# Exhibit 12
# "There will be Blood: Decommissioning California's Oil Fields", Carbon Tracker, D. Purvis, May 2023

County of Ventura
Planning Commission Hearing
Case Nos. PL21-0099 and PL21-0100
Exhibit 12 - "There Will be Blood: Decommissioning California's OilFields"; Carbon Tracker, D. Purvis, May 2023

May 2023

# "There will be blood:" Decommissioning California's Oilfields

## About Carbon Tracker

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

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## About the Author

**Dwayne Purvis, P.E.**

Mr. Purvis is the founder and principal advisor of Purvis Energy Advisors. Registered as a professional engineer in the state of Texas, he has advised upstream oil and gas operators as a consulting petroleum engineer since 1995 on matters of reserves, field development, and cash flow analysis both in the normal course of business and in contested settings. He is an active speaker and teacher within the industry and an adjunct professor at Texas Christian University. He is member of oil and gas professional societies including an active volunteer with the Society of Petroleum Engineers. He holds a bachelor of science degree in petroleum engineering from Texas A&M University and is pursuing a master's degree in sustainable energy at Johns Hopkins University.

## Acknowledgements

Background research and data were provided by Theron Horton (Critical State) and Kyle Ferrar (FracTracker). The report was edited and reviewed by Rob Schuwerk, Mike Coffin, and Neil Quach (Carbon Tracker); Theron Horton; and Kassie Siegel and Hollin Kretzmann (Center for Biological Diversity), BLR Digital provided data.

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# Key Findings

- The decommissioning phase of California's oil industry has come into sight. Production rates have fallen 42% since 2014, drilling has almost ceased, 39% of unplugged wells now stand idle, and remaining wells already produce close to the point at which they cannot operate profitably.
- Based on the state regulator's proposed methodology, we quantified $13.2 billion in onshore decommissioning obligations — downhole and surface — due at the end of life. Extrapolating for known but unquantified costs and inflation increases the estimate to $21.5 billion.
- Financial surety provided by industry for those final costs is minimal, $106 million for onshore operations which constitutes 0.8% of quantified costs. It has been widely, but implicitly, assumed that oil companies will pay for their decommissioning obligations out of on-going cash flow.
- To test this assumption, we made scoping estimates of future cash flows at a summary level for each onshore producing region in the state. We calculated that undiscounted future net proceeds over many years of future production total only $6.3 billion.
- Small changes in our assumptions significantly change the estimate of future net proceeds. However, even large changes to our assumptions do not project enough cash flow to pay for the quantified liabilities statewide, much less the extrapolated liabilities which are more than three times as large as estimated future cash flow.

| (millions) | Future Cash Flow | Quantified Liabilities | Inflated Liabilities | Extrapolated Liabilities |
|---:|---:|---:|---:|---:|
| Coastal | $100 | $1,900 | $2,300 | $3,000 |
| LA Basin | $1,700 | $1,700 | $2,100 | $2,700 |
| Sacramento Basin | $300 | $500 | $600 | $1,000 |
| Inland | $4,200 | $9,000 | $10,800 | $14,900 |
| **Total** | **$6,300** | **$13,200** | **$15,800** | **$21,500** |

- **It is unlikely that the upstream oil and gas industry in California will generate enough cash flow in its remaining economic life to fund its current decommissioning obligations even if all future proceeds of operations are used to pay for decommissioning. Absent other interventions, unsettled decommissioning costs will fall to California taxpayers.**

02

# Executive Summary

California's oil and gas producing resources have been in overall decline for nearly four decades, but the industry turned a corner downward with the price collapse of 2015. The inherent cyclicality of the commodity markets overlapped with the intrinsic depletion of the aged resource base and accelerated the decline of the onshore industry. Since 2014, onshore oil production in California has decreased by 42%, and production from gas wells has dropped even further. More importantly, for the first time in decades, new drilling slowed, and the number of actively producing wells also declined even before increasing political pressure.

Unlike better days of by-gone decades, California today contributes 2.7% of U.S. crude production and 0.4% of global production, more than Turkmenistan but less than Thailand.[1] Also at this point, 39% of the unplugged onshore wells in the state officially sit idle, unable to operate economically, and the state of California reports nearly half of those have stood idle already for more than 15 years. Most jurisdictions qualify wells making less than 10 or 15 barrels of oil per day (bopd) as "stripper" wells. By comparison, the median active oil producing well in California produces 3.9 bopd. Including other kinds of wells used to support production, the average rate per active well falls to a little over 2 bopd.

Though commodity prices cycled back up again in 2022, neither drilling nor production showed a meaningful response in the data available. At last report in 2023, only two drilling rigs were active in the whole state of California. By nature, non-renewable resources deplete and eventually end, and these turns of events show that the time has arrived to plan for decommissioning in California.

**At last report in 2023, only two drilling rigs were active in the whole state of California.**

In the past, onshore production in California was stronger financially, more important to the state and more important to the market as a whole. Revenue from oil sales peaked with exceptional prices in 2008 and maintained a high plateau with sustained prices from 2011 to 2014. After years of lower prices, oil price stepped up again in 2022 to previous levels, but production had declined. Gross oil revenues during last year's extraordinary prices weighed in about $800 million per month, less than half of their plateau of revenue ten years before. By comparison, the gross domestic product (GDP) of California in late 2022 was running $303 billion each month,[2] making oil revenue during the recent high prices less than 0.3% of the state's GDP.

Legislation and regulation in California — as in the rest of the country — allowed the inevitable costs of decommissioning to be deferred during those better days, and thus they have now accumulated against declining assets. What financial security does exist as bonding falls far short of actual costs.[3] Industry and regulators have implicitly believed that on-going profits from reinvestments would provide for the eventual cost. Oil companies have historically measured and reported their future cash flow (only sometimes including decommissioning costs) using present value instead of undiscounted figures.

1 bp, "bp Statistical Review of World Energy 2022 | 71st edition", Oil: Production in thousands of barrels per day, bp, London, June 2022, page 15, https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2022-full-report.pdf, (accessed May 2023).

2 Bureau of Economic Analysis, "Gross Domestic Product by State and Personal Income by State, 4th Quarter 2022 and Year 2022", Table 1. Gross Domestic Product by State and Region: Level and Percent Change from Preceding Period", bea, Washington, D.C., 2022, https://www.bea.gov/data/gdp/gdp-state, (accessed May 2023).

3 Carbon Tracker Initiative, "Asset Retirement Obligations (ARO) Portal: State Profiles: Total bond amount, Total liability amount, bonding ratio", Carbon Tracker Initiative, London, 2020, https://carbontracker.org/aro-portal-state-profiles/, (accessed May 2023).

As discussed elsewhere,[4] the fact that all liabilities are discounted more than all profits mean that present value can remain positive even after the point in time when total future liabilities exceed total future profits. Net present value can create a false sense of financial security, and thin margins late in life mean that neither current production rates nor remaining productive life serve as useful proxies for financial security.

If an oil company does not use its own money to plug its wellbores and remediate its surface locations, the cost will fall to government which must raise the funds from other oil companies or from the taxpaying public. California's energy regulator seemed to recognize the risk of unfunded liabilities when it began a rulemaking process to require operators to disclose their decommissioning liabilities according to a standardized formula. This study picks up where the rulemaking left off, attempting to quantify the statewide retirement obligation of the industry and then to compare that against forecasts of those thinning cash flows.

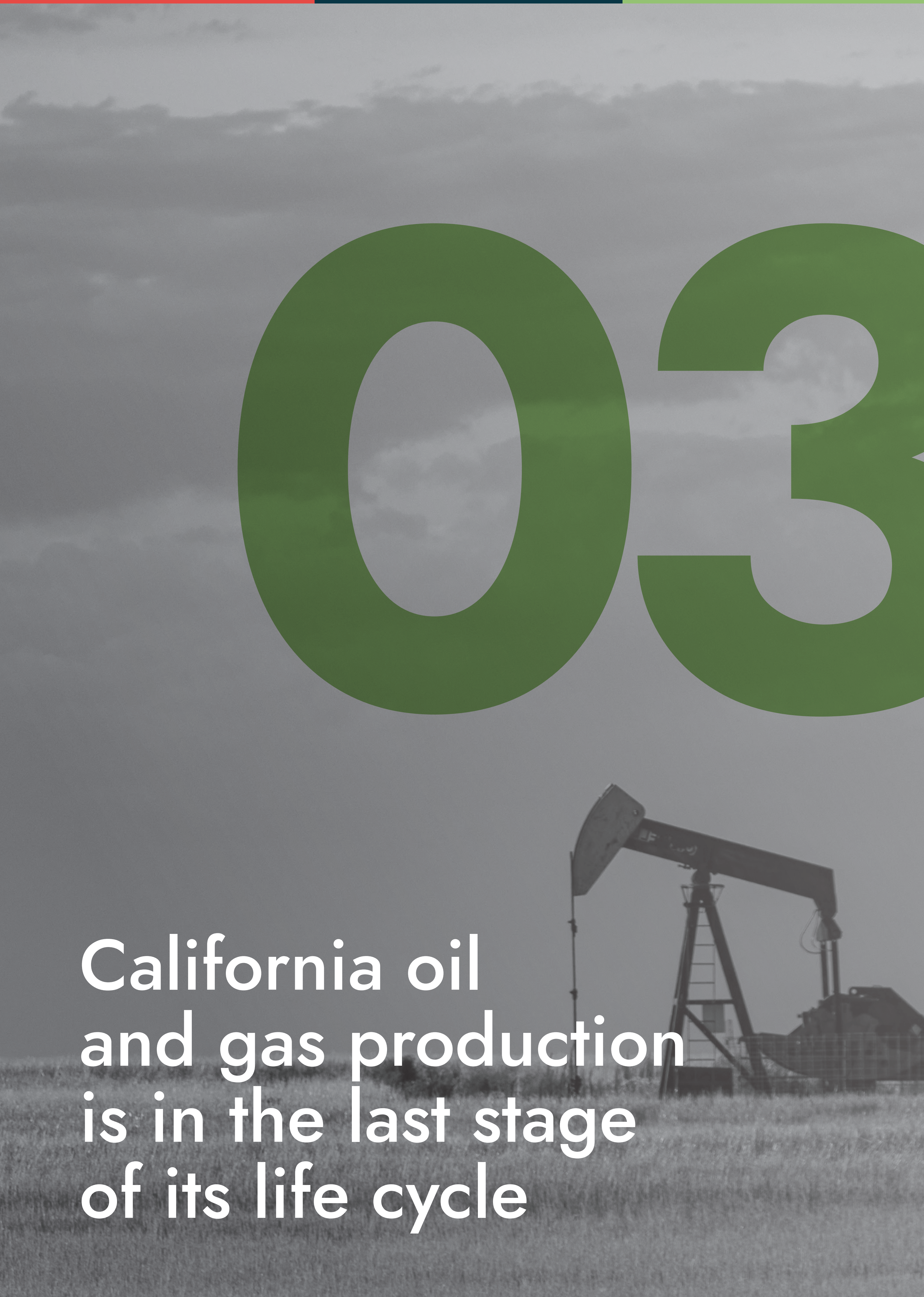
We used the methodology and inputs outlined in the state's rulemaking to estimate the decommissioning liabilities coming due. We populated the inputs using public data, and when we lacked information about a component of costs, we left it out. We quantified downhole plugging costs of $7.5 billion, similar to prior published estimates and consistent with actual costs found in the public record. We also quantified – for the first time in the public record – costs of $5.7 billion to decommission upstream surface sites and facilities. Since the methodology was developed largely before recent cost inflation experienced in the oil industry, we estimated what those costs would be at today's prices, namely 20% greater. Then, to account for excluded costs, we have compared our figures to public estimates and extrapolated to a total of over $21 billion for all decommissioning costs.

**We quantified downhole plugging costs of $7.5 billion and costs of $5.7 billion to decommission upstream surface sites and facilities.**

On the other side of the ledger, we estimated future proceeds using cash flow analysis, the same method used to value assets within the oil industry. However, by necessity we have performed the calculations using high-level summaries and generalized inputs. We relied on historical records of actual production, public markets for future commodity prices, and well-constrained figures for many other inputs. As with decommissioning costs, we compared our cash flow projections over decades of future production against public figures to test their validity, and we found that our estimate of $6.3 billion in future cash flow comports with those public figures. Sensitivity cases offer some insight to the effect of uncertainty when margins wear thin, but those uncertainties pale by comparison to the known and extrapolated costs.

In the end, we find that oil companies' existing financial assurance totals 0.8% of the subset of costs quantified and that estimated future cash flows total less than a third of the total costs. If all proceeds from upstream oil production in the state were redirected now to pay for decommissioning costs, the oil companies or taxpaying public would still need to come out of pocket to fund billions of dollars of clean-up.

4 D. Purvis, "Using Holdback to Avoid the Closing Cash Flow Trap", Carbon Tracker Initiative, London, 24 May 2022, https://carbontracker.org/using-holdback-to-avoid-the-closing-cash-flow-trap/, (accessed May 2023).



# 03

# California oil and gas production is in the last stage of its life cycle

Non-renewable resources progress through a natural life cycle. At field, basin, and even national levels, production follows a pattern of increasing, plateau, decreasing, and finally a long tail of very low production. Oil exploration and production in California began in the 19th century, and the discoveries proved enormous. On-going exploration and diligent efforts to improve recovery historically extended production in the state. However, hydrocarbon resources in the ground do not replenish, regrow, or reproduce. Physical realities require that production and unrecovered reserves eventually deplete toward zero. In the words of fictional California oilman Daniel Plainview, "It's called drainage."

## 3.1 Production decline started decades ago, now has accelerated

The graph below shows historical oil production for the state as well as the number of active wells since 1977 reflecting systematically the vagaries of oil price and resulting activity up to and since its peak in 1985 when it produced about 1.1 million bopd. Since then, production slowly slid by 48% over nearly 30 years from 1985 to 2014. From the recent high in 2014, production in the last eight years has declined to a rate now 42% lower.

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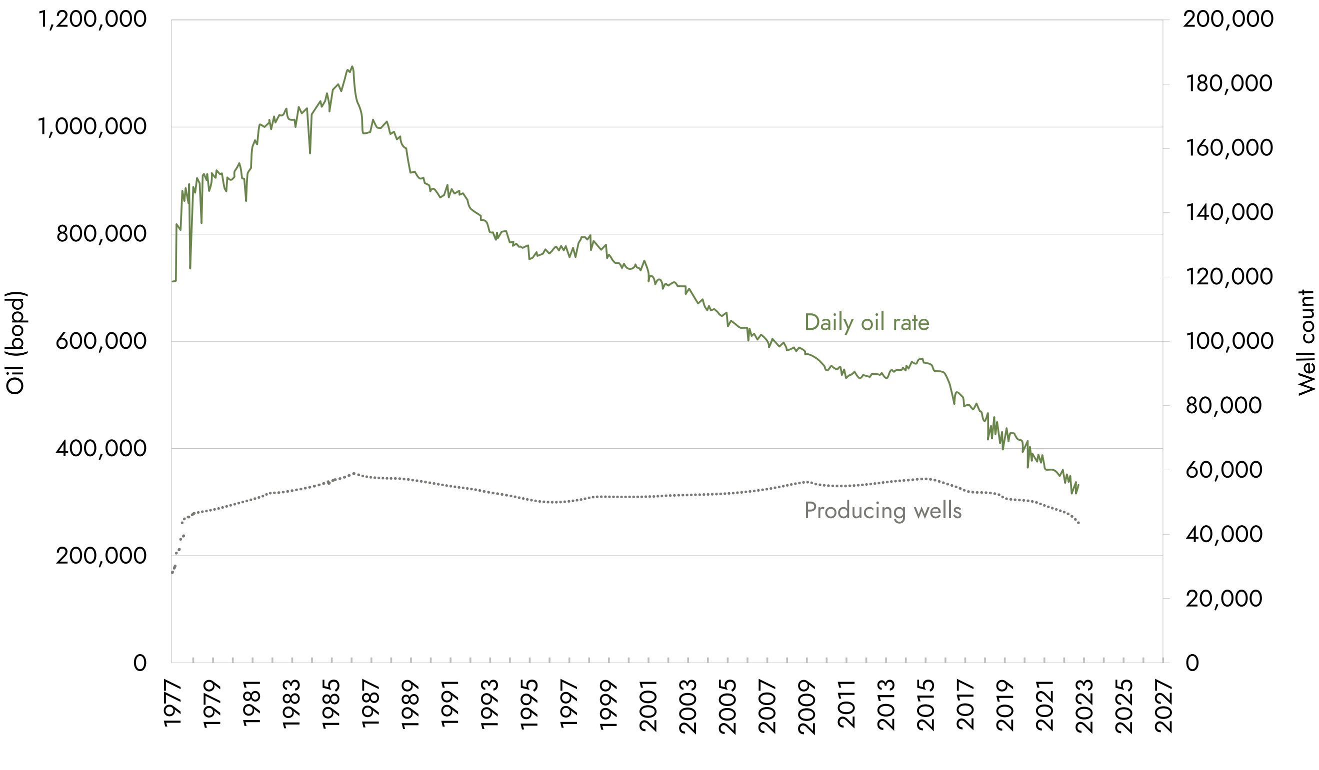
For years while total production shrank, the producing well count increased to mitigate the decline. Since 2014, though, well count reversed it decades long growth as more wells reached the end of their economic life than were drilled to begin their productive life. Partly the decline is simple, natural depletion to the economic limit of production from existing wells. Partly driving the accelerated decline is the fact that drilling of new producing wells declined.

