CITY OF LONG BEACH

Memorandum

Date: February 17, 2026

To: Thomas B. Modica, City Manager

From: Bob Dowell, Director of Energy and Environmental Services

For: Mayor and Members of the City Council

Subject: **Oil Field Liability Assessment Study**

The City recognizes that oil and gas production is not in its long-term future. Decisions for the early phase out of oil and gas production require meticulous planning, funding of abandonment activities, and recognition of the existing legal commitments and liabilities that exist. The City's Fiscal Year 2023 Budget included funding to prepare an oil liability assessment study to better understand the fiscal liability and feasibility considerations associated with ending oil and gas production in the City. On June 18, 2024, the City Council awarded a contract with Catalyst Environmental Solutions Corporation (Catalyst) to study the various regulatory, legal, financial, and policy considerations associated with an early phase-out of all existing oil and gas operations.

Catalyst has prepared and provided their Technical Report (attached) to highlight the numerous cost, financial, and regulatory issues that exist and identify the issues that must be evaluated in greater detail to provide the City Council with the necessary background to undertake any contemplated actions. Catalyst found that, should the City Council wish to proceed with the phasing out oil and gas production within the City prior to the end of the productive economic life of the oil fields, an additional comprehensive study will be needed to fully evaluate the significant potential legal and financial ramifications for the City from such action. The cost to move ahead with comprehensive technical and legal studies is estimated to be approximately $1 to $1.3 million and would require 12 to 18 months to complete.

Catalyst prepared a scope of work to support a potential Request for Proposal (RFP) should City Council desire to fund this additional study, tentatively titled "*Comprehensive Analysis of Oil Field Liabilities"*. The remainder of this memo summarizes the findings and recommendations of Catalyst's Technical Report in greater detail.

Summary of Findings/Recommendations

It is important to note that Catalyst's Technical Report was designed to identify the various regulatory, legal, financial, and policy liabilities associated with undertaking an early phase-out of all existing oil and gas operations within the City, not evaluate the magnitude or impact of the liabilities. The evaluation would be determined by funding an additional RFP covering a *Comprehensive Analysis of Oil Field Liabilities*, if ordered by the City Council.

This memo addresses the three topics in turn:

- Identification of cost and financial issues
- Comparison to actions by other municipalities both inside and outside of California
- Future *Comprehensive Analysis of Oil Field Liabilities* RFP development support

Cost and Financial Issues

Asset retirement obligations (ARO) for oil fields operated or partially owned by the City totaled about $1.36 billion. The State of California's (State's) share of the obligation is expected to be nearly $1.04 billion, while the City's share is projected to be $153 million with other entities' share expected to be $169 million.

Because the ARO is the basis for the City and State's current abandonment funding set-aside targets, the proposed *Comprehensive Analysis of Oil Field Liabilities* will review the ARO basis to ensure that any changes in conditions or assumptions which have occurred since 2017, and which would substantially affect estimates of future abandonment costs, are adequately accounted for in the study.

It is also recommended to study the ability of all independent oil and gas operators within the City to meet their ARO on assets that would be affected by any City decision(s) to reduce or eliminate oil and gas operations prior to the end of the economic life of the fields.

The proposed RFP for the *Comprehensive Analysis of Oil Field Liabilities* should weigh ranges in ARO costs, lost revenue from early shutdown, and ranges of income available to the City for a range of shutdown dates. This study would summarize the potential for unfunded liabilities for a potential range in shutdown dates.

The *Comprehensive Analysis of Oil Field Liabilities* should also address the issue of managing subsidence in the City under the scenario of early phase out of oil and gas operations. The study should focus on longer term subsidence management in the absence of produced water. This review would consider the City's existing Subsidence Fund and its adequacy to support the costs of early phase out of oil and gas production.

The proposed RFP for the *Comprehensive Analysis of Oil Field Liabilities* should evaluate the potential unrealized lease revenue and profits for non-City oil and gas operators using current levels of annual production.

This initial phase of the study indicates that, while estimation of future revenues for some of these revenue sources would be relatively straight-forward – determined by terms of specific contracts and oil and gas production levels – others would be more complex. Two areas of particular significance are: 1) the impacts of an early shutdown on assessed valuations for LA County property taxes starting immediately; and 2) additional fiscal losses to the City due to impacts of an early shutdown on employment, income and spending by consumers and businesses in the region. It is recommended that these analyses be incorporated into an overall

large cost study conducted by the City and that this study quantifies any indirect economic impacts.

Legal Landscape

The City is uniquely situated among municipalities in California due to its governance under State oil regulations specific to the Wilmington Oil Field. These regulations include (among others) Chapter 138, Statutes of 1964, as revised by Chapter 941, Statutes of 1991, which designate the City as the trustee to the State and unit operator of the Wilmington Oil Field. This designation imposes complex responsibilities on the City related to revenue generation and management of oil and gas production, along with the obligation to hold the tidelands in trust for the benefit of both the City and the State.

In addition to these statutory considerations, the operation of oil and gas production in Long Beach is governed by a network of contractual agreements between the City and oil contractors. These agreements, approved by the State, contain financial and operational obligations on the City and its contractors that extend over the economic life of the oil field. These unique regulatory, constitutional, and contractual implications may impact the City's discretion to phase out oil and gas production early.

Comparison to Actions by Other Municipalities

Several California cities and counties have addressed transitioning or regulating oil and gas activity in their jurisdictions. None of these municipalities have the unique ownership, oversight role, multiple contractual obligations, or significant fiscal liabilities that the City has as trustee for the State and Unit Operator for the oil and gas operations in the Wilmington Oil Field. To provide context, Table 3.1-1 in Catalyst's Technical Report provides a summary of actions taken by other California municipalities to assist in identifying issues and recommendations for consideration during the scope development for the proposed RFP for the *Comprehensive Analysis of Oil Field Liabilities*.

Outside of California, oil and gas regulations vary by state. While various efforts have been made by individual local jurisdictions to ban oil and gas production (or specific activities such as hydraulic fracturing), when litigated, these local ordinances have been overturned in court. The primary examples of these cases have occurred in Texas, Louisiana, New Mexico, and Colorado, and are described in the attached report.

Future *Comprehensive Analysis of Oil Field Liabilities* RFP Development Support

Catalyst's Technical Report has been prepared to assist the City in framing up the issues that will require additional investigation and analysis to support any contemplated decision-making regarding the future of oil and gas operations in the City. The final section of this report presents a series of tasks to address current data gaps and develop a proposed scope of work. The objective of this section is to provide the information necessary to support the City in drafting future RFPs for implementation of the recommended studies.

The current estimate of the cost to complete the technical studies suggested by Catalyst for the *Comprehensive Analysis of Oil Field Liabilities* RFP Scope could range from approximately $711,000 to $1,037,000 and would likely take approximately 12 months to complete.

Additionally, to supplement such studies, a comprehensive legal assessment would be appropriate to evaluate both the current and developing legal frameworks specific to the issues at hand. Undertaking this specialized analysis would involve a significant increase in overall expenses, estimated to be up to $250,000 or more.

When the legal evaluation is added, the total cost increases to $1 to $1.3 million and would require 12 to 18 months to complete.

City staff would also conduct a detailed internal study of the potential lost revenues from any decisions related to early shutdown, estimated to take approximately 5 months. A Gantt chart is also included in the Technical Report to illustrate the anticipated overall timeline to develop an RFP, select the consultant, and complete the studies listed in the table. The actual dates when the work would start are dependent on when funding for the work would be approved by City Council and made available. The start date on the Gantt chart would shift to the actual start date and currently shows relative timing.

A list of consultants that possess the qualifications and expertise to develop an RFP to address each of the studies discussed above as well as conduct the necessary analyses is included at the end of the Technical Report.

