracker for their expert reviews and contributions. Any errors and omissions are of the authors alone.

About the Author

Greg Rogers – Senior Advisor

Greg is a practitioner-scholar in accounting for climate change. He wrote the seminal desk book on financial reporting of environmental liabilities and risks. In addition, Greg is a Fellow and Advisor to the Master of Accounting Program at Cambridge Judge Business School. He worked as an advisor to BP and its auditors Ernst & Young on liability estimates and disclosures arising from the Deepwater Horizon disaster. He has consulted/ testified as an expert in environmental and climate-related litigation.

Robert Schuwerk – Executive Director, North America

Rob Schuwerk is Executive Director of Carbon Tracker's North American office. He leads Carbon Tracker's work on asset retirement obligations. 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.

Table of Contents

1 Key Findings

- Legal obligations to decommission oil and gas infrastructure assets (e.g., wells, pipelines, and refineries) amplify the potential harm from—and could be the spark that ignites—a climate-related financial shock in oil and gas asset prices.
- Oil and gas decommissioning obligations are large. Our first-order estimate to decommission existing oil and gas infrastructure in the U.S. alone exceeds $1.2 trillion. Total costs globally could be four times as large.
- Opaque accounting and disclosures obscure the uncertainties associated with these obligations and their contribution to systemic risk, making them a possible "black swan".
- Systemic risk analyses have focused on the potential for a sudden devaluation of oil and gas financial assets but overlooked decommissioning liabilities. More study of this topic is needed.

2 Introduction

The key message of this paper is that oil and gas decommissioning obligations amplify the potential harm from—and could be the spark that ignites—a climate-related financial shock in oil and gas asset prices. The message is intended for macroprudential regulators focusing on climate-related financial stability risk—e.g., members of The Network of Central Banks and Supervisors for Greening the Financial System (NGFS). This paper is not intended for climate policymakers and does not address the implications of oil and gas AROs for the energy transition. For example, we do not examine whether and how AROs may thwart the fossil fuel industry's ability to transition to renewable energy.

A short story may help explain how oil and gas retirement obligations could threaten financial stability. Imagine you are an oil and gas regulator in a jurisdiction like California with more than 100,000 active and idle wells, all of which will eventually require plugging and abandonment and site restoration under existing law, at a cost of potentially tens of billions of dollars. Historically, the state's decommissioning policies have favored oil and gas producers. As a result, average collateral coverage (financial assurance divided by estimated closure costs) is a fraction of one percent, and a large portion of the state's wells are already either "orphaned" without a responsible party who can pay for plugging and abandonment, or at high risk of becoming so.[1] For the first three decades of the 20th century, California battled with Oklahoma as the leading oil-producing state in the U.S.[2] Once a major source of jobs and taxes, the oil industry is now a relatively minor contributor to the state's economy. Then you read this:

> *Across the country, a profound shift is taking place that is nearly invisible to most Americans. The nation that burned coal, oil and gas for more than a century to become the richest economy on the planet, as well as historically the most polluting, is rapidly shifting away from fossil fuels.*
>
> *A similar energy transition is already well underway in Europe and elsewhere. But the United States is catching up, and globally, change is happening at a pace that is surprising even the experts who track it closely.*[3]

An obvious response might be to protect the state's taxpayers from exposure to operator defaults on decommissioning obligations by demanding more collateral before it's too late. The precise pace of the energy transition is of secondary concern. Many of the operators in your state are already thinly capitalized. Worse, they are actively buying up low producing and inactive wells from larger operators they cannot possibly afford to retire. Responsibility for closure generally transfers with well ownership to these smaller single-purpose entities. But even the producers with the deepest pockets are not a sure bet. These companies typically operate in multiple jurisdictions, all of which are in competition for a diminishing pool of financial resources to pay the unfunded legacy cleanup obligations of more than a century of oil and gas production. Better to position yourself at the front of the creditor line by acting now.

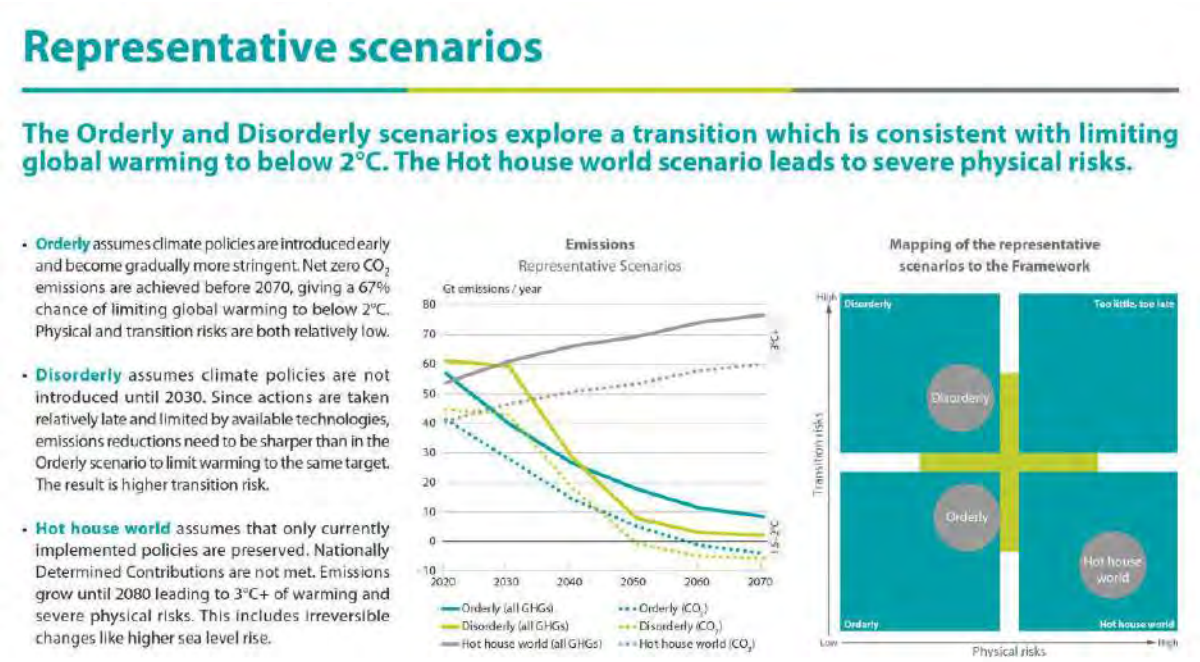
The transition to a low carbon economy is underway, even though (as illustrated in Figure 1) its global pace and orderliness remain uncertain, and it may happen too slowly to avoid the worst effects of climate change. The International Energy Agency (IEA) predicts that peak fossil fuel

[1] For information on California's orphan well problem, see California Assembly Bill No. 1167 (Section 1 Legislative findings) and Orphan Wells In California (California Council on Science and Technology, 2020).
[2] California oil and gas industry (Wikipedia).
[3] The Clean Energy Future Is Arriving Faster Than You Think (New York Times, August 13, 2023).

demand will happen this decade, even though the decline in oil, gas and coal will not be steep enough to limit global warming to 1.5°C.[4]

An inevitable consequence of this historic transformation is that much of the vast long-lived oil and gas infrastructure built to power the world over the past 150 years will be retired early and at great cost. The biggest uncertainty is how and when governments and private litigants will act to ensure that retirement costs are borne by industry.

FIGURE 1 – REPRESENTATIVE SCENARIOS



Source: NGFS Climate Scenarios

[4] Peak fossil fuel demand will happen this decade (Financial Times, September 11, 2023). The declines in oil and gas demand in the IEA's updated NZE Scenario are sufficiently steep that it is possible to satisfy them without approving new, long-lead time upstream conventional projects. Nonetheless, continued investment in existing oil and gas assets is essential in the NZE Scenario both to ensure that oil and gas supply does not fall faster than the decline in demand and also to reduce the emissions arising from oil and gas operations. New IEA report highlights the need and means for the oil and gas industry to drastically cut emissions from its operations (IEA May 3, 2023).

It is widely understood by macroeconomic regulators that some portion of existing petroleum reserves and infrastructure will be stranded as a result of climate change.[5] It is less well understood that the transition to a low carbon economy will cause massive liabilities for decommissioning and cleanup costs—so-called "asset retirement obligations" or "AROs"—to come due early.

Tangible assets can lose their value, but like financial assets, their value generally cannot fall below zero. Investors correctly assume that potential losses from investments in oil company stocks and bonds are limited to principal. However, this assumption may obscure the potential impact of AROs.

Petroleum reserves, which are not burdened by AROs, are at risk of becoming unburnable and economically worthless, but their value will never fall below zero. By contrast, petroleum infrastructure assets, because they are burdened by costly AROs, are at risk of becoming economic liabilities with valuations far below zero.

Mature upstream segments of the petroleum industry are already deeply upside-down with AROs that far exceed the value of all future profits.[6] It seems a near certainty that an industry in terminal decline that has not saved for retirement will someday become a liability to society.

[5] "A sharp adjustment with a view to lowering emission pathways might mean that large shares of fossil fuel reserves can no longer be extracted, thus becoming stranded." Positively Green: Measuring climate change risks to financial stability (European Systemic Risk Board, June 2020) at p. 9.
[6] See There will be blood: Decommissioning California's Oilfields (Carbon Tracker, May 2023).

3 What are oil and gas AROs?

Unique and often misunderstood attributes of AROs make it possible that markets could be caught off guard by accelerated retirements and the attendant impact on cash flows. Here, we describe how these largely unfunded debt-like legal obligations could impact the least financially viable companies and result in subsequent contagion across the sector.

3.1 Nature and Purpose

Fossil fuel asset retirement activities include plugging spent onshore and offshore wells, decommissioning offshore platforms, closure and decontamination of pipelines, gas processing facilities and refineries, remediation of contaminated soil and groundwater, and proper disposal of hazardous substances and wastes.[7]

Regulations in many jurisdictions across the world impose legal obligations on owners and operators of oil and gas assets to safely decommission them at the end of their economic useful life and then remediate any residual environmental impacts. See the *Appendix* for examples. For upstream and midstream assets (e.g., wells and pipelines), AROs are imposed as a condition of construction and operating permits.[8] Decommissioning obligations for downstream assets (e.g., refineries) arise from normal operations and are generally prescribed by laws and regulations governing the treatment, storage and disposal of hazardous substances and wastes.[9]

Oil and gas AROs have two objectives. The first objective is to prevent pollution conditions that could harm human health, the environment, or the climate. The second objective is to remediate pollution conditions that have already occurred. Plugging an oil well to prevent migration of hydrocarbons into potable aquifers is an example of a preventive ARO. Cleaning up soil and groundwater contaminated by hydrocarbon leaks and spills is an example of a remedial ARO.[10]

Failure to properly complete asset retirement activities can lead to conditions that harm human health, damage the environment, contribute to climate change by leaking significant amounts of methane, interfere with the use and enjoyment of private property, impair property values, and impede future economic development.[11] Consequently, oil and gas regulators face mounting public pressure to ensure that the petroleum industry fulfills its retirement obligations.

[7] Fossil fuel AROs also include coal mine reclamation, dismantling and decontaminating coal-fired power plants, and closure, post-closure care, and corrective action for coal ash ponds and landfills.
[8] See e.g., Summary of State Statutes and Regulations (Interstate Oil and Gas Compact Commission); Overview of International Offshore Decommissioning Regulations—Volumes 1 and 2 and pipeline decommissioning briefing (International Association of Oil & Gas Producers).
[9] For example, refineries in the U.S. are subject to the remediation requirements of the Resource Conservation and Recovery Act.
[10] Preventive AROs are by their nature easier to estimate than remedial AROs because the scope of work is more easily known in advance. For example, it is much easier to estimate the cost to plug a well than to estimate the cost to remediate spills along a hundred miles of pipeline or to decommission a refinery sitting atop extensive soil and groundwater contamination.
[11] See Deserted oil wells haunt Los Angeles with toxic fumes and enormous cleanup costs (Los Angeles Times, March 6, 2020). An oil refinery in the U.S. Virgin Islands that the Environmental Protection Agency shut down in spring 2021 now poses the risk of a fire, explosion or other "catastrophic" releases of "extremely hazardous substances." EPA closed a refinery that rained oil. Now it's a 'ticking time bomb' (Washington

3.2 Accounting for AROs

AROs are defined by U.S. accounting standards as legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, or development and (or) the normal operation of that long-lived asset.[12] Also known as decommissioning obligations,[13] oil and gas AROs arise from national and provincial laws and regulations intended to protect human health, the environment, and more recently, the climate from hydrocarbon releases and contamination.

3.3 Accumulated debt-like legal obligations

Oil and gas AROs are debt-like liabilities associated with the retirement of infrastructure assets.[14] They are analogous to the obligations of a pension fund to provide defined benefits for beneficiaries upon retirement. In each case, retirement age and benefit amount can be reasonably estimated. But instead of monetary retirement benefits, AROs are nonmonetary service obligations to restore the conditions that existed before the asset was constructed and operated. AROs can be subject to substantial cost variance and fat-tail risk that would not be attached to a liquidated liability, such as a loan. This is especially true offshore where unanticipated surface and downhole conditions can cause decommissioning costs to greatly exceed statistical norms. Unlike pension fund obligations, regulators do not require oil and gas operators to prefund their AROs. As a result, operators typically pay to retire assets constructed decades ago with cash flow from current operations.

Oil and gas AROs are important because they represent a claim on the oil and gas industry that has been accumulating for decades. Unlike most other sectors, the petroleum industry has a revolving balloon loan that comes due as its infrastructure assets are retired from service.[15] In theory, repayments on this loan should roughly match new withdrawals as old assets are retired and replaced with new ones. In reality, the principal amount of the loan has steadily grown as oil companies have systematically deferred settlement. The balloon loan has now reached levels that likely far exceed what the industry can possibly afford to repay. In a climate scenario of abrupt transition away from fossil fuels,[16] this massive loan could come due in its entirety all at once. This is a concern for the intended beneficiaries of AROs—namely citizens, taxpayers, and landowners—and regulators responsible for protecting their interests.

Post, October 28, 2022); *see also* Special Report: Millions of abandoned oil wells are leaking methane, a climate menace (Reuters, June 16, 2020).

[12] See Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 410-20-15-2(a).

[13] International Accounting Standard (IAS) No. 37.

[14] S&P describes AROs as "debt-like liabilities". Standard & Poor's Encyclopedia of Analytical Adjustments of Environmental Liabilities for Corporate Entities at p. 9.

[15] A balloon loan is a loan that does not fully amortize over its term. Often, payments cover accrued interest only with the entire principal amount coming due at maturity in what's known as a balloon payment.

[16] See e.g., Too late, too sudden: Transition to a low-carbon economy and systemic risk (ESRB 2016) ("The later the transition starts, the more likely it is that either the targeted limit will be revised (at the risk of catastrophic physical implications) or the transition to the low-carbon economy will be late and abrupt.").

3.4 Maturities

AROs to decommission existing oil and gas infrastructure may be unmatured, matured, or incipient. AROs associated with productive assets are unmatured. AROs become matured when assets reach the end of their useful life. Incipient AROs are those associated with assets to be constructed or acquired in the future.

Like a bathtub with an open spigot (new projects) and a closed drain (retirement of existing assets), the inventory of matured AROs, particularly for upstream infrastructure, has swollen over time. The flow imbalance between construction and retirement has been incentivized by low financial assurance levels and lax government enforcement.[17]

Useful life, also called economic life or depreciable life, refers to the length of time an asset is expected to be useful to the owner. The measure of an asset's usefulness is how profitable it is to keep—in other words, how long an asset generates more income than it costs to maintain and operate.[18]

The useful life of petroleum assets is determined by three factors: wear and tear, natural resource usage, and obsolescence. Tangible assets depreciate over time due to normal wear and tear and eventually wear out unless periodically reconditioned.