**Figure 1: California oil production and producing well count onshore and state waters since 1977.**

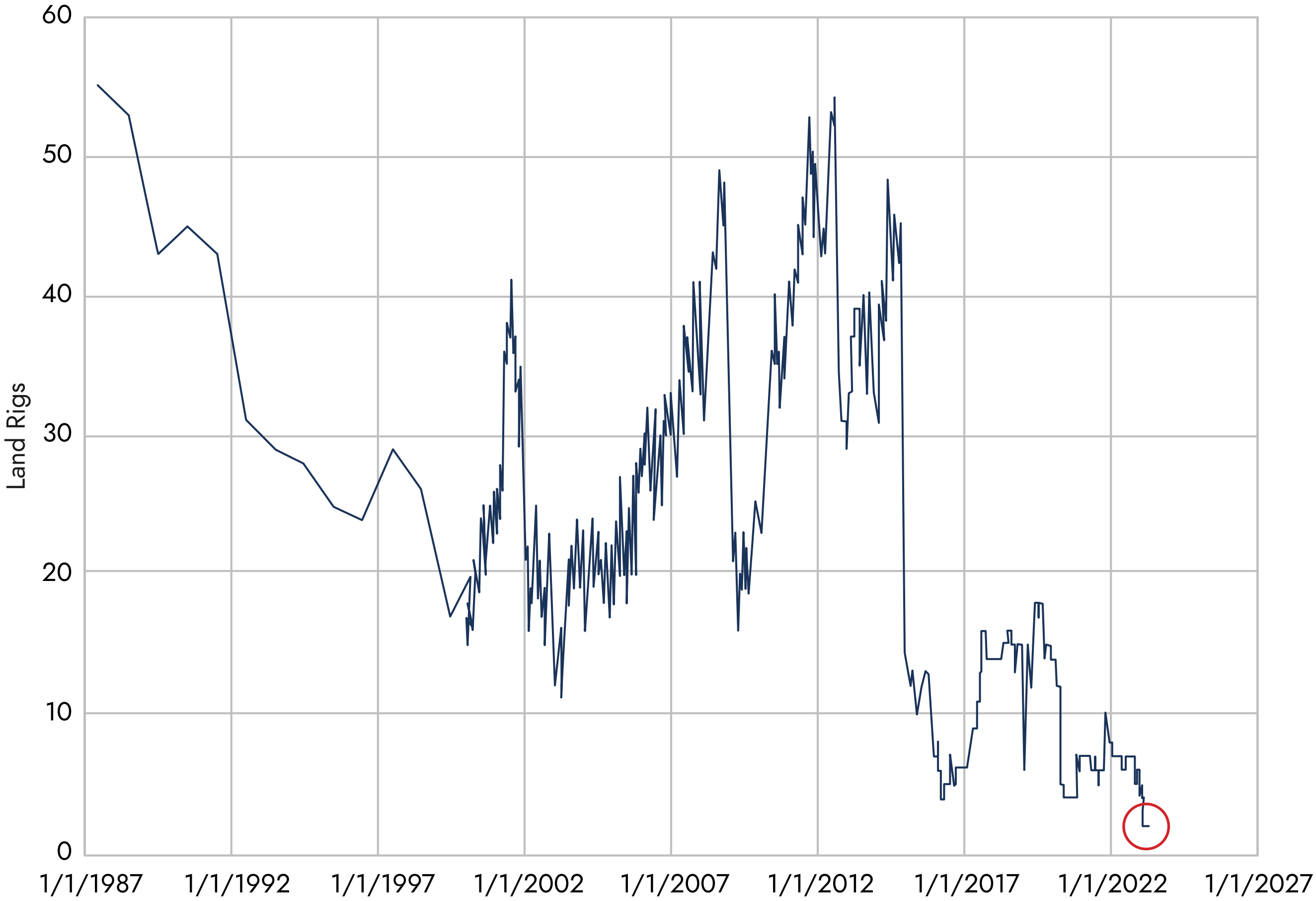


## 3.2 New drilling has fallen steeply

Baker Hughes has documented the number of rigs actively drilling onshore in California since 1987, and Figure 2 below shows their research. From its recent high of 48 rigs in 2014, activity crashed and only partially recovered to about 15 rigs then fell again to about seven rigs in 2021. Though oil prices again spiked in 2022 and though rig count increased again across the country, California rig count held steady. When prices retreated in more recent months and rigs in the rest of the country held steady, California set down rigs. In the last report available at the writing of this report, only two land drilling rigs are active in the state of California, and only one of those was drilling for oil.

**Only two land drilling rigs are active in the state of California, and only one of those was drilling for oil.**

Figure 2: Land rigs active in California since 1987.



To corroborate and clarify, we also examined the pace of new producing wells brought online. For decades, hundreds of new producing wells were brought online each month in California. The recent peak came in 2014 with an average of 236 new producers per month. The 2015 downturn knocked the pace down to a new plateau around 100 new producers each month. Though records become less clear in 2022, it is clear that the number of new producers slashed again, all in tandem with the rig count recorded by Baker Hughes.

Though less important, the story of drilling for dry natural gas in the state traces a more severe history than oil drilling. The pace of new gas producers spiked with prices in 2007 and 2008, then collapsed in subsequent years. Baker Hughes identified zero gas-directed rigs in the state of California from December 2015 until May 2021. In 2021 and 2022, natural gas prices increased by multiples over the previous period, but Baker Hughes identified only a single rig deployed to drill for gas. That last gas-directed rig was laid down in January of this year. Like the pattern in oil, gas production did not respond to the latest price spike.

### 3.3 Drilling activity since 2014 not driven directly by bans

The drop in drilling activity begs the question of causation, whether restrictive regulation or poor economics lay at the root. There have been a number of efforts to restrict drilling in recent years, but it is clear that they are not primarily responsible for the statewide drop in activity since 2014.

Attempted restrictions in Monterey and Ventura Counties persisted briefly but were overturned. At the last peak, these minor counties represented only 3% of statewide activity. The ban on drilling in Los Angeles county and city only took effect in the beginning of 2023, so it played no part in the fact that approved drilling permits for the county had already dropped from an average of 169 per year from 2011 to 2014 to only two permits in 2017. Again in 2021, the calendar year before the ban was proposed, operators received only six permits for all varieties of drilling in the county.

By contrast, Kern County has been home to 85% of drilling permits in recent years, and the county government has attempted to support – not hinder – drilling activity. The county nevertheless suffered three periods of suspension since 2020 over legal challenges. While drilling continued throughout, the business of permitting has proceeded in fits and starts. When the second suspension was lifted late last year, for example, Kern County approved more than 1,000 applications in less than three months, and those permits remain valid for future drilling.[5]

Statewide restrictions on setbacks from activities did not become effective until January 2023, and they remained in force scarcely more than a month. They will now remain impotent until at least late 2024. Perhaps most impactful statewide restriction is the de facto ban on hydraulic fracturing created by California Geologic Energy Management Division’s (CalGEM) refusal to grant permits for that activity related to drilling. In the two years before the shadow ban, CalGEM approved 4,441 onshore drillbit operations, and it approved 303 permits (7% as many) for frac’ing the formation after drilling. In the last two years since the start of the shadow ban, CalGEM approved only 1,732 drillbit operations, a 61% reduction. The ban on permits for hydraulic fracking may have affected hundreds of applications, but the applications for permits have fallen far more than the proportion of previously affected permits.

5 J. Cox, “Appeals court orders halt to Kern oilfield permitting pending review”, Bakersfield.com, California, USA, The Bakersfield Californian, 27 January 2023, https://www.bakersfield.com/news/appeals-court-orders-halt-to-kern-oilfield-permitting-pending-review/article_24aaf4a6-9e8a-11ed-b620-3f1063e6a59d.html#:~:text=A%20state%20appellate%20court%20this,the%20California%20Environmental%20Quality%20Act., (accessed May 2023).

We have not been able to quantify the effects of possible slower permitting at the state or local level or any qualitative effects of a hostile operating environment. On the other hand, most of the concrete efforts to impend drilling seem to have emerged since 2021, well after the start of the recent declines and have been active only intermittently.

## 3.4 Many wells already stand idle

Wells shut down when they stop making money, not when they stop making oil. Costs may decline over life, but production declines more. Production ceases at its "economic limit", when revenues generated — volumes times prices — no longer cover the costs necessary to produce those volumes. For years, many wells have been hitting their economic limit and not been promptly plugged. Decommissioning costs for surface facilities wait for the end of the life of the field, but downhole plugging could be conducted. At this point, 39% of the unplugged onshore wells in the state stand idle; only 61% of the wells remain in use. Nearly half of the idle wells have stood inactive for 15 years or more.[6]

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These costs could have been paid already, but regulations have allowed idle wells to sit unplugged in California as in other jurisdictions. Thus, operators have abided by the law. That practice did, though, allow accumulation of billions in liabilities payable against a diminishing resource base.

## 3.5 Wells mostly producing at rates near historical limits

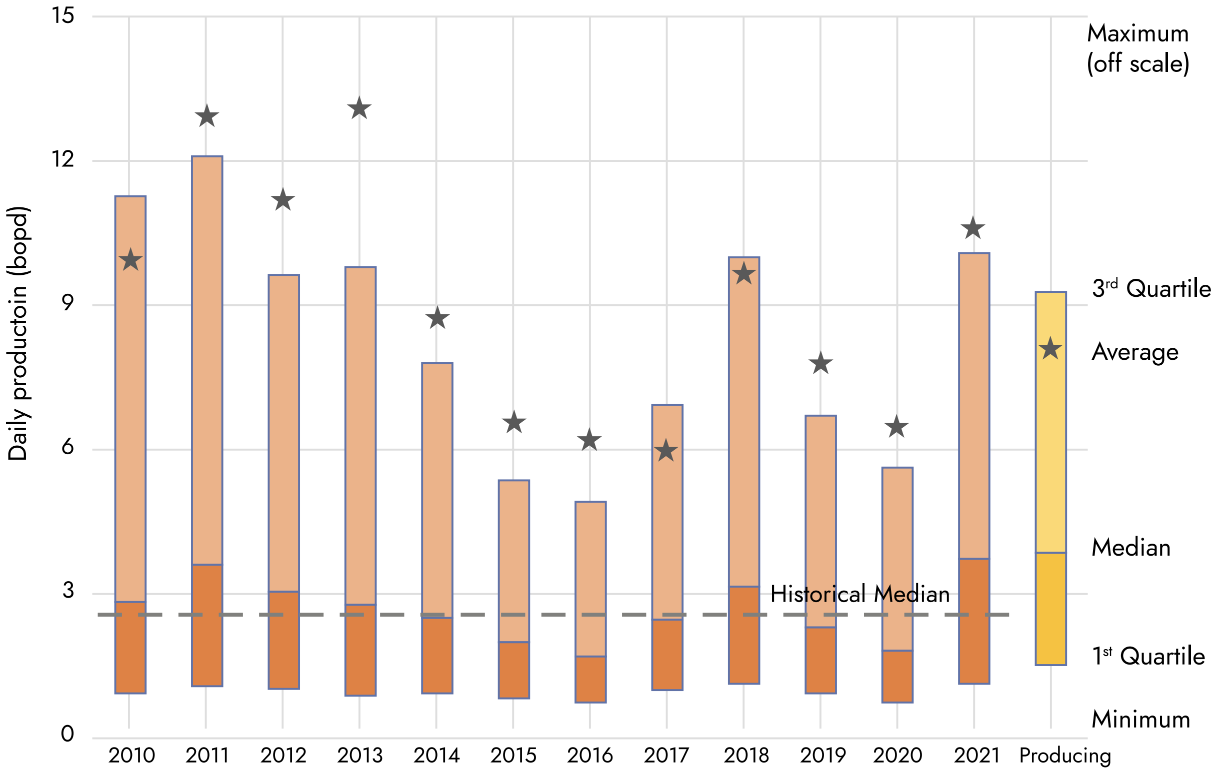
Economic limit varies from well to well, but the commodities sold and the cost of operations tend to correlate within basins and over time. Notwithstanding short-cycle variations in price, historical terminal rates of production can serve as a rough guide to when remaining producers might also by analogy turn uneconomic and end production.

Figure 3 below characterizes the distribution of final rates observed in oil wells that ceased producing in recent years. Among oil wells that stopped producing from 2010 to 2021, the median final rate was 2.5 bopd, but the distribution has a long high side tail which pulls the average terminal rate up to 8.8 bopd. By comparison, among oil wells still producing in 2022, the median production rate was 3.9 bopd, and the average was 8.1 bopd. The same patterns and similar figures apply in each oil region. Though not shown separately, wells in the gassy Sacramento basin follow the same pattern with the distribution of current rates only slightly greater than the distribution of final rates in the past. These figures suggest by analogy what could be inferred by the long history of declining production and declining drilling: remaining producers are systematically close to the economic limit of their production.

**Remaining producers are systematically close to the economic limit of their production.**

6 California Geologic Energy Management Division (CalGEM), "State Oil and Gas Well Plug and Abandonments", California Department of Conservation, California, USA, 21 February 2023, https://www.conservation.ca.gov/calgem/Pages/State-Abandonments.aspx, (accessed May 2023).

Figure 3: Box plot of terminal oil production rates for wells offline 2010 to 2021 plus current rates of wells still producing in 2022.




## 3.6 What these facts say about the future

Whatever happens with commodity prices, wells will continue to deplete or fail mechanically and become uneconomic. Some will end sooner and some later. Production at some level is likely to continue in the state for decades. Permits to drill continue to be filed, and oil price has recently taken a modest step upward with another cut announced by OPEC. Drill pace has recovered in the past, and it will almost certainly recover somewhat again in the future.

On the other hand, measured both by production and by drilling activity, the most recent two price upcycles since 2014 created substantively less activity and less new production than previous cycles. These offer examples of what might be expected in the future from the depleting resource.

The drilling and production figures also show how the shale revolution skipped over California. While most other producing states saw a resurgence of drilling in new locations and achieved fresh peaks of production from new resource bases unlocked by horizontal drilling and hydraulic fracturing, California's geology proved unresponsive to the new techniques. Legacy production in those other states suffered the same depleting trajectory as California, but high-rate, short-lived production from new wells in new locations masked the continuing decline of the larger portion of wells in states like Texas and North Dakota. At this point in the life cycle of North American petroleum resources, there is no class of subsurface resources remaining that might be unlocked by future technology to revive domestic production besides the aging shale revolution. There is no prospect for a geologic revolution in California.

**There is no prospect for a geologic revolution in California.**

04

# Can California operators pay for their decommissioning costs?

The state continues to produce from many wells and will for many years, but remaining duration of production and remaining volumes are not good proxies for the ability to pay for end-of-life costs. At low rates, per barrel costs increase, and operating margins narrow. The slim cash flow preceding financial death is followed by the significant capital expense of decommissioning.

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If the producing fields in California were part of much larger portfolios with active reinvestment programs to expand production, then the profits from other assets might be able – depending also on the legal nature of the subsidiary company - to provide security for the liabilities in these aging fields. Indeed, the largest operator in the state is a subsidiary of a much larger company, Chevron Corporation. However, most operators in the state focus exclusively or mostly within the state. Aera Energy left the aegis of Shell Oil Company and ExxonMobil Corporation with its recent sale. California Resources Company (CRC) and Berry Petroleum (Berry) are independent public companies, and Sentinel Peak is privately owned. In fact, two of these top five producers have already filed bankruptcy once in recent years.

Without the benefit of younger and more profitable assets in the portfolios, the profits from California fields must be used to fund the clean-up of California fields. As production declines, profit narrows and crosses into negative territory before production hits zero. As costs accumulate from deferred plugging, the ability to pay diminishes. We compare undiscounted figures to judge the balance of the ledger of assets and liabilities since discounting for timing can distort the reality of cash flowing in and out.

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By comparison to the initial investments, the decommissioning liabilities may not be large, but they are large by comparison to the cash flows just before the economic limit. As mentioned before, some of those liabilities could be paid during the economic life of the field because operators can pay for the plugging of individual wells as they cease production. In California as throughout the country, operators have been allowed to defer – and thus accumulate – individual well plugging costs also to the end of field life. At a wider scale, though, shared locations and facilities remain in service until the death of the last of the wells, and their decommissioning costs also wait until the end of the economic life of the whole.

A report by California Council on Science and Technology (CCST) written in 2018 but released in 2020 generated a good deal of discussion about the future of the oil industry in California by rightly pointing out the low average production rates in the state and the paucity of surety bonds compared to the total downhole plugging liability for individual wells.[7] Like Colorado and Alberta, California embarked on a process of understanding and potentially addressing the challenges of the decommissioning phase. In November 2021, the CalGEM invited operators to contribute data about the cost of retirement operations. CalGEM incorporated this data and brought forward a proposed methodology in April 2022 for public comment.[8] Since the end of the comment period and while oil and gas prices remained high, no further steps have been taken publicly.

This analysis combines and extends the previous work by CCST and CalGEM using the financial yardstick of holdback as described in our own previous work[9] to propose an answer to the question: At this late stage of life, can future cash flows from the onshore oil industry in California cover the accumulated capital liabilities required to decommission and clean-up their producing infrastructure?

**At this late stage of life, can future cash flows from the onshore oil industry in California cover the accumulated capital liabilities required to decommission and clean-up their producing infrastructure?**

We use public data as inputs to the proposed CalGEM methodology in order to estimate the liabilities – both downhole plugging and surface remediations - which will come due. We estimate the impacts of inflation since the methodology was released, and we extrapolate the value of unquantified costs. On the other side of the ledger, we project production into the future and mate them with estimates of prices and costs to estimate future cash flows. These steps constitute standard evaluation practices, though with less data and less precision than available to the operating companies.

Even with perfect historical information, both sides of the ledger involve inherent uncertainties about the future, but those risks are lopsided. Decommissioning liabilities are certain, but profits are not. Inflation and decaying materials tend to push decommissioning costs upward. On the other side, profits suffer the risk of small changes in operations, costs, or prices, including cost inflation and mechanical decay. Profits can certainly expand with increasing prices as they did in 2022. Of course, when prices cycle back down, production will have also decreased during the episode, and it becomes necessary for commodity prices to increase by larger percentages to have the same effect on cash flow.

7 J. Boomhower et al, "Orphan Wells in California: An Initial Assessment of the State's Potential Liabilities to Plug and Decommission Orphan Oil and Gas Wells", CCST, California, USA, November 2018, pages ix-x, California Council on Science and Technology, https://ccst.us/wp-content/uploads/CCST-Orphan-Wells-in-California-An-Initial-Assessment.pdf, (accessed May 2023).

8 California Geologic Energy Management Division (CalGEM), "Operator Financial Responsibility Program: Cost Estimates for Abandonment of Wells and Decommissioning of Facilities", California Department of Conservation, California, USA, April 2022, https://www.conservation.ca.gov/calgem/Pages/Bonding-and-Financial-Security-Program.aspx, (accessed May 2023).

9 D. Purvis and R. Schuwerk, "Event Horizon: A Case Study of Holdback and the Point of No Return for Decommissioning Upstream Oil and Gas "Assets", Carbon Tracker Initiative, London, 29 July 2022, https://carbontracker.org/reports/event-horizon-a-case-study-of-holdback-analysis/, (accessed May 2023).

05

# Billions in decommissioning liabilities can be quantified and tested, and remaining costs can be extrapolated

To estimate decommissioning liabilities, we adopted the methodology proposed by CalGEM in the spring of 2022, and we relied on public data and industry experience to estimate the inputs. The CalGEM methodology employed the department's own data on costs as well as data submitted by industry. Besides being built on data from multiple sources, the proposed methodology offers two important improvements over other estimates: First, it includes the full scope of decommissioning activities, not just the downhole plugging of wellbores but also the removal and remediation of well sites and surface facilities. Secondly, it includes not just the base costs expected for a simple, problem-free procedure but also includes additional costs related to complicating factors like urban locations and geologic hazards. On the other hand, the methodology considers only initial decommissioning. It does not estimate on-going legacy liability for subsequent issues which do sometimes develop.