City staff recommends that City Council defer undertaking the *Comprehensive Analysis of Oil Field Liabilities RFP* currently. The significant funding requirements for the RFP, given the projected upcoming fiscal challenges for the City, would likely result in impacts on other City services. There are multiple legal challenges currently in California courts brought by other entities seeking to end local oil and gas extraction. The outcome(s) of these proceedings will likely provide any impetus needed for the City Council to undertake any future action.

Additionally, since the request for the study, the Mayor and City Council have taken action to increase the funding for the abandonment reserves for the City to be fully funded for its oil liability and have started the process of reducing reliance on oil in the City's general fund. Both of these are significant steps to change the City's dependence on oil revenues, recognizing that oil is not in our long-term future. If the City Council chooses to move forward, it is strongly recommended that this be considered in the FY 27 budget process along with all the priorities the City will be facing, so that a comprehensive financial overview can be taken.

If you have any questions, please contact me at (562) 570-2001. For further discussion or clarification on legal and regulatory considerations, please contact Deputy City Attorney Adam Jacobs at Adam.Jacobs@longbeach.gov.

ATTACHMENT

CC: DAWN MCINTOSH, CITY ATTORNEY
DOUGLAS P. HAUBERT, CITY PROSECUTOR
LAURA L. DOUD, CITY AUDITOR
APRIL WALKER, ASSISTANT CITY MANAGER
TERESA CHANDLER, DEPUTY CITY MANAGER
MEREDITH REYNOLDS, DEPUTY CITY MANAGER
GRACE YOON, DEPUTY CITY MANAGER
TYLER BONANNO-CURLEY, DEPUTY CITY MANAGER
KEVIN LEE, CHIEF PUBLIC AFFAIRS OFFICER
MONIQUE DE LA GARZA, CITY CLERK
DEPARTMENT HEADS

Catalyst
ENVIRONMENTAL SOLUTIONS

Oil Field Liability Assessment Study

Prepared for: City of Long Beach

Date: September 2025

Table of contents

SECTION 1 Introduction **1**

SECTION 2 Cost and Financial Issues **2**

2.1 Abandonment Cost: Review of Citywide Asset Retirement Obligations *2*

2.2 How Best to Pay for Asset Retirement Cost Obligations? *3*

2.3 External Forces Influencing the Potential Timing of Abandonment Obligations *4*

2.3.1 Idle Well Fees 4

2.3.2 Injection Reduction Work Plan 5

2.3.3 Health Protection Zones 5

2.4 Anticipated Revenue: Financial Issues Related to Early Termination of OWPAs *6*

2.5 Long Term Subsidence Management Costs *7*

2.6 Expected Remaining Life of Leases and Reasonably Anticipated Unrealized Lease Revenues and Profits *9*

2.7 City Taxes and Fees Related to Oil and Gas Production *9*

2.8 Indirect Economic Effects of Early Phase Out of Oil and Gas Production *10*

2.9 Well Ownership and Liability Questions *10*

SECTION 3 How Have Other Cities and Counties Managed Oil and Gas Transitions? **11**

3.1 California *11*

3.2 Outside California *13*

3.2.1 Texas 13

3.2.2 Louisiana 13

3.2.3 New Mexico 14

3.2.4 Colorado 14

SECTION 4 RFQ Development **16**

4.1 RFQ Scope *17*

4.1.1 Task #1. Update 2017 CRC Asset Retirement Obligation Study 17

4.1.2 Task #2. Evaluate Adequacy of the ARO Reserve Fund and Anticipated Revenue 17

4.1.3 Task #3. Allocate foregone profits between the City and other Stakeholders 18

4.1.4 Task #4. Property Tax and Other Revenue Evaluation 18

4.1.5 Task #5. Update 1999 TRAPPS Study and Focus on Costs of Post-oil development subsidence management costs 19

4.2 Anticipated Timeframe and Costs *19*

4.3 List of Recommended Consultants to Develop RFQ *22*

List of tables

Table 2.1-2. Idle Wells Owned by Active Operators in the City 4

Table 2.3-2. Active Wells by Operator and Number of Wells Affected by SB 1137 5

Table 2.4-1. Asset Retirement Reserves as a Percentage of Obligations as of December 31, 2035 (SB 1137 Case) 7

Table 3.1-1. Past Municipal Efforts to Restrict Oil and Gas Production 11

SECTION 1 Introduction

Oil and gas production has been ongoing throughout the City of Long Beach (City) since 1921 and is a significant contributor to the City's revenue stream. The City is unique because it is not only the trustee for the State for the oil and gas operations in the Wilmington Oil Field, but it is also the Unit Operator. As a result, the City's oil and gas role is governed by a complex web of statutes, unit agreements, operating agreements, and contractor agreements. The City's Energy Resources Department (Energy Resources) manages the oil and gas assets located within the Wilmington Oil Field, including oversight of ground subsidence control operations, under a public-private partnership trust agreement that includes the California State Lands Commission (CSLC) and approximately 6,000 individual mineral interest (town lot) owners.

Other oil and gas operators are also located within the City. These operators pay a tax to the City for each barrel of oil produced on a quarterly basis in addition to an annual property tax based on the Los Angeles County Assessor's valuation of their oil and gas reserves.

The City derives nearly $56 million annually directly from revenues tied to the production of oil and gas which is used to fund City services including the Fire Department, Police Department, Office of Youth Development, and the implementation of the City's Climate Action Plan.[1] The City also benefits from a web of indirect revenue streams tied to oil and gas development.

In recent years, changes in State regulations related to oil and gas production and increasing interest from advocacy groups regarding potential environmental and health impacts of oil and gas production have resulted in greater public scrutiny of such operations. In 2022, members of the Long Beach City Council inquired about the feasibility of an early phasing out oil and gas production in the City, well before reaching the end of the productive economic life of the oil fields. While the City recognizes that oil and gas production is not in its long-term future, any decisions by the City Council for the early phase out of oil and gas production would entail meticulous planning, funding of abandonment activities, and recognition of the existing legal commitments and liabilities that exist. On June 21, 2022, the City's Climate Action and Environmental Review Committee recommended to the Mayor and City Council that the City Manager take the following actions:

- Request inclusion in the County and/or City of Los Angeles amortization studies, or work with specialty consultants to conduct a similar study and report back with the cost to conduct a study;
- Direct a percentage of surplus oil revenues to the abandonment fund and to address any other costs associated with abandonment, alongside important one-time capital projects;
- Direct City staff and the State Legislative Committee to request the State to fully fund their portion of their abandonment liability;
- Work with South Coast Air Quality Management District (AQMD) to prioritize leakage mitigation and detection, emissions control, and carbon capture measures;
- Work with labor organizations in the transition of workers from the local energy sector to other employment;

[1] City of Long Beach. 2024. Climate Transition Impact Review to Prepare for Long Beach's Transition from Fossil Fuel Production and Preserve Critical Infrastructure and City Services. Presentation to City Council. July 24.

- Work with the City Attorney, CSLC and other applicable state entities to determine the legal options available to the City to end new drilling as soon as is legally defensible, including studying prohibiting new oil and gas extraction in all City zones and, studying changing oil and gas extraction to a legal nonconforming use in all City zones; and,
- Request that the City Manager report back with timelines and costs associated with the above recommendations as well as potential funding streams for them.

In light of these recommended actions, the City Council requested preparation of a Technical Report to better understand the various regulatory, legal, financial, and policy liabilities associated with undertaking an early phase-out of all existing oil and gas operations within the City. Catalyst Environmental Solutions Corporation (Catalyst) has prepared this Technical Report to highlight the numerous cost and financial and regulatory issues that exist and that must be evaluated in greater detail to address the recommended actions.[2] Catalyst has also prepared a scope of work to support a potential Request for Proposal (RFP) should City Council desire to conduct a full comprehensive evaluation.