Oil and gas infrastructure tends to have long lives lasting over many decades. Indeed, operators claim midstream and downstream assets can be operated indefinitely with proper maintenance.

The useful life of upstream infrastructure is determined by natural resource usage. Petroleum reserves decline over time from production. Secondary and tertiary recovery techniques can extend a field's productive life, but once these resources can no longer be extracted profitably the related infrastructure is no longer needed.

An asset becomes obsolete when it is no longer salable or useful. Climate-related factors that threaten to render fossil fuel assets unprofitable and obsolete include:

- New technologies in renewable energy and transportation
- Shifting consumer preferences toward electric vehicles and home solar panels
- Government taxes and constraints on greenhouse gas emissions
- Policy actions that reduce the profitability of oil and gas infrastructure

The transition to a low carbon economy threatens to render upstream midstream, and downstream oil and gas infrastructure obsolete unless these assets can be successfully repurposed (e.g., repurposing oil and gas wells for geothermal energy or renewable energy storage, gas pipelines for hydrogen, and refineries for biofuels).

[17] The timing of permanent well retirement is subject to uncertainty (e.g., the possibility of commodity price increases and new production technologies that make unprofitable wells once again profitable) and conflicting objectives (e.g., operators are incentivized to extract the last profitable drop of hydrocarbons and indefinitely defer or evade decommissioning costs that generate no return on investment).
[18] Economic Life (CFI Education Inc.).

Obsolescence will force many oil and gas assets into early retirement, thereby accelerating ARO maturities. We use the term "ARO acceleration" to denote conditions that pull asset retirement costs forward in time, with the result that asset retirement costs are incurred sooner than expected.

Our concept of ARO acceleration is like an acceleration clause in a loan agreement that allows a lender to require a borrower to immediately repay all of an outstanding loan if certain requirements are not met. For example, insurers are discontinuing coverage in areas prone to hurricanes and wildfires and home mortgage loans generally contain an acceleration clause triggered by cancellation of homeowner's insurance.

ARO acceleration may be either physical or financial. Physical acceleration occurs when oil and gas assets are retired sooner than expected due to premature obsolescence. Financial acceleration occurs when regulators demand more collateral to ensure that retirement costs are paid by industry not taxpayers.

Asset retirement costs include actual closure costs, financial assurance costs (e.g., surety bond premiums), and collateral to secure future performance—i.e., anything that diverts cash from operations toward asset retirement.

The inventory of matured and unmatured AROs will continue to grow as new oil and gas infrastructure is constructed. The IEA has reported that keeping energy markets in balance while staying on the path to net zero will require continued investments in existing oil and gas assets of USD $400–500 billion per year until 2030.[19] To the extent these investments create new infrastructure, they will give rise to new AROs.

[19] Investing in Oil and Gas Transition Assets En Route to Net Zero (Columbia University Center for Energy Policy, March 2023).

4 What is the magnitude of liability?

In Section 7, we discuss how oil and gas AROs can amplify climate-related financial stability risk. AROs pose a systemic risk in part because they are so large. We estimate that oil and gas AROs for oil and gas assets in the U.S. alone exceed $1.2 trillion. Based on a comparison of U.S. versus global investments in exploration and production (total AROs globally could be four times as large. By comparison, the 2008 financial crisis led to a loss of $2 trillion from the global economy.[20]

TABLE 1 - OIL AND GAS ARO ESTIMATES (U.S. ONLY)

Oil and gas Assets	U.S. ARO Estimate ($B USD)
Upstream Onshore	$280
Upstream Offshore	$34
Midstream	$760
Downstream USTs[21]	$67
Downstream Refineries	$84
TOTAL	$1,225

Source: Carbon Tracker

All fossil fuel infrastructure is subject to AROs, including coal mines and coal-fired power plants. However, the largest fossil fuel AROs are associated with the production, distribution and processing of oil and natural gas.

The costs to retire oil and gas assets are large in absolute terms and can be material relative to the cost of infrastructure, projected future revenues from operations, and market capitalization. For example, the petroleum industry assumes that costs to decommission offshore production infrastructure will be 15 percent of capital expenditures. BP's self-disclosed undiscounted AROs amount to 16% of its total market capitalization (as of August 2023).

Decommissioning costs may be affected by numerous site-specific factors and are thus subject to high estimation uncertainty. The estimates in this report are Class 5 estimates, meaning they were prepared based on a desktop analysis without site-specific information. They consequently have significant accuracy ranges, i.e., +50%/-30% or more. In other words, these are ballpark estimates.[22]

4.1 Upstream

Upstream infrastructure includes onshore and offshore wells, offshore platforms, and gathering lines. Related AROs include plugging wells, decommissioning offshore platforms, removing or decontaminating gathering lines and equipment, reclaiming impacted surface areas, and remediating soil and groundwater contaminated with hydrocarbon releases.

[20] 2007-2008 financial crisis, Wikipedia.
[21] Underground storage tanks used to store petroleum products.
[22] See Cost Estimate Classification System (AACE International).

We have previously estimated that plugging 2.6 million documented onshore wells in the U.S. alone will cost **$280 billion** (approximately $108,000 per well).[23] This is a depth-based estimate for downhole plugging only. It excludes costs for surface reclamation and site remediation.

Our per well estimate appears conservative compared to recent cost data from North Dakota and California that include surface cleanup costs. The average cost to plug, abandon and reclaim orphan wells in California is significantly higher at $216,000 per well.[24] The average cost to plug, abandon and reclaim orphan wells in North Dakota is higher still at $259,000 per well.[25]

U.S. government estimates of AROs in the Gulf of Mexico (GOM) range between **$34 and $48 billion.**[26] As a rule of thumb, the petroleum industry assumes that costs to decommission offshore production infrastructure will be 15 percent of capital expenditures.[27] The average real cost to drill an onshore oil and gas well in the U.S. between 1960—2007 was $646,000.[28] At 15 percent, the average ARO would be $97,000, which aligns closely with our average ARO per well of $108,000 per well.

Figure 1 illustrates the scale of global capital investment in petroleum exploration and production. Real global capital expenditures for upstream exploration and production between 1985—2022 totaled USD $14 trillion. Assuming AROs are 15% of capex, these investments generated AROs of USD $2 trillion, 75 percent located outside the U.S.

---

23 Our estimates and methodology are described in Billion Dollar Orphans (Carbon Tracker, September 2020). This estimate covers only documented wells for which information was available. It excludes costs to plug an additional estimated 1.2 million unplugged abandoned onshore wells that are undocumented. The inventory of unplugged wells in the U.S. includes about one million producing wells. The total number of operating U.S. oil and natural gas wells has decreased about 11.1% from a peak in 2014 to 2021—from more than 1,031,183 wells to about 916,934 wells. The Distribution of U.S. Oil and Natural Gas Wells by Production Rate (U.S. Energy Information Administration, December 2022). It also includes as many as three million inactive wells, many of which are abandoned and (or) undocumented. *See* Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Abandoned Oil and Gas Wells (EPA 2018).

24 California will cap hundreds of orphaned oil wells, some long suspected of causing illness (LA Times, July 18, 2023).

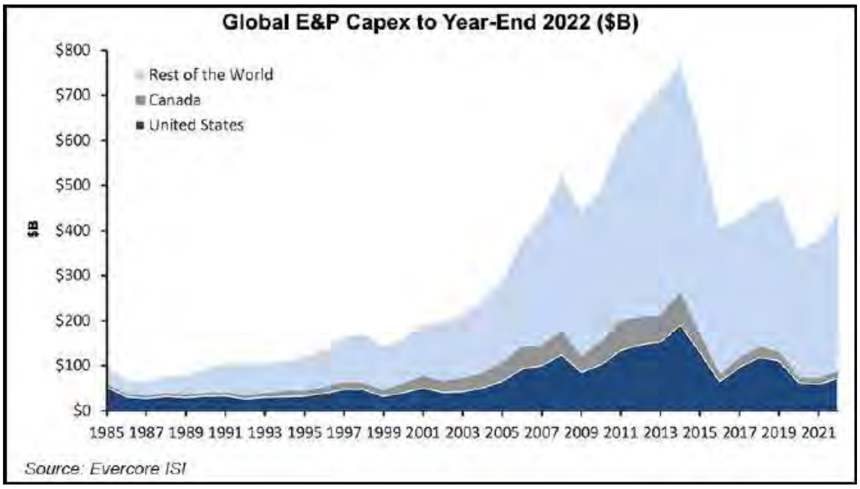
25 Cares Act Report and Documentation (Northwest Landowners Association).

26 Double or Nothing: How regulators are gambling on the future self-interest of large oil and gas companies to decommission the Gulf of Mexico's aging infrastructure (Carbon Tracker, June 2022) at p. 12.

27 "Decommissioning cost is assumed to be 15 percent of capex, in line with industry standards, with these incurred over the last six years of production." Libra Project, Brazil Narrative Report (OpenOil.net since taken offline). The Libra Project is a five-company consortium, including Brazil's Petrobras (operator, 40% stake), UK's Shell (20%), France's Total (20%), and China's CNPC (10%) and Cnooc (10%), that signed Brazil's first production sharing contract.

28 Costs of Crude Oil and Natural Gas Wells Drilled (U.S. Energy Information Agency).

FIGURE 2 GLOBAL UPSTREAM CAPEX (1985 - 2021)



Source: Natural Gas Intelligence

4.2 Midstream

Midstream infrastructure includes onshore assets used to process, transport, store, and market petroleum products. Related AROs include pipeline decommissioning and remediation of soils impacted by hydrocarbon releases.

Data on midstream ARO costs is limited. The best data we could find comes from a study prepared for the New Mexico State Land Office.[29] The study includes average unit costs for in-place decommissioning and remediation of above and below ground pipelines and other midstream infrastructure in New Mexico. We applied these unit costs to approximately 2 million miles of oil and gas transmission pipelines in the U.S. to produce an estimate of $400 billion in AROs for pipelines and $360 billion for other midstream infrastructure for a total of **$760 billion**.

4.3 Downstream

Downstream infrastructure includes assets used in the refining of petroleum crude oil and the processing and purifying of raw natural gas, as well as the marketing and distribution of products derived from crude oil and natural gas. Related AROs include decommissioning and remediation of oil refineries, gas processing plants, and underground petroleum storage tanks. AROs for gas processing plants were included in the New Mexico midstream infrastructure ARO estimate and are excluded here.

Underground storage tank (UST) systems are tanks and connected piping used to store petroleum products or hazardous substances. Approximately 542,000 USTs nationwide store petroleum or hazardous substances.[30] About 95% of all USTs store petroleum products like gasoline or oil.[31] The

[29] An Analysis of the Adequacy of Financial Assurance Requirements for Oil and Gas Infrastructure Located on State Trust and Private Lands in New Mexico (The Center for Applied Research, Inc., April 30, 2021).
[30] Underground Storage Tanks (EPA).
[31] Underground Storage Tank Factsheet (Cit of Springfield Environmental Services).

U.S. Environmental Protection Agency estimates that the average cleanup cost per UST is $130,000.[32] Total AROs for petroleum USTs in the U.S. thus amount to **$67 billion**.

Based on very limited available cost data for refinery closures, we estimate AROs for U.S. refineries are **$84 billion** ($4,500 per barrel of daily throughput capacity times current U.S. operable throughput of 18 million barrels per day).[33] This excludes AROs for inoperable refineries.

4.4 Cost mitigation unlikely

Costs to settle oil and gas AROs may be mitigated in part by nonenforcement, relaxation of standards, government assistance, asset repurposing, and advances in technology. Such developments are speculative, and government assistance seems likely to be small relative to total liability and largely limited to orphaned assets that do not have viable owners to pay retirement costs. For example, the U.S. Department of Interior recently announced $660 million in grant funding for states to plug orphaned oil and gas wells, a tiny fraction of the amount needed to plug the estimated 2.3 million to approximately 3 million abandoned unplugged wells across the U.S.[34] Also, to avoid throwing good money after bad, the U.S. will distribute $1.5 billion to states that take effective action to reduce the number of wells becoming orphaned in the future.[35] Rather than offering an open-ended bailout, the U.S. federal government is incentivizing states to hold the oil and gas industry accountable.

Socializing AROs while privatizing profits creates a moral hazard—what incentive do oil and gas companies have to fulfill their retirement obligations if they know they will not pay the bill? The industry's culpability in causing the climate crisis makes a large-scale bailout politically challenging. California recently sued several of the world's biggest oil companies, one headquartered in the state, claiming they caused tens of billions of dollars in damage from record heat, drought and water shortages, wildfires, extreme storms, flooding, crop damage, coastal erosion and biodiversity loss and that they deceived the public by downplaying the risks posed by fossil fuels.[36]

4.5 Cost inflation likely

As the petroleum industry moves into its winddown phase, labor constraints may push upstream asset retirement costs higher. There is already some evidence of ARO inflation corresponding with the Biden Administration's efforts to plug orphaned wells across the U.S.[37]

[32] Frequent Questions About Underground Storage Tanks (U.S. EPA).
[33] This is an average of the ARO/throughput of refinery closures recently announced by Shell and Marathon.
[34] Biden-Harris Administration Invests $660 Million for States to Plug Orphaned Oil and Gas Wells through President's Investing in America Agenda (U.S. Department of the Interior, July 2023).
[35] See Request for Information to Inform the Orphaned Wells Program Office's Development of Regulatory Improvement Grants Under the Bipartisan Infrastructure Law (U.S. Department of Interior, Oct. 2023).
[36] California Sues Giant Oil Companies, Citing Decades of Deception (New York Times, Sept. 25, 2023).
[37] "Officials say they are having a hard time finding enough crews to plug the wells under the timelines dictated by the federal funds, and available workers are charging higher prices than originally anticipated." States struggle to plug oil wells with infrastructure law cash (EnergyWire, July 14, 2023).

5 Are there sufficient funds to settle these liabilities as they come due?

Oil and gas asset retirement costs are funded on a pay-as-you-go basis from operating revenues. They are generally unfunded and unsecured. Unlike nuclear energy, where regulations require operators to establish sinking funds to finance decommissioning costs over the operating life of power plants, oil and gas companies fund retirement costs from current operating revenues as they come due.

Non-accountants often assume that accrued liabilities such as AROs are accompanied by cash reserves to fund their settlement. This is not the case. Recognition of AROs on corporate balance sheets does not indicate that funds of an equal amount are set aside in a sinking fund to resolve the liability when it matures. Oil and gas companies generally do not set aside restricted assets to settle AROs, and they must therefore be paid from future cash flows that may not materialize if the industry does not successfully navigate the energy transition.[38]

Regulations in different jurisdictions include a patchwork of financial assurance requirements intended to assure that upstream onshore and offshore decommissioning obligations are not orphaned to governments and taxpayers. For example, surety bonds, which can be called upon in the event of operator defaults but which the operator must repay, are generally required to secure AROs for oil and gas wells. Financial assurance is generally not required for midstream and downstream assets, with the exception of USTs.