When we encountered uncertainty on inputs, we used a central estimate or one expected to be conservative. We have also run some alternative sensitivity cases to illustrate the effects of remaining uncertainties. When we could not constrain the value of a decommissioning cost, we left it out of the equation. For costs as with cash flow below, we also attempted to test our conclusions against what little available data we found in the public domain. Comparisons to other public estimates combined with the size and scale of infrastructure we have omitted suggests that actual costs are much more likely to come in above than below our estimates.

## 5.1 Downhole plugging

To estimate the cost of downhole plugging, most inputs could be attained from public data (such as the boundaries of incorporated municipalities and the outline of groundwater resources) or inferred by analogy to other wells with public data. Parameters which could not be reasonably estimated were excluded from the analysis such as environmental sensitivity, history of leaks, and condition of the wellbore. Those parameters, if known, could only add to the overall cost estimate. These figures do include consideration for multiple wellbores in a single well, and as prescribed by CalGEM this subtotal of costs does not include a few surface operations which would normally be incurred at the same time as downhole plugging. Those costs, especially removal of the wellhead at a cost of $10,158, would likely be included in the downhole portion of others' estimates.

Table 1 summarizes the quantified downhole plugging costs using the CalGEM methodology. For a sense of uncertainty, it also shows 20% of the incremental costs which would be implied if all possible unquantified risk factors were included.

Table 1: Estimated costs for downhole plugging using CalGEM methodology.

| | | | | CalGEM Method (millions) | |
|---|---|---|---|---|---|
| | Unplugged Wellbores | | Avg per wellbore | Costs Quantified | Incl 20% of Unquantified Risks |
| Coastal | 11,055 | 51% inactive | $123,000 | $1,400 | $1,500 |
| LA Basin | 7,110 | 36% inactive | $162,000 | $1,100 | $1,300 |
| Sacramento Basin | 2,147 | 53% inactive | $82,000 | $180 | $200 |
| Inland | 87,124 | 38% inactive | $55,000 | $4,800 | $5,200 |
| **Total** | **107,436** | **39% inactive** | **$69,000** | **$7,500** | **$8,200** |

These figures compare well with previous estimates. The CCST study in 2018 estimated the total plugging liability in the state to be $9.2 billion based on extrapolation of costs paid by the state to remediate a small group of 86 orphan wells in prior years. Previous estimates by Carbon Tracker based on more distant analogs totaled $7.0 and $6.4 billion in 2020 and 2021.[10]

Per well estimates also compare well. The CCST study found an average of $86,500 per well. A study by Ventura County in the Coastal area released in 2022 found that CalGEM had paid an average of $143,300 per well to contractors to clean up 50 orphan wells from 2017 to 2019.[11] In the Inland area, the Kern County Assessor-Recorder specified last year that wells between 1500 and 2000 ft deep should use a plugging and abandonment cost of $57,000 and $66,700 per well to 2500 ft. Last year, the field office manager for the federal Bureau of Land Management estimated that they spent an average of about $100,000 per well to plug four problematic wells in Kern County and that a fifth was estimated to cost $300,000.[12] California's Legislative Analyst's Office reported in January 2022 that CalGEM's most recent analysis showed an average cost of about $111,000 per well in its plugging program.[13] All of these independent estimates serve to corroborate the estimate we've performed since most exceed our own.

## 5.2 Well sites and facilities

As described above, downhole plugging costs for individual wells may be payable first, but they hardly constitute the total cost owed. CalGEM's methodology extends to other aspects of surface remediation like separation vessels, storage tanks, and pipelines. Using a list of facilities from its WellStar database and combining with public data about factors such as urban locations as described above, we could calculate some of the costs associated with some of the facilities but not for all of the costs nor for all of the facilities.

**We could calculate some of the costs associated with some of the facilities but not for all of the costs nor for all of the facilities.**

We could reasonably estimate most of the costs associated with 63% of the unremoved, onshore facilities identified by CalGEM. These estimates, tallied below, include no costs associated with items that we could not quantify, namely pumps and compressors, electrical equipment, refuse, auxillary holes, asphalt and concrete, access roads, and buildings. Although they certainly exist, we found no method and have included no specific estimate for these costs.

10 See https://carbontracker.org/reports/billion-dollar-orphans/ and https://carbontracker.org/reports/race-to-the-top/, (accessed May 2023).

11 County of Ventura Resource Management Agency, "Proposed Amendments to Oil and Gas Regulations: Item 6: Well Abandonment Surety", County of Ventura Resource Management Agency, California, USA, 18 August 2022, https://vcrma.org/en/proposed-oil-and-gas-regulations, (accessed May 2023).

12 J. Cox, "Feds step in to plug deep, dry oil well in Midway-Sunset", Bakersfield.com, California, USA, The Bakersfield Californian, 23 October 2022, https://www.bakersfield.com/news/feds-step-in-to-plug-deep-dry-oil-well-in-midway-sunset/article_3266df40-5184-11ed-a2b6-e71d75ecc48c.html, (accessed May 2023).

13 Legislative Analyst's Office, California Legislature, The 2022 23 Budget: "Report: Oil Well Abandonment and Remediation", Legislative Analyst's Office, California, USA, 21 January 2022, https://lao.ca.gov/Publications/Report/4508, (accessed May 2023).

Table 2: Estimated costs for removal and remediation of site and surface facilities, quantifiable facilities using CalGEM methodology.

| | Facilities Quantified | Costs Quantified (millions) | Unquantified facilities | |
|---|---|---|---|---|
| Coastal | 2,261 | $560 | 880 | incl 632 Settings |
| LA Basin | 2,357 | $560 | 4,581 | incl 107 Urban Drill Sites and 4,149 Pipelines |
| Sacramento Basin | 3,809 | $360 | 1,974 | incl 1,386 Settings |
| Inland | 9,602 | $4,200 | 3,195 | incl 2,380 Settings |
| **Total** | **18,029** | **$5,680** | **10,630** | |

CalGEM data offers no insight to the constituents of the remaining 37% of unremoved facilities which house and interconnect quantified items like tanks and unquantified items like pumps and compressors. Settings for equipment can be as simple as a dirt berm for a single tank or a much more elaborate home for a large family of equipment, and they can include soil pollution in need of remediation. We found no method to quantify these costs directly.

Table 3: Known facilities for which little or no costs are estimated.

| Type | Count | Notes |
|---|---|---|
| Facility Group | 117 | mostly urban drill sites in Los Angeles basin |
| Pipelines | 5,790 | mostly in Los Angeles basin |
| Settings | 4,723 | included only minimal flowlines per Setting |
| **Total** | **10,630** | |

We can, however, make directional estimates for each of these excluded categories. An urban drill site on the campus of Beverly Hills High School was decommissioned with taxpayer money when its former owner filed bankruptcy. The cost to plug 19 wells and to remediate the 0.6-acre site ran to $40 million,[14] compared to an estimated cost of $5 million for the costs which we could quantify. By this example the unquantified costs associated with 107 urban drill sites could run from over $1 billion to nearly $4 billion. If we assume each pipeline runs one mile above ground and one mile below ground, then the Pipelines would total another $1.3 billion. Assuming an average up to $100,000 for each Setting, the total could range from merely tens of millions to nearly $500 million.

We lack the data to opine on the reasonableness of these example calculations, but they do suggest the high probability that excluded facilities are material, especially in the Los Angeles area. Adding excluded costs for facilities considered plus the cost of unquantified facilities, it is possible that the total cost of decommissioning could be much greater than we have used in the following analyses.

**Adding excluded costs for facilities considered plus the cost of unquantified facilities, it is possible that the total cost of decommissioning could be much greater than we have used in the following analyses.**

14 L. Coleman, "Beverly Hills shells out $40M to plug oil wells", Beverly Press Park Labrea News, California, USA, 12 November 2020, https://beverlypress.com/2020/11/beverly-hills-shells-out-40m-to-plug-oil-wells/, (accessed May 2023).

Table 4: Total quantified decommissioning liabilities without extrapolation to unquantified costs.

| (millions) | Wells | Facilities | Quantified Liabilities |
|---|---|---|---|
| Coastal | $1,400 | $600 | $1,900 |
| LA Basin | $1,100 | $600 | $1,700 |
| Sacramento Basin | $180 | $360 | $540 |
| Inland | $4,800 | $4,200 | $9,000 |
| **Total** | **$7,480** | **$5,760** | **$13,140** |

## 5.3 Comparison to public figures

As before, we attempted to validate our summaries with costs stated publicly by other parties, and all three we found suggest actual costs will be higher than our estimates.

In the first case, we find validation of our implementation of CalGEM's methodology by comparison to an estimate of costs by CalGEM itself. Operator HVI Cat Canyon in Santa Barbara County filed bankruptcy when fined for its repeated spills. CalGEM expects the first phase of the decommissioning to cost approximately $34 million to plug 171 wells and remediate facilities. It is interesting to note that CalGEM will handle additional wells – 19% of the total inventory - separately because they "may require more complex remedial work."[15] Our implementation of the standardized CalGEM methodology quantified $35 million for about the same scope of work. The similarity of our quantified costs to the CalGEM figures suggests support for our application of their methodology to most of the wells. The fact that additional wells will cost more supports the extrapolation of downhole plugging costs that we have quantified.

In the second case, we found a point of reference and corroboration in investor filings of Berry Corporation. Neither Berry nor CRC, the other major public company focused in the state,[16] disclose the fraction of assets for which cost is estimated, what the estimate is exactly, the timing of the expenditures, nor the discount rate used to calculate the present value of the ARO which is presented. It should be noted that their disclosures are not anomalous; they follow standard practice.

Back-calculations of Berry's 2022 10-K report shows that its asset retirement obligations total $903 million across all operating areas,[17] but they imply that this estimate is not complete: "We recognize the fair value of asset retirement obligations (AROs) in the period in which a determination is made that a legal obligation exists to dismantle an asset and remediate the property at the end of its useful life and the cost of the obligation can be reasonably estimated."

By comparison to approximately $726 million for the California portion of its costs, our estimate of their liability in California comes to only $512 million. Berry's estimate, incomplete as it seems to be, comes in 42% higher than our estimate.

**Berry's estimate, incomplete as it seems to be, comes in 42% higher than our estimate.**

15 California Geologic Energy Management Division (CalGEM), "HVI Cat Canyon State Abandonment", California Department of Conservation, California, USA, 13 September 2021, https://www.conservation.ca.gov/calgem/Pages/CatCanyon.aspx, (accessed May 2023).

16 We have not compared against asset retirement obligations reported by CRC because they offer less information overall and because their figures seem to exclude some assets for which they've determined they have no liability.

17 Total future capital costs including ARO of $1,608,890 less $706 million for capital costs associated with development of Proved reserves. Allocation based on proportion of unplugged wells.

The last validation compares our figure against a complete and rigorous public estimate of decommissioning costs, and that figure comes in 70% above our methodology. The City of Long Beach as one of the owners of the Wilmington field determined in early 2022 that the total cost of decommissioning both wells and facilities (but not removing production islands) would cost $1.2 billion.[18] Extending our calculations to include wells and facilities in statewaters creates a quantified cost of $718 million. That is, the detailed estimate prepared by the City of Long Beach is 70% higher than our figure calculated using the CalGEM methodology.The special circumstances of this field may make the ultimate cost higher than average. Nevertheless, our estimate of the quantified costs to decommission 30 times as many wells and their facilities statewide runs only 11 times as much as the better estimate of the Wilmington field alone.

**The detailed estimate prepared by the City of Long Beach is 70% higher than our figure calculated using the CalGEM methodology.**

## 5.4 Inflation and extrapolation

Like unquantified costs of downhole plugging and surface decommissioning, another major cost issue certainly exists but remains excluded from our base quantified case: inflation.

The forecasts of commodity prices - and thus revenues - inherently include expected increases in nominal prices due to inflation. In more normal times, one could expect the cost of decommissioning also to inflate appreciably during the years or decades of delay until the fields die due to mechanical deterioration and normal cost inflation. We have not accounted for this continuous and compounding inflation.

More importantly, though, the oilfield has already endured large and systematic cost inflation during the time since the research and preparation of the CalGEM methodology. Concrete data escapes us, but anecdotal evidence of cost increases over recent years for oilfield project generally range from 20% to 40%. The historical information relied upon by CalGEM came mostly from observations of actual expenses before this exceptional inflation. The same activities should be expected to cost significantly more now than when CalGEM performed its work.

**The oilfield has already endured large and systematic cost inflation during the time since the research and preparation of the CalGEM methodology.**

18 B. Richardson, "State bill to increase oil well abandonment funds for Long Beach is on its way to Newsom's desk", Long Beach Business Journal, California, USA, 24 August 2022, https://lbbusinessjournal.com/news/state-bill-to-increase-oil-well-abandonment-funds-for-long-beach-is-on-its-way-to-newsoms-desk, (accessed May 2023).

Independently, to extrapolate for existing but not quantified costs, we've estimated 20% of the maximum unquantified costs for downhole operations and up to a 70% uplift of the facilities estimate. Table 5 shows how the quantified costs could change with inflation and how extrapolated costs would also increase in tandem.[19]

**Table 5: Quantified decommissioning liabilities updated to reflect cost inflation already observed since the creation of the methodology and extrapolated for unquantified costs.**

| (millions) | Quantified Liabilities | Inflated Liabilities | Extrapolated Liabilities |
|---|---|---|---|
| Coastal | $1,900 | $2,300 | $3,000 |
| LA Basin | $1,700 | $2,100 | $2,700 |
| Sacramento Basin | $540 | $650 | $980 |
| Inland | $9,000 | $10,800 | $14,900 |
| **Total** | **$13,140** | **$15,850** | **$21,580** |

19 It might be noted that we have not attempted to adjust for economies of scale or learning by doing in a dedicated, widespread plugging initiative.

# 06

# Existing funds are minor, mostly public money

Other sources of funds to pay for decommissioning do exist besides ongoing operations. By comparison to the $1.1 billion estimated for their share of retiring the Wilmington field both onshore and off, the State of California and the City of Long Beach had set aside a combined $359 million by last year.[20]

For all of the rest of the onshore operations in the state, financial assurance already provided by operators totals $106 million. In 2018, CCST reported the sum of statewide surety to be $107 million.[21] In 2019, the state legislature passed a law allowing CalGEM to seek additional security, but those powers appear not yet to have been exercised for onshore fields.

Some taxpayer money has already been approved to clean up wells orphaned by their previous operators. At the state level, California's state budget has allocated $50 million a year for this year and next evidently from its general funds to plug an estimated 900 of its current inventory of 5,300 wells.[22,23] The initial federal grant from the Bipartisan Infrastructure Act to California for the purpose of plugging orphan wells totaled $25 million, and subsequent formula grants over the next few years have been estimated to come in at $140 million.[24]

Table 6: Existing funds dedicated to decommissioning onshore operations in the state.

| Source | Amount | |
|---|---|---|
| Savings | $359 | state and city funds for Wilmington field |
| Surety | $106 | from operators |
| Federal | $165 | federal money for existing orphan wells |
| State | $100 | state budget for existing orphan wells |
| **Total** | **$730** | **million** |

These alternative sources of funding do not come close to the total liability in the state. Ironically, 86% of existing funds come from or through government entities and only 14% directly from industry. Industry's contribution to financial assurance is 0.8% of the quantified costs of decommissioning.

**Industry's contribution to financial assurance is 0.8% of the quantified costs of decommissioning.**

It should be noted that neither the CalGEM methodology nor this tally of existing funds consider possible value from the salvage of equipment removed during decommissioning. The value of salvage may well be greater than the industry's surety. A market may exist for scrap metal or for used equipment, but both depend upon other market conditions problematic to quantify and beyond scope of this report. The value

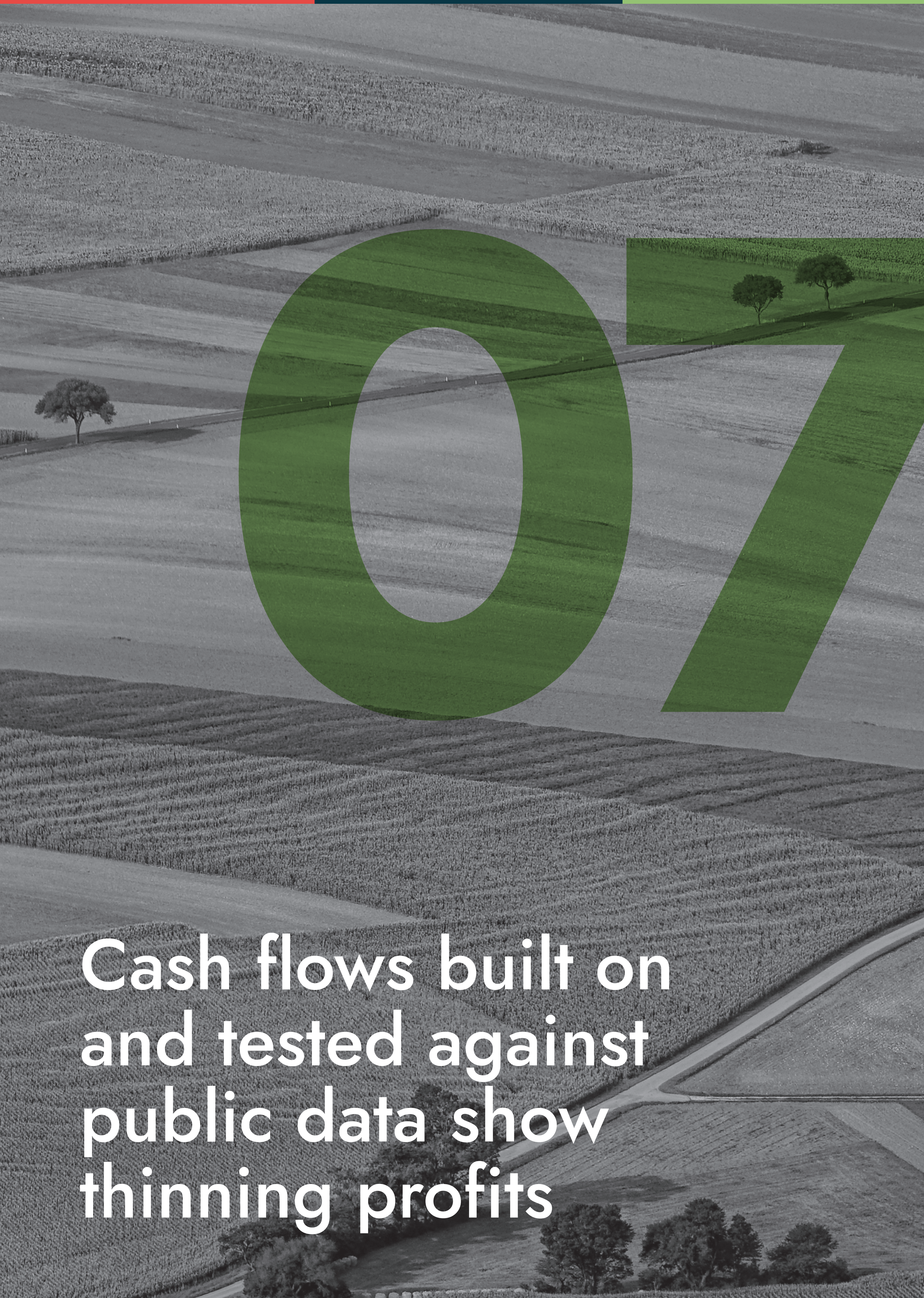
20 J. Ruiz, "Long Beach's plan to safely shut down its oil wells could cost $133 million, take decades to finish", Long Beach Business Journal, California, USA, 25 April 2022, https://lbpost.com/news/long-beachs-plan-to-safely-shut-down-its-oil-wells-could-cost-133-million-take-decades-to-finish, (accessed May 2023).