Consistent with the City's request, the Technical Report is organized by:

- Cost and financial issues
- Comparison to actions by other municipalities both inside and outside of California
- Future RFP development support

SECTION 2 Cost and Financial Issues

This section discusses the financial implications for the City and key stakeholders that would result from an early phase-out of all oil and gas production in the City. As requested by the City Council, this section addresses the following financial considerations:

- The funding of the City's and other oil operator's asset retirement obligations
- Potential loss of revenue to the City budget from oil operators and oil service providers
- Costs associated with City-operated oil assets after cessation of oil and gas production

2.1 Abandonment Cost: Review of Citywide Asset Retirement Obligations

For oil operations where the City itself acts as operator, the City relies on a 2017 Wilmington Oil Field Asset Retirement Obligation (ARO) study for its anticipated costs that would occur at the end of field life. The ARO study was prepared by California Resources Long Beach (CRC), SPEC Services, Inc., Moffat & Nichol, and Geosyntec Consultants, for full field abandonment of the Long Beach Unit (LBU, THUMS) and Tidelands.[3] The ARO study presumed that asset retirement would be conducted in tandem with tapering off of production so that the ongoing revenue stream would be used for the ARO. The same ARO study is included in a 2017 CSLC Staff Report[4] seeking CSLC approval to increase the Long Beach oil

[2] Although originally part of Catalyst's scope of work, the City has determined that legal and policy issues and associated recommendations identified through that work will be conducted separately by City Counsel and are not included in this Technical Report.
[3] Full Field Abandonment Opinion of Probable Cost, Revision 1, Sept 2017. Included as an attachment to CSLC Staff Report 82.
[4] CSLC Staff Report 82. (2017). Included as Appendix C in Walker report

and gas abandonment reserve fund from its then-current cap of $300 million. The ARO study used by both the City and the 2017 CSLC Staff Report is also used as the basis for the City-commissioned report in 2024: *Review of Economic Impacts to the City of Long Beach Associated with California's Anticipated Transition Away from Crude Oil and Natural Gas Production*[5] (herein referred to as the Walker Report) that estimates potential economic impacts to the City of the loss of oil and gas revenue.

According to the Walker Report, asset retirement obligations for oil fields operated or partially owned by the City totaled about $1.4 billion. The Walker Report projected that these obligations would rise to $1.9 billion by 2035 due only to inflation. The State of California's share of the 2035 obligation is expected to be nearly $1.4 billion, while the City's share is projected to be $206 million with other entities' share expected to be $262 million. Senate Bill 1425 (Gonzalez 2024), signed by Governor Newsom on September 25, 2024, increases the State funds set aside to cover abandonment obligations each month to $5,000,000 or 50% of the oil revenue, whichever is greater. With these funds set aside, the State anticipates enough in reserve to cover 100% of its abandonment obligation by 2035, using the 2017 ARO estimate as its target. The State projection did not consider inflation. *Because the ARO is the basis for the City and State's abandonment funding set aside targets, we recommend that the ARO be reviewed to ensure that any changes in conditions or assumptions which have occurred since 2017 and which would substantially affect estimates of future abandonment costs are adequately accounted for in the study.*

The ARO study addresses LBU and Tidelands operations, and the Walker Report quantifies the total estimated oilfield abandonment liability to the City both currently and in 2035. However, there are other independent oil and gas operators located in the City, each with their own abandonment liability(ies) at end of field life. The Walker Report estimated the combined abandonment liability of these operators at $141 million. If the other independent oil and gas operations end prematurely as a result of any City action to end oil and gas production, it is likely that those operators would not have reserved enough funds for their eventual abandonment liability(ies). *We recommend studying the ability of independent operators to meet their asset retirement obligations on assets that would be affected by any City decision(s) to reduce or eliminate oil and gas operations prior to the end of the economic life of the fields.*

2.2 How Best to Pay for Asset Retirement Cost Obligations?

There are generally two broad models for cessation of oil and gas operations:

1) allow operators to be responsible for phasing out operations, well abandonment, and restoration in a manner that can be fully funded by revenues; or,
2) a more abrupt cessation with shared or no cost sharing from the operator.

An example of the first approach is an oil field transition in northern Los Angeles County: the transition has been orderly, occurring over a reasonable amount of time to allow planning and approvals for beneficial reuse of the oil field, and the operator has fully funded the decommissioning and restoration. An example of the second approach occurred at an urban oil field in Los Angeles: slow movement by the municipality to approve field restoration resulted in no significant abandonment and decommissioning

[5] Evans and Walker. 2024. Review of Economic Impacts to the City of Long Beach Associated with California's Anticipated Transition Away from Crude Oil and Natural Gas Production.

being completed before the operator filed for bankruptcy. The full abandonment cost then fell to the municipality as the landowner. Without the field-specific experience (the fields still had significant downhole pressure) the abandonments conducted by the municipality were much more expensive than they would have been if conducted by a knowledgeable operator. *We recommend an integrative study that weighs ranges in ARO costs, lost revenue from early shutdown, and ranges of income available to the City for a range of shutdown dates. This study would summarize the potential for unfunded liabilities for a potential range in shutdown dates.*

2.3 External Forces Influencing the Potential Timing of Abandonment Obligations

2.3.1 Idle Well Fees

AB 1866 (Hart, 2024) sharply increases idle well fees payable in lieu of filing an idle well management plan (IWMP), and it raises the rate at which idle wells in IWMPs must either be returned to service or be plugged and abandoned. The maximum fee for idle wells has increased from $2,500 to $60,000 per year. In addition, the percentage of idle wells in IWMPs that must be either returned to service or plugged and abandoned has increased from 6% to 20% annually. Table 2.3-1 below provides the number of idle wells owned by active operators located in the City as of November 2024[6]. In addition to those idle wells owned by active operators, over 70 idle wells located in the City are owned by operators who are no longer current operators in the State. These wells are most likely either buried under buildings or abandoned historically without documentation. As shown in Table 2.3-1, a small percentage of the idle wells owned by operators other than the City, who pay annual idle well fees would be affected by the new regulation. The cumulative annual idle well fees paid by non-City operators will increase from approximately $135,000 per year to $882,500 per year, representing a 554% increase in annual costs.

It is unknown if the increased idle well fees will affect business decisions by individual operators related to the retirement of these assets. In addition, a forced shut-in by the City at a specific date may not align with individual operator plans for plugging and abandoning idle wells. Oftentimes, plugging and abandonment is funded by revenue generated from continued production of other active wells. Impacts on the financial solvency of individual operators increases the risk of wells becoming orphaned in the City, with increased financial liability to the City.

Table 2.1-2. Idle Wells Owned by Active Operators in the City

Operator Name	Number of Idle Wells	Idle Wells over 25 Years	IWMP or Fee
Tidelands Oil Production Co.	182	126	IWMP
THUMS Long Beach	239	84	IWMP
Signal Hill Petroleum, Inc.	34	7	Fee
Synergy Oil & Gas, LLC	12	6	Fee
P&M Oil Company, Inc.	8	0	Fee
The Termo Company	8	3	IWMP

[6] Source: CalGEM WellSTAR database as reviewed November 15, 2024.

2.3.2 Injection Reduction Work Plan

An injection reduction work plan (IRWP) was initiated in July 2024 for the City-operated portion of the Wilmington field. The IRWP was developed to address CalGEM's request to reduce overall injection gradients throughout the Wilmington field to prevent possible incursion of the injection water into the groundwater. Initial estimates from the IRWP are forecasting approximately a 20% injection rate reduction over a 5-year period. Due to the requirement to maintain stable surface elevations at Wilmington, any reduction in injection will result in a proportionate reduction in oil and water production. This will result in revenue reduction as well as the field reaching its economic limit earlier than anticipated.