EPA's federal financial responsibility regulation requires UST owners and operators to have the ability to pay for cleanup or third-party liability compensation. Since 2002 state UST financial assurance funds have paid approximately $20 billion to clean up leaking UST sites.[39]

Where government-mandated financial assurance is required to secure AROs for oil and gas assets other than USTs, it often amounts to pennies on the dollar.[40] Available bonding data shows that regulators on average have secured less than 1% of estimated upstream onshore AROs in surety bonds.[41] Financial assurance coverage for offshore upstream AROs is higher but still low. The U.S. federal government holds $3.5 billion in active bonds that secure AROs in the Gulf of Mexico for a coverage ratio of 10%.[42]

The upstream oil and gas industry actively lobbies against financial assurance. It has argued successfully that financially strong companies ("haves") pose low ARO default risk and financially weak companies ("have nots") cannot afford increased bond premiums.[43] Low bond coverage ratios (bond amounts as a percentage of estimated AROs) (Table 2) indicate that regulators have assumed

[38] Navigating Peak Demand (Carbon Tracker, Nov. 2023).
[39] U.S. Environmental Protection Agency, Underground Storage Tanks (USTs) State Financial Assurance Funds.
[40] *See e.g.*, Billion Dollar Orphans: Why millions of oil and gas wells could become wards of the state (Carbon Tracker, October 2020) ("Billion Dollar Orphans").
[41] Billion Dollar Orphans: Why millions of oil and gas wells could become wards of the state (Carbon Tracker, October 2020) ("Billion Dollar Orphans").
[42] Double or Nothing: How regulators are gambling on the future self-interest of large oil and gas companies to decommission the Gulf of Mexico's aging infrastructure (Carbon Tracker, June 2022) at p. 12.
[43] Colorado Oil and Gas Looking to Have its Cake and Eat it Too (Carbon Tracker, December 2021).

ARO defaults are the exception rather than the rule, and the imperative of energy production at competitive prices has persuaded them to accept the risk that AROs may on occasion be socialized.[44]

TABLE 2 - BONDING COVERAGE AND LIABILITY, SELECTED STATES (2020)

State	CTI Estimate ($B)	State Bonds ($B)	Federal Bonds ($B)	Total Bonds ($B)	Orphan Well Liability Risk ($B)	Bond Coverage Ratio
Colorado	7.09	0.16	0.02	0.18	6.92	2%
Montana	1.86	0.01	0.00	0.01	1.85	1%
New Mexico	10.31	0.10	0.07	0.17	10.14	2%
North Dakota	7.92	0.08	0.01	0.09	7.83	1%
Pennsylvania	14.58	0.05	0.00	0.05	14.53	0%
Utah	4.99	0.02	0.02	0.04	4.95	1%
West Virginia	7.66	0.03	0.00	0.03	7.63	0%
Wyoming	9.51	0.19	0.07	0.26	9.25	3%
TOTAL	63.92	0.64	0.19	0.83	52.96	1%

As a result of lax financial assurance rules, the vast majority of oil and gas AROs are "self-bonded".[45] Because retirement costs produce no return and operators can often delay them without financial penalty, the oil and gas sector is strongly incentivized to defer retirement costs, accumulating ever more AROs against assets of declining value. Unless regulators act quickly to increase financial assurance, ARO defaults are likely to rise in lock step with declining commodity demand and sales revenues.

[44] *See* Joseph Stiglitz, Phony Capitalism (Harpers, 2014).

[45] *Billion Dollar Orphans.*

6 What is climate-related financial stability risk?

Central banks and others concerned about financial stability risks have identified climate-related drivers of this risk but appear to nearly universally overlook AROs as a driver for such risks.

Systemic risk denotes severe potential harm to the financial system and the real economy arising from a sudden downward repricing of financial assets. The Financial Stability Board (FSB) defines systemic risk as "the risk of disruption to the flow of financial services that is caused by an impairment of all or parts of the financial system and has the potential to have serious negative consequences for the real economy."[46] Climate-related financial stability risks are risks that may result from climate change that could potentially impact the safety and soundness of the financial system.[47]

In a 2015 speech at Lloyds of London, Mark Carney, then chairman of the Bank of England and the Financial Stability Board, introduced the idea of a "climate Minsky moment" that could be triggered by insurance losses, climate change liability, or stranded carbon-intensive assets.[48]

One-third of equity and fixed income assets issued in global financial markets fall within the natural resource and extraction sectors, as well as carbon-intensive power utilities, chemicals, construction, and industrial goods firms. Decarbonization would essentially strand those assets, resulting in losses in asset values for the energy sector of $1 trillion to $4 trillion. In the broader industrial sector, the stranded asset risks could rise to $20 trillion.[49]

Stranded assets, under one definition, are tangible assets that experience premature devaluations (impairments) or conversion to liabilities as a result of over-exposure to poorly understood and mispriced exogenous risks such as climate change.[50] Tangible oil and gas assets at risk of becoming stranded by climate change and the associated transition to a low-carbon economy include petroleum reserves, oil and gas wells, offshore platforms, gathering lines, processing facilities, transmission pipelines, aboveground and belowground storage tanks, and refineries.[51]

It is widely agreed that strong regulatory actions are needed to avoid the potentially catastrophic physical consequences of climate change. As global warming is mostly attributable to the combustion of fossil fuels, new regulations are needed to significantly curb greenhouse gas emissions. Whether, how, and when climate policies will be implemented is highly uncertain, and the transition to a low-carbon economy may be smooth or abrupt.[52]

---

[46] Systemic risk: how to deal with it? (Bank of International Settlements, February 12, 2010).
[47] Climate-related Financial Stability Risks for the United States: Methods and Applications (Federal Reserve Board, 2022).
[48] Mark Carney: Breaking the tragedy of the horizon—climate change and financial stability, speech at Lloyd's of London, London, 29 September 2015.
[49] Adam Tooze, Columbia professor and author of Crashed, Why Central Banks Need to Step Up on Global Warming (Foreign Policy, July 20, 2019).
[50] Stranded Assets Programme (Smith School of Enterprise and the Environment, March 25, 2014).
[51] Fossil fuel asset retirement activities also include coal mine reclamation, dismantling and decontaminating coal-fired power plants, and closure, post-closure care and corrective action for coal ash ponds.
[52] See e.g., NGFS Scenarios Portal ("The future is uncertain"); Approaches to Climate Risk Analysis in FSAPs (IMF Staff Climate Notes, July 14, 2022) ("… long time horizons come with high uncertainty about how policy and socio-economic factors might evolve. There is also a very wide range of climate models to choose from giving rise to sizable model uncertainty. Inherent uncertainty in modeling increases with the complexity of the system. This generates higher-than-typical uncertainty regarding projections of emissions

Firms with carbon-intensive business models, particularly oil and gas companies, are most affected by this uncertainty. According to the European Systemic Risk Board, "Climate shocks appear inevitable [and a] sharp adjustment with a view to lowering emission pathways might mean that large shares of oil and gas reserves can no longer be extracted, thus becoming stranded."[53]

Current market prices of oil and gas financial assets do not reflect a significant portion of the cost to offset the unrealized greenhouse gas emissions in petroleum reserves. This exposes these assets to sudden downward repricing. According to the European Systemic Risk Board:

> *Contrary to shocks to the global financial system with potentially sizeable economic effects, financial market pricing of climate risks appears heterogeneous at best, and absent at worst.*[54]

Climate change and the energy transition are sources of systemic risk. According to the FSB, "A manifestation of physical risks as well as a disorderly transition to a low-carbon economy could have destabilizing effects on the financial system, including through a rise in risk premia and falling asset prices in the relatively short term."[55] The U.S. Financial Stability Oversight Council (FSOC) has said that, "Increasing adverse effects from climate change to households, communities, and businesses will exacerbate climate-related risks to the U.S. and global financial systems if not addressed."[56] According to the Network for Greening the Financial System (NGFS), climate change is a source of "structural change" in the financial system and the economy.[57]

Figure 2 illustrates how the transition to a low carbon economy could cause financial instability. Transition risk drivers such as climate policy, technology, and consumer preferences result in stranded assets, retirement and replacement of these assets, and increases in energy prices. Devaluation of corporate and residential assets, lower profitability and increased litigation[58] then lead to financial and credit market losses. Asset fire sales and credit tightening result in financial contagion that feedback to the real economy.

---

and temperature. As such, there are many pathways for emissions and temperatures with high levels of uncertainty around them, though the general tendency is for a clear increase in temperatures without policy action to decarbonize.").

[53] Positively green: Measuring climate change risks to financial stability (ESRB, June 2020).

[54] ESRB, Positively green: Measuring climate change risks to financial stability (June 2020).

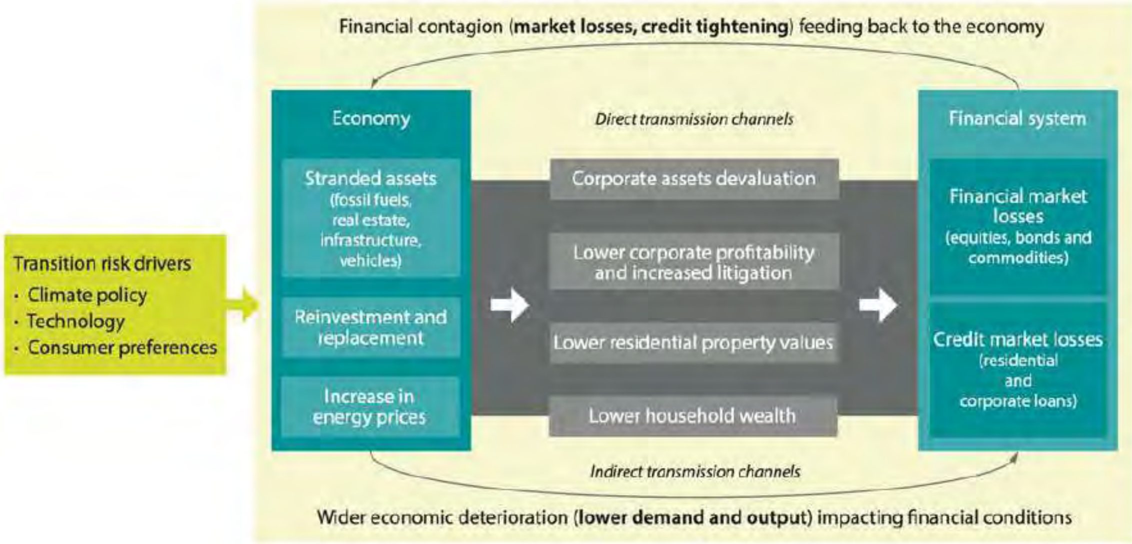
[55] FSB Roadmap for Addressing Climate-Related Financial Risks (7 July 2021).

[56] Report on Climate-Related Financial Risk (FSOC, 2021).

[57] A call for action: Climate change as a source of financial risk (NGFS, April 2019).

[58] The NGFS has issued several reports on climate-related litigation risk, which it defines as cases involving material issues of climate change science, policy, or law. Examples of climate-related litigation described in these reports include cases alleging responsibility for climate-related conditions and events and failure to take sufficient action to reduce greenhouse gas emissions. ARO litigation (discussed in Section 7.1.4) does not directly involve issues of climate change science, policy, or law. Consequently, the NGFS has not examined its potential contribution to transition risk.

FIGURE 3 - FROM TRANSITION RISK TO FINANCIAL STABILITY RISKS



Source: NGFS

Macroprudential regulators now widely acknowledge that an abrupt transition to a low-carbon economy could cause a major shock to the valuation of financial assets with the potential for destabilizing effects.[59] However, these assessments consistently overlook AROs as an exacerbating factor. The following excerpt is a typical of statements about systemic risks posed by stranded oil and gas assets that omit any mention of AROs:

> *The Paris Agreement aims to limit the increase in global average temperature to 'well below 2°C above pre-industrial levels'. This requires that a fraction of existing reserves of fossil fuels and production capacity remain unused, hence becoming stranded fossil-fuel assets (SFFA). Where investors assume that these reserves will be commercialised, the stocks of listed fossil-fuel companies may be over-valued.*[60]

Our survey of research on climate-related financial stability risk identified no mention of AROs whatsoever. Our survey included search engine queries for research papers referencing systemic risk, climate change, oil and gas, and asset retirement obligations and discussions with experts in climate-related systemic risk to confirm our findings.

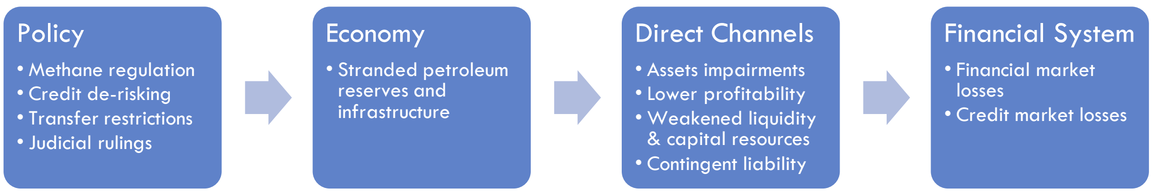
[59] See Financial institutions' exposures to fossil fuel assets.
[60] Mercure, J. F., Pollitt, H., Viñuales, J. E., Edwards, N. R., Holden, P. B., Chewpreecha, U., & Knobloch, F. (2018). Macroeconomic impact of stranded fossil fuel assets. Nature Climate Change, 8(7), 588-593. doi:10.1038/s41558-018-0182-1.

7 How do oil and gas AROs amplify climate-related financial stability risk?

This section explains how oil and gas AROs amplify climate-related financial stability risk by increasing both the magnitude and probability of a climate Minsky moment.

Figure 3 is a version of Figure 2 that zeros in on AROs. It depicts how policy actions pertaining to oil and gas infrastructure and AROs can cause petroleum reserves and infrastructure to become stranded resulting in asset impairments, reduced profitability, weakened liquidity and capital resources, and contingent liability. We explain these cause-and-effect relationships in more detail below.

FIGURE 4 – FROM OIL AND GAS AROS TO FINANCIAL STABILITY RISKS



7.1 Policy actions

Several climate-driven policy actions could exacerbate the negative financial impact of AROs on the oil and gas sector. Some of these policies (e.g., carbon-pricing mechanisms, energy-efficiency incentives, and renewable energy subsidies) are well understood by financial market participants and regulators. However, these parties may not be familiar with other policy actions specific to oil and gas infrastructure. These include ARO credit de-risking,[61] ARO liability transfer restrictions, methane regulations, and ARO-related judicial rulings.

7.1.1 ARO credit de-risking

To understand their financial implications, it helps to think of AROs like an interest-free loan. AROs are statutory debt-like obligations owed by oil and gas companies (debtors) to a collection of stakeholders, including regulators, landowners, and taxpayers (creditors). ARO credit risk is the probability of loss resulting from a debtor's failure to fulfill its AROs. The primary means available to oil and gas regulators to reduce ARO credit risk is financial assurance, usually in the form of a surety bond.

Today, the oil and gas regulatory system finances the industry's AROs with free credit on "self-bonded" AROs—*i.e.*, they don't require industry to fully bond these obligations, as they could. This lack of security exposes governments and ultimately taxpayers to ARO credit risk—if operators can't pay, non-economic wells, offshore platforms, pipelines, and refineries may become wards of

[61] Some research in the power sector has recognized shortfalls in available financing for retirement of existing coal infrastructure. See e.g., Scaling Up to Phase Down (World Bank, April 2023).

the state. It is in a state's interests to not allow this. To preempt a "rush to the courthouse" regulators need to convert their unsecured AROs into senior secured debt by demanding financial assurance equal to 100 percent of expected asset retirement costs, even for AROs now expected to mature decades from now, just as would a home mortgage lender.

As the energy transition gains speed, regulators can be expected to significantly increase financial assurance coverage on new and existing infrastructure. This is already happening. For example, in 2019 Colorado passed landmark legislation directing the state's oilfield regulator to establish rules that ensure oil and gas companies are "financially capable of fulfilling every obligation" under state law, including AROs.[62]

In July 2023, the Biden administration proposed to sharply increase bonds securing the retirement of oil and gas wells on federal land. Under the proposal, the minimum lease bond would rise to $150,000 from the existing $10,000, a level that has been in place for more than 60 years. The minimum for a statewide bond, which would cover all leases and operations in a single state, would rise to $500,000 from the current $25,000.[63] These levels are insufficient to fully guarantee the liabilities, but additional increases are possible, particularly if in response to an uptick in ARO defaults.