21 J. Boomhower et al, "Orphan Wells in California: An Initial Assessment of the State's Potential Liabilities to Plug and Decommission Orphan Oil and Gas Wells", CCST, California, USA, November 2018, page 28, California Council on Science and Technology, https://ccst.us/wp-content/uploads/CCST-Orphan-Wells-in-California-An-Initial-Assessment.pdf, (accessed May 2023).

22 California Geologic Energy Management Division (CalGEM), "State Oil and Gas Well Plug and Abandonments", California Department of Conservation, California, USA, 21 February 2023, https://www.conservation.ca.gov/calgem/Pages/State-Abandonments.aspx, (accessed May 2023).

23 Legislative Analyst's Office, California Legislature, The 2022 23 Budget: "Report: Oil Well Abandonment and Remediation", Legislative Analyst's Office, California, USA, 21 January 2022, https://lao.ca.gov/Publications/Report/4508, (accessed May 2023).

24 J. Cox, "State welcomes federal dollars for helping plug orphan oil wells", Bakersfield.com, California, USA, The Bakersfield Californian, 27 April 2022, https://www.bakersfield.com/news/state-welcomes-federal-dollars-for-helping-plug-orphan-oil-wells/article_b33f4026-c65b-11ec-9c3e-b35a96afe5d2.html, (accessed May 2023).



# 07

# Cash flows built on and tested against public data show thinning profits

is widely uncertain, but not uncertain enough to alter the fundamental balance of assets and liabilities.

On the other side of the ledger, we have made a scoping study of the potential cash flow of fields in California and thus clarified the possibility of their being able to fund their own retirement and remediation. It is the same style of analysis that would be used for a purchase of the assets but with less resolution since it makes the calculations at a summary level instead of a well level.[25]

Of course, it is not possible or even practical to use detailed and proprietary cash flow information for all wells throughout the state. However, a good deal of data is available from public sources. To evaluate the producing assets we use standard cash flow analysis populated with a combination of public data, disclosures by public companies, and industry experience.

## 7.1 Components of current cash flow

As demonstrated by history, it is possible for production to flatten or even increase with dramatic changes in price. Of course, those gains in revenue require significant capital expenses. Though some operators have reported Proved Undeveloped reserves ready to be drilled and produced, our analysis considers only what is online, producing today.

Future revenues are the product of volumes sold and the price received for the interest owned. Historical production guides expectations of future production, and expectations of commodity prices are quantified in the futures market. History also tells us about the likely royalty owed. Consequently, multiple inputs can be constrained reasonably well.

The revenue quantified above must cover four categories of costs before excess funds become available for retirement activities: direct operating costs, general and administrative (G&A) overhead, local and state taxes, and maintenance capital. Little data exists in the public domain on these private costs. We have considered the investor disclosures of the few public companies whose reporting isolates California operations and tempered that research with experience. We have also assumed that costs will decline in aggregate in the future with the declining count of producers.

Maintaining production in old fields like those in California commonly requires a regular pace of modest maintenance capital such as the replacement of facilities or re-drilling of wells. We have not been able to quantify those costs separately, and we have excluded them from our forecasts. Instead, our work assumes that operating costs alone are sufficient to maintain observed trends.

25 We have not tried to test the balance sheets of operators in the state which may include debt, cash, or other cash-flowing assets, and we have not tried to consider whatever price hedges operators may have bought at lower or higher commodity prices which would impact future revenue.

Figure 4: Map of unplugged well locations, groundwater, urban areas, and geologic hazards in the state of California.

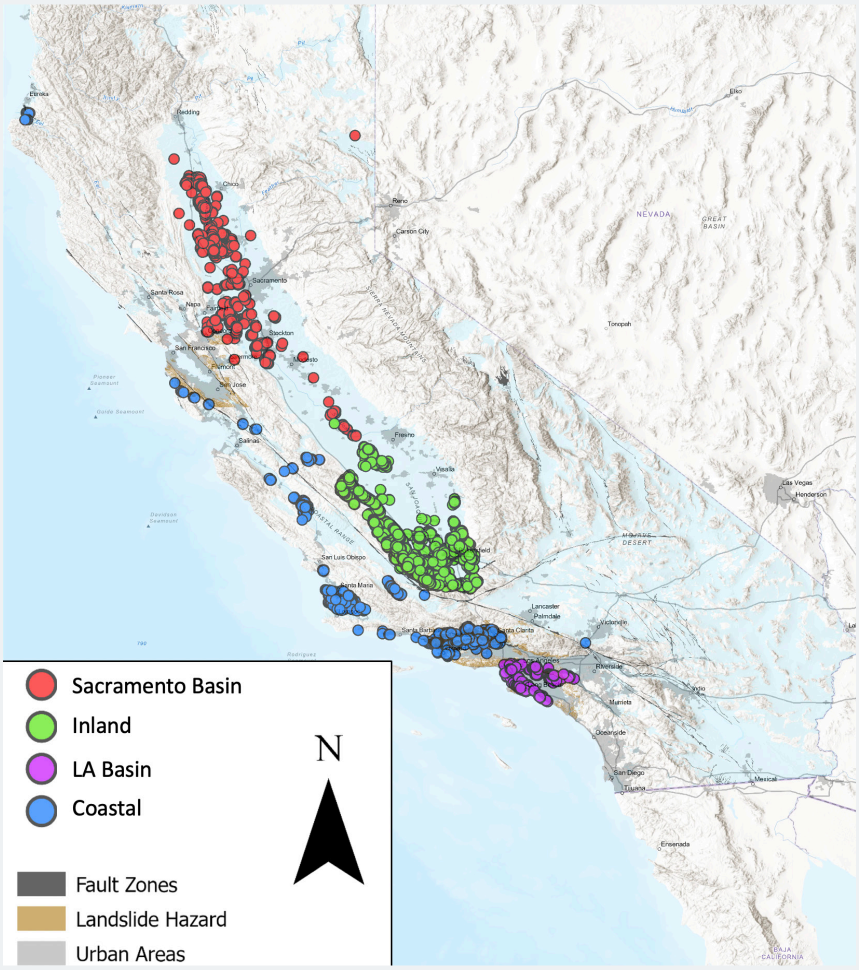



Table 7: Projected revenues, costs and cash flow by area.

| (millions) | Future Revenues | Future Costs | Future Cash Flow |
|---|---|---|---|
| Coastal | $1,400 | ($1,300) | $100 |
| LA Basin | $7,100 | ($5,500) | $1,700 |
| Sacramento Basin | $660 | ($410) | $250 |
| Inland | $21,300 | ($17,100) | $4,200 |
| **Total** | **$30,460** | **($24,310)** | **$6,250** |

## 7.2 Uncertainties

Our calculations project smoothly changing production, prices and costs. Thus, the resulting cash flow tapers down smoothly to a single ending point for the entire region. The net cash flows are thus sensitive to inputs which change those margins, and reality will be more complex than assumed. When the difference between a large revenue and a large cost is small, then small changes in either revenue or costs create a large proportional change in the difference. As discussed more below, minor changes to inputs can create a large percentage change in the answer even without making large changes in absolute magnitude and without changing our overall conclusions. Though we forecast declining overall costs, we hold operating costs constant on a per well basis notwithstanding recent cost inflation and the remaining life up to several decades. Decreasing overall costs less or inflating per well costs would, for example, pinch out the forecasts sooner.

**When the difference between a large revenue and a large cost is small, then small changes in either revenue or costs create a large proportional change in the difference.**

Our projections do not include the potential for disruptive risks and cascading shut-ins, though these are not uncommon. Of course, price fluctuations strongly correlate among wells and systematically float or sink revenues, causing similarly-producing wells to hit their economic limits at about the same time. It also happens that groups of wells become uneconomic simultaneously when they can no longer support shared costs. Correlation among the economics of wells, such as demonstrated in the Sacramento basin in 2020 below, can cause widespread shut-ins, and there are anecdotal reports of group shut-ins in the area. Experience validates that aggregate production decline often steepens late in life. These risks asymmetrically threaten cash flows, accelerating unchanged liabilities, but remain excluded from our analysis.

**Correlation among the economics of wells can cause widespread shut-ins. Experience validates that aggregate production decline often steepens late in life.**

On the other hand, there are likely to be cases where the wells manage to produce much longer than the bulk of the area. Though this tail production can be long, it is invariably small by comparison to the preceding group rates. Though the future will be complex and paradoxical, on balance it faces higher systematic risk than is reflected in our forecast.

### 7.3 Comparison to public figures

As with information about retirement costs and operating costs, information about future cash flow of Californian fields is scant. To test our cash flows, we compared the results of our assumptions against high-level figures available from investor filings for CRC plus the recent sale price of Shell Oil Company's (Shell) interest in Aera Energy to IKAV.

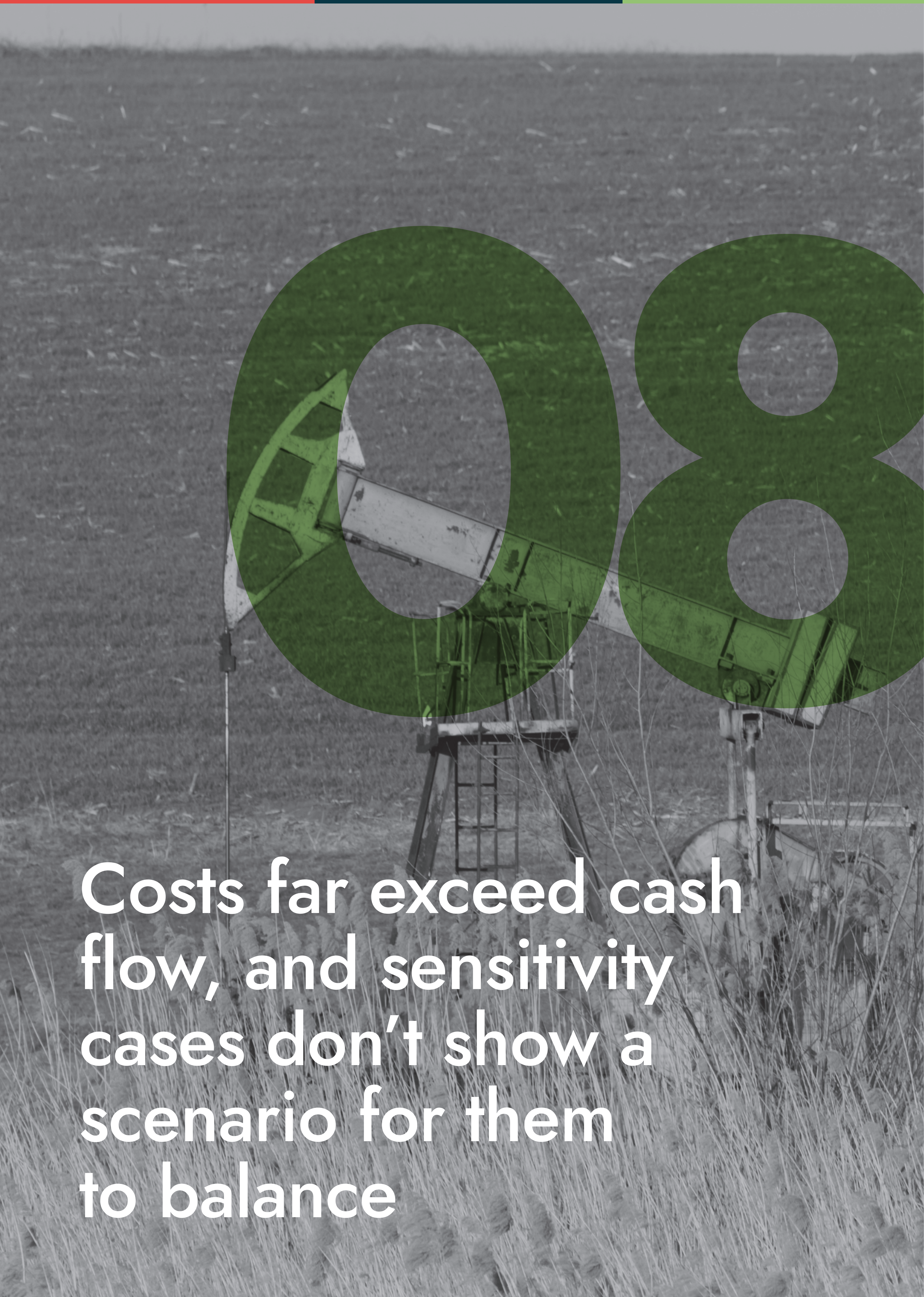
Over the last three years, both commodity prices and operating costs have increased significantly for California Resources Company, and the effects show up clearly in the pattern of reporting of their Standardized Measure of Oil and Gas (SMOG) in investor filings. Adjusting its year end 2022 figures for undeveloped reserves, current price expectations, and on-going G&A, the figure reduces to an undiscounted sum on the order of $2 billion in future available cash flow. The resolution is poor, but the figures are the same order of magnitude as our estimates for their interests.

Each of the adjustments are reasonable and relatively minor taken separately, but the new bottom line figure differs markedly from the figure presented in the securities filing. Concerning its use of "existing economic, operating and contractual conditions," CRC rightly admonishes, "Such assumptions, which are prescribed by regulation, have not always proven accurate in the past. Other valid assumptions would give rise to substantially different results."

The last test of our methodology comes from the recent sale of Shell's 52% interest in Aera Energy, the state's second largest producer, for "approximately $2 billion." The deal was announced on September 1, 2022, so the buyer presumably had the opportunity to lock in the highest oil prices seen in many years, starting with nearly $100/bbl in the early months of the forecast. What is more, the effective date of the sale was nearly a year earlier, meaning that the purchase price gave them rights to the last year of profit at those elevated prices. (Ironically, the price still came in approximately 20% below Shell's book value for the asset, [26] meaning that the actual value judged by the market was much less than Shell had been carrying on its books.) Lastly, the purchaser announced that it purchased the asset for uses besides oil production. These factors mean that it is not appropriate to extrapolate the purchase price directly to the value today of either the company or the statewide assets today.

Instead of bringing that private valuation to the present, we tried applying our methodology to value the assets at the date of higher price expectations and including a previous year of income. Using our work on forecasts, costs and other economic inputs to try to reproduce the purchase price, we calculate the interest to have had a net present value of $3.3 billion discounted at 10%, significantly above the $2 billion purchase price. Without knowing what considerations the purchaser may have given to retirement costs and the unrelated upside value, we can conclude that our evaluation is not inconsistent with the actual sale of Shell's interests in Aera.

26 Shell Global, "Shell to sell interest in Aera Energy to IKAV", Shell Global, London, 01 September 2022, https://www.shell.com/media/news-and-media-releases/2022/shell-to-sell-interest-in-aera-energy-to-ikav.html (accessed May 2023).



# 08

# Costs far exceed cash flow, and sensitivity cases don't show a scenario for them to balance

Table 8 summarizes our calculations of the remaining undiscounted cash flows and costs of decommissioning quantified strictly using CalGEM's methodology without inflation or extrapolation. Notwithstanding uncertainties and conservatism discussed above, the base results suggest a statewide cash flow shortfall of $6.9 billion assuming that all future proceeds of operations are used for decommissioning. Updating the costs for inflation known to exist increases the shortfall to $9.5 billion, and extrapolating the total for unquantified activities enlarges the shortfall to $15 billion which is more than twice our estimate of future cash flow.

**Notwithstanding uncertainties and conservatism discussed above, the base results suggest a statewide cash flow shortfall of $6.9 billion assuming that all future proceeds of operations are used for decommissioning.**

**Table 8: Shortfall of project cash flow against quantified liabilities without updating for known inflation or extrapolation for unquantified costs.**

| (millions) | Future Cash Flow | Quantified Liabilities | Shortfall | % of Future Cash Flow |
|---|---|---|---|---|
| Coastal | $140 | $1,900 | -$1,800 | 1300% |
| LA Basin | $1,700 | $1,700 | $0 | 0% |
| Sacramento Basin | $250 | $540 | -$290 | 120% |
| Inland | $4,200 | $9,000 | -$4,800 | 110% |
| **Total** | **$6,300** | **$13,200** | **-$6,900** | **110%** |

**Table 9: Shortfall of project cash flow against inflated and extrapolated costs.**

| (millions) | | Inflated Liabilities | Shortfall | % of Future Cash Flow |
|---|---|---|---|---|
| Coastal | | $2,300 | -$2,200 | 1500% |
| LA Basin | | $2,100 | -$400 | 20% |
| Sacramento Basin | | $650 | -$400 | 160% |
| Inland | | $10,800 | -$6,600 | 160% |
| **Total** | | **$15,800** | **-$9,600** | **150%** |

| (millions) | | Extrapolated Liabilities | Shortfall | % of Future Cash Flow |
|---|---|---|---|---|
| Coastal | | $3,000 | -$2,800 | 2000% |
| LA Basin | | $2,700 | -$1,000 | 60% |
| Sacramento Basin | | $980 | -$720 | 290% |
| Inland | | $14,900 | -$10,700 | 250% |
| **Total** | | **$21,500** | **-$15,220** | **240%** |

The following discussion looks in more detail at the unique aspects of each area and how sensitivity cases could affect the balance in each area.