Both the City and CRC have maintained that the historical injection gradients were in compliance with all applicable regulations and CalGEM's decision to reduce the gradient is the result of injection gradient interpretations not applicable for the Wilmington field. Despite the differences, measurable steps have been taken to comply with the agreed-upon reductions outlined in the IRWP. Close engagement with CalGEM is ongoing to discuss and refine key aspects of the plan while reinforcing the shared commitment to the safe and responsible management of the Wilmington field.

2.3.3 Health Protection Zones

SB 1137 became effective in June 2024. The regulation prohibits CalGEM from issuing permits for new oil and gas wells or rework of wells (unless for health and safety) within 3,200 feet of sensitive receptors, which is broadly defined in the regulation to include homes, schools, and any commercial building open to the public. It also prohibits the construction and operation of new production facilities within this distance, known as a health protection zone (HPZ).

A review of active wells in the City[7] indicates that 100% of the non-City wells are within HPZs, as shown in Table 2.3-2 below.

Table 2.3-2. Active Wells by Operator and Number of Wells Affected by SB 1137

Operator	Number of Wells Inside HPZ	Number of Wells Outside HPZ	Total Number of Active Wells
Arrowhead Operating Inc	5	0	5
California Resources Long Beach, Inc	50	0	50
E & T Limited Liability Co.	16	0	16
Herley-Kelley LLC	1	0	1
S & C Oil Co., Inc.	3	0	3
Signal Hill Petroleum, Inc.	58	0	58
Synergy Oil & Gas, LLC	49	0	49
The Lansdale Co.	7	0	7

[7] Note that the RFP from the City indicated there were 17 active operators with wells in the City, our review of current well data from CalGEM finds that there are actually 10 active operators as of January 2025.

Operator	Number of Wells Inside HPZ	Number of Wells Outside HPZ	Total Number of Active Wells
The Termo Company	14	0	14
THUMS Long Beach Company	723	630	1,353
Tidelands Oil Production Co.	344	250	594
TJ Scott Family Investments, LLC	1	0	1
Grand Total	1,271	880	2,151

There is significant uncertainty regarding the impact of SB 1137 on oil production over the next decade – and more generally what the production baseline will be over the next decade. This uncertainty is driven by the difficulty of forecasting the location and timing of future well failures. In its 2022 evaluation of SB 1137, the City estimated that the measure would result in an immediate doubling of the decline rate – from 6% to nearly 12% per year. Over half of the wells on the THUMS and Tidelands Islands are located within an HPZ. The Walker Report estimated that the impact would be more gradual, with the decline rate steepening 1% per year starting in 2026, finally reaching 12% in 2032. Further adding to uncertainty is that the rate of decline in 2024 steepened sharply before SB 1137 took effect due to the cessation of drilling in December 2023.

2.4 Anticipated Revenue: Financial Issues Related to Early Termination of OWPAs

After "how much is decommissioning and abandonment going to cost?" summarized in the previous sections, the next question is "how much oil and gas revenue is available to offset that cost?" The State's share of the abandonment obligation is expected to be nearly $1.4 billion, while the City's share is projected to be $206 million with other Unit entities' share expected to be $262 million.

Both the State and City have established reserve funds for future abandonment, but neither has a reserve sufficient to address the 2035 cost derived from the 2017 ARO, which we recommend updating with current numbers and sensitivity analyses. As of January 2024, the City had reserves of $81 million and the State had reserves of $330 million. Taken together, it is likely that more oil and gas revenue would be directed towards abandonment costs than is the current practice for the reserve fund.

The City commissioned the Walker Report in 2024. Much of the Walker Report addressed potential future oil and gas revenues. However, there are substantial uncertainties regarding the ability of the City to support these costs through continued oil and gas revenues. *These uncertainties are quantifiable, and we recommend that they be addressed in future work to support decision-making on the future of oil and gas production in the City.*

Presently, the City is contributing to its reserve at a rate of nearly $750,000 per month, while the State is funding its reserves at a rate of 50% of net oil revenue or $5 million per month, whichever is greater. The Walker Report finds that if the City continues to fund reserves at current rates, the City will have reserve balances by the end of 2035 that are equal to 117% of its asset retirement obligations. It also found that, based on contribution rates in effect prior to enactment of SB 1425, the State would only have enough in reserves to cover 49% of its share of obligations, leaving a deficit of $712 million (see

Table 2.4-1). However, if future contributions match the new higher amounts required by SB 1425, total state reserves will be sufficient to cover the State's currently estimated $1.4 billion obligation.

Table 2.4-1. Asset Retirement Reserves as a Percentage of Obligations as of December 31, 2035 (SB 1137 Case)

Entity	Obligations	Reserves	Deficit	Reserves as % of Obligations
State of CA	$1,390,241,298	$677,871,654	($712,369,645)	49%
COLB	$205,320,883	$240,770,994	$35,450,112	117%

Source: Evans and Walker 2024.

While the approach used in the Walker Report makes sense, it is based on production levels that are in flux due to the implementation of SB 1137 and injection pressure reductions - both of which will have major impacts on future production levels and associated City contribution levels to asset retirement reserve funds. The study could also be expanded to consider the impacts of a shutdown on drilling and other investments between now and the shutdown data. Lastly, the study limits its analysis to the year 2035, although the period beyond 2035 may still include economic production. We recommend further analysis to understand the potential for post-2035 production and profits, which could be used to address any remaining ARO funding deficits due to lower contribution rates prior to 2035 or higher than currently estimated ARO expenses. Future State contributions of $5 million per month to its reserves are not assured, given the large projected deficits in its General Fund budget (General Fund contributions would be needed if State net revenues from the Tidelands fell short of $5 million per month). Moreover, reductions in monthly production levels resulting from SB 1137 and reduced injection pressures will correspond with reduced monthly revenue for both the City and State. For example, in its 2022 evaluation of SB 1137, the City estimated that the measure would result in an immediate doubling of the decline rate – from 6% to nearly 12% per year. The Walker Report estimated that the impact would be more gradual, with the decline rate steepening 1% per year starting in 2026, finally reaching 12% in 2032. Further adding to uncertainty is that the rate of decline in 2024 steepened sharply before SB 1137 took effect, due to the cessation of drilling in December 2023. A longer-term analysis would be needed to determine additional resources that would be available to cover both higher than expected plugging and abandoning costs and potentially lower profits and contribution levels between now and 2035.

Accordingly, it is not clear whether the City will accrue enough funds to cover its abandonment obligations if it terminates the Optimized Waterflood Program Agreements (OWPAs) prior to the end of the economic life of its oil and gas reserves. Similarly, it is unknown how the City will ensure that facilities are sufficiently remediated and in a timely manner. This uncertainty leaves a risk of leaving the land unable to be redeveloped and remaining idle.

2.5 Long Term Subsidence Management Costs

The port area of the City had been subject to substantial reservoir compaction prior to the initiation of comprehensive produced water injection in the 1960s. With accumulated oil and gas extraction from a relatively shallow reservoir, the depressurization led to subsidence to relieve the lower reservoir pressure. Since that time, subsidence has been slowed to manageable levels by injection of produced

water, a process known as waterflooding. With cessation of waterflooding along with the cessation of oil and gas extraction, there would be no replacement mechanism to slow and manage subsidence.

In 1999, the City evaluated the requirements for managing subsidence related to oil and gas reservoir depressurization after production ends[8] (LBER 1999; herein referred to as TRAPPS Study). While a revision to that study was anticipated by the end of 2024, it was not available for review at the time that this Technical Report was prepared. The Walker Report relies on the results of the 1999 TRAPPS study for its subsidence cost opinion. There are many variables in this evaluation including: natural reservoir pressures and overpressures; the degree to which depressurization has been fully addressed so that no further injection is required; and the time and magnitude response of the reservoir and the land surface to injection.