If individual oil and gas companies can't pay, regulators may tax the industry to cover the shortfall. For example, in 2022, Australia imposed a levy on oil and gas producers to cover the ARO on the Northern Endeavour floating production storage and offloading (FPSO) vessel after it was abandoned by Northern Oil & Gas Australia in 2019.[64]

Applying offshore joint and several liability regimes to onshore operations is another way for regulators to de-risk. Liability for U.S. offshore AROs is joint and several among all who have accrued the liability and survives until those obligations are met.[65] Lessees and grant holders are liable for the entire amount of decommissioning obligations that have accrued prior to and during their ownership. This means operators are legally responsible for the decommissioning obligations of co-lessees. Former lessees also bear contingent decommissioning liability for infrastructure that they do not currently own.[66] Unique among states in the U.S., California regulators can pursue previous operators seriatim as far back as January 1, 1996, for onshore plugging and decommissioning responsibilities.[67]

---

[62] *See* Shining a Light on Colorado's Financial Assurance Plans (Carbon Tracker, March 2023).
[63] In addition to increasing financial assurance costs, the proposal would also reduce net revenue by raising the royalty rates paid by operators that drill on federal lands to 16.67% from 12.5%, and to increase the minimum bid at auctions for drilling leases to $10 per acre from $2 per acre, among other provisions. The 12.5 percent royalty rates have been in place since 1920. Interior Department Takes Steps to Modernize Oil and Gas Leasing on Public Lands, Ensure Fair Return to Taxpayers (U.S. Department of the Interior, July 20, 2023).
[64] Australia slaps tax on oil industry to pay for field clean-up (Reuters, April 1, 2022).
[65] 30 CFR § 250.146. Joint and several liability is a common feature of offshore oil and gas regulatory regimes around the world. This is distinguished from onshore regulation, which generally does not impose joint and several liability. See Understanding decommissioning of offshore infrastructures: A legal and economic appetizer.
[66] See 30 CFR § 250.146.
[67] California Code, Public Resources Code - PRC § 3237.

7.1.2 ARO transfer restrictions

From a legal perspective, absent laws imposing joint and several or trailing liability, AROs follow the asset. This means, as a general rule, when mature assets are sold, the buyer assumes legal responsibility for asset retirement. It also means that the seller is off the hook if the buyer defaults.

As oil and gas companies seek to reduce their greenhouse gas emissions to meet strengthening climate standards, some have utilized divestiture as a means to reach these goals. However, divestitures may impede global carbon emissions reductions and increase climate risk if buyers defer or default on AROs. Less responsible oil and gas companies often sell mature assets to less creditworthy entities for the purpose of evading AROs, but regulators may eliminate this "exit strategy" as they become increasingly burdened with orphaned assets.[68]

Efforts to ensure that corporate transfers don't circumvent timely settlement of AROs include case-specific regulatory interventions, sector-wide policy actions, and voluntary codes of conduct.[69]

Changes in regulatory policy and commercial litigation could hold sellers financially responsible for AROs on former assets, making transfers less appealing. If asset retirement costs cannot be avoided by selling mature assets, owners may be forced to retire them instead.

These reactions are already beginning to unfold. Regulatory and voluntary efforts to address AROs in connection with asset transfers include the following:

- **Australia trailing liability for offshore decommissioning.** In response to an offshore leaseholder's insolvency and resulting default on its obligation to decommission an offshore platform, Australia introduced trailing liability for decommissioning offshore oil, gas and carbon capture and storage assets.[70] Trailing liability holds predecessors in interest responsible for AROs when current operators default.[71]
- **BP sale of North Slope assets to Hilcorp.** Concerned about the transfer of AROs to a less creditworthy company, Alaska's Department of Natural Resources and Department of Environmental Conservation approved the transfer of BP's oil and gas North Slope leases to Hilcorp Energy Company as part of the $5.6 billion sale the two companies announced in August 2019 only "[a]fter ten months of in-depth analysis, stress-testing of Hilcorp's financial capacity to hold and operate these assets, and successfully securing secondary liability guaranties from BP."[72]
- **Colorado financial assurance regulations.** New rules in Colorado require operators who are receiving wells through a transfer to increase their financial assurance for the transferred wells before the selling operator's financial assurance is released.[73]

[68] A New Theory of ARO Creditor Rights (Carbon Tracker, January 2023).
[69] In October 2023 California Governor Gavin Newsom signed AB 1167, which requires companies purchasing marginally productive oil wells to provide financial assurance in an amount determined by the State to be sufficient to cover, in full, all costs of plugging and abandonment, decommissioning, and site restoration.
[70] Trailing liability for asset decommissioning in Australia (Corrs Chambers Westgarth, August 30, 2022).
[71] Similar trailing liability legislation already exists in international jurisdictions including Norway, the United Kingdom and the United States (see pages 71—84 of the enclosed link).
[72] State agencies approve transfer of BP's upstream assets to Hilcorp (State of Alaska Joint Press Release, June 29, 2020).
[73] C.R.S. § 34-60-106(13).

- **Voluntary asset transfer principles.** Recognizing that acquisition and divestment activities may defer or prevent timely asset decommissioning, voluntary principles developed by the Environmental Defense Fund (EDF) and Ceres, provide that AROs for transferred assets should be fully accounted for at the point of transfer, along with disclosure of the responsible party's mechanism for assuring those obligations.[74]

7.1.3 Methane regulation

Regulation of fugitive methane emissions from upstream and midstream assets will make marginal assets unprofitable and bankrupt the most marginal operators.[75]

Low-producing, inactive, and orphaned wells leak methane, a powerful greenhouse gas. According to a recent EDF study, low-producing oil and gas wells are responsible for approximately half of the methane emitted from all well sites in the United States while accounting for only 6% of the nation's oil and gas production. The total methane emitted from a half million low-producing wells has the same impact on the climate every year as 88 coal-fired power plants.[76]

Concerns about the contribution of fugitive methane emissions was a factor in the allocation of $1.15 billion in funding to states under the Bipartisan Infrastructure Law to clean up orphaned oil and gas wells across the U.S. According to the U.S. Department of Interior, cleaning up orphaned wells will reduce dangerous methane leaks and advance the goals of the U.S. Methane Emissions Reduction Action Plan.[77]

The recently enacted U.S. Inflation Reduction Act includes a tax rising to $1,500 per ton on methane emissions from petroleum and natural gas production and processing facilities and natural gas pipelines.[78]

As concerns about climate change intensify and remote monitoring capabilities improve, the imperative to reduce upstream fugitive methane emissions may motivate operators and regulators to decommission leaking infrastructure sooner than once expected thereby accelerating ARO maturities.

[74] EDF/Ceres Climate Principles for Oil and Gas Mergers and Acquisitions.
[75] The Global Methane Pledge (GMP) was launched at COP26 in November of 2021 by the US and the EU. The pledge has gained momentum, reaching 150 participants of which 50 have or are on their way to developing national methane plans. The US, EU, and 11 other countries launched the GMP Energy Pathway in June 2022 targeting methane emissions from fossil energy. This pathway led to new national policies (such as Canada's proposed regulations for a 75% methane reduction from the oil and gas sector relative to 2012 levels by 2030) as well as plans for national oil companies such as PEMEX and PETRONAS to reduce their methane. The UNEP's International Methane Emissions Observatory (IMEO) was launched just before COP to help improve the data collection and reconciliation that is key to measuring the success of the GMP. A methane tax was introduced in the Inflation Reduction Act rising to $50 per tonne of CO2e in 2026. Other policy ideas such as emissions trading systems (ETSs), emission rate regulations, or technology mandates could also increase the operating costs for assets and reduce their profitability.
[76] New Study: Low-Producing Oil and Gas Wells Drive Roughly Half of Well Site Methane Pollution Nationwide (EDF, April 2022).
[77] Biden Administration Announces $1.15 Billion for States to Create Jobs Cleaning Up Orphaned Oil and Gas Wells (U.S. Department of Interior, January 31, 2022).
[78] Inflation Reduction Act Methane Emissions Charge: In Brief (Congressional Research Service, August 29, 2022).

7.1.4 Judicial rulings

Litigation is another avenue for ARO policy action. Oil and gas AROs generally arise under statute and are enforceable by regulators. However, they may also be enforced by the beneficiaries they are intended to protect (e.g., surface owners whose land is burdened by inactive and non-economic wells, production equipment, pipelines, and hydrocarbon contamination) and other parties in interest.

7.1.4.1 Contingent ARO liability

The 2021 bankruptcy of Fieldwood Energy LLC exemplifies how oil and gas companies can incur contingent liability for AROs on formerly owned assets. The case exemplifies a strategy where large oil and gas companies spin off riskier assets—in this case offshore wells nearing the end of their productive lives—into undercapitalized companies like Fieldwood. The facts are complicated but worth the time to understand, so we cover them in detail below.

Fieldwood was a Houston-based, private-equity backed exploration and production (E&P) company established in 2013. In 2021 it was the 11th biggest producer in the U.S. GOM) by volume. It began acquiring producing assets in the GOM with the acquisition of Apache Corporation's Gulf of Mexico Shelf business in 2013, followed by the acquisition of Sand Ridge's Gulf of Mexico and Gulf Coast business units.

Operators in the GOM are jointly and severally liable for AROs, and the number of E&P companies with joint and several decommissioning liability for Fieldwood's GOM assets is large. Over 500 companies own or once owned an interest in GOM assets ultimately acquired by Fieldwood. With a few notable exceptions including Apache, ConocoPhillips, and Marathon, all appear to be subsidiaries of publicly traded E&P companies or small special purpose limited liability entities.

Fieldwood entered bankruptcy for the first time in February 2018 and emerged on April 11, 2018. The next day it announced the acquisition of all of Noble Energy's deepwater oil and gas assets located in the GOM.[79]

Fieldwood filed for bankruptcy again in August 2020, characterizing the decommissioning costs it shared with Apache as "among the Company's most significant liabilities."[80] In June 2021, a federal judge ordered Shell Offshore, BP Exploration & Production, ConocoPhillips, and Marathon to pay part of Fieldwood's estimated $7.2 billion liability to retire hundreds of aging wells in the GOM that they once owned and had sold to Fieldwood or its predecessor, Apache.[81]

Apache's experience with the Fieldwood bankruptcy illustrates how joint and several liability for decommissioning can boomerang back to former lessees through the U.S. Department of Interior's regulatory process. Under the terms of Fieldwood's 2013 purchase agreement with Apache, Fieldwood paid $3.75 billion in cash and assumed the obligation to decommission the acquired properties. To secure its decommissioning obligations, Fieldwood posted letters of credit in favor of

---

[79] Fieldwood Energy corporate web site; see also How bankruptcy lets oil and gas companies evade cleanup rules.(Grist, June 2021).
[80] Dane Declaration, *In re Fieldwood Energy LLC, et al.*, Case No. 20-33948 (S.D. Tex., Aug. 4, 2020), at 28.
[81] Fieldwood Energy faces pushback to reorganization plan from oil producers (Reuters, June 2021).

Apache and established trust accounts of which Apache was a beneficiary and which were funded by two net profits interests depending on future oil prices.[82]

In September 2021, GOM Shelf LLC (listed as an affiliate of Fieldwood in the bankruptcy petition) notified the U.S. Bureau of Safety and Environmental Enforcement (BSEE) that it was unable to fund its decommissioning obligations. BSEE in turn issued orders to Apache to decommission certain assets included in GOM Shelf's notification to BSEE.

Apache recorded a contingent liability of $1.2 billion for estimated decommissioning costs it may be required to perform on the assets sold to Fieldwood. Apache also recorded a $740 million asset, which represented the amount it expected to be reimbursed from the security provided by Fieldwood. Apache recorded a loss of $446 million ($1.2 billion minus $740 million).

The Fieldwood case illustrates several important points. First, if bankrupt companies default on their offshore decommissioning obligations, co-lessees and predecessors in interest may be on the hook due to joint and several liability. How much of the possibly $50 billion in GOM decommissioning liability is held by companies that are only a dragged anchor, hurricane, leaking pipeline, or oil price shock away from default?

Second, company exposure to contingent joint and several liabilities, like Apache's liability for Fieldwood's wells, remain off-balance sheet until a default occurs. This suggests that investors are typically unaware of a company's full exposure. Apache's financial statements, for example, did not recognize a contingent decommissioning liability until it received notification from BSEE of Fieldwood's default. Even if this is permitted practice under applicable accounting standards, it is little comfort to investors who may see billions in liability appear on the balance sheet overnight.

Third, parties in interest other than regulators such as Apache can and do take steps to protect themselves from ARO defaults by others.

7.1.4.2 ARO creditor rights

In addition to regulatory actions, private parties adversely impacted by ARO defaults (e.g., surface owners whose property is burdened by zombie oil and gas wells) may pursue private rights of action against current and former operators for the resulting harm.[83]

In July 2022, West Virginia landowners on behalf of a proposed class of similarly situated landowners filed a federal lawsuit in the U.S. District Court for the Northern District of West Virginia against Diversified Energy Company Plc and EQT Production Company. *McEvoy et al v. Diversified Energy Company PLC et al*, Case 5:2022cv00171 (N.D. W. Virginia) (the "Diversified Suit").

The case centers on thousands of inactive gas wells in West Virginia operated by Diversified, some of which were acquired from EQT. Diversified is a public limited corporation incorporated in the United Kingdom and headquartered in Alabama.[84]

The plaintiffs are members of a proposed class of landowners whose properties are burdened by these wells. The complaint asserts common law claims for trespass, nuisance, and negligence on

[82] Apache Form 10-K 2021.
[83] See A New Theory of ARO Creditor Rights.
[84] More lenient ARO accounting standards may help explain why a company originally incorporated in the U.S. that operates exclusively in the U.S. would reincorporate in the UK.

grounds that: (a) state law requires operators to decommission wells that remain inactive for one year; and (b) inactive wells are hazardous to human health, damage the environment, contribute to climate change by leaking significant amounts of methane, interfere with plaintiffs' use and enjoyment of their property, and impair plaintiffs' property values.[85]

The complaint states that Diversified owns 23,309 wells in West Virginia, including more than 2,000 wells acquired from EQT in two separate transactions in 2018 and 2020. Plaintiffs assert that Diversified has an obligation to plug more than 2,000 wells in West Virginia that are abandoned or otherwise not productive.[86]

The suit aims in the first instance to enforce the landowners' common law right to have inactive wells decommissioned by Diversified in accordance with state law. The case also asserts that the acquisitions of wells from EQT were fraudulent and should be voided under Alabama's uniform fraudulent conveyance statute, which is functionally equivalent to the California UVTA.[87]

The *Diversified* complaint asserts that the value of the consideration received by Diversified in the two transactions with EQT was not reasonably equivalent to the net amount of the assets transferred and obligations Diversified incurred, assuming appropriate accounting practices are used to value the wells involved in the transfer.[88]

Plaintiffs ask the court to void the EQT transfers and seek damages for decommissioning costs as well as compensation for their lost use of the property and the annoyance, inconvenience, and aggravation associated with the unplugged wells.[89]

When viewed as service obligations owed to governments rather than rights to payment, AROs may not be seen as "debts" within the meaning of state fraudulent conveyance statutes and federal bankruptcy law.[90] But damages resulting from failure to timely decommission inactive and noneconomic wells may be treated differently than the ARO itself.[91]

The legal theory in the Diversified case is novel for two reasons. First, it asserts a new theory of creditor rights: Common law claims for damages arising from inactive wells can create a debtor-creditor relationship between operators and landowners. Second, as creditors, landowners have standing to sue current and former operators for the cost to properly retire inactive wells and related damages.