## 8.1 Coastal

Production in the Coastal region dropped 20% quickly after the 1986 price crash, another example of correlation, then continued to slide for decades until around 2006. From 2008 to 2015, robust oil prices spurred development and the largest reversal of decline among the regions. More importantly, in the year after the 2015 price collapse, production again dropped 12%. The decline accelerated in mid-2019 as oil prices retreated prior to COVID, and production has already declined 47% off its recent peak eight years ago. Unlike previous decades, the number of producing wells has also been dropping; a third of producers have been shut-in during the last eight years. Interestingly, production history of associated natural gas (not shown) also suggests that operators have systematically begun to cut costs by curtailing the injection that has sustained production in steam floods.

Our headline figure of a mere $141 million of future cash flow is highly uncertain, but we have high confidence in the overall conclusion. It is the most delicate balance in our study between costs and revenues and the shortest projected life. Our forecasts are based on a direct operating cost of only $24.17/BOE in 2021. Still, reducing operating costs by 20% increases the net cash flow by over 3.5 times, an enormous proportional increase. Sustained Brent oil price of $85/bbl would increase the net cash flow by over 2.7 times. More importantly, though, increasing the net cash flow by multiples – to $503 or $388 million – still leaves the projection short of the quantified liabilities by multiples. Our cash flows suggest that, in order for prices to create enough free cash to cover just the quantified costs, oil prices must jump instantly to $115/bbl and stay there for about 20 years.

**Figure 5: Map of unplugged onshore wells in the Coastal area.**

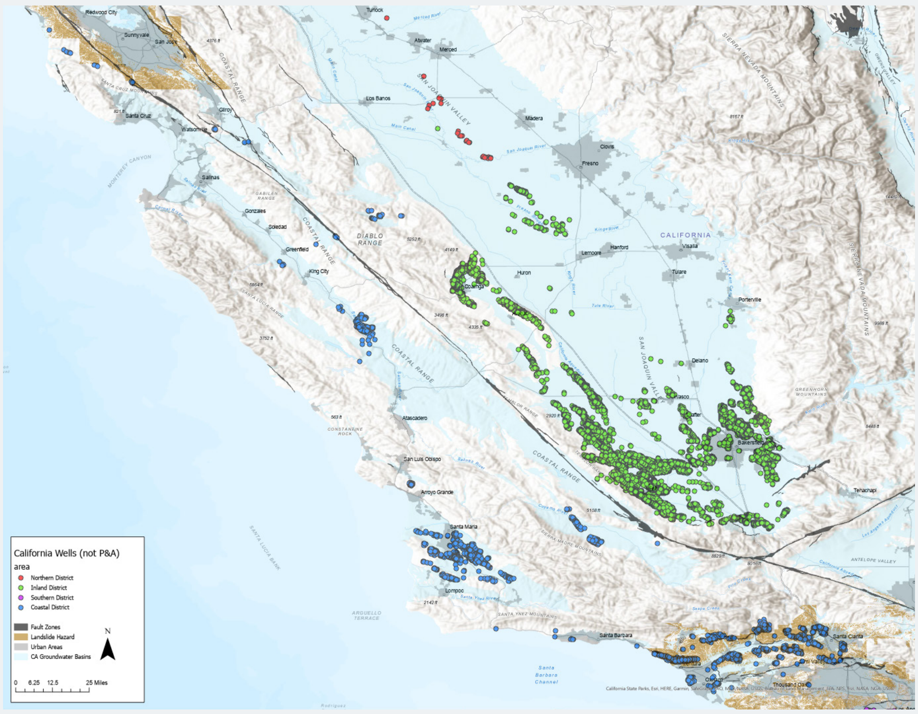


Figure 6: Daily oil production and producing well count from the Coastal area.


## 8.2 Los Angeles Basin

Like the Coastal area, the LA Basin had been mostly declining for decades when in 2012 to 2014 Brent oil prices consistently over $100 provoked a modest increase in production. Also like the Coastal area, decline has since been steeper than the years before, and production is now 43% lower than it was eight years ago. The number of actively producing wells has also been slipping continuously.

Where the Coastal area may exceed the forecast, the LA Basin seems more likely to underperform. The steeper decline in well count compared to oil decline makes this area appear more profitable in the future than other areas, but it is not clear that the continued decline in wells (and thus costs) is compatible with the same continued decline in production.

This is the only area whose projected cash flow comes close to the quantified decommissioning costs, but it is also the area with the largest unquantified liability. To accumulate the cash flow about equal to quantified liabilities requires the next 36 years of operations, but we quantified only 34% of the enumerated facilities, excluding mostly pipelines of unknown length and over 100 urban drill sites. As described above, the example of Beverly Hills high school site shows how our quantified estimate of $5 million compared to actual cost of $40 million. Extrapolating our estimates for over 100 such urban drill sites means billions more in costs. More to the point, it means that we should expect this area also to generate less future income than future decommissioning costs. In the meantime, the projection remains, like all of the other base cases, subject to all of the normal risks and uncertainties of volumes, prices, and costs.

Figure 7: Map of unplugged onshore wells in the Los Angeles area.

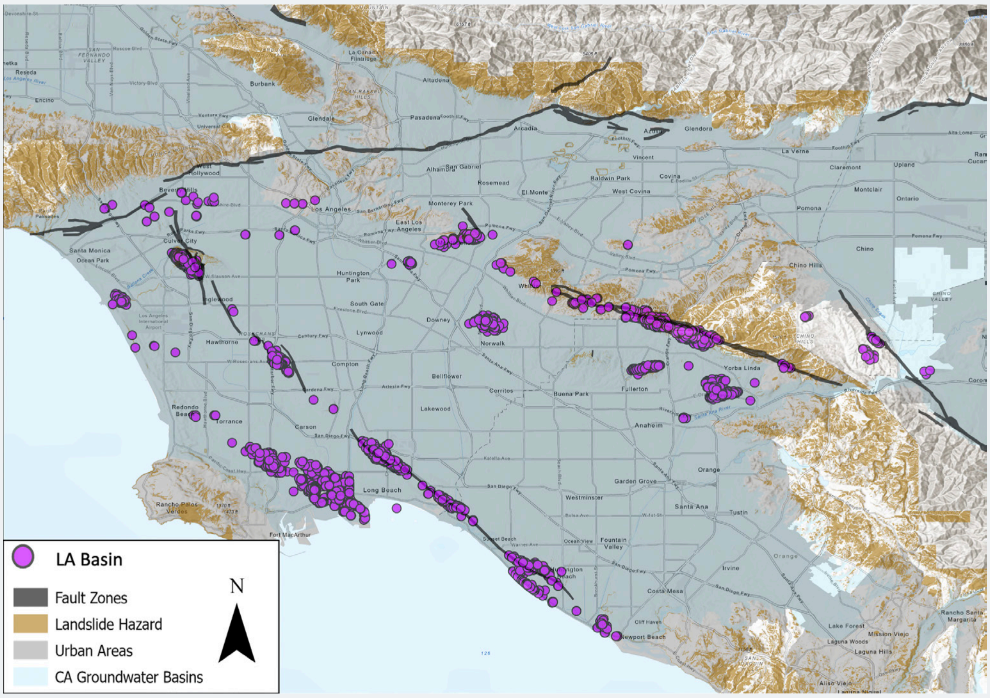
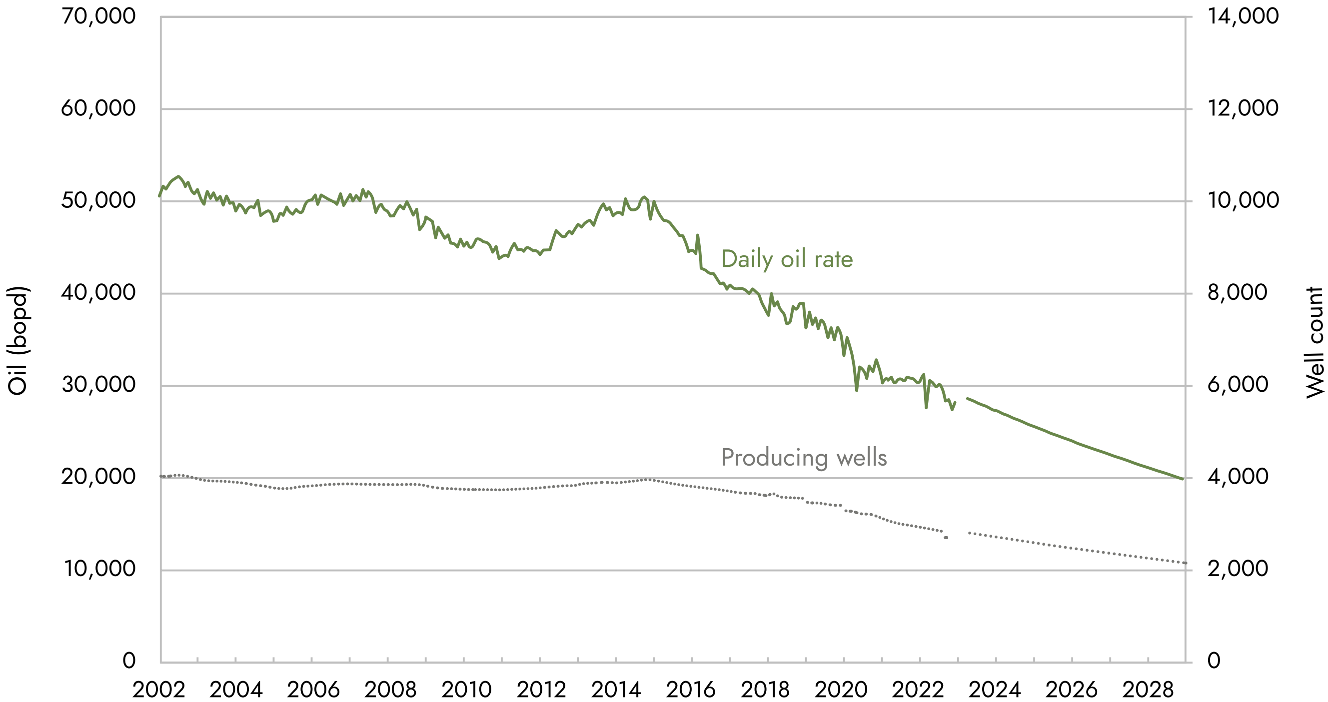



Figure 8: Daily oil production and producing well count from the Los Angeles area.



## 8.3 Sacramento

The Sacramento Basin produces very little oil, but its historical production of gas does correlate to natural gas prices in the same way that the oil basins' production has followed oil prices. Starting about 30 years ago and lasting for about 15 years, the basin sustained production of about 200 million cubic feet per day (MMcfpd) or more, but that trend reversed quickly after the price collapsed in 2009. Today, the whole basin produces only 12% of the rate it achieved shortly before the price collapse. Part of that productivity loss came as a step down in early 2020 as gas prices collapsed and as California Resources Company subsequently declared bankruptcy. Since then, natural gas prices recovered to multiples of its prior lows, but production has not improved.

The large-scale operational changes in 2020 and after disrupted established patterns of decline and complicated forecasting. On the other hand, as described above, the current per well rates in the basin hover close to the rates at which wells have historically been shut-in, and the profit margins remain thin. Our base case projects economic life 33 years into the future, but the cash flow during that time still comes to less than half of the quantified costs. To generate enough cash flow over even more decades to meet the minimal measure of currently quantified costs would require a much lower decline rate or decades of natural gas prices above $6.50 /MMBtu without a tandem increase in costs.

**Figure 9: Map of unplugged onshore wells in the Sacramento area.**

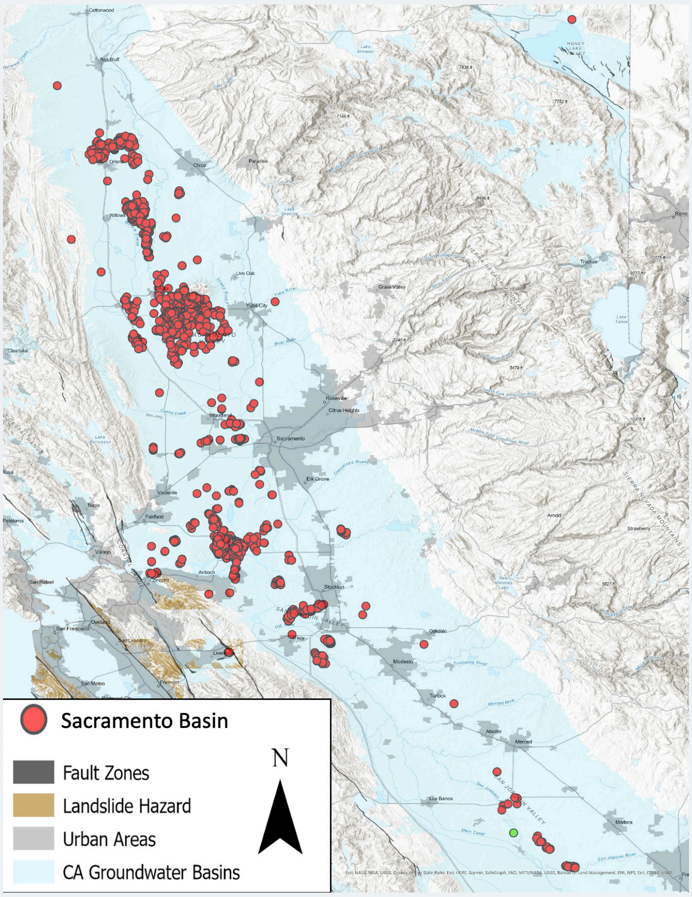
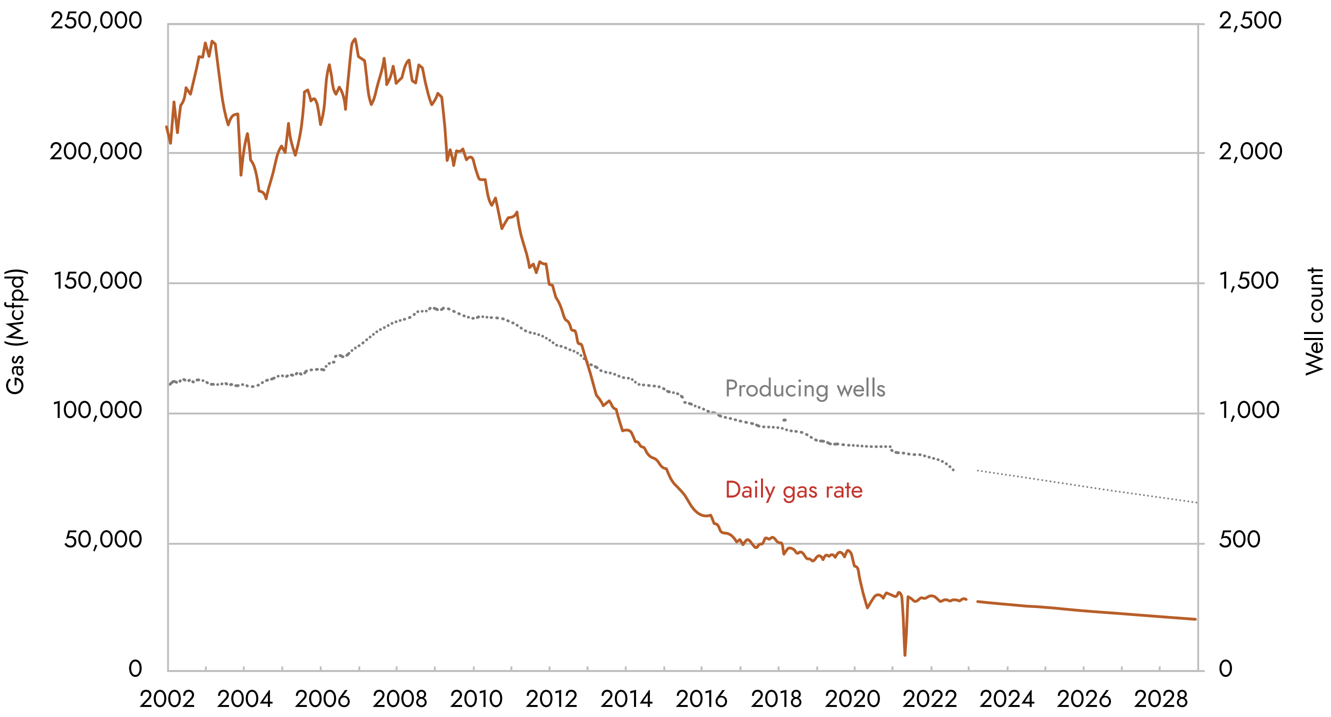


Figure 10: Daily gas production and producing well count from the Sacramento area.




## 8.4 Inland

The Inland basin represents by far the most wells and the largest volumes among the areas. It reached a peak just before the 1986 price collapse and slid, though slowly, for nearly 30 years. Less responsive than other areas, Brent crude prices consistently over \$100 from 2011 to 2014 flattened and slightly reversed the trend. However, since the price bust in 2015, production has dropped by 42%. For the first time in decades the number of actively producing wells has maintained a decline.

Almost as sensitive as the Coastal area, the Inland region is also systematically balanced near its economic limit. Our estimates of direct operating costs imply \$28.13 /BOE during 2021. By comparison, Berry's operating costs dominated by the Inland area averaged \$34.52 /BOE in 2022. Assuming a 20% reduction from our base costs nearly doubles the net income, but it still leaves the area short of its quantified liabilities.

In the same way, the forecast is sensitive to oil price. If the price of oil jumped to over \$86 /bbl and stayed there for a decade, then the area would generate enough to pay for its quantified liabilities but not inflated or extrapolated liabilities. Over the last decade, the spot price for Brent exceeded \$86 /bbl only 26% of the time, and expectations were at all times backwardated, meaning that prices were expected to decrease (not hold or increase). Recently, for example, when the spot price of Brent beat that price, the market expected the price to fall to less than \$65 /bbl seven years from now. Though \$86 /bbl will sometimes be realized, it is not reasonable to expect prices above that level for the next 10 or more years.

Lastly, the project can pivot with the assumed decline rate of oil production. A much lower decline rate would be necessary to payout quantified liabilities. All three of these sensitivities assume no corresponding change in other variables when, in fact, the dynamics are likely to oppose each other. A sustained increase of price probability increases costs also. A flatter decline probably requires more expenses to be incurred, and lower costs probably results in lower production. What is more, none of the tested scenarios come close to covering extrapolated liabilities.