A fundamental issue with respect to the TRAPPS Study is that it assumed an orderly process of progressive cessation of oil and gas operations to ensure that subsurface pressures were addressed during operation. This orderly transition would allow optimization of using oil and gas produced water for minimizing the need for future subsidence management with purchased water.

The TRAPPS Study contains action plans for a range of scenarios (expected case and worst and best cases) depending upon the degree to which the Energy Resources Department will be required to monitor and control subsidence in the post-production era of the oil field. However, all of the scenarios assume the orderly and prolonged shutdown of oil and gas production. For the prolonged shutdown case, the Fault Block Units were identified to help stop subsidence and to produce economic oil. As the Fault Block Units and the Long Beach Unit become uneconomical, the units may need to be terminated. In the Fault Block Units, the rights to develop unproduced resources revert to the mineral owners when the units are terminated.

Without an orderly transition and prolonged shutdown, there is a need for new sources of injection water because produced water from pumping oil wells will not be available. At the time of the TRAPPS Study, water sources for injection were assumed to be water source wells on Chaffee and White Islands, and Pier J. This water is the least expensive, high-quality water that is available. Its drawback is a high sulfate content that results in the formation of hydrogen sulfide gas when injected into the reservoirs. The relatively small volumes of water to be injected during post-production in the absence of production lessens the potential for exposure to this hazardous gas when compared to current operations. However, with an accelerated schedule for shutdown, additional sources of water, other than water produced by oil and gas production, would need to be secured.

Even at the time of the TRAPPS Study, the potential large cost for water to counter subsidence was considered, as follows:

> *An example of a problem associated with the current contracts is that the expense of "repressuring operations" is a cost of production. When oil operations are profitable and most reservoirs are producing oil for sale, such costs are an appropriate cost of the waterflood operations. As more and more reservoirs become uneconomic and are shut-in, the cost of injection for subsidence control becomes an unreasonable burden.*

[8] Long Beach Energy Resources. 1999. Transitional Reservoir Abandonment and Post-production Subsidence Control Plan. (1999). TRAPPS study.

This burden would increase substantially with an early cessation of oil and gas (and produced water) development.

Subsidence management is a key issue post-oil production. Without a replacement source of produced water from active oil wells, the cost would be much higher than the TRAPPS Study projects. The Walker Report, citing the 1999 TRAPPS Study, projects that by 2035 there would be no more depressurization that would require active management. The Walker Report's interpretation of the TRAPPS Study is counterintuitive, and counter to Catalyst experience with this issue in other parts of southern California. *We recommend that the issue of managing subsidence in the City under the scenario of early phase out of oil and gas operations be addressed in a study that revises and updates the TRAPPS Study and focuses on longer term subsidence management in the absence of produced water. This review would consideration of the City's existing Subsidence Fund and its adequacy to support the costs of early phase out of oil and gas production.*

2.6 Expected Remaining Life of Leases and Reasonably Anticipated Unrealized Lease Revenues and Profits

An early phase-out of oil and gas operations before the economic life of any oil and gas field has the potential for legal actions by affected oil and gas operators who currently expect to continue producing until the field is no longer economic. An early cessation of production carries with it the liability that operators will seek compensation for that lost revenue.

The City has evaluated the anticipated productive life of its own leases, but the remaining economic life of non-City leases based on proved plus probable reserves is unknown. The Los Angeles County tax assessor would likely have reserve assessments for all the independent oil and gas mineral leases throughout Long Beach; however to what extent this information would be made available is unknown and requires a more detailed review and analysis. Further, the economic life of these other leases is affected by changes in the regulatory environment, the same as is the case for City operations. For instance, CalGEM's ongoing project-by-project reviews of existing underground injection control projects has likely adversely affected the maximum allowable rate of injection for other operators as it has for City production. Similarly, delays in permitting by the State for modified, expanded or new underground injection projects as well as new wells and rework and sidetrack permits for existing wells has decreased the economic life of these leases. *We recommend that a future study evaluate potential unrealized lease revenue and profits for non-City operators using current levels of annual production.*

2.7 City Taxes and Fees Related to Oil and Gas Production

A key element of a future study will be to determine how much tax and fee revenues the City would receive from all the oil and gas operations throughout the City (and thus, what would need to be replaced once these operations are gone). These include revenues associated with its share of profits in City operated oil and gas properties as well as other local taxes, fees and charges paid by businesses and households of employees involved in oil and gas production. These oil and gas revenue sources include: franchise fees on surface lands and pipelines used in oil and gas operations; property taxes on reserves and surface equipment; overhead charges to compensate the City for its costs associated with its oversight of oil and gas operations; utility user taxes; "Proposition H" per-barrel extraction taxes;

Measure US and, sales taxes. The Walker Report included estimates from these sources through 2035. However, these estimates would need to be updated to reflect: (1) operations beyond 2035; (2) updated estimates of production, prices and profits associated with oil and gas operations within the City; and (3) impacts related to a potential early shutdown of operations.

Our review indicates that, while estimation of future revenues for some of these revenue sources would be relatively straight-forward – determined by terms of specific contracts and oil and gas production levels – others would be more complex. Two areas of particular significance are: (1) the impacts of an early shutdown on assessed valuations for property taxes starting immediately; and (2) additional losses to the City due to impacts of an early shutdown on employment, income and spending by consumers and businesses in the region. *We recommend these analyses be incorporated into an overall large cost study conducted by the City.*

2.8 Indirect Economic Effects of Early Phase Out of Oil and Gas Production

As an ongoing economic activity in the City, oil and gas operations have both direct and indirect effects on the local economy. The available studies associated with economic effects do not include revenue losses to the City from the loss of sizable indirect effects of oil and gas operations on employment, income, and tax payments by households of oil and gas industry employees and businesses that supply goods and services to the oil and gas industry. These impacts would likely be significant given the relatively high rates of pay and purchases made by the oil and gas industry each year.

There is a commonly used numerical model for this type of quantification, called IMPLAN (Impact Analysis for Planning). IMPLAN uses national production functions to determine how industries spend their money, and a national matrix to determine the byproducts each industry generates. IMPLAN treats households as an industry to determine their spending patterns. As such, it captures most monetary market transactions between industries and institutions over a given time period to quantify the indirect economic effects. It is particularly useful for estimating the change in these indirect economic effects to planning-level decisions such as the ones before the City Council with respect to future oil and gas development. *We recommend that the overall large cost study conducted by the City include an IMPLAN analysis to quantify indirect economic impacts.*

2.9 Well Ownership and Liability Questions

The City and the operator community have routinely used “quit claims” to end or transfer well ownership to other owners. Quitclaiming by an entity does not offer a warranty to the title; the buyer or grantee must accept the title as is. Accordingly, a quit claim allows an operator to transfer the liability associated with its wells to the buyer. Once the operator quit claims, those interests are divided among the remaining working interest owners. The remaining working interest owners retain the value of the well, and the liability for its abandonment cost. Ultimately, the City and the State cannot quit claim, so liability finally resides between them.

The City has noted the long history of quitclaims by operators over the years, which may leave the liability for the well and infrastructure either with the City or the State. For one example:

> *“In 1991, most of the major oil companies (ARCO, Chevron, Exxon, Mobil, Phillips, Texaco, and others) with working interests in Fault Block Units IV and V quit claimed their interests back to the*

thousands of mineral rights owners. Most of the new working interest owners reduced their participation to zero with their interests divided among the remaining working interest owners. The City became Unit Operator for Segment 2."

The City does not appear to have clear accounting for the abandonment obligations of the other oil and gas operations within the City, or the level of financial assurance that each operator has to properly abandon and remediate their operations before quitclaim or bankruptcy.