7.1.5 Unlawful dividends

In a recent report, Carbon Tracker estimated the total cleanup bill for California's onshore oil and gas industry to be $21.5 billion. Meanwhile, California oil and gas production is expected to earn only $6.3 billion in future profits over the remaining course of operations.[92] Stated another way,

---

[85] *Diversified Complaint.*
[86] *Id.*
[87] *Id.*
[88] *Id.*
[89] *Id.*
[90] Rogers, Accounting for Oil and Gas Environmental Liabilities in Bankruptcy, Journal of Petroleum Accounting and Financial Management (Summer 2015), at p. 6.
[91] *Diversified Complaint.*
[92] There will be blood: Decommissioning California's Oilfields (Carbon Tracker, May 2023).

the California oil and gas industry has distributed about $15 billion in earnings to shareholders that were owed to ARO creditors at a time when its liabilities exceeded its assets.

Although not alleged in the Diversified Suit, in addition to claims for fraudulent conveyance, landowners and other creditors may have claims against corporate directors and shareholders for unlawful dividends. Dividends and other distributions to owners made when a corporation is insolvent, or which render a corporation insolvent, are unlawful under state corporation laws.[93] This harkens back to the principle that creditors must be repaid before equity holders.[94]

Importantly, in this context, a creditor may challenge distributions that hinder collection of debts that are not yet due, such as an unresolved claim for relief. The Delaware Court of Chancery recently considered this issue, answering whether to have standing as a "creditor" a party must have been a judgment creditor at the time of the challenged dividends. The court answered 'no', holding that it is sufficient that a party have a claim against the corporation at the time of the challenged dividends, whether or not reduced to a judgment.[95]

7.2 Economic impacts

Asset stranding accelerates AROs and vice versa: AROs reduce the return on assets making marginal assets non-economic and candidates for early retirement. Stranded oil and gas assets impact the financial system through several transmission channels, including asset devaluations, reduced profitability, weakened liquidity and capital resources, and litigation.

This section discusses how AROs directly impact the economy and financial markets.

7.2.1 Asset impairment

Discussion of stranded oil and gas assets generally focuses on petroleum reserves. It's true that unburnable carbon will remain in the ground. However, it is also true that petroleum reserves are worthless without the infrastructure needed to bring them to market. If this infrastructure cannot be built and operated profitably, after consideration of expected asset retirement costs, reserves will remain in the ground.

Whereas petroleum reserves are not burdened by AROs, infrastructure assets are. Assets burdened by AROs must generate additional economic benefits needed to fund their eventual retirement. **If a tangible asset such as an oil well cannot pay for its own retirement, in economic terms, it is a liability not an asset.**

Because AROs reduce the profitability and return on investment from oil and gas infrastructure they make impairment and stranding more likely.

7.2.2 Reduced profitability

AROs are liabilities for future asset retirement costs. Although expenditures for decommissioning oil and gas assets come at the end, they are charged against income (amortized) over the life of the asset. All other things being equal, an asset burdened by an ARO is thus less profitable (and less

[93] See Cal. Corp. Code §§500-509.
[94] *Which Creditors Are Paid First in a Liquidation?*, Investopedia.
[95] *Chancery Decides Questions of First Impression Regarding Statutory Claims for Unlawful Dividends and Fraudulent Transfers*, Morris James (August 2019).

valuable) than one without. However, AROs come with other expenses in addition to asset retirement costs. These include financial assurance fees and higher borrowing costs. At the margin, these expenses can determine whether an asset is profitable or not.

As a general rule, assets that cannot be operated profitably are retired. Accordingly, increased ARO-related expenses can accelerate asset retirement.

7.2.2.1 ARO amortization expenses

AROs are amortized over the useful life of the asset in the form of accretion expense (the unwinding of discounting) and depreciation (the systematic expensing of capitalized asset retirement costs over the remaining useful life of the asset). Policy actions that accelerate the maturity of oil and gas AROs will increase ARO amortization expense and reduce corporate profits. In other words, the same retirement costs must be spread out over a shorter time period. In an extreme example, if burning of fossil fuels was abruptly banned, asset retirement costs that were previously spread over decades would be instantly expensed in the current year.

7.2.2.2 Increased financial assurance costs

Financial assurance is not free. Surety bond premiums for oil and gas well decommissioning, for example, typically range from one to five percent of the face value of the bond depending on the operator's creditworthiness.[96] Operators with poor creditworthiness may be required to pay higher premiums and also post substantial collateral, or alternatively post a cash bond. If regulators increase bond coverage levels (e.g., face value of bonds as a percentage of estimated asset retirement costs) toward 100 percent, the added bond premium fees could significantly impact the profitability of affected assets as well as overall enterprise profitability.

7.2.2.3 Increased borrowing costs

Collateral requirements for ARO financial assurance may increase borrowing costs for oil and gas operators due to the impact of security on loan interest rates. Secured debts are those for which the borrower puts up some assets to serve as collateral for the loan. Unsecured debt has no collateral backing. Lenders issue funds in an unsecured loan based solely on the borrower's creditworthiness and promise to repay. All other things being equal, because the lender's risk of loss on a secured debt is reduced by the value of the collateral, interest rates on secured debt are lower than rates on unsecured debt.

An ARO surety bond is a three-party contract by which the surety guarantees the debtor's performance to a creditor, typically a government entity. When issuing ARO bonds, sureties consider the creditworthiness of the debtor. If the debtor's ability to settle the ARO is in doubt, the surety may insist on collateral, which may be increased or decreased over the life of the bond.[97] The surety agreement may preclude cross-collateralization, so that assets used as a collateral for an ARO bond cannot be used as collateral for other loans. To the extent that capital tied up as bond collateral forces operators to borrow on an unsecured basis, borrowing costs will increase.

[96] See e.g., Oil and gas bonds, Higginbotham and Oil and gas bonds, MG Surety Bonds.
[97] Indemnity Agreements, Explained: Part 2—General Indemnity Agreements (Surety 1, July 2016).

The policy actions described in Section 7.1 will tend to reduce the creditworthiness of the oil and gas sector and individual operators leading to higher borrowing costs, which will in turn further reduce profitability and creditworthiness.

7.2.3 Weakened corporate liquidity and capital resources

The combination of asset stranding, accelerated ARO maturities, and declining profitability could place significant strain on corporate liquidity and capital resources.

The stranding of petroleum reserves and infrastructure are likely to be tightly correlated. If falling commodity prices cause existing petroleum reserves to become stranded, this will accelerate the maturities of oil and gas AROs and the cash outflows required to settle them. Conversely, rising production costs may render marginal reserves and infrastructure unprofitable.

Increased cash outflows for asset retirement costs, higher bond premiums, and higher borrowing costs will consume cash needed for capital maintenance to keep mature infrastructure in safe working order. In a vicious cycle, this may cause assets to become noneconomic sooner, resulting in lower revenues and higher expenditures for asset retirement.[98]

7.2.4 Contingent liability

If regulators fail to enforce AROs, private litigants may do so. New regulatory and judicial policies may increase the contingent liability of oil and gas companies for AROs on current and formerly owned assets. Liability is likely to disproportionately impact older and larger corporations, as ARO creditors seek to hold deep pocket predecessors in interest financially responsible. For example, just ten large corporate groups bear contingent joint and several liability for over 3/4 of total estimated AROs in the U.S. Gulf of Mexico.[99]

7.3 The impairment-retirement cycle

Like the reinforcing relationship between AROs and asset valuations, what we call the “impairment-retirement cycle” is important from a systemic risk perspective because it can cause the rate of ARO acceleration to increase exponentially at the same time revenues and asset valuations are declining from obsolescence.

In Section 4.6 we introduced the term “ARO acceleration” to denote conditions that pull asset retirement costs—both actual closure costs and the carrying costs of financial assurance—forward in time, with the result that asset retirement costs are incurred sooner than expected. In this section, we expand on that idea by explaining how the reinforcing feedback loops shown in Figure 5 and Figure 6 can cause the rate of ARO acceleration to increase exponentially.

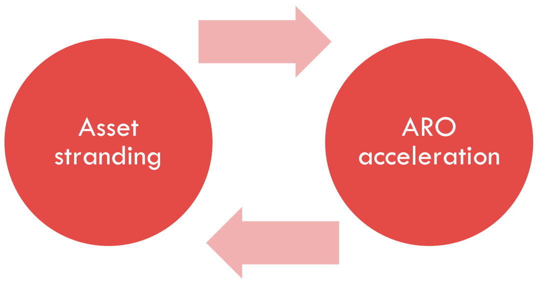
Stranding of oil and gas infrastructure will pull AROs forward in time, but as depicted in Figure 4 the reverse is also true. Under reasonably foreseeable conditions, oil and gas AROs are sufficiently

[98] For example, in its 2019 10-K, California Resources Corporation reported accelerated estimated timing of ARO costs following new California idle well regulations.
[99] Double or Nothing: How regulators are gambling on the future self-interest of large oil and gas companies to decommission the Gulf of Mexico’s aging infrastructure (Carbon Tracker, June 2022) at p. 18, section 4.2 Joint and Several Liability Concentrates Risk.

large to accelerate the stranding of oil and gas infrastructure on a wide scale. As such, they may become the spark that ignites a collapse in financial asset prices.

The idiom "the straw that broke the camel's back" describes how minor actions can cause an unpredictably large and sudden reaction because of the cumulative effect of other actions. Oil and gas AROs could become the last straw for oil and gas financial assets if a combination of policy actions causes the existence and scale of these obscure liabilities to abruptly come into focus.

FIGURE 5 – IMPAIRMENT-RETIREMENT CYCLE

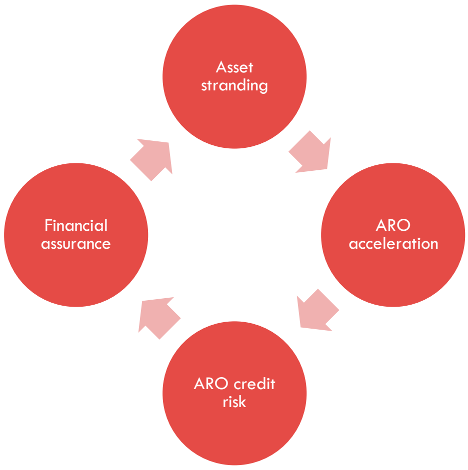


Oil and gas infrastructure assets become impaired and may eventually become stranded when they cannot produce enough future economic benefits to cover the cost to acquire and retire them. Events and conditions that reduce future benefits, increase retirement costs, or both, increase the probability of asset impairment and stranding. These include:

- Higher operating costs
- Taxes on greenhouse gas emissions
- Lower commodity prices
- Lower production volumes from maturing oil and gas wells
- Higher asset retirement costs (e.g., post-closure methane monitoring)
- Higher ARO financial assurance premiums and collateral
- Lower equipment salvage values

Financial assurance costs such as annual surety bond premiums and collateral are particularly pernicious due to the vicious cycle between asset stranding and ARO credit risk. When ARO maturities are accelerated the risk of default on self-bonded AROs rises. Figure 5 expands on the positive feedback loop in Figure 4 to show how **increased financial assurance to mitigate ARO credit risk increases the risk of asset stranding and vice versa.**

FIGURE 6 – OIL AND GAS ARO IMPAIRMENT CYCLE



This cycle would be of less concern if either the future prospects of the petroleum industry were bright or the sector's AROs were prefunded. Neither is true. As noted in Section 1 mature upstream segments of the petroleum industry are already deeply upside-down with AROs that far exceed the value of all estimated future profits from existing reserves and infrastructure.

The reinforcing cycle in Figure 5 pits ARO creditors, including governments and private litigants, against the owners of fossil companies in a cage fight over a dwindling pool of resources. Future actions on the policies discussed in Section 7.1 will determine whether and to what degree the industry's remaining finite resources will be used to settle its AROs or distributed to shareholders.

Climate-driven asset stranding will be reflected in individual corporate financial statements as "impairment losses," also called asset write-downs. Impairments are an important early indicator of systemic risk. Financial statement valuations of petroleum reserves and infrastructure are unlikely to fall to zero in one fell swoop. Instead, devaluation most likely will occur in a series of asset write-downs and ARO write-ups.

As noted earlier, all other things being equal, an asset burdened by an ARO is less profitable and less valuable than one without. A corollary is that an asset burdened by a fully matured ARO is less valuable than the same asset burdened by an identical ARO expected to mature 50 years from now. It then follows that assets may be devalued or impaired as ARO maturities are pulled forward in time due to climate-driven obsolescence and vice versa. As assets become economically impaired, useful lives are shortened, and ARO maturities are pulled forward in time. In sections 7.1 and 7.5 we described policy actions and economic impacts that could cause one or the other.

Financial accounting standards recognize the correlation between AROs and asset impairment. The accounting explanation provided below is technical and for non-accountants hard to follow, but the economic relationship is simple and straightforward. If asset valuations go down due to obsolescence and shortened useful lives, AROs go up (less discounting). If AROs go up due to obsolescence and shortened useful asset lives, asset devaluations are likely to follow. In both scenarios, net asset values (asset value minus ARO) go down.

Under U.S. and international accounting principles, impairment tests compare the capitalized cost of the asset (book value), which includes capitalized asset retirement costs, against expected future cash flows.

Impairment losses are recognized when book values exceed expected future cash flows. Impairments can therefore be driven by higher costs for asset acquisition and retirement or lower cash flows from operations, or both. Higher regulatory costs worsen both sides of the impairment equation by reducing cash flow and increasing the present value of asset retirement costs.

Higher asset-related regulatory costs reduce expected future cash flow and will cause some marginal assets to become non-economic sooner than anticipated. Shortened asset lives increase the present value of AROs and the book value of the associated assets. How? Asset retirement costs are already included in an asset'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 oil and gas assets shorten, and their book values increase.

Impairments losses are recognized when book values exceed expected future cash flow. If expected cash flow goes down (due to increased regulatory costs) and book values go up (due to accelerated asset retirement caused by increased regulatory costs), impairment is more likely. In sum, increased regulatory costs, including higher financial assurance costs, will tend to drive asset write-downs.

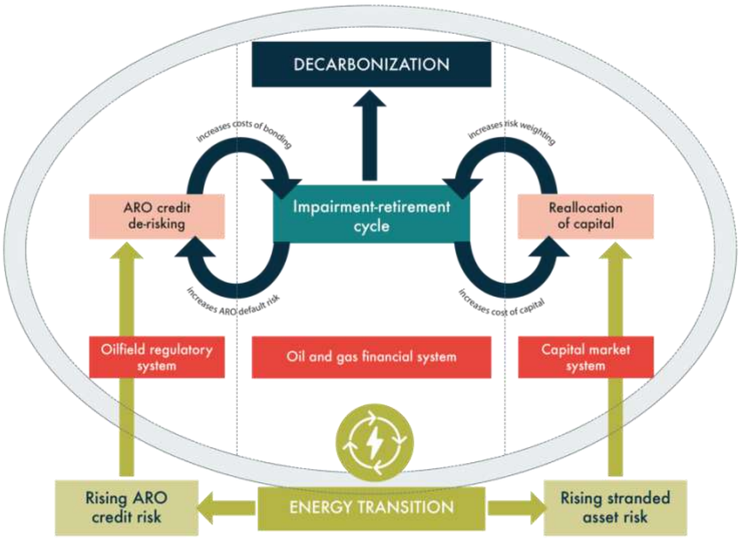
7.4 Financial system impact

The oil and gas finance system is complex, non-linear and dynamic. Reinforcing feedback loops can accelerate suddenly and unexpectedly. Figure 5 illustrates indirect transmission channels between the real economy and the financial system, as they pertain to oil and gas AROs.