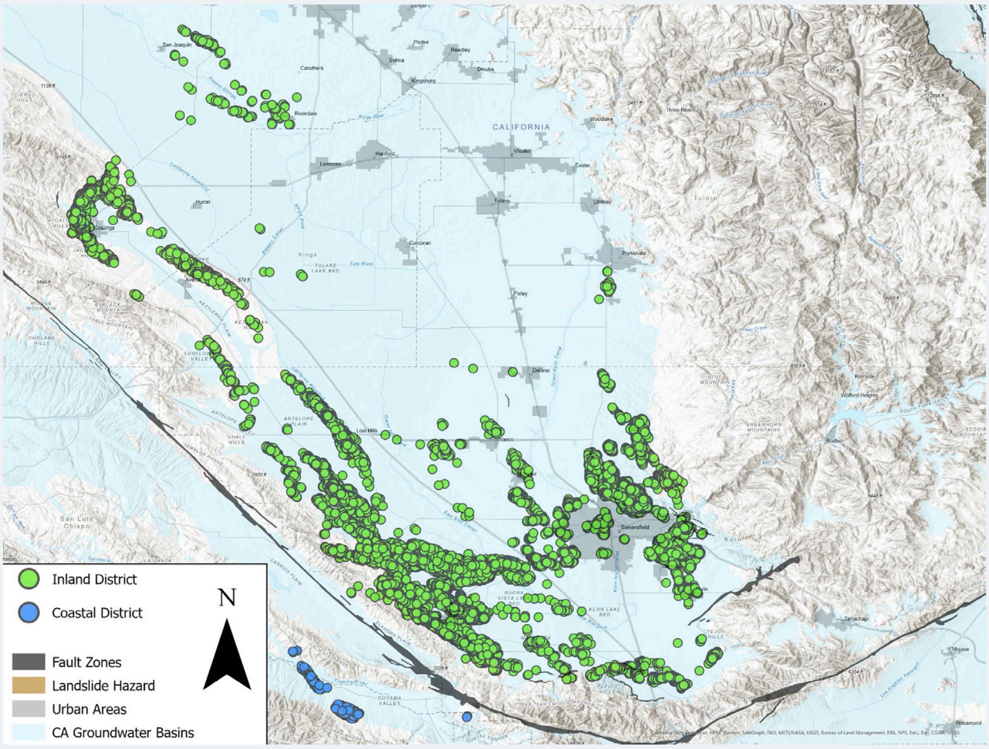
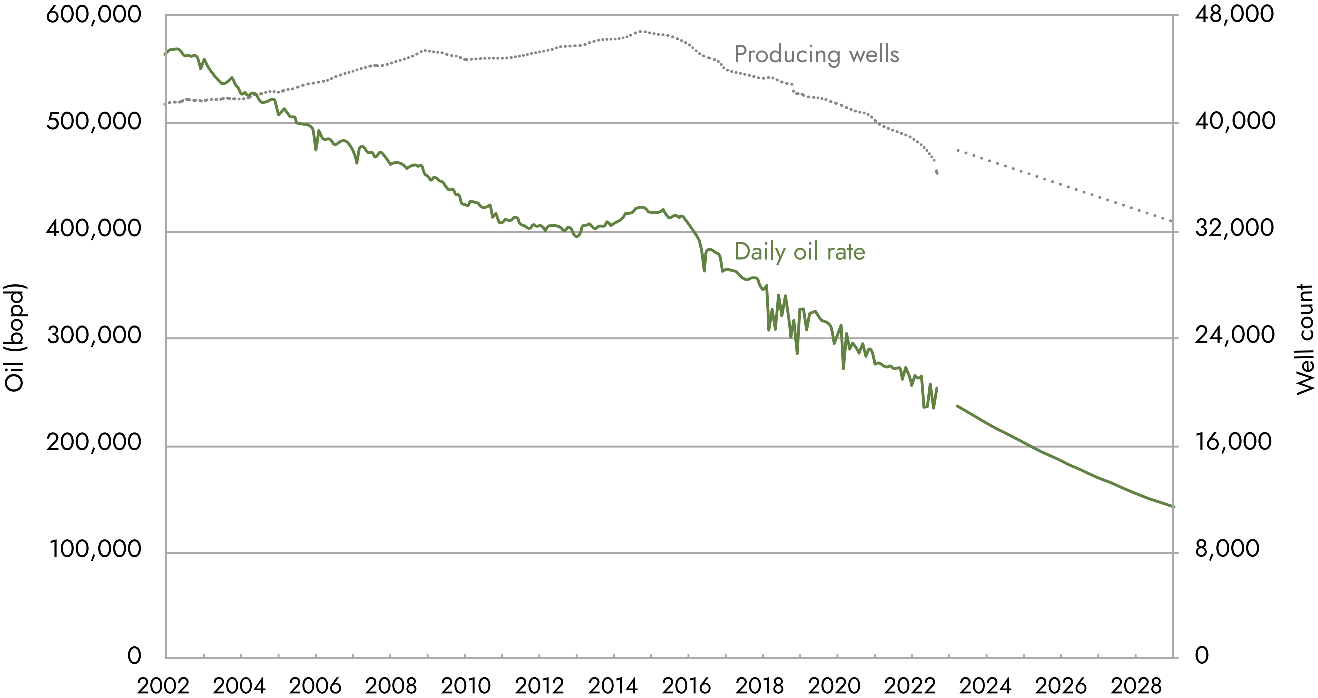



Figure 12: Daily oil production and producing well count from the Inland area.



# 09

# Conclusions

Oil production in the state of California will not grow significantly and will, in fact, come to a practical end within the foreseeable future, but it is unlikely that the remaining production of over 100,000 wellbores and nearly 30,000 facilities operating today will suffice to pay for their own decommissioning even if all future profits are applied to the liabilities.

Because they are running close to their economic limits, small changes to individual assumptions have outsized effects on projected cash flows. A sudden and sustained increase in the price of oil, for example, could significantly improve cash flows. As they stand, though, projected cash flows would need to more than double in aggregate to match the minimal quantified decommissioning costs. Reasonable uncertainties in our scoping cash flow projections do not generate enough money in most basins to pay for this minimal estimate. What is more, extension of the estimate for unquantified costs and/or known inflation brings the liability estimates up to three and half times the base projected cash flows.

Notwithstanding the obvious maturity of the fields, current cash flows are not being deployed or saved by operators to retire their aging assets. If business as unusual continues, proceeds will instead continue to be distributed to owners, used to buy back shares, or in a few cases reinvested in less mature assets. State regulators have not yet exercised their authority and mandate to collect the relevant data or to increase guarantees that the taxpaying public will not shoulder the final capital costs of the onshore industry.

Already in recent years, two of the state’s five largest operators have filed bankruptcy. Both were triggered by the kind of cyclical price downturns endemic to the industry. Both emerged again, and creditors suffered the deeper losses. Other notable producers Venoco and HVI Cat Canyon filed bankruptcy and instead left sizable assets for taxpayers to clean up. Next time an oil company like one of these goes bankrupt in California, it will likely have less assets than it does today.

The issues outlined here merit deeper analysis and more discussion. Accelerated shut-down of the oil industry could reduce the funds industry can bring to the task, but business as usual also won’t allocate enough funds to decommissioning. Meanwhile, while debate and deliberations continue, production will continue to decline. Between declining production and backwardated price expectations, $3.65 billion – 58% of the remaining proceeds from existing wells – will be generated during just the next two years, and then the liability to taxpayers will be that much greater.

# 10

# Appendix A: Decommissioning Costs

The CalGEM method divides decommissioning costs into three categories: downhole well plug and abandonment costs, well site removal and remediation, and facilities decommissioning and remediation. All three rely on a base case estimate, sometimes varying by location, and then apply a multiplier tied to qualitative measures of risk. They were developed, with input from industry, prior to the publication of the draft methodology and sample spreadsheets in April 2022.

Downhole costs begin with estimates of the average number of days required and the average cost per day of work based on experience prior to spring of 2022. Qualitative risk factors measured by points are translated to a multiplier between 1.0 and 2.0 applied to the base estimate. Inflation affects that cost per day most directly.

Costs are specified for each unit of equipment on well sites and facilities, such as a cost per wellhead, per tank or per linear foot of pipeline. Then fixed percentage uplifts are applied for project costs and variable percentage uplifts are applied for contingencies. Project costs total 18% over the expenses per the CalGEM methodology, and contingency ranges from a minimum of 10% to a maximum of 30% based on a qualitative points system. Inflation affects that base cost for each.

We began with CalGEM's inventory of wellbores. We removed boreholes which do not need to be plugged (already plugged or never drilled) and those offshore (beyond scope), but we did retain multiple wellbores when present in a single well. From public data sources and data vendors, we collected information about technical specifications such as depth and age of the wells. When data was not available on a wellbore itself, we relied on analogy to similar wells. Some inputs were measured by comparing the well's location to maps of, e.g., municipalities and mapped geologic hazards. For a few inputs, we used generalizations, such as assuming only two casing strings for all wells except those in the Los Angeles basin. For items without data or generalizations, we left the risks out of the calculations. In the end we quantified only 43 of the 83 points of the well score. We then ran sensitivities with half and with all of the remaining points included.

The CalGEM inventory of facilities came from its online WellStar database, but it contains less information about each facility. Though tanks, vessels, and evaporation pits ("sumps") appear to be individually enumerated, the overall facilities that include them and other equipment ("settings" and "facility groups") include no further details. Similarly, we found no useful information to describe the length, size, or contents of pipelines enumerated.

We reduced the list to onshore facilities not marked as removed and located the facilities to be removed based on their county. Some information, like the number of wellheads and vessels, could be tabulated, but others required estimates. Of the nearly 13,000 tanks tallied in the state, we assumed 90% were evenly split between the smallest two sizes and that only 2% were the largest size. Consistent with experience and estimates used by CalGEM as examples, we've used 150 ft of combined flowlines per well and 1250 ft of combined lines for each setting as named by CalGEM. Note that we have assumed no flowlines separate for each tank.

We estimated the facilities contingency based on a combination of generalizations of the regions and the percentage of wells located within geospatial boundaries as defined the California Geologic Survey and Department of Water Resources. We could only estimate 45 of the 55 points, but we used the contingency required based on that subtotal of points. The table below summarizes the methodology and our treatment.

**Decommissioning Assumptions: Well Plugging**
*Source: CalGEM Decommissioning Cost estimate draft as of April 2022*

| | | | | |
|---|---|---|---|---|
| **Total Cost =** | **Cost per day *** | **(Base no. days** | ***** | **Complexity multiplier)** |
| WACE = | BDC * ( | BWD | * | WSM) |
| Well Abandonment | Base Daily Cost | Base Well Days | | Well Score |
| Cost Estimate | | | | Multiplier |

| Base assumptions per CalGEM | | Well Score Multiplier (WSM) | | Aggregated Well Score (AWS) | | | | Source or Treatment |
|---|---|---|---|---|---|---|---|---|
| **Base Cost per Day** | *BDC, Base Daily Cost* | **AWS** | **Mutliplier** | **Well Factors** | ***quantitative up to 23 pts*** | **(tiered)** | **pts** | |
| Northern Valley Region | $7,700 | 0 | 1.00 | | **Age** | 0 - 25 yrs | 0 | based on spud data, first production date, |
| Northern Coastal Region | $7,500 | 10 | 1.00 | | | 25-50 | 3 | or date of similar API numbers. |
| Southern Region | $6,000 | 11 | 1.01 | | | 50+ | 5 | |
| Inland Region | $3,750 | 12 | 1.03 | | | | | |
| | | 14 | 1.05 | | **Depth** | under 1000 | 0 | based on public data or average of nearby wells |
| | | 16 | 1.08 | | | to 3000 | 4 | |
| | | 18 | 1.10 | | | to 5000 | 7 | |
| **Base number of days** | BWD, Base Well Days | 20 | 1.13 | | | over 5000 | 10 | |
| Northern Valley Region | 9 | 22 | 1.15 | | | | | |
| Northern Coastal Region | 14 | 24 | 1.18 | | **No. of Casing Strings** | 2 | 0 | 2 strings for all wells except |
| Southern Region | 20 | 26 | 1.20 | | | 3 or 4 | 4 | 3 strings in LA Basin and for depths > 5000 ft |
| Inland Region | 13 | 28 | 1.23 | | | 5 or more | 8 | none 5 or more |
| | | 30 | 1.25 | | | | | |
| | | 32 | 1.28 | **Location** | *qualitative up to 27 pts* | **(yes/no)** | **pts** | |
| **Complexity multiplier** | **from 1.0 to 2.0** | 34 | 1.30 | | within urban area | | 10 | whether within municipal boundaries |
| *WSM, Well Score Multiplier* | | 36 | 1.33 | | environmentally sensitive | | 7 | excluded |
| | | 38 | 1.35 | | geohazards | | 5 | whether within boundaries of hazards per California Geologic Survey |
| translated from | | 40 | 1.38 | | surface access difficulties | | 5 | excluded |
| **AWS, Aggregated Well Score** | | 42 | 1.40 | | | | | |
| point system for 13 considerations | | 44 | 1.43 | **Condition** | *qualitative up to 25 pts* | **(yes/no)** | **pts** | |
| | | 46 | 1.45 | | unknown | | 25 | |
| We have estimated 43 of the 85 points available. | | 48 | 1.48 | | | or | | |
| Points shown in light gray are not estimated. | | 50 | 1.50 | | pressure at surface | | 5 | excluded |
| | | 51 | 1.53 | | failed integrity | | 6 | excluded |
| | | 52 | 1.55 | | junk or other obstacles | | 9 | excluded |
| | | 54 | 1.60 | | fluid level above base freshwater | | 5 | excluded |
| | | 56 | 1.65 | | | | | |
| | | 58 | 1.70 | **Other Health or Safety** | *up to 10 pts* | **(yes/no)** | **pts** | |
| | | 60 | 1.75 | | history of spills or leaks | | 5 | excluded |
| | | 62 | 1.80 | | presence of $H_2S$ or $CO_2$ | | 5 | assumed present in waterfloods and steamfloods |
| | | 64 | 1.85 | | | | | |
| | | 66 | 1.90 | | | | | |
| | | 68 | 1.95 | | | | | |
| | | 70 | 2.00 | | | | | |
| | | 85 | 2.00 | | | | | |

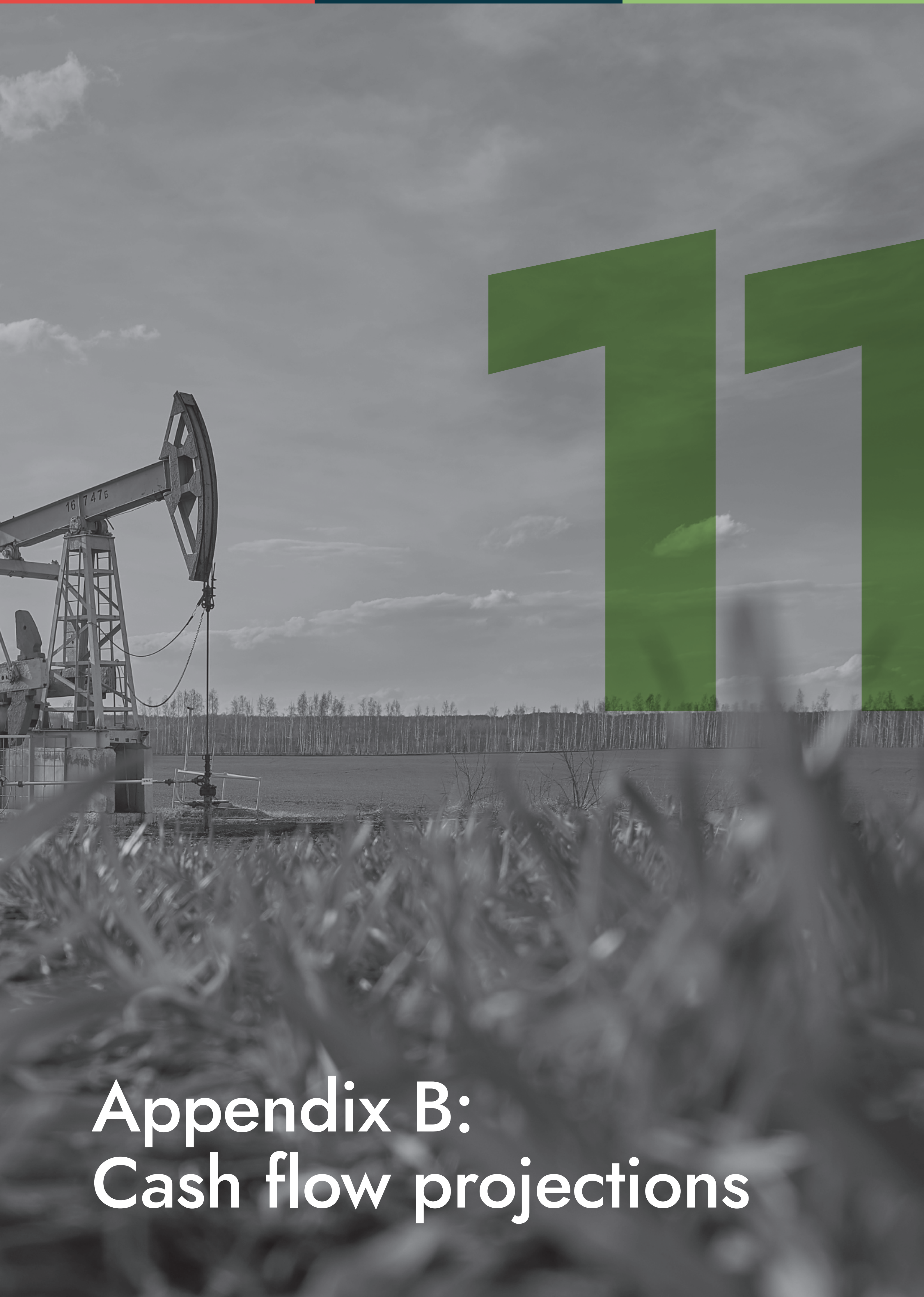
## Wells Sites and Facilities Assumptions