Based on our review, quit claiming was and remains a common practice in the City, and the entity holding liability for well abandonment costs is often unclear. Because the City may well be the last solvent entity with liability over a well, this represents a substantial risk. *We recommend that a future study evaluate this further to characterize the full nature of this "quit claim issue" and the associated cost liability to the City.*

SECTION 3 How Have Other Cities and Counties Managed Oil and Gas Transitions?

3.1 California

Several California cities and counties have addressed transitioning or regulating oil and gas activity in their jurisdictions. None of these municipalities have the unique ownership, oversight role, multiple contractual obligations, or significant fiscal liabilities that the City of Long Beach has as trustee for the State and Unit Operator for the oil and gas operations in the Wilmington Oil Field. However, in order to provide context, Table 3.1-1 below provides a summary of actions taken by other California municipalities to assist in identifying issues and recommendations for consideration during the development of the scope of the future study.

Table 3.1-1. Past Municipal Efforts to Restrict Oil and Gas Production

Municipality	Summary	Estimated Legal Costs to Defend Ordinance
Culver City	Culver City adopted an Oil Termination Ordinance on October 25, 2021, after years of consideration and completion of an amortization study. The only oil and gas operations in Culver City consist of a portion of the Inglewood Oil Field which is operated by a single operator (currently Sentinel Peak Resources). Following the adoption of the ordinance, the City was sued by Sentinel Peak Resources for takings, which ultimately resulted in a Settlement Agreement executed on December 7, 2023. The Settlement Agreement resulted in phased plugging and abandonment of all wells within the City (at total of 32 active or idle wells are located in Culver City) (at an agreed upon rate extending to December 31, 2029, and allowing Sentinel Peak Resources to continue normal operations of active wells through to the agreed upon end date.	$1.3 million[1]

Monterey County	Monterey County passed Measure Z in the 2016 election, which would have banned the practice of hydraulic fracturing, as well as any new oil and gas wells in the County. The measure was immediately litigated by industry. In 2018, Monterey County Superior Court ruled that local jurisdictions do not have the authority to regulate industry. The decision was appealed by the non-governmental organizations who supported the ballot measure in 2021, and was affirmed by the Supreme Court in 2023.	The County settled with plaintiffs in order to avoid attorney's fees and plaintiff attorney's fees
Los Angeles County	LA County Board of Supervisors approved an ordinance in 2022 prohibiting new oil wells and production facilities, and designating existing facilities as non-conforming uses. The ordinance excludes the Baldwin Hills Specific Plan Area, although in 2023 the supervisors voted to amend the Specific Plan to align with the ordinance and prohibit new oil wells in the Inglewood Oil Field. The County was sued by an individual operator in 2023, and settled out of court with an agreement to allow the operator to continue operations and to rescind the ordinance. LA County Board of Supervisors unanimously voted to repeal the ordinance on May 13, 2025.	$143,000[2]
	In March 2025, LA County Department of Regional Planning issued a Notice of Preparation for an Environmental Impact Report for a proposed revised ordinance. The proposed revised oil well ordinance would prohibit new oil wells and production facilities, designate existing wells without approved discretionary permits as nonconforming with a 20-year amortization period, and establish performance standards for site maintenance, well plugging, and site restoration. Additionally, within Title 22, amendments to the Baldwin Hills Community Standards District (CSD) ensure consistency with countywide oil well prohibitions and performance standards during the amortization period. The County also proposes to revise its General Plan to prohibit new well operations and remove designations that support oil and gas production.	Not yet completed
	In June 2024, LA County Board of Supervisors approved a contract with CJM Petroleum Inc to conduct the Los Angeles County Oil Well Amortization Study under the direction of LA County Department of Regional Planning. The study is estimated to take 3 years to complete with a cost of $974,160. Drafts of the amortization study were presented in public workshops in May 2025.	Not yet completed
Santa Barbara County	Santa Barbara County Measure P failed in vote 61% to 39% 2014 Measure P would have prohibited land uses that support new "high intensity petroleum operations" in Santa Barbara County. These operations include hydraulic fracturing, acidizing, and steam injection.	Not enacted
San Benito County	San Benito County passed Measure J in the 2014 election which proposed changes to the County general plan which would ban well stimulation activities, including hydraulic fracturing and enhanced oil recovery activities such as steam injection. The measure was sued almost immediately by an individual operator who had planned to drill up to 1,000 steam-injection wells in the	$36,000

	Bitterwater Oil Field claiming over $1 billion in damages, arguing that the measure's prohibitions would deprive the company of profits expected from mineral rights, previous purchases and previously constructed infrastructure. The County never responded to the lawsuit, but did authorize $36,000 to retain a law firm to provide legal representation in court and began establishing a legal defense fund related to the measure to solicit private donations. However, ultimately, the operator filed a request to dismiss the case.	
City of Los Angeles	The Los Angeles City Council approved an ordinance in 2023 making oil production a non-conforming land use and requiring the phase out of all oil production operations within a 20 year period. This ordinance was challenged in court and overturned in September 2024, with the judge specifically stating that only the State has the authority to regulate oil and gas production and that City's do not have the authority to ban all new wells. The ordinance was officially rescinded in June 2025, and the City introduced a new ordinance to end oil production in September 2025.	All parties bore their own legal costs and there was no monetary settlement. It is not published how much the City expended in in-house legal costs
	The Los Angeles City Council approved a motion in December 2024 to prepare an ordinance to halt the practice of oil well acid maintenance. The item was approved by the Planning and Land Use Maintenance Committee on March 25, 2025, and is scheduled to go before the City Planning Commission in fall 2025.	Not yet completed

1. Source: https://www.culvercity.org/files/assets/public/v/1/documents/city-attorney/2023-12-07_culver-city-sentinel_settlement-agreement_fully-executed.pdf

2. Source: https://patch.com/california/culvercity/inglewood-oil-field-issues-linger-despite-summer-settlement

3.2 Outside California

Outside of California, oil and gas regulations vary by State. While various efforts have been made by individual local jurisdictions to ban oil and gas production (or specific activities such as hydraulic fracturing), when litigated, these local ordinances have been overturned in court. The primary examples of these cases have occurred in Texas, Louisiana, New Mexico, and Colorado, as described below.

3.2.1 Texas

In Texas, the town of Denton adopted an ordinance banning hydraulic fracturing in 2014. However, House Bill 40 signed into law in 2015 expressly gave exclusive control of oil and gas operations to the state government and specified that state law preempts local regulation of those operations. The Denton City Council repealed its ordinance the same year.

3.2.2 Louisiana

In 2016, the Louisiana Supreme Court voted 4-3 against hearing an appeal of district and circuit court rulings upholding the issuance of a state drilling permit. St. Tammany Parish had attempted to use zoning ordinances to block the project, but the lower courts found that the parish's ordinances were preempted by state oil and gas regulations. Subsequently, St. Tammany Parish filed suit against the

project in June 2014 due to concerns that it would pollute the area's water supply and adversely affect property values, which led to the 2016 Supreme Court decision.

3.2.3 New Mexico

In New Mexico, in *SWEPI, LP v. Mora County, New Mexico*, a producer holding leases on state-owned lands challenged a County Ordinance that, among other things, declared it unlawful for any corporation to engage in the extraction of hydrocarbons; construct or maintain infrastructure related to the extraction of hydrocarbons; engage in the extraction of water from any surface or subsurface source within the county for use in the extraction of hydrocarbons; or deposit, store, transport or process waste water, "produced" water, "frack" water, brine or other materials, chemicals or by-products used in the extraction of hydrocarbons.