As illustrated in Figure 5, asset stranding increases ARO credit risk and vice versa. Because oil and gas AROs are mostly unfunded, when producing assets are stranded there are no more operating revenues to fund asset retirement costs. Regulators need to increase financial assurance to reduce ARO credit risk and force financially capable companies to fulfill their legal obligations but face a dilemma: belated increases in financial assurance will cause more assets to become stranded in the near term as financially incapable companies abandon their AROs and enter bankruptcy.[100] Regulators must choose between the lesser of two evils.

[100] "[New Colorado financial assurance rules] are difficult for small producers and the [Colorado Oil and Gas Conservation Commission] needs to be cautious about unnecessarily exacerbating that problem," Dan Haley, president and CEO of the Colorado Oil and Gas Association, said in a statement. "The COGCC runs the risk of creating more orphan wells if those operators are forced to walk away. The state views low-producing wells as a nonviable business model, but that is just not true." Colorado Seeks Payments for Oil & Gas Cleanup (Capital & Main, January 11, 2023).

FIGURE 7 – OIL AND GAS FINANCE SYSTEM



If retirement dates are brought forward as a result of increased financial assurance and other asset-related costs, the combined effect of accelerated asset retirement and higher costs can impact the financial statements triggering the "impairment-retirement" cycle described in Section 7.3 and shown in the center of Figure 6 causing capital markets to reallocate capital away from oil and gas financial assets. This cycle may happen smoothly or abruptly. If it happens abruptly, it could ignite a sudden repricing event with systemic impact.

As explained above, ARO creditors and the oil and gas industry are in a contest to control a dwindling pool of resources. The outcome of this contest will determine the future of the industry and its vast retirement obligations.

8 Why are oil and gas AROs capable of surprise?

AROs are reported as liabilities on oil company balance sheets. Indeed, in the U.S., AROs have their own dedicated accounting standard. Shouldn't this mitigate systemic risk? Unfortunately, no.

Our unpublished research showed that AROs reported by U.S. oil and gas companies totaled $50 billion in 2019. Although not a direct apples-to-apples comparison due to U.S. companies having assets located outside the U.S. and vice versa, this amounts to under five percent of the $1.2 trillion estimate in **Table 1**.

Opaque ARO accounting and disclosures obscure the uncertainties associated with oil and gas AROs and their capacity to cause or amplify financial instability. Consequently, the scale of these liabilities and their potential to rapidly accelerate may surprise financial market participants. Climate change is a gray swan. Oil and gas AROs may be a black swan.[101]

Some but not all oil and gas AROs are reported as liabilities in oil company financial statements, with unreported AROs for midstream and downstream assets far exceeding reported ones for upstream assets. Worse still, those AROs that are reported may be valued at a fraction of the expected cost to settle them.

Ironically, in an effort to make ARO estimates more reflective of their market value—i.e., what would it cost to transfer these liabilities to a third party today? —accountants have made it impossible for market participants to evaluate the potential financial impact of these obligations in a zero emissions future.

This excerpt from Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, describes the expected present value model used to calculate AROs under U.S. generally accepted accounting principles (GAAP). We have included this for the express purpose of demonstrating the complexity of the model.

> *In estimating the fair value of a liability for an asset retirement obligation using an expected present value technique, an entity shall begin by estimating the expected cash flows that reflect, to the extent possible, a marketplace assessment of the cost and timing of performing the required retirement activities.*
>
> *Considerations in estimating those expected cash flows include developing and incorporating explicit assumptions, to the extent possible, about all of the following:*
>
> a) *The costs that a third party would incur in performing the tasks necessary to retire the asset*
> b) *Other amounts that a third party would include in determining the price of the transfer, including, for example, inflation, overhead, equipment charges, profit margin, and advances in technology*

[101] The term grey swan is derived from the book, *The Black Swan: The Impact of the Highly Improbable*, written by Nassim Nicholas Taleb. Taleb describes black swans as unforeseen and highly uncertain events with extreme potential harm. By contrast, grey swans are foreseen.

> c) *The extent to which the amount of a third party's costs or the timing of its costs would vary under different future scenarios and the relative probabilities of those scenarios*
>
> d) *The price that a third party would demand and could expect to receive for bearing the uncertainties and unforeseeable circumstances inherent in the obligation, sometimes referred to as a market risk premium.*
>
> *It is expected that uncertainties about the amount and timing of future cash flows can be accommodated by using the expected present value technique and therefore will not prevent the determination of a reasonable estimate of fair value.*
>
> *An entity shall discount expected cash flows using an interest rate that equates to a risk-free interest rate adjusted for the effect of its credit standing (a credit-adjusted risk-free rate).*[102]

Key data and assumptions used as inputs to this model, such as the amount and timing of future cash flows, discount rates, and the range of uncertainty associated with these assumptions, are generally undisclosed, making it impossible for market participants to reproduce reported estimates and test assumptions against emerging risks and uncertainties.

8.1 Discounting

Discounting is important from a systemic risk perspective because it obscures the potential financial impact of an abrupt transition.

AROs are reported as expected present value estimates. In this approach an *expected value* is computed using multiple cash flow scenarios with different expected probabilities. This expected value is then discounted to estimate the expected *present* value.

As illustrated by the discounted present values in Table 2, which shows the present value of $1 discounted over various periods at various rates, long asset lives combined with high discount rates can reduce reported AROs to just pennies on the dollar of current dollar costs.

[102] Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, ¶¶ A20-21.

TABLE 3 – EFFECT OF ARO DISCOUNTING

Years/Rate	0	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%	11%	12%	13%	14%	15%
0	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00
1	$ 1.00	$0.99	$0.98	$0.97	$0.96	$0.95	$0.94	$0.93	$0.93	$0.92	$0.91	$0.90	$0.89	$0.88	$0.88	$0.87
2	$ 1.00	$0.98	$0.96	$0.94	$0.92	$0.91	$0.89	$0.87	$0.86	$0.84	$0.83	$0.81	$0.80	$0.78	$0.77	$0.76
3	$ 1.00	$0.97	$0.94	$0.92	$0.89	$0.86	$0.84	$0.82	$0.79	$0.77	$0.75	$0.73	$0.71	$0.69	$0.67	$0.66
4	$ 1.00	$0.96	$0.92	$0.89	$0.85	$0.82	$0.79	$0.76	$0.74	$0.71	$0.68	$0.66	$0.64	$0.61	$0.59	$0.57
5	$ 1.00	$0.95	$0.91	$0.86	$0.82	$0.78	$0.75	$0.71	$0.68	$0.65	$0.62	$0.59	$0.57	$0.54	$0.52	$0.50
6	$ 1.00	$0.94	$0.89	$0.84	$0.79	$0.75	$0.70	$0.67	$0.63	$0.60	$0.56	$0.53	$0.51	$0.48	$0.46	$0.43
7	$ 1.00	$0.93	$0.87	$0.81	$0.76	$0.71	$0.67	$0.62	$0.58	$0.55	$0.51	$0.48	$0.45	$0.43	$0.40	$0.38
8	$ 1.00	$0.92	$0.85	$0.79	$0.73	$0.68	$0.63	$0.58	$0.54	$0.50	$0.47	$0.43	$0.40	$0.38	$0.35	$0.33
9	$ 1.00	$0.91	$0.84	$0.77	$0.70	$0.64	$0.59	$0.54	$0.50	$0.46	$0.42	$0.39	$0.36	$0.33	$0.31	$0.28
10	$ 1.00	$0.91	$0.82	$0.74	$0.68	$0.61	$0.56	$0.51	$0.46	$0.42	$0.39	$0.35	$0.32	$0.29	$0.27	$0.25
11	$ 1.00	$0.90	$0.80	$0.72	$0.65	$0.58	$0.53	$0.48	$0.43	$0.39	$0.35	$0.32	$0.29	$0.26	$0.24	$0.21
12	$ 1.00	$0.89	$0.79	$0.70	$0.62	$0.56	$0.50	$0.44	$0.40	$0.36	$0.32	$0.29	$0.26	$0.23	$0.21	$0.19
13	$ 1.00	$0.88	$0.77	$0.68	$0.60	$0.53	$0.47	$0.41	$0.37	$0.33	$0.29	$0.26	$0.23	$0.20	$0.18	$0.16
14	$ 1.00	$0.87	$0.76	$0.66	$0.58	$0.51	$0.44	$0.39	$0.34	$0.30	$0.26	$0.23	$0.20	$0.18	$0.16	$0.14
15	$ 1.00	$0.86	$0.74	$0.64	$0.56	$0.48	$0.42	$0.36	$0.32	$0.27	$0.24	$0.21	$0.18	$0.16	$0.14	$0.12
16	$ 1.00	$0.85	$0.73	$0.62	$0.53	$0.46	$0.39	$0.34	$0.29	$0.25	$0.22	$0.19	$0.16	$0.14	$0.12	$0.11
17	$ 1.00	$0.84	$0.71	$0.61	$0.51	$0.44	$0.37	$0.32	$0.27	$0.23	$0.20	$0.17	$0.15	$0.13	$0.11	**$0.09**
18	$ 1.00	$0.84	$0.70	$0.59	$0.49	$0.42	$0.35	$0.30	$0.25	$0.21	$0.18	$0.15	$0.13	$0.11	**$0.09**	**$0.08**
19	$ 1.00	$0.83	$0.69	$0.57	$0.47	$0.40	$0.33	$0.28	$0.23	$0.19	$0.16	$0.14	$0.12	**$0.10**	**$0.08**	**$0.07**
20	$ 1.00	$0.82	$0.67	$0.55	$0.46	$0.38	$0.31	$0.26	$0.21	$0.18	$0.15	$0.12	**$0.10**	**$0.09**	**$0.07**	**$0.06**

Discount rates and periods can vary widely. AROs reported under international accounting standards are generally discounted using low risk-free rates. This reduces the effect of discounting. For example, BP, which uses an ARO discount rate under two percent has reported $16.9 billion in estimated undiscounted cash flows to settle upstream AROs (about 16% of BP's total market capitalization). This compares to discounted ARO liabilities of $12.3 billion.[103]

AROs reported under U.S. accounting standards are discounted using higher "credit-adjusted" rates. Counterintuitively, owners with lower credit ratings have higher credit-adjusted discount rates and lower ARO estimates even though those lower credit ratings might indicate a higher risk of default. Notably, although AROs are debt-like obligations, not all credit ratings agencies even consider them.[104]

Also, some operators assume very long lives for upstream assets that may be incompatible with the energy transition. As demonstrated by Table 2, long discount periods combined with high discount rates greatly reduce the expected present value of AROs. For example, Diversified Energy Company says it expects many of its 64,000 mature natural gas wells to profitably operate for another 50 years or more.[105] Diversified uses a credit-adjusted discount rate of seven percent to discount its AROs.[106] One dollar discounted at 7 percent for 50 years is $0.03.

For reasons discussed in the next section, most oil and gas AROs are not reported on corporate balance sheets. Heavy discounting means that those that are may materially obscure ARO acceleration risk.

---

[103] BP 2022 Form 20-F.
[104] S&P considers AROs in its credit ratings. Moody's and Fitch do not.
[105] Diversified Energy Company. Essential to the Energy Transition: Delivering Sustainable Shareholder Value (Diversified Energy, 2021).
[106] We back-calculated ARO discount rates for BP and Diversified by dividing reported annual accretion expense by reported ARO liabilities at the beginning of the year.

8.2 Off-balance sheet AROs

Like discounting, accounting loopholes that allow large oil and gas AROs to remain undisclosed and off-balance sheet are important from a systemic risk perspective because they obscure the potential financial impact of an abrupt transition.

Calculation of discounted present value requires assumptions about the expected timing of future cash flows. It's literally impossible to calculate the expected present value of an ARO without making assumptions about the timing of asset retirement. Where owners claim that an asset's retirement date cannot be reasonably predicted—e.g., midstream and downstream assets that in theory can be operated forever with proper maintenance—liabilities for AROs are not reported at all, leaving them entirely off-balance sheet. Moreover, companies are not required to disclose the undiscounted expected value of these liabilities.[107] **This suggests that 75 percent of oil and gas AROs are entirely off-balance sheet** (see **Table 1).**

Following is a typical example of disclosure related to AROs with indeterminate settlement dates contained in Note 1 to the Consolidated Financial Statements in Philips 66 2021 Annual Report:

> *When we have a legal obligation to incur costs to retire an asset, we record a liability in the period in which the obligation was incurred provided that a reasonable estimate of fair value can be made. If a reasonable estimate of fair value cannot be made at the time the obligation arises, we record the liability when sufficient information is available to estimate its fair value . . .*
>
> *Our practice is to keep our refining and other processing assets in good operating condition through routine repair and maintenance of component parts in the ordinary course of business and by continuing to make improvements based on technological advances. As a result, we believe that generally these assets have no expected retirement dates for purposes of estimating asset retirement obligations since the dates or ranges of dates upon which we would retire these assets cannot be reasonably estimated at this time. We will recognize liabilities for these obligations in the period when sufficient information becomes available to estimate a date or range of potential retirement dates.*

The U.S. Securities & Exchange Commission rejected a proposal by the State of New Jersey Common Pension Fund requesting the Phillips 66 board of directors to issue an audited report that describes the undiscounted expected value to settle obligations for its asset retirement obligations with indeterminate settlement dates on grounds that the proposal "micromanages" the company.[108]

8.3 Disclosure

The magnitude and risk associated with oil and gas AROs may be underappreciated by financial institutions and regulators due to opaque financial accounting and disclosure.

[107] Some investors are concerned that the transition to a low-carbon economy will accelerate ARO maturities. They are seeking more information from fossil fuel companies about reported and off-balance sheet liabilities based on the risk that early asset retirements may leave companies without the cash flow needed to fund asset retirement costs. See 2023 proposal by Legal & General Investment Management America, Inc. requesting detailed quantitative disclosures from ExxonMobil of AROs using the IEA Net Zero Emissions by 2050 (IEA NZE) scenario.
[108] SEC letter dated March 20, 2023.

U.S. accounting standards requires companies to disclose the following information about their AROs:[109]

a. A general description of the AROs and the associated long-lived assets
b. The fair value of assets that are legally restricted for purposes of settling AROs
c. A reconciliation of the beginning and ending aggregate carrying amount of AROs showing separately the changes attributable to the following components, whenever there is a significant change in any of these components during the reporting period:
    1. Liabilities incurred in the current period
    2. Liabilities settled in the current period
    3. Accretion expense
    4. Revisions in estimated cash flows.

If the fair value of an ARO cannot be reasonably estimated, that fact and the reasons therefore shall be disclosed.

Abstract of ARO disclosures in Chevron's 2022 Form 10-K

Asset Retirement Obligations	**12 Months Ended**
	Dec. 31, 2022
Asset Retirement Obligation Disclosure [Abstract]	
Asset Retirement Obligations	Asset Retirement Obligations The company records the fair value of a liability for an asset retirement obligation (ARO) both as an asset and a liability when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. The legal obligation to perform the asset retirement activity is unconditional, even though uncertainty may exist about the timing and/or method of settlement that may be beyond the company's control. This uncertainty about the timing and/or method of settlement is factored into the measurement of the liability when sufficient information exists to reasonably estimate fair value. Recognition of the ARO includes: (1) the present value of a liability and offsetting asset, (2) the subsequent accretion of that liability and depreciation of the asset, and (3) the periodic review of the ARO liability estimates and discount rates. AROs are primarily recorded for the company's crude oil and natural gas producing assets. No significant AROs associated with any legal obligations to retire downstream long-lived assets have been recognized, as indeterminate settlement dates for the asset

[109] ASC 410-20-50-1 & 2.

retirements prevent estimation of the fair value of the associated ARO. The company performs periodic reviews of its downstream long-lived assets for any changes in facts and circumstances that might require recognition of a retirement obligation.