*Source: CalGEM Decommissioning Cost estimate draft as of April 2022*

| Methodology | | | | | | | | | Input | Source |
|---|---|---|---|---|---|---|---|---|---|---|
| **Well Site** | **Equipment Removal** | | | | | | | | **Equipment Removal** | |
| | Above ground lines | $ | 30 | per linear foot | | | | | 100 ft per well | assumed, consistent with CalGEM example |
| | Buried lines | $ | 12 | per linear foot | | | | | 50 ft per well | assumed, consistent with CalGEM example |
| | Electrical vaults & equipment | $ | 390 | per ton | | | | | 2 ton per well | assumed, consistent with CalGEM example |
| | Asphalt & concrete | $ | 10 | per cubic foot | | | | | - | *excluded* |
| | Pumps | $ | 4,386 | each | | | | | - | *excluded* |
| | | | | | | | | | | |
| | **Site Remediation** | | | | | | | | **Site Remediation** | |
| | Wellhead | $ | 10,158 | each | | | | | 1 per well | CalGEM well inventory |
| | Cellar | $ | 8,540 | each | | | | | 1 per well | CalGEM well inventory |
| | Refuse removal | $ | 137 | per cubic yard | | | | | - | *excluded* |
| | | | | | | | | | per calculations on next tab (which excludes some considerations) | |
| | **Contingency** | | 10% | variable 10% to 30% | | | | | 5% | |
| | **Permitting & Regulatory Compliance** | | 5% | | | | | | 5% | |
| | **Mobilization & Demobilization** | | 5% | | | | | | 8% | |
| | **Project Management & Engineering** | | 8% | | | | | | | |
| | | | | | | | | | | |
| **Facilities** | **Decommissioing** | | | | **Site Remediation** | | | | **Decomissioning and Site Remediation** | |
| | Tank (extra large) | $ | 159,804 | each | Tank (extra large) | $ | 1 20,30 | each | 2% | of Tanks in CalGEM inventory |
| | Tank (large or urban) | $ | 104,564 | each | Tank (large or urban) | $ | 54,345 | each | 8% (100% in LA) | % split is assumed |
| | Tank (med) | $ | 65,321 | each | Tank (med) | $ | 21,450 | each | 45% | |
| | Tank (small) | $ | 19,149 | each | Tank (small) | $ | 6,549 | each | 45% | |
| | Vessel | $ | 12,621 | each | Vessel | $ | 6,549 | each | All Vessels in CalGEM inventory | |
| | | | | | | | | | | |
| | Above ground lines | $ | 30 | per linear foot | | | | | 750 ft per Setting* | assumed, consistent with CalGEM example |
| | Buried lines | $ | 12 | per linear foot | | | | | 500 ft per Setting* | assumed, consistent with CalGEM example |
| | Electrical vaults & equipment | $ | 390 | per ton | | | | | - | *excluded* |
| | Asphalt & Concrete | $ | 10 | per cubic ft | | | | | - | *excluded* |
| | Pumps & Compressors | $ | 4,386 | each | | | | | - | *excluded* |
| | Buildings | $ | 30 | per sq ft | | | | | - | *excluded* |
| | | | | | | | | | | |
| | | | | | Sumps & Auxillary Holes | $ | 3.86 | per cubic ft | 75,000 | assumed 100 ft x 50 ft x 15 ft each |
| | | | | | Refuse Removal | $ | 1 37 | per cubic yard | - | *excluded* |
| | | | | | Access Road Removal | $ | 2.25 | per cubic ft | - | *excluded* |
| | | | | | | | | | | |
| | **Contingency** | | 10% | variable 10% to 30% | | | | | 10%, 20%, 30% | per separate calculations |
| | **Permitting & Regulatory Compliance** | | 5% | | | | | | 5% | |
| | **Mobilization & Demobilization** | | 5% | | | | | | 5% | |
| | **Project Management & Engineering** | | 8% | | | | | | 8% | |
| | | | | | | | | | * Note that none assumed for Facility Group, Tank, Sump, Vessel, or Pipeline categories. | |

**Continency for Wells Sites and Facilities Assumptions**
*Source: CalGEM Decommissioning Cost estimate draft as of April 2022*

| | | | District (Basin / Area) Northern | Inland | Southern | Coastal | Source |
|---|---|---|---|---|---|---|---|
| | | | (Sacramento / 1) | San Joaquin / 2) | (LA / 3) | (Various / 4) | |
| **Components** | (yes/no) | pts | | | | | |
| | sensitive or urban | 10 | 0 | 0 | 10 | 10 | generalization |
| | any other potential threat | 10 | 0% | 67% | 73% | 69% | % of wells with H2S risk (water or steam flood) |
| | history of spills or leaks | 10 | - | - | - | - | *excluded* |
| | presence of freshwater aquifer | 5 | 94% | 92% | 85% | 53% | % of wells underlain by groundwater per Dept. of Water Resources |
| | known geologic hazards | 5 | 1% | 0% | 48% | 32% | % of wells within boundaries of hazards per California Geologic Survey |
| | surface access difficulties | 5 | 0 | 0 | 5 | 5 | generalization |
| | older than 50 years | 5 | 23% | 2% | 3% | 17% | % of wells |
| | unresolved violations | 5 | - | - | - | - | *excluded* |
| | | | | | | | |
| **Total and Assigned Values** | | 55 pts max | 5.9 | 11.5 | 29.1 | 27.1 | weighted sum |
| | 10% | <10 pts | **10%** | | | | |
| | 20% | 10-19 pts | | **20%** | | | |
| | 30% | >20 pts | | | **30%** | **30%** | |
| | | | | | | | |



# 11

# Appendix B: Cash flow projections

We relied upon historical production data as reported to CalGEM and subdivided it into areas of more similar character. Our divisions into regions as shown in the figure below closely but not precisely mirror the regulatory districts of similar names. We further subdivided some regions in attempts to refine the forecasts. Using data from public companies, we made assumptions about the portion of produced gas sold to market and, in a couple of the areas, the natural gas liquids extracted and sold separately. We extrapolated summary production using standard engineering techniques. Given the vintage of the fields, we’ve assumed they bear a royalty of 12.5% as was standard for most of the history of the industry.

We assumed future commodity prices based on settled prices on April 21, 2023 for financial futures contracts on the New York Mercantile Exchange. The front month for oil is $81.66/bbl, and the prices decline into the future, reaching $77.51 in 12 months, breaking below $70 in 2027, and concluding at $66.14/bbl in 2030. To remove the seasonality of futures prices for gas, we assumed annual averages of the monthly contracts, namely $2.71/MMBtu in the remainder of 2023 and increasing to $4.30/MMBtu in 2026, and slowly escalating to $4.96 in 2035 and beyond.

We estimated the difference between received prices and benchmark prices based on experience and figures reported by public companies. Specifically, we assumed an oil price of $5 less than Brent crude and a gas price 22% above Henry Hub.

Most fundamental among the three kinds of costs are the direct operating costs expended on site to keep production flowing. Our inputs are applied as cost per producer per month but are tuned to figures of operating costs measured as dollars per barrel of oil equivalent ($/BOE) as reported by public companies and observed in our experience.

General and administrative expenses to operate the company itself also take away from funds available for eventual decommissioning operations and similarly cannot be avoided. We assume those costs to be 25% of the direct operating costs, less than the actual proportion in the public companies examined. Both direct and G&A costs are tied in our calculations to the number of active producing wells, and neither are inflated over time. We do, however, forecast a decline in the number of those producing wells and thus forecast a decline in total operating costs.

Taxes paid to the state of California and to the counties in which the fields produce are relatively minor, and we have used standard defaults.

Some drilling and other improvements have added production in recent years, offsetting the natural decline of pre-existing wells. Those additions have, of course, required capital. As described above, we have forecast the historical trends of production and well count which included some degree of on-going capital activity. However, we have projected that same decline into the future without including ongoing, additional capital for any kind of reserve additions.

**Cash Flow Assumptions**
*Source: Engineering analyses of public data and filings of public companies*

| Input | | Sacramento | Inland | Los Angeles | Coastal | | Source |
|---|---|---|---|---|---|---|---|
| | | | | | Waterflood | Steamflood | |
| **Ownership** | Royalty | 12.5% | | | | | based on the age of most fields |
| **Production Decline** | Oil | 64%, b 0.74 | 8.4% | 6.2% | 8.5% | 12.0% | Prod data from BLR Digital, confirmed against EIA |
| | Gas | 6.0% | flat GOR | flat GOR | flat GOR | incr GOR | Further subdivided into functional groups |
| | Water | not forecast | | | | | |
| | Wellcount | 3.0% | 2.6% | 4.5% | 6.0% | 4.0% | |
| **Price Differentials** | Oil | Brent futures mid April minus $5 | | | | | NYMEX futures prices |
| | Gas | Henry Hub futures mid April plus 22% | | | | | public filings of CA-focused companies |
| | Gas shrink | 0% | 62% | 83% | 33% | | discussions with people experienced in the state |
| | NGL | - | Brent minus 30% | - | Brent minus 30% | | |
| **Operating Costs** | Per well/month | $1,400 | $6,000 | $8,000 | $11,000 | to $12,000 | discussions with people experienced in the state |
| | *implied $/BOE in 2021 for comparison* | $9.40 | $28.13 | $21.48 | $20.77 | to $29.65 | public filings of CA-focused companies |
| | G&A | 25% of per well cost | | | | | |
| **Taxes** | Fee per BO, per Mcf | $0.87 | | | | | 2022 fee |
| | Ad valorem | 2.5% | | | | | discussions with people experienced in the state |

# ECONOMIC PROJECTION

| | | | |
|---|---|---|---|
| | As Of Date : 05/01/2023 | **Case** | : Area 1 Sacramento |
| | Discount Rate (%) : 10.00 | **Reserve Cat.** | : Proved Producing |
| | Area 1 Sacramento | **Field** | : |
| | | **Operator** | : |
| | | **Reservoir** | : |
| | | **Co., State** | : , CA |
| **Cum Oil (Mbbl) :** | **5,833.55** | | |
| **Cum Gas (MMcf) :** | **4,215,848.65** | | |

| Year | Gross Oil (Mbbl) | Gross Gas (MMcf) | Net Oil (Mbbl) | Net Gas (MMcf) | Oil Price ($/bbl) | Gas Price ($/Mcf) | Oil Revenue (M$) | Gas Revenue (M$) | Misc. Revenue (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 2023 | 12.55 | 6,348.70 | 10.98 | 5,555.11 | 75.78 | 3.30 | 832.00 | 18,332.42 | 0.00 |
| 2024 | 15.41 | 9,005.66 | 13.49 | 7,879.95 | 72.12 | 4.37 | 972.70 | 34,397.24 | 0.00 |
| 2025 | 12.53 | 8,440.74 | 10.97 | 7,385.65 | 68.75 | 5.14 | 753.99 | 37,943.16 | 0.00 |
| 2026 | 10.50 | 7,933.61 | 9.19 | 6,941.91 | 66.17 | 5.25 | 608.00 | 36,451.13 | 0.00 |
| 2027 | 8.98 | 7,456.95 | 7.86 | 6,524.83 | 64.02 | 5.23 | 503.12 | 34,101.91 | 0.00 |
| 2028 | 7.83 | 7,027.54 | 6.85 | 6,149.10 | 62.35 | 5.24 | 427.06 | 32,250.68 | 0.00 |
| 2029 | 6.88 | 6,586.71 | 6.02 | 5,763.37 | 61.39 | 5.36 | 369.28 | 30,881.53 | 0.00 |
| 2030 | 6.12 | 6,190.97 | 5.36 | 5,417.10 | 61.14 | 5.38 | 327.57 | 29,158.31 | 0.00 |
| 2031 | 5.50 | 5,819.02 | 4.82 | 5,091.64 | 61.14 | 5.42 | 294.41 | 27,592.81 | 0.00 |
| 2032 | 5.00 | 5,483.93 | 4.37 | 4,798.44 | 61.14 | 5.47 | 267.39 | 26,249.75 | 0.00 |
| 2033 | 4.55 | 5,139.92 | 3.98 | 4,497.43 | 61.14 | 5.61 | 243.17 | 25,212.16 | 0.00 |
| 2034 | 4.17 | 4,831.11 | 3.65 | 4,227.22 | 61.14 | 5.80 | 223.09 | 24,517.39 | 0.00 |
| 2035 | 3.85 | 4,540.86 | 3.36 | 3,973.25 | 61.14 | 6.05 | 205.73 | 24,018.68 | 0.00 |
| 2036 | 3.57 | 4,279.37 | 3.13 | 3,744.45 | 61.14 | 6.05 | 191.10 | 22,635.57 | 0.00 |
| 2037 | 3.31 | 4,010.93 | 2.90 | 3,509.56 | 61.14 | 6.05 | 177.26 | 21,215.65 | 0.00 |
| **Rem** | 36.63 | 42,220.04 | 32.05 | 36,942.54 | 61.14 | 6.05 | 1,959.66 | 223,321.32 | 0.00 |
| **Total** | **147.38** | **135,316.06** | **128.96** | **118,401.55** | **64.79** | **5.48** | **8,355.53** | **648,279.74** | **0.00** |
| **Ult** | **5,980.93** | **4,351,164.71** | | | | | | | |

| Year | Well Count | Net Tax Production (M$) | Net Tax AdValorem (M$) | Net Investment (M$) | Net Lease Costs (M$) | Net Well Costs (M$) | Other Costs (M$) | Net Profits (M$) | Annual Cash Flow (M$) | Cum Disc. Cash Flow (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2023 | 782.00 | 0.00 | 1,724.80 | 0.00 | 0.00 | 11,060.00 | 0.00 | 0.00 | 6,379.63 | 6,174.16 |
| 2024 | 759.00 | 0.00 | 3,183.29 | 0.00 | 0.00 | 16,177.00 | 0.00 | 0.00 | 16,009.65 | 20,435.94 |
| 2025 | 736.00 | 0.00 | 3,482.74 | 0.00 | 0.00 | 15,694.00 | 0.00 | 0.00 | 19,520.41 | 36,173.23 |
| 2026 | 714.00 | 0.00 | 3,335.32 | 0.00 | 0.00 | 15,225.00 | 0.00 | 0.00 | 18,498.81 | 49,674.05 |
| 2027 | 693.00 | 0.00 | 3,114.45 | 0.00 | 0.00 | 14,768.25 | 0.00 | 0.00 | 16,722.33 | 60,722.17 |
| 2028 | 672.00 | 0.00 | 2,941.00 | 0.00 | 0.00 | 14,323.75 | 0.00 | 0.00 | 15,413.00 | 69,940.20 |
| 2029 | 652.00 | 0.00 | 2,812.57 | 0.00 | 0.00 | 13,893.25 | 0.00 | 0.00 | 14,544.99 | 77,813.22 |
| 2030 | 632.00 | 0.00 | 2,653.73 | 0.00 | 0.00 | 13,480.25 | 0.00 | 0.00 | 13,351.91 | 84,355.86 |
| 2031 | 613.00 | 0.00 | 2,509.85 | 0.00 | 0.00 | 13,074.25 | 0.00 | 0.00 | 12,303.12 | 89,813.49 |
| 2032 | 595.00 | 0.00 | 2,386.54 | 0.00 | 0.00 | 12,684.00 | 0.00 | 0.00 | 11,446.60 | 94,410.11 |
| 2033 | 577.00 | 0.00 | 2,290.98 | 0.00 | 0.00 | 12,304.25 | 0.00 | 0.00 | 10,860.10 | 98,357.12 |
| 2034 | 560.00 | 0.00 | 2,226.64 | 0.00 | 0.00 | 11,933.25 | 0.00 | 0.00 | 10,580.58 | 101,838.26 |
| 2035 | 543.00 | 0.00 | 2,180.20 | 0.00 | 0.00 | 11,578.00 | 0.00 | 0.00 | 10,466.21 | 104,955.57 |
| 2036 | 527.00 | 0.00 | 2,054.40 | 0.00 | 0.00 | 11,228.00 | 0.00 | 0.00 | 9,544.27 | 107,528.97 |
| 2037 | 511.00 | 0.00 | 1,925.36 | 0.00 | 0.00 | 10,892.00 | 0.00 | 0.00 | 8,575.55 | 109,621.61 |
| **Rem.** | | 0.00 | 20,275.29 | 0.00 | 0.00 | 148,806.23 | 0.00 | 0.00 | 56,199.47 | 8,333.45 |
| **Total** | | **0.00** | **59,097.17** | **0.00** | **0.00** | **347,121.48** | **0.00** | **0.00** | **250,416.62** | **117,955.06** |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Major Phase : | Gas | | | Abandonment Date : | 1/8/2056 | **Present Worth Profile (M$)** | | |
| Perfs : | 0 - 0 | | | Working Int : | 1.00000000 | **PW** | **5.00% :** | **164,389.06** |
| Initial Rate : | 805,107.55 | Mcf/month | | Revenue Int : | 0.87500000 | **PW** | **8.00% :** | **133,512.27** |
| Abandonment : | 106,067.06 | Mcf/month | | Disc. Initial Invest. (M$) : | 0.00 | **PW** | **10.00% :** | **117,955.06** |
| Initial Decline | 6.01 | % year | b = 0.000 | ROInvestment (disc/undisc) : | 0.00 / 0.00 | **PW** | **12.00% :** | **105,266.93** |
| Beg Ratio : | 0.002 | | | Years to Payout : | 0.00 | **PW** | **15.00% :** | **90,191.03** |
| End Ratio : | 0.001 | | | Internal ROR (%) : | 0.00 | **PW** | **20.00% :** | **72,161.10** |

# ECONOMIC PROJECTION

| | | |
|---|---|---|
| As Of Date : 05/01/2023 | **Case** | : Area 2 Inland |
| Discount Rate (%) : 10.00 | **Reserve Cat.** | : Proved Producing |
| Area 2 Inland | **Field** | : |
| | **Operator** | : |
| | **Reservoir** | : |
| | **Co., State** | : , |