The Court held that New Mexico's state law pre-empted the county's ban against hydrocarbon extraction. First, the Court held that local governments cannot enforce zoning regulations on state lands without the state's consent, which Mora County did not obtain. Second, the Court held that a ban on the extraction of hydrocarbons was impliedly preempted by New Mexico's Oil and Gas Act, because it attempted to prohibit activities that the statute allows; it would cause a waste of hydrocarbon resources; and it failed to recognize or protect mineral owners' correlative rights. The Court acknowledged that the state's Oil and Gas Act does not expressly say that extraction of hydrocarbons is permitted in New Mexico, but it noted that the state had created an extensive statutory and regulatory scheme to govern such activities. [9]

3.2.4 Colorado

In November 2013, the City of Boulder was one of four local governments in Colorado with oil and gas questions put on the ballot. Voters approved Question 2H with nearly 80% approval. The measure extended a moratorium on new oil and gas exploration, and the use of hydraulic fracturing, for five years. No lawsuits were filed against Boulder over this issue.

In contrast, in the same year voters in Fort Collins approved Question 2A which established an ordinance prohibiting for five years the use of hydraulic fracturing or storing fracking waste within city limit with 55% approval and voters in the City of Lafayette approved Question 300 with 60% approval, which banned all oil and gas development and related activities within the city. The Colorado Oil and Gas Association filed lawsuits against both cities in December of 2013. The Colorado Supreme Court ruled that the ordinances were preempted by state law and overturned both in 2014. This ruling was upheld by District Court in 2020.

In 2019, the State of Colorado adopted Senate Bill 19-181 which gave local jurisdictions the ability to have greater oversight in oil and gas operations. Since then, a review of all counties in Colorado indicates that only two (Arapahoe County and Boulder County) have updated their Land Development

[9] https://www.bwenergylaw.com/wp-content/uploads/sites/1404044/2022/02/Federal_Court_Rebuffs_Local_Attempt_to_Ban_Oil_and_Gas_Development.pdf

Codes since the passage of the state legislation.[10] A summary of the adopted changes is provided in the two subsections below.

4.2.3.1 Arapahoe County, Colorado

Following the passage of Colorado Senate Bill 19-181 in April 2019, Arapahoe County Commissioners amended its Land Development Code and approved oil and gas regulations on November 9, 2021. Since that time, the regulations were amended twice in 2023 and once in 2024. The regulations address safety, traffic and quality of life considerations. According to the County Commissioners, the existing rules create parity between industry and resident concerns while also allowing for continued production and growth in unincorporated Arapahoe County.[11]

The following list includes the provisions included in the 2023 and 2024 amendments to the regulation that address community compatibility issues:

- Require access roads to comply with current fire code;
- Require alternative emergency access roads for well pads located in areas with only one way in and one way out, unless emergency responders decide that an alternative access road is not needed;
- Require handwashing supplies for workers at oil and gas sites;
- Require additional application information, including a project narrative, photo simulations and documentation of floodplain, wetlands and riparian area boundaries.
- Ensure the operation of oil and gas facilities are in compliance with all applicable federal, state, and local laws and regulations.
- Require oil and gas operations to be 3,000 feet away from existing and planned reservoirs when downgradient conditions can be demonstrated;
- Increase setbacks from occupied structures, platted lots, outside activity areas and water bodies from 2,000 feet to 3,000 feet;
- Require one-mile setbacks from existing and planned surface water reservoirs;
- Include wildland urban interface protections determined necessary by the fire district;
- Require soil contamination testing for any incidents where fluids move off a well pad. This includes a remediation plan if testing reveals contaminants are present off the well pad;
- Require the creation of groundwater and surface water quality plans, which provide additional water testing beyond state requirements;
- Develop an air quality mitigation plan. This includes air quality monitoring beyond state requirements with additional monitoring stations and increased leak detection monitoring, plus County notification should a test result exceed air quality standards. Monitoring to be conducted by an independent third-party consultant, paid for by the operator;
- Require continuous noise monitoring by an independent third-party consultant, paid for by the operator.
- Require financial assurance of $120,000 for each approved wells on a pad. The cost will be adjusted annually for inflation. This ensures there are sufficient funds to cover the costs of plugging, abandoning and meeting the State's requirement for site reclamation, which protects the environment and public interest.

[10] https://www.oilandgasbmps.org/laws/colorado_localgovt_law.php

[11] https://www.arapahoeco.gov/your_county/county_departments/public_works_and_development/oil_and_gas/index.php

- Require drilling and permanent production equipment be operated with electric equipment and power where available.
- Require air quality monitoring that will identify areas with poor air quality and pollutants responsible for it. This proposal would use air quality sensors and other devices to monitor air quality to protect public health.
- Require water monitoring.
- Create a County inspection program that would conduct site inspections at every oil and gas operation within unincorporated Arapahoe County. The inspections will be in addition to inspections done by the state Department of Public Health and Environment and the Energy and Carbon Management Commission (ECMC).
- Increase setbacks from oil and gas facilities for new development. Setbacks for new developments proposed in proximity to existing oil and gas facilities is 2,000 feet. Setbacks for new developments from a plugged and abandoned oil and gas well that was abandoned in 2014 or later increase from 150 feet to 250 feet.
- Prohibit commercial injection wells for the disposal of wastewater to alleviate the risk of potential leaks and compromising the water table. During oil and gas drilling, operators will inject used, contaminated water from the hydraulic fracturing process into underground wells placed in deep rock formations for disposal—this regulation would prevent this practice.

4.2.3.2 Boulder County, Colorado

Even though no new oil and gas development has occurred in unincorporated Boulder County since 2012, and no drilling applications have been submitted since 2011, in 2020, Boulder County reviewed and updated its oil and gas regulations in response to changes made by Colorado Senate Bill 19-181.

According to the ordinance, the purpose of the new regulations was to protect public health, safety, and welfare, and the environment and wildlife resources; and regulate the surface impacts of oil and gas operations in a reasonable manner to address matters including the following: local land use impacts; the location and siting of oil and gas facilities; impacts to public facilities and services; water quality and source; noise; vibration; odor; light; dust; air emissions and air quality; land disturbance; reclamation procedures; cultural resources; emergency preparedness and coordination with first responders; security; traffic and transportation impacts; financial securities; indemnification; insurance; other effects of oil and gas development; and providing for the planned and orderly use of land and protection of the environment in a manner consistent with constitutional rights. The County ordinance states that it will deny applications where the proposed oil and gas operations cannot be conducted in a manner that appropriately protects public health, safety, and welfare, and the environment and wildlife.

SECTION 4 RFQ Development

As described in Section 1, this Technical Report has been prepared to assist the City's Energy Resources Department in framing up the issues that will require additional analysis to support decision-making regarding the future of oil and gas in the City. This section takes the issues identified in Section 2 and presents a series of tasks to address current data gaps and develop a proposed scope of work. The objective of this section is to provide the information necessary to support Energy Resources in drafting future RFPs for implementation of the recommended studies.

4.1 RFQ Scope

4.1.1 Task #1. Update 2017 CRC Asset Retirement Obligation Study

The City relies on the 2017 CRC ARO study for the anticipated costs that would occur at the end of field life, or progressively in tandem with tapering off of production. Uncertainties inherent in ARO studies have been a persistent issue for other southern California cities and counties as they have addressed issues of bonding, insurance, and amortization. The key issues to be addressed in an updated ARO study are those described previously in Section 2.1 and our recommendations for this task are listed below:

1. Well abandonment costs and cleanup of contamination associated with oil and gas field operation is particularly difficult to estimate with accuracy. The remediation estimates have a high inherent variability. We recommend an update of the ARO evaluate these uncertainties to better support future decision-making.
2. We recommend that the updated ARO include all decommissioning costs that would be affected by decisions to reduce or eliminate oil and gas operations prior to the end of the economic life of the fields.
3. We recommend that the update of the ARO study include a broader range of unit costs for items that are treated with a single representative cost in the 2017 study and apply the unit costs to the full field assets.
4. We recommend that the ARO be updated to clearly identify the “known unknowns” (as described in Section 2.1) because they constitute a cost risk that should be disclosed.
5. We recommend that the update to the ARO incorporate a sensitivity analysis that applies a reasonable range of values for each of the variables listed in items 1-4 above.