The following table indicates the changes to the company's before-tax asset retirement obligations in 2022, 2021 and 2020:

	2022	2021	2020
Balance at January 1	$12,808	$13,616	$12,832
Liabilities assumed in the Noble acquisition	—	—	630
Liabilities incurred	**9**	31	10
Liabilities settled	**(1,281)**	(1,887)	(1,661)
Accretion expense	**560**	616	560
Revisions in estimated cash flows	**605**	432	1,245
Balance at December 31	**$12,701**	$12,808	$13,616

In the table above, the amount associated with "Revisions in estimated cash flows" in 2021 primarily reflects increased cost estimates and scope changes to decommission wells, equipment and facilities. The long-term portion of the $12,701 balance at the end of 2022 was $11,419.

Information that is not required to be disclosed includes:

- The expected value (undiscounted) of liability for recognized and unrecognized AROs.
- The expected timing of asset retirement.
- The discount rate used to calculate liability estimates.
- The quality of estimates using the AACE cost estimation classification system.
- Key assumptions used in calculating estimates.
- Whether estimates/assumptions are reasonably likely to change in the future.
- Quantification of the uncertainty and risk associated with estimates and key assumptions.
- Sensitivity of estimates to change based on other outcomes that are reasonably likely to occur and would have a material effect, including consideration of climate change, the transition to a low carbon economy, and the company's emission reduction targets.

- The amount of financial assurance (other than legally restricted assets) in place to secure performance in absolute terms and as a percentage of undiscounted AROs.
- The annual cost of financial assurance premiums.
- The impact on financial assurance premiums and collateral requirements if financial assurance coverage were increased to 100 percent.
- Contingent joint and several liability for AROs associated with formerly owned and operated assets.
- Potential shortfalls in funds needed to settle self-bonded AROs as they come due, likely at a time when revenues from commodity sales are falling.

Without this information, financial market participants—including credit rating agencies—seeking to ascertain the quantitative impacts of climate change and the energy transition on reported and unreported AROs will find it impossible to do so. Oil and gas companies could of course voluntarily disclose such information as part of the climate transition plans, as requested by some investors.[110]

[110] See 2023 proposal by Legal & General Investment Management America, Inc. requesting detailed quantitative disclosures from ExxonMobil of AROs using the IEA Net Zero Emissions by 2050 (IEA NZE) scenario. As further evidence of the importance of the proposal, Climate Action 100+, a group of 700 investors with $68 trillion in assets under management, "flagged" it, signaling to investors its significance. Climate Action 100+, Proxy Season & Flagged Shareholder Votes.

9 Conclusions

Oil and gas AROs amplify the potential harm from—and could be the spark that ignites—a climate-related financial shock in oil and gas asset prices. Models of climate-related systemic risk that omit consideration of oil and gas AROs are incomplete and may underestimate both the magnitude and probability of a climate Minsky moment.

Market participants and financial regulators cannot rely on continuation of government policies favorable to the petroleum industry, financial reporting, regulatory financial assurance regimes, or credit rating agencies to mitigate this risk. Indeed, they should fear efforts to correct legacy problems caused by past shortfalls in these areas, as reforms are sure to come as the world transitions to a low carbon economy.

Financial regulators responsible for identifying and mitigating systemic risks should carefully examine the positive feedback loops shown in Figures 4, 5, and 6, which can cause the rate of ARO acceleration to increase exponentially, and consider ways to safeguard the financial system from this possibility.

10 Appendix—Global ARO Regulations

The chart below compares different aspects of national policies regarding oil and gas AROs. Countries such as Brazil, where the state owns the largest oil and gas production company, face different risks to countries like the United States where most companies are privately owned or publicly traded.

Liability regimes, including making all operators liable for the full costs (joint and several liability) and trailing liability (making past owners liable) also vary. Many major producing countries with information available about their laws and regulations impose joint and several liability, including Canada, the UK, and Norway. Trailing liability is slightly less common.

Requirements for financial assurance vary. As is the case of the U.S., these can also vary within the country. Financial assurance (or security as it is called in some national regulations) for decommissioning is required in the U.S. For some countries, financial assurance "may be required" by the regulator (UK), while others simply do not require it (Norway).

One aspect that is a little more nebulous, but still may have significant implications on decommissioning is a "maximizing economic recovery" policy, such as in the UK, which has been pointed out as a reason to keep wells unplugged longer than is reasonable on the grounds that they could be economic in the future; this may tend to leave decommissioning obligations as an open-ended, future problem.

Country	State-owned?	Joint & Several Liability	Trailing Liability	Security/Financial Assurance	Maximising Economic Recovery
United States	No	Varies	Varies	Yes*	No
Canada	No	Yes	Yes	Varies	No
Denmark	No	Yes	Yes	Yes	No
UK	No	Yes	Yes	May be required	Yes
Australia	No	Yes	Yes	No	No
Norway	No	Yes	Yes	No	No
Netherlands	No	No	No	Yes	No
New Zealand	No	Yes	Yes	Yes	No
Italy	No	Yes	No	Yes	No
Germany	No	Yes	No	May be required	No
Brazil	Yes	Yes	Unclear	Yes	Yes
Colombia	Yes	No	No	Yes	Yes
Argentina	Yes	Several**	No	No	Yes

*Financial assurance is required in the U.S., though the amount varies widely depending on federal and state jurisdiction.

**In Argentina, several liability is the default legal obligation but joint and several liability is legally allowed and is often included in the contract for joint ventures between state-owned YPF and private companies.

Disclaimer

To know more please visit:

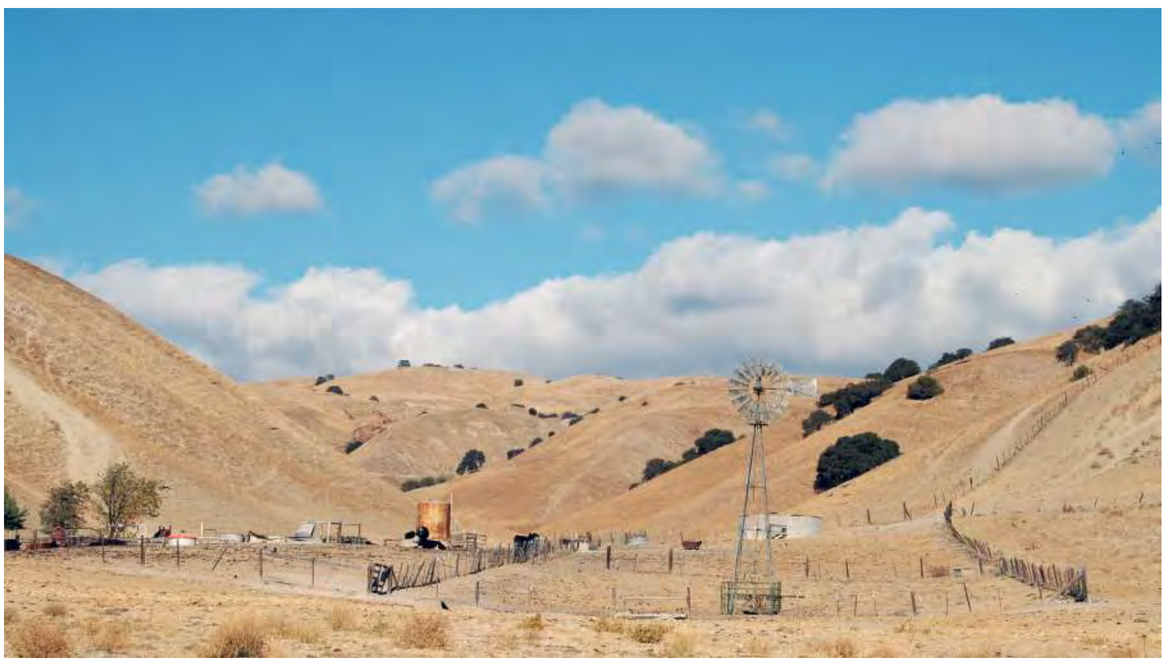
www.carbontracker.org

@carbonbubble

Carbon Tracker Initiative

Orphan Wells in California:

An Initial Assessment of the State's Potential Liabilities to Plug and Decommission Orphan Oil and Gas Wells



An Emerging Topic Report prepared by the California Council on Science and Technology

CCST
CALIFORNIA COUNCIL ON SCIENCE & TECHNOLOGY

A nonpartisan, nonprofit organization established via the California State Legislature — making California's policies stronger with science since 1988.

Orphan Wells in California:

An Initial Assessment of the State's Potential Liabilities to Plug and Decommission Orphan Oil and Gas Wells

An Independent Review of Scientific & Technical Information

Judson Boomhower, PhD
University of California, San Diego
Lead Author

Mikel Shybut, PhD
California Council on Science and Technology
Author and Project Manager

M. Daniel DeCillis, PhD
California Council on Science and Technology
Author

Terence Thorn
JKM Consulting
Steering Committee Chair

Sarah E. Brady, PhD
California Council on Science and Technology
Project Director

Amber J. Mace, PhD
California Council on Science and Technology
Interim Executive Director

November 2018

Summary

In 2017, California was the fourth largest producer of crude oil and the fifteenth largest producer of natural gas among U.S. states (US EIA). There are about 107,000 active and idle oil and gas wells in California. At some point all of these wells will end their productive life and the operator/owner of the well will be required to carefully plug the well with cement and decommission the production facilities, restoring the well site to its prior condition. There is a large population of nonproductive wells in the state, known as idle wells, which have not produced oil and gas for at least two years and have not been plugged and decommissioned. Idle wells can become orphan wells if they are deserted by insolvent operators. When this happens, there is the risk of shifting responsibilities and costs for decommissioning the wells to the State.

There are policies in place to protect the State from the potential liabilities of orphan and idle wells. Operators are required to file indemnity bonds when drilling, reworking, or acquiring a well, to support the cost of plugging a well should it be deserted. However, the available bond funds are often not enough to fully cover the costs of plugging and decommissioning a well. In two recent insolvencies involving offshore facilities, Rincon Island and Platform Holly, the bonds recoverable by the State totaled about $32 million—well under the more than $100 million estimated cost to plug and decommission the wells at both facilities.

Issues with orphan wells are not limited to offshore wells. The vast majority of orphan wells in the state are located onshore. These wells represent potentially large liabilities for the State. In some cases, especially for older orphan wells, there may be no bond available. In an effort to prevent orphan wells, the operators of idle wells are required to pay fees or develop management plans to eliminate long-term idle wells. The Division of Oil, Gas, and Geothermal Resources (the Division) is in the process of updating these regulations and implementing new well testing requirements from recent legislation.

Concerned about the potential financial risks involved with idle and orphan wells and aware of similar problems in other parts of North America, the Division requested the California Council on Science and Technology (CCST) produce a study assessing the State's potential orphan well liabilities. Using existing data from the Division, we have conducted a rough estimate of potential future costs to the State for plugging and decommissioning orphan wells. We have also summarized recent studies that compare the policies and practices of California to other states and regions.

The preliminary analysis performed here finds that 5,540 wells in California may already have no viable operator or be at high risk of becoming orphaned in the near future. The likely plugging and abandonment costs for these wells, based on the State's historical experience with orphan wells, exceed the available bond funds by a factor of 10 or more. The State's potential net liability for these wells appears to be about $500 million. This

estimate ignores environmental or health damages that could be caused by orphan wells, which is a poorly understood category of potential impacts that is outside of the scope of this report and deserves greater study.

An additional 69,425 economically marginal and idle wells are identified here that could become orphan wells in the future as their production declines and/or as they are acquired by financially weaker operators. Increasing the financial security for these wells while they are still profitable may avoid enforcement challenges in the future. Idle Well Fee and Management Plan requirements may also reduce the stock of idle wells, but operators have less incentive to comply with regulations after wells cease production.

The total costs of plugging and abandoning all of the state's 106,687 active and idle oil and gas wells are found to be about $9.1 billion. This gives an unlikely worst-case scenario for the state's total costs. The share of this cost that is ultimately borne by the State (as opposed to operators) will depend on policy choices, market dynamics, and other factors. In comparison, the bond amounts currently held by the state for these wells cover only about $110 million. This study recommends several specific areas where more in-depth research will better inform future policy approaches.

Findings, Conclusions, and Recommendations

Recommendations:

Using the data, results, and recommendations of this study as a framework, the Division should perform a more detailed analysis of orphan well liabilities guided by the following recommendations:

Chapter 1

Background

Among states in 2017, California was the fourth largest producer of crude oil (US EIA) and the fifteenth largest producer of natural gas (US EIA). The state's oil and gas fields are considered mature, and there is a growing population of nonproductive wells in the state.

The life cycle of oil and gas wells depends on a number of factors, the most important of which are production rates and energy market prices (Figure 1). A well can operate profitably for several years or decades depending on the rate of production and operating expenses. At low prices, or as production slows, operators may be inclined to shut down, idle, or hand off non-economic wells and leases. Once a well's productive life comes to an end, it must be carefully plugged with cement and its attendant production facilities decommissioned[1] to prevent any potential hazards. In California, this process is the operator's responsibility.

Under current rules (which have recently been revised), prior to drilling, reworking, or acquiring a well, an operator must file a security with the State in the form of an indemnity bond or other deposit. As of January 1, 2018, this bond cannot be released until the well is properly plugged and decommissioned. Indemnity bonds are an agreement between a principal (the operator), an obligee (the State), and a surety bond company (the surety) that protects the State in cases where operators do not fulfill their obligations to decommission a well—providing payment of the bond amount to the State. These bonds range in amount depending on the depth of the well and the number of wells to be covered. Current requirements for onshore wells range from $25,000 for a single well to $3 million for a blanket bond to cover all of an operator's wells. For offshore leases, there is a blanket $1 million bond required for drilling or modifying one or more wells. The historic and existing bond requirements as well as the availability and adequacy of bonds on file to cover the plugging and decommissioning of potential orphan wells are discussed in Chapters 2 and 3.

Finding 1-1: California requires well operators to obtain an individual or blanket indemnity bond prior to drilling, reworking, or acquiring a well or wells, not to be released until the well is plugged and decommissioned.

1. 14 CCR § 1760 "Decommission" means to safely dismantle and remove a production facility and to restore the site where it was located.

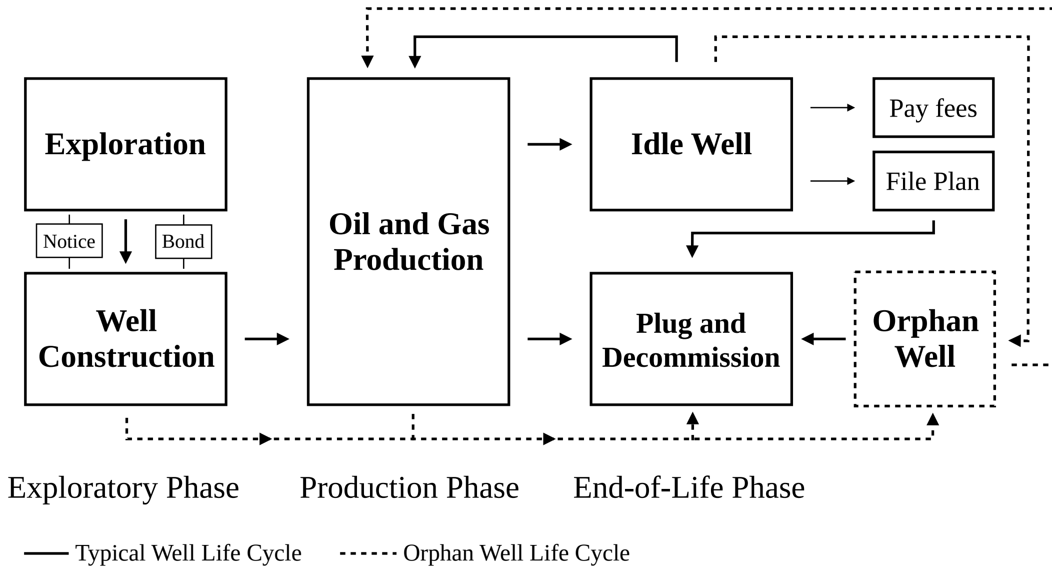


Figure 1. Typical well life cycle in California compared with the orphan well cycle. The initial exploratory phase encompasses the discovery and evaluation of reserves, drilling and completion of the exploratory well, and the determination that the well (field) can economically produce oil or gas. Prior to drilling, a notice of drilling along with an indemnity bond must be filed and approved. Production can last several years or decades depending on the size of the field and operating expenses. When the rate of production and sales fails to cover the expenses associated with maintenance and production, it has reached its economic limit. At that limit, the well may be considered a liability by the owner and may be plugged and abandoned, the production facilities decommissioned, and the indemnity bond recovered. Production can also be idled. A well is classified as idle when there is zero production, or other defined uses, for at least 24 consecutive months. Operators may eventually return idle wells to production, but while idle they may need to either pay annual idle well fees or file an Idle Well Management Plan. Finally, if a well is orphaned prior to plugging, the responsibilities of plugging and decommissioning the well may ultimately fall upon the State.