**Cum Oil (Mbbl) :** **8,937,459.33**
**Cum Gas (MMcf) :** **8,922,201.46**

| Year | Gross Oil (Mbbl) | Gross Gas (MMcf) | Net Oil (Mbbl) | Net Gas (MMcf) | Oil Price ($/bbl) | Gas Price ($/Mcf) | Oil Revenue (M$) | Gas Revenue (M$) | Misc. Revenue (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 2023 | 55,640.36 | 63,986.41 | 48,685.32 | 21,275.48 | 75.76 | 3.30 | 3,688,290.15 | 70,211.22 | 110,776.12 |
| 2024 | 77,230.83 | 88,815.45 | 67,576.97 | 29,531.14 | 72.08 | 4.37 | 4,870,979.20 | 128,908.14 | 146,759.75 |
| 2025 | 70,522.30 | 81,100.65 | 61,707.01 | 26,965.96 | 68.73 | 5.14 | 4,241,219.64 | 138,535.49 | 128,189.34 |
| 2026 | 64,580.83 | 74,267.95 | 56,508.22 | 24,694.09 | 66.16 | 5.25 | 3,738,416.61 | 129,665.72 | 113,290.48 |
| 2027 | 59,139.92 | 68,010.91 | 51,747.43 | 22,613.63 | 64.01 | 5.23 | 3,312,571.48 | 118,189.67 | 100,621.62 |
| 2028 | 4,787.14 | 5,505.21 | 4,188.74 | 1,830.48 | 62.98 | 5.24 | 263,807.12 | 9,600.47 | 8,022.86 |
| **Rem** | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total** | **331,901.37** | **381,686.58** | **290,413.70** | **126,910.79** | **69.26** | **4.69** | **20,115,284.21** | **595,110.71** | **607,660.16** |
| **Ult** | **9,269,360.70** | **9,303,888.04** | | | | | | | |

| Year | Well Count | Net Tax Production (M$) | Net Tax AdValorem (M$) | Net Investment (M$) | Net Lease Costs (M$) | Net Well Costs (M$) | Other Costs (M$) | Net Profits (M$) | Annual Cash Flow (M$) | Cum Disc. Cash Flow (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2023 | 37,144.00 | 0.00 | 348,234.97 | 0.00 | 0.00 | 2,248,080.00 | 0.00 | 0.00 | 1,272,962.52 | 1,232,876.73 |
| 2024 | 36,189.00 | 0.00 | 463,198.24 | 0.00 | 0.00 | 3,299,760.00 | 0.00 | 0.00 | 1,383,688.85 | 2,468,413.14 |
| 2025 | 35,261.00 | 0.00 | 405,715.00 | 0.00 | 0.00 | 3,215,107.50 | 0.00 | 0.00 | 887,121.97 | 3,185,518.71 |
| 2026 | 34,357.00 | 0.00 | 358,323.55 | 0.00 | 0.00 | 3,132,660.00 | 0.00 | 0.00 | 490,389.26 | 3,544,886.44 |
| 2027 | 33,476.00 | 0.00 | 317,824.45 | 0.00 | 0.00 | 3,052,327.50 | 0.00 | 0.00 | 161,230.82 | 3,652,532.39 |
| 2028 | 32,615.00 | 0.00 | 25,328.74 | 0.00 | 0.00 | 250,785.00 | 0.00 | 0.00 | 5,316.71 | 3,655,856.99 |
| **Rem.** | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total** | | **0.00** | **1,918,624.96** | **0.00** | **0.00** | **15,198,720.00** | **0.00** | **0.00** | **4,200,710.13** | **3,655,856.99** |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Major Phase : | Oil | | | Abandonment Date : | 1/31/2028 | **Present Worth Profile (M$)** | | |
| Perfs : | 0 - 0 | | | Working Int : | 1.00000000 | **PW** | **5.00% :** | **3,912,729.41** |
| Initial Rate : | 7,116,937.97 | bbl/month | | Revenue Int : | 0.87500000 | **PW** | **8.00% :** | **3,755,151.54** |
| Abandonment : | 4,682,727.89 | bbl/month | | Disc. Initial Invest. (M$) : | 0.00 | **PW** | **10.00% :** | **3,655,856.99** |
| Initial Decline : | 8.43 | % year | b = 0.000 | ROInvestment (disc/undisc) : | 0.00 / 0.00 | **PW** | **12.00% :** | **3,560,873.99** |
| Beg Ratio : | 1.150 | | | Years to Payout : | 0.00 | **PW** | **15.00% :** | **3,425,974.66** |
| End Ratio : | 1.150 | | | Internal ROR (%) : | 0.00 | **PW** | **20.00% :** | **3,219,580.55** |

# ECONOMIC PROJECTION

| | | |
|---|---|---|
| As Of Date : 05/01/2023 | **Case** | : Area 3 Los Angeles |
| Discount Rate (%) : 10.00 | **Reserve Cat.** | : Proved Producing |
| Area 3 Los Angeles | **Field** | : |
| | **Operator** | : |
| | **Reservoir** | : |
| | **Co., State** | : , CA |

**Cum Oil (Mbbl) :** **1,317,611.65**
**Cum Gas (MMcf) :** **593,643.58**

| Year | Gross Oil (Mbbl) | Gross Gas (MMcf) | Net Oil (Mbbl) | Net Gas (MMcf) | Oil Price ($/bbl) | Gas Price ($/Mcf) | Oil Revenue (M$) | Gas Revenue (M$) | Misc. Revenue (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 2023 | 6,852.44 | 3,563.27 | 5,995.89 | 530.04 | 75.75 | 3.30 | 454,212.47 | 1,749.17 | 0.00 |
| 2024 | 9,704.02 | 5,046.09 | 8,491.01 | 750.61 | 72.07 | 4.37 | 611,970.89 | 3,276.51 | 0.00 |
| 2025 | 9,077.09 | 4,720.09 | 7,942.45 | 702.11 | 68.73 | 5.14 | 545,853.58 | 3,607.05 | 0.00 |
| 2026 | 8,514.68 | 4,427.64 | 7,450.35 | 658.61 | 66.15 | 5.25 | 492,857.82 | 3,458.29 | 0.00 |
| 2027 | 7,987.12 | 4,153.30 | 6,988.73 | 617.80 | 64.01 | 5.23 | 447,350.87 | 3,228.94 | 0.00 |
| 2028 | 7,512.13 | 3,906.31 | 6,573.11 | 581.06 | 62.35 | 5.24 | 409,811.09 | 3,047.55 | 0.00 |
| 2029 | 7,026.81 | 3,653.94 | 6,148.46 | 543.52 | 61.38 | 5.36 | 377,416.71 | 2,912.33 | 0.00 |
| 2030 | 6,591.43 | 3,427.55 | 5,767.50 | 509.85 | 61.14 | 5.38 | 352,644.87 | 2,744.32 | 0.00 |
| 2031 | 6,183.04 | 3,215.18 | 5,410.16 | 478.26 | 61.14 | 5.42 | 330,776.94 | 2,591.79 | 0.00 |
| 2032 | 5,815.33 | 3,023.97 | 5,088.41 | 449.82 | 61.14 | 5.47 | 311,105.48 | 2,460.71 | 0.00 |
| 2033 | 5,439.63 | 2,828.61 | 4,759.68 | 420.76 | 61.14 | 5.61 | 291,006.60 | 2,358.71 | 0.00 |
| 2034 | 5,102.60 | 2,653.35 | 4,464.77 | 394.69 | 61.14 | 5.80 | 272,976.15 | 2,289.13 | 0.00 |
| 2035 | 4,786.45 | 2,488.95 | 4,188.14 | 370.23 | 61.14 | 6.05 | 256,062.85 | 2,238.09 | 0.00 |
| 2036 | 4,501.79 | 2,340.93 | 3,939.07 | 348.21 | 61.14 | 6.05 | 240,834.67 | 2,104.99 | 0.00 |
| 2037 | 4,210.96 | 2,189.70 | 3,684.59 | 325.72 | 61.14 | 6.05 | 225,275.62 | 1,968.99 | 0.00 |
| **Rem** | 27,236.45 | 14,162.96 | 23,831.90 | 2,106.74 | 61.14 | 6.05 | 1,457,082.11 | 12,735.45 | 0.00 |
| **Total** | **126,541.95** | **65,801.82** | **110,724.21** | **9,788.02** | **63.92** | **5.39** | **7,077,238.74** | **52,772.03** | **0.00** |
| **Ult** | **1,444,153.60** | **659,445.39** | | | | | | | |

| Year | Well Count | Net Tax Production (M$) | Net Tax AdValorem (M$) | Net Investment (M$) | Net Lease Costs (M$) | Net Well Costs (M$) | Other Costs (M$) | Net Profits (M$) | Annual Cash Flow (M$) | Cum Disc. Cash Flow (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2023 | 2,722.00 | 0.00 | 41,036.55 | 0.00 | 0.00 | 221,100.00 | 0.00 | 0.00 | 193,825.10 | 187,619.85 |
| 2024 | 2,599.00 | 0.00 | 55,372.27 | 0.00 | 0.00 | 319,170.00 | 0.00 | 0.00 | 240,705.14 | 402,223.30 |
| 2025 | 2,482.00 | 0.00 | 49,451.46 | 0.00 | 0.00 | 304,800.00 | 0.00 | 0.00 | 195,209.17 | 559,705.08 |
| 2026 | 2,370.00 | 0.00 | 44,668.45 | 0.00 | 0.00 | 291,100.00 | 0.00 | 0.00 | 160,547.66 | 676,950.96 |
| 2027 | 2,264.00 | 0.00 | 40,552.18 | 0.00 | 0.00 | 278,010.00 | 0.00 | 0.00 | 132,017.63 | 764,223.67 |
| 2028 | 2,162.00 | 0.00 | 37,157.28 | 0.00 | 0.00 | 265,480.00 | 0.00 | 0.00 | 110,221.36 | 830,180.48 |
| 2029 | 2,065.00 | 0.00 | 34,229.61 | 0.00 | 0.00 | 253,520.00 | 0.00 | 0.00 | 92,579.43 | 880,293.69 |
| 2030 | 1,972.00 | 0.00 | 31,985.03 | 0.00 | 0.00 | 242,130.00 | 0.00 | 0.00 | 81,274.17 | 920,109.82 |
| 2031 | 1,883.00 | 0.00 | 30,003.19 | 0.00 | 0.00 | 231,250.00 | 0.00 | 0.00 | 72,115.55 | 952,091.77 |
| 2032 | 1,798.00 | 0.00 | 28,220.96 | 0.00 | 0.00 | 220,840.00 | 0.00 | 0.00 | 64,505.23 | 977,994.20 |
| 2033 | 1,717.00 | 0.00 | 26,402.88 | 0.00 | 0.00 | 210,900.00 | 0.00 | 0.00 | 56,062.44 | 998,363.27 |
| 2034 | 1,640.00 | 0.00 | 24,773.88 | 0.00 | 0.00 | 201,410.00 | 0.00 | 0.00 | 49,081.41 | 1,014,506.29 |
| 2035 | 1,566.00 | 0.00 | 23,247.08 | 0.00 | 0.00 | 192,350.00 | 0.00 | 0.00 | 42,703.85 | 1,027,220.74 |
| 2036 | 1,496.00 | 0.00 | 21,864.57 | 0.00 | 0.00 | 183,690.00 | 0.00 | 0.00 | 37,385.09 | 1,037,300.98 |
| 2037 | 1,429.00 | 0.00 | 20,452.02 | 0.00 | 0.00 | 175,430.00 | 0.00 | 0.00 | 31,362.60 | 1,044,950.87 |
| **Rem.** | | 0.00 | 132,283.58 | 0.00 | 0.00 | 1,228,814.66 | 0.00 | 0.00 | 108,719.32 | 19,571.56 |
| **Total** | | **0.00** | **641,700.97** | **0.00** | **0.00** | **4,819,994.66** | **0.00** | **0.00** | **1,668,315.13** | **1,064,522.43** |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Major Phase : | Oil | | | Abandonment Date : | 9/15/2046 | **Present Worth Profile (M$)** | |
| Perfs : | 0 - 0 | | | Working Int : | 1.00000000 | **PW 5.00% :** | **1,302,345.45** |
| Initial Rate : | 869,563.97 | bbl/month | | Revenue Int : | 0.87500000 | **PW 8.00% :** | **1,148,550.69** |
| Abandonment : | 194,769.74 | bbl/month | | Disc. Initial Invest. (M$) : | 0.00 | **PW 10.00% :** | **1,064,522.43** |
| Initial Decline | 6.20 | % year | b = 0.000 | ROInvestment (disc/undisc) : | 0.00 / 0.00 | **PW 12.00% :** | **992,002.40** |
| Beg Ratio : | 0.520 | | | Years to Payout : | 0.00 | **PW 15.00% :** | **900,305.95** |
| End Ratio : | 0.520 | | | Internal ROR (%) : | 0.00 | **PW 20.00% :** | **780,983.80** |

# ECONOMIC PROJECTION

| | | | |
|---|---|---|---|
| | As Of Date : 05/01/2023 | **Case** | : Area 4 Coastal Steamfloods |
| | Discount Rate (%) : 10.00 | **Reserve Cat.** | : Proved Producing |
| | Custom Selection | **Field** | : |
| | | **Operator** | : |
| | | **Reservoir** | : |
| | | **Co., State** | : , CA |
| **Cum Oil (Mbbl) :** | **485,838.75** | | |
| **Cum Gas (MMcf) :** | **139,746.74** | | |

| Year | Gross Oil (Mbbl) | Gross Gas (MMcf) | Net Oil (Mbbl) | Net Gas (MMcf) | Oil Price ($/bbl) | Gas Price ($/Mcf) | Oil Revenue (M$) | Gas Revenue (M$) | Misc. Revenue (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 2023 | 4,164.60 | 1,807.42 | 3,123.45 | 908.23 | 75.76 | 3.30 | 236,644.93 | 2,997.25 | 4,597.24 |
| 2024 | 5,592.64 | 2,654.88 | 4,194.48 | 1,334.08 | 72.09 | 4.37 | 302,393.33 | 5,823.47 | 6,444.33 |
| 2025 | 1,943.20 | 994.30 | 1,457.40 | 499.64 | 69.56 | 5.14 | 101,383.78 | 2,566.85 | 2,335.29 |
| **Rem** | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total** | **11,700.44** | **5,456.61** | **8,775.33** | **2,741.95** | **72.98** | **4.15** | **640,422.04** | **11,387.56** | **13,376.86** |
| **Ult** | **497,539.19** | **145,203.34** | | | | | | | |

| Year | Well Count | Net Tax Production (M$) | Net Tax AdValorem (M$) | Net Investment (M$) | Net Lease Costs (M$) | Net Well Costs (M$) | Other Costs (M$) | Net Profits (M$) | Annual Cash Flow (M$) | Cum Disc. Cash Flow (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2023 | 1,451.00 | 0.00 | 21,981.55 | 0.00 | 0.00 | 176,520.00 | 0.00 | 0.00 | 45,737.87 | 44,357.59 |
| 2024 | 1,392.00 | 0.00 | 28,319.50 | 0.00 | 0.00 | 255,810.00 | 0.00 | 0.00 | 30,531.62 | 71,802.17 |
| 2025 | 1,336.00 | 0.00 | 9,565.73 | 0.00 | 0.00 | 93,603.38 | 0.00 | 0.00 | 3,116.81 | 74,403.83 |
| **Rem.** | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total** | | **0.00** | **59,866.78** | **0.00** | **0.00** | **525,933.38** | **0.00** | **0.00** | **79,386.30** | **74,403.83** |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Major Phase : | Oil | | | Abandonment Date : | 5/19/2025 | **Present Worth Profile (M$)** | | |
| Perfs : | 0 - 0 | | | Working Int : | 1.00000000 | **PW** | **5.00% :** | **76,827.16** |
| Initial Rate : | 539,698.46 | bbl/month | | Revenue Int : | 0.75000000 | **PW** | **8.00% :** | **75,357.46** |
| Abandonment : | 415,245.14 | bbl/month | | Disc. Initial Invest. (M$) : | 0.00 | **PW** | **10.00% :** | **74,403.83** |
| Initial Decline | 12.00 | % year | b = 0.000 | ROInvestment (disc/undisc) : | 0.00 / 0.00 | **PW** | **12.00% :** | **73,470.48** |
| Beg Ratio : | 0.419 | | | Years to Payout : | 0.00 | **PW** | **15.00% :** | **72,107.28** |
| End Ratio : | 0.522 | | | Internal ROR (%) : | 0.00 | **PW** | **20.00% :** | **69,929.19** |

# ECONOMIC PROJECTION

| | | |
|---|---|---|
| As Of Date : 05/01/2023 | **Case** | : Area 4 Coastal Waterfloods |
| Discount Rate (%) : 10.00 | **Reserve Cat.** | : Proved Producing |
| Custom Selection | **Field** | : |
| | **Operator** | : |
| | **Reservoir** | : |
| | **Co., State** | : , CA |

| | |
|---|---|
| **Cum Oil (Mbbl) :** | **674,612.21** |
| **Cum Gas (MMcf) :** | **1,105,758.19** |

| Year | Gross Oil (Mbbl) | Gross Gas (MMcf) | Net Oil (Mbbl) | Net Gas (MMcf) | Oil Price ($/bbl) | Gas Price ($/Mcf) | Oil Revenue (M$) | Gas Revenue (M$) | Misc. Revenue (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 2023 | 3,873.90 | 4,067.60 | 2,905.43 | 2,043.97 | 75.76 | 3.30 | 220,108.94 | 6,745.30 | 10,347.45 |
| 2024 | 5,373.72 | 5,642.40 | 4,030.29 | 2,835.31 | 72.08 | 4.37 | 290,506.01 | 12,376.57 | 13,699.99 |
| 2025 | 4,009.36 | 4,209.82 | 3,007.02 | 2,115.44 | 68.98 | 5.14 | 207,423.89 | 10,867.88 | 9,810.44 |
| **Rem** | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total** | **13,256.98** | **13,919.82** | **9,942.73** | **6,994.71** | **72.22** | **4.29** | **718,038.85** | **29,989.76** | **33,857.89** |
| **Ult** | **687,869.18** | **1,119,678.01** | | | | | | | |

| Year | Well Count | Net Tax Production (M$) | Net Tax AdValorem (M$) | Net Investment (M$) | Net Lease Costs (M$) | Net Well Costs (M$) | Other Costs (M$) | Net Profits (M$) | Annual Cash Flow (M$) | Cum Disc. Cash Flow (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2023 | 1,652.00 | 0.00 | 21,348.15 | 0.00 | 0.00 | 185,460.00 | 0.00 | 0.00 | 30,393.54 | 29,469.55 |
| 2024 | 1,552.00 | 0.00 | 28,492.43 | 0.00 | 0.00 | 264,206.25 | 0.00 | 0.00 | 23,883.90 | 50,878.60 |
| 2025 | 1,459.00 | 0.00 | 20,529.20 | 0.00 | 0.00 | 200,227.87 | 0.00 | 0.00 | 7,345.15 | 56,912.96 |
| **Rem.** | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total** | | **0.00** | **70,369.78** | **0.00** | **0.00** | **649,894.12** | **0.00** | **0.00** | **61,622.59** | **56,912.96** |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Major Phase : | Oil | | | Abandonment Date : | 10/23/2025 | **Present Worth Profile (M$)** | | |
| Perfs : | 0 - 0 | | | Working Int : | 1.00000000 | **PW** | **5.00% :** | **59,189.40** |
| Initial Rate : | 495,633.37 | bbl/month | | Revenue Int : | 0.75000000 | **PW** | **8.00% :** | **57,805.55** |
| Abandonment : | 397,617.82 | bbl/month | | Disc. Initial Invest. (M$) : | 0.00 | **PW** | **10.00% :** | **56,912.96** |
| Initial Decline : | 8.50 | % year | b = 0.000 | ROInvestment (disc/undisc) : | 0.00 / 0.00 | **PW** | **12.00% :** | **56,043.43** |
| Beg Ratio : | 1.050 | | | Years to Payout : | 0.00 | **PW** | **15.00% :** | **54,780.75** |
| End Ratio : | 1.050 | | | Internal ROR (%) : | 0.00 | **PW** | **20.00% :** | **52,781.39** |

To know more please visit:

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Carbon Tracker Initiative