Finding 1-2: The amount of the required indemnity bond depends on well depth for individual bonds, the number of wells in the state to be covered for blanket bonds, and whether the well is located onshore or offshore. Bond amounts range from $25,000 for a single well to $3 million for a blanket bond covering multiple wells. The amount on file may also depend on when the well was last drilled, reworked, or acquired, and the bonding requirements at that time.

Of the approximately 229,000 oil and gas wells in California, about 122,000 have already been plugged. The remaining 107,000 of them are classified as either active or idle wells. California regulators consider a well to be an idle well if it has not produced oil or gas for

24 consecutive months.[2] Many of California's idle wells are long-term idle wells—wells that have been idle wells for eight or more years.[3] These idle wells are potentially at risk of becoming orphan wells. If not properly maintained or plugged, idle and orphan wells can present a potential environmental hazard. In some cases, these wells may provide a source for fluid and gas migration to unwanted zones. For example, they may leak oil, injected fluids, or formation water into nearby underground drinking water or surface water reservoirs, or release methane or other gases into groundwater or the atmosphere.

From idle to orphan

Wells are not always plugged and decommissioned immediately after production ceases. Operators often maintain wells in a nonproductive, idle state—either to preserve the option of resuming production in the future, or simply to defer the expense of permanently plugging the well.

It costs much less in the short term for operators to maintain a well in an idle state than to properly plug and decommission a well. In California, the required fees to maintain an idle well range from $150 per year to $1,500 per year. This approach also maintains the potential to return the well to production if energy prices increase. Although this "option value" from the ability to resume production can in principle be quite important, research in Alberta, Canada, has shown the decision to leave a well idle is more often driven by a desire to defer decommissioning costs on wells with little likelihood of resuming production (Muehlenbachs, 2015). Ultimately, some operators may declare bankruptcy in order to relinquish their leases and forfeit any requirement to plug and decommission the well, potentially leaving the costs to the governmental regulator.

Wells deserted by insolvent operators become orphan wells. Since orphan wells have no financially viable operator, the State may become responsible for plugging and decommissioning costs. At this point, the State may use the available indemnity bond funds on file, if any, to contribute toward the cost of plugging and decommissioning the well.

Orphan wells are a concern in every state and region that produces oil and gas. At the federal level, a recent study by the U.S. Government Accountability Office (GAO) made several recommendations to the U.S. Department of Interior in order to better protect against billions of dollars of potential decommissioning liabilities for offshore wells in the Gulf of Mexico (GAO, 2016). In Alberta, Canada, potential liabilities were estimated at between $129 million and $257 million for known orphan wells, with the total costs of well liabilities (when considering potential future insolvencies) estimated at up to $8.6 billion (Dachis et al., 2017).

2. PRC §3008(d) Wells that for 24 consecutive months have not produced oil or gas, or have not produced water used to stimulate production, for enhanced oil recovery, reservoir pressure management, or injection.

3. PRC §3008(e).

Recent offshore cases in California: Rincon Island and Platform Holly

In California, there have been several prominent cases where the State has had to take responsibility for an oil or gas field. Two offshore facilities in southern California and their associated wells recently became the responsibility of the State: Rincon Island in Ventura County and Platform Holly in Santa Barbara County. Offshore wells are much more expensive to plug and decommission than their onshore counterparts—often amounting to millions of dollars rather than thousands—and have a high priority to plug due to their environmental risk. For these reasons, operators of offshore wells are required to file higher amounts of security than what is required for onshore wells, either as part of their lease with the State or under Division regulations. This security, typically in the form of a surety bond, is intended to protect the State against losses in the event that the operator cannot afford the cost of plugging and decommissioning their wells. However, at Rincon Island and Platform Holly, the security amounts available were not enough for either facility. The State Lands Commission (the Commission) is responsible for managing leases on submerged lands in the state, including the three miles off the Pacific coast. The Commission requested $108.5 million over three years from the state's General Fund to plug and decommission the wells (California State Lands Commission, 2018a), in addition to millions already appropriated to maintain and monitor the wells.

Finding 1-3: The amount of an indemnity bond may not be adequate to cover the actual plugging and decommissioning costs. For example, bonds on file from the leases at Rincon Island and Platform Holly, $10 million and $22 million, respectively, were a fraction of the estimated costs of over $100 million for both leases.

In the case of Rincon Island, operated by Rincon Island Limited Partnership, the lease had not produced oil or gas since 2008. According to a staff report, Commission staff were prepared to recommend termination of the lease in August 2016 over regulatory violations (potentially risking environmental contamination) and other lease requirements. However, Rincon Island Limited Partnership filed for chapter 11 bankruptcy before the lease was terminated (Fabel & Blackmon 2018). After bankruptcy and eventual relinquishment of the leases, the Commission—with no responsible operator available to take over—entered into an emergency contract with a company to oversee the wells. The Commission also obtained $8 million in a settlement agreement with prior lessee ARCO and worked to secure a combined $10 million surety bond that was held by Rincon Island Limited Partnership.[4] The cost to plug the 49 wells and decommission the facilities at Rincon Island was estimated to be around $50 million over three years (California State Lands Commission 2018a).

At Platform Holly, which had been non-operational since the Refugio Oil Spill in May 2015, the operator Venoco relinquished its leases of the South Ellwood Field in April 2017 and filed

4. According to a February 2018 SLC staff report (Fabel & Blackmon), the Division requested their combined $350,000 bond be released to the Commission, which holds a $9.65 million bond.

a petition for relief under chapter 11 bankruptcy, returning the lease and the platform's 32 wells to the Commission. The Division subsequently ordered that the Venoco wells be plugged and abandoned. When Venoco was unable to do so, the Commission called on and received Venoco's $22 million bond. This bond amount was intended to be larger. In August 2013, an amendment to the lease included provisions for increasing the bond amount incrementally by $4 million per year to eventually reach $30 million in September 2018. This amount was intended to be adjusted in 2025 and every 10 years to accurately reflect the full cost of Venoco's liabilities (California State Lands Commission, 2013).

In 1997, Venoco became the third operator assigned to the lease, following approximately 28 years by ARCO and 4 years by Mobil Oil Company. Under California law, the Division can pursue previous operators as far back as January 1, 1996, for plugging and decommissioning responsibilities. After calling on Venoco's bond, the Commission sought an agreement with the prior lessee, now ExxonMobil, to plug and abandon the wells. In August 2017, the Commission and ExxonMobil filed a letter of intent to discuss the plugging and abandonment of the Venoco wells and collaborated to assess needed repairs that would ease the plugging process. Meanwhile, the Commission hired a contractor to take over daily operations of Platform Holly. Anticipating a potentially lengthy process to reach a final agreement on the extent of liability and funding amount with ExxonMobil—and recognizing the urgency of the situation—the Commission requested $58.04 million from the General Fund to manage the platform and plug and abandon the wells (California State Lands Commission 2018a). In June 2018, the Commission and ExxonMobil entered into a Phase 1 agreement for plugging and abandoning the 32 wells on site, with provisions addressing contested wells modified by Venoco (California State Lands Commission and Exxon Mobil 2018).

In response to these recent offshore bankruptcies, the Governor signed legislation in September 2018 to specifically address any inadequate financial security of offshore oil and gas wells in California (SB 1147, Hertzberg).

The decommissioning of onshore wells

Though these recent cases highlight the more expensive and complicated nature of the offshore plugging and decommissioning process, most wells in California are located onshore. In fact, offshore wells account for just over 2% of all wells in California and, as of January 2018, there were only 19 offshore leases remaining in the state (California State Lands Commission, 2018b). No new offshore lease has been approved by the Commission since 1968.

Like their offshore counterparts in California, onshore wells can also be hazardous and expensive to decommission, especially in dense urban areas. In 2004, an orphan well leaked in a neighborhood in the city of Huntington Beach for several hours. An emergency rig was called in to plug the well (Division of Oil, Gas, and Geothermal Resources, 2011). In 2016, two buried orphan wells were discovered on Firmin Street in the residential Echo

Park neighborhood of downtown Los Angeles after reports of an odor coming from one of the wells. Drilled before 1903, these wells were deserted by their operators. The Division utilized industry funds from their orphan wells program to properly plug the wells. It cost the Division more than $1 million to plug the wells, according to its own estimates. The expense of such onshore projects, along with the sheer number of onshore wells and their location throughout the state, makes them a major point of concern for the State in terms of potential liabilities.

Finding 1-4: The vast majority (nearly 98%) of wells in the state are located onshore. The vast majority of idle wells in the state are also onshore.

Conclusion 1-1: Recent cases in California highlight the potentially expensive and complicated nature of plugging and decommissioning offshore wells and the difficulty of determining liabilities following bankruptcy. As most of California's wells are located onshore, it will be important to assess the potential liabilities for onshore wells in situations where idle wells may become orphan wells.

Considering these recent experiences and concerned about the potential cost and liabilities associated with plugging and decommissioning both existing orphan wells and wells that may become orphaned—which may include some of the thousands of idle and long-term idle wells—the Division asked CCST to assess these potential costs. CCST was also asked to look at the policies of other states and regions regarding orphan well management and cost recovery for how they could inform California policy. To accomplish these tasks, the CCST study team undertook a literature review and examined available datasets from the Division and elsewhere. Through meetings, investigations, and literature and data review, the CCST study team has drafted this report to address the questions and concerns of the Division.

Conclusion

Significant financial concerns exist about decommissioning inactive wells—that is, permanently plugging the wells and reclaiming the surrounding well sites. All producing states and regions face challenges with managing and decommissioning what are known as orphan wells, those without a responsible owner. Since drilling began in the United States in the 1850's, over 2.5 million wells have ceased production. As of 2007 at least 149,000 of these are known to be orphan wells, though the actual number of orphan wells requiring potential remediation is almost certainly significantly higher.

Even the most productive well has a certain useful lifetime. Plugging the well properly at the end of this lifetime can be an expensive procedure whose cost can fluctuate significantly depending on numerous factors, including the well's depth, location, and the price of oil. Wells often pass through the hands of multiple operators through their operational lifetime; frequently operators controlling wells near the end of their lifetime are smaller companies more vulnerable to bankruptcy or dissolution, resulting in orphan wells which the state must then step in and plug itself.

As the overall number of wells has increased, so too has the number of orphan wells, and concomitantly the various states' financial burden. In recent years, state legislatures and oil and gas regulators have increased funding for well cleanup by appropriating more money and increasing bonding requirements. They also have tried to make it harder for companies to walk away from their wells, such as by intervening earlier to prod companies to reactivate or plug wells that are sitting idle.

California, like many states, has devoted increasing effort in recent years to designing a regulatory framework which seeks to both reduce the number of operators orphaning wells in the first place and secure financial assurances adequate to pay for plugging the well when necessary. Currently, California requires well operators to obtain individual or blanket bonds prior to drilling, reworking, or acquiring a well or wells. The amount of the bond required depends on the depth of the well, the number of wells owned by the operator, and the location of the well; bond amounts for most wells range from $25,000 for a single well to $3,000,000 for a blanket bond covering multiple wells. Offshore wells, which comprise only 2% of wells in California but are much more expensive to plug, require an additional bond. The State also collects fees on wells that are kept idle by operators. While the effective amount of bond funds varies across wells, an analysis of the Division data shows that bond funds are typically far below likely plugging and remediation costs.

The Division is currently in the process of implementing updates to their idle well fee and management requirements, including new idle well testing and reporting requirements. These requirements are intended to improve management of this population of wells and protect the State and public against both environmental and financial costs. Future evaluation efforts will gauge the success of these new regulations. For now, at least, there remain significant financial concerns about the existing inventory of orphan wells and the stock of inactive wells that could be orphaned.

While the State currently maintains a comprehensive list of idle (non-producing) wells, the share of these wells that are orphan wells is unknown. A coarse analysis of data provided by the Division on 228,648 wells suggests there are 2,565 “likely” orphan wells belonging to operators with no reported California activity in five years, and an additional 2,975 wells at high risk of becoming orphaned, which have had no production over the past five years and are owned by smaller operators with primarily low-producing wells (which other research suggests are more likely to orphan wells). After subtracting out bond funds associated with the wells, the potential net liability to the State for wells in these categories is about $500 million. There are an additional 69,425 idle and marginal wells and 31,722 higher-producing wells. The eventual cost to plug and abandon all existing wells in California is found to be about $9.1 billion. The share of this long-run cost that will be borne by the State (as opposed to operators) will depend on policy, market outcomes, and other factors.

It is too soon to tell whether California’s current bond requirements and idle well fee collection will prove adequate to cover the cost of orphan well plugging in upcoming years. One of the most significant challenges facing California, along with every other state, is inadequate data. It is not possible to adequately assess the scope of the problem when information about the status of idle wells is incomplete and gathered intermittently. For one thing, existing wells in California may be grandfathered in under previous bond requirements if operators have not reworked or acquired any wells since the most recent requirements were implemented. Also, some wells may have had their bonds released upon well completion, prior to plugging and decommissioning, under old requirements. This contrasts with the approach taken in other states such as Texas, which has implemented a universal bond requirement applicable to all wells, and which was one of the few whose available bond funds have been sufficient to offset the cost of plugging orphan wells in recent years.

As noted earlier, California’s situation is not unique. Analyses have found that most states struggle to meet the costs of plugging orphan wells and typically decommission only a fraction of known orphan wells each year. Like California, the states surveyed have updated their regulations in recent years but these efforts have generally proven insufficient to meet expenses so far.

The estimates we provide in this paper are preliminary and based on coarse sorting criteria using available data. As the Division implements the updated idle well regulations, with mandatory annual reporting requirements, California will gain a more comprehensive and accurate list of remaining hazardous and orphan wells, along with a better sense of responsible operators based on compliance with the updated requirements.

Historical experience and policy analysis in oil-producing regions throughout North

America demonstrate the urgency and importance of orphan and idle well regulation. Most studies agree that higher bond requirements for operators will more fully mitigate the State's orphan well liabilities. Laws governing the priority of decommissioning costs are also important in determining potential costs to governments when operators become insolvent.

California's recent regulatory changes are encouraging. However, it is essential that California continue to evaluate the status of its potential financial liability in upcoming years. A more detailed analysis will be necessary once the State's new idle well reporting requirements are in place, in order to ascertain the State's actual and potential liability more accurately.

The State must also be prepared to accept the fact that, due to the rising number of wells overall, cost to plug each well, and number of older wells requiring remediation, it is likely that any financial assurance model based on a static cost level will require periodic revision. Hopefully, the new information collected and subsequent analyses will help ensure that the State is in a better position to understand its liability, and that such revisions may be implemented in a timely manner.