4.1.2 Task #2. Evaluate Adequacy of the ARO Reserve Fund and Anticipated Revenue

According to the Walker Report, asset retirement obligations for oil fields operated by the City totaled about $1.4 billion in January 2024. These obligations are expected to rise to $1.9 billion by 2035 due mainly to inflation. The State’s share of the 2035 obligation is expected to be nearly $1.4 billion, while the City’s share is projected to be $206 million with other entities’ share expected to be $262 million.

While the approach used in the Walker Report to evaluate funding of the City’s asset retirement obligations makes sense, it is based on production levels that are in flux due to recent implementation of SB 1137 and injection gradient reductions - both of which will have major impacts on future production levels and associated contribution levels to ARO reserve funds. In addition, the study could be expanded to consider the impacts of an early shutdown on drilling and other investments in field operations, as well as include sensitivity analyses regarding impacts of production rates and oil prices on contribution rates, which may further accelerate the decline in production over the next decade.

Lastly, we recommend an updated study consider the production and profit outlook beyond 2035, which could still include economic production. This issue is important to understanding the potential for future profits that could be used to meaningfully reduce the ARO funding deficits that would emerge if abandonment costs were to be significantly higher or asset retirement costs turn out to be higher than expected or contribution levels turn out to be lower than expected between now and 2035. More

specifically, a cost study would need to update the assumptions and expand the timeframes of the ARO analysis to incorporate the more recent production and profit forecasts, as well as independent estimates of well plugging, abandonment and surface remediation costs in light of revised investment plans. The updated study should include an assessment of how much post-2035 production could reduce ARO reserve shortfalls from lower contributions made prior to 2035 or additional reserves needed to cover higher than expected AROs.

4.1.3 Task #3. Allocate foregone profits between the City and other Stakeholders

As noted above, a comprehensive study of City costs from an early termination would need to account for foregone production and profits to all entities involved in oil and gas production in the City. The City receives anywhere from 1% to 20% of the profits generated from its oil production in the Tidelands, LBU and several other Long Beach operating areas. The remaining portion of the profits goes to other stakeholders – specifically, the State of California, California Resources Corporation, and various other working interest owners in the LBU (Town lot).

The City's current 8% weighted share implies that each dollar in foregone profits to the City corresponds to roughly $12 in foregone profits to the other stakeholders. In addition, other producers within the City (not tied to City operations) would also lose future profits as a result of an early termination shutdown mandate. Accordingly, we recommend the City conduct a detailed study of the potential economic impact of any decisions related to early shut-down.[12]

4.1.4 Task #4. Property Tax and Other Revenue Evaluation

The Walker Report included estimates of property taxes through 2035 based on a methodology that assumed property taxes would be a constant share of annual production. While this is a reasonable approach for estimating property taxes under existing laws, such a methodology would not accurately measure the impacts of an early shutdown of oil and gas operations. This is because county assessors typically use an income approach to estimating reserve values. Under this approach, the assessment is based on estimates of the present discounted value of the future stream of income generated from oil and gas production and remaining reserves. A premature shutdown before reaching the economic life of an oil and gas field would reduce the income stream, and thus the property tax valuation starting immediately after announcement of the shutdown. The cost study would need to replicate county assessor valuation practices to compare annual property taxes under the existing law to property taxes assuming an early termination. Additionally, the write down of oil and gas reserves would trigger an immediate loss in Market Cap for any publicly traded oil and gas company and could be as high as billions of dollars. It is very likely that any City action(s) resulting in the write down of an operator's oil and gas reserves would result in litigation against the City.

In order to estimate potential impacts of early termination on valuations of personal property (i.e. surface equipment), the study's authors would need guidance from the county assessor's office on assessment methods used to determine their assessed values – specifically how an early termination would affect the depreciation of the asset. Regarding estimation of indirect impacts, the comprehensive

[12] Note – discussion of potential examinations of "takings" claims and other associated liabilities are addressed separately by City Counsel and are not included in this report.

cost study would need to take into account reductions in economic activity associated with City businesses that supply goods and services to the oil and gas industry and their employees. Revenue from these entities are significant because of: (1) the relatively high pay and benefits paid by oil and gas companies; and (2) the industry spends a lot of money on products and services each year.

To prepare these estimates, the study authors would need to obtain information on the number of oil and gas industry employees (including both public sector and private sector employees) that live and/or work in the City along with average wages for these employees. Information on local purchases made for City Operations needs to be obtained from the City and its contractor, and, if possible, other companies with operations within the City boundaries. If non-City operators are unwilling to provide such data because they consider such information to be proprietary, estimates could alternatively be based on experience with City operations and other public data sources, such as the Quarterly Census of Employment and Wages data and the American Community Survey.

4.1.5 Task #5. Update 1999 TRAPPS Study and Focus on Costs of Post-oil development subsidence management costs

We recommend that the City update the 1999 TRAPPS study (including a sensitivity analysis of the results) and the updates anticipated by the Energy Resources Department as the updated TRAPPS report was not available for our review. As such, the following are issues raised by our review of the 1999 TRAPPS study may already be part of the Energy Resources Department's update:

- What will happen to reservoir fluid pressures after the field is shut down?
- Will the aquifers that have been shown to be in connection with other oil producing areas again lose pressure and cause subsidence in Long Beach?
- Are the deeper zones and the interbedded shales slowly compacting but are being masked by rebound of the overlying sand layers?
- Will the deeper reservoirs depressurize the upper zones through subsidence-damaged wells that could not be properly abandoned and other sources?

Some of these questions will be addressed in the next few years through additional engineering studies and investigations. As in the 1950s, some of the potential contributing mechanisms of post-production subsidence will not be understood until they have been experienced in future reservoir operations. A study that develops a transitional reservoir abandonment and post-production subsidence control plan needs to consist of a coordinated, organized approach to control subsidence and abandon unnecessary wells and facilities once oil and gas production has ceased in each fault block.

The 1999 TRAPPS study assumed an orderly transition to cessation of oil and gas development, which would maximize the use of oil and gas derived produced water for subsidence management. Under this assumption, some purchased or alternate water was required, but the amount was minimized. With accelerated shutdown, the amount and cost of "new" water would be substantially higher. This issue should be disclosed and evaluated in this revised study.

4.2 Anticipated Timeframe and Costs

We estimate that the cost to complete all studies suggested for the RFQ Scope could range from approximately $711,000 to $1,037,000 and would likely take approximately 12 months to complete.

Figure 4.2-1 provides a Gantt chart to illustrate anticipated overall timeline to develop an RFQ, select consultant, and complete the studies listed in the table.

Additionally, to supplement such studies, a comprehensive legal assessment would be appropriate to evaluate both the current and developing legal frameworks specific to the issues at hand. Undertaking this specialized analysis would involve a significant increase in overall expenses. If conducted within the stated timeline, the cost of this legal assessment is estimated to be up to $250,000 or more.

ID	Task Name	Duration	Start	Finish
1	City Council Authorizes RFQ	1 day	Mon 8/4/25	Mon 8/4/25
2	**Financial Issues**	**136 days**	**Tue 9/30/25**	**Tue 4/7/26**
3	LBER Issues RFQ	1 day	Tue 9/30/25	Tue 9/30/25
4	SOQs received	5 wks	Wed 10/1/25	Tue 11/4/25
5	Contractor Selection Process	6 wks	Wed 11/5/25	Tue 12/16/25
6	Contracting	4 mons	Wed 12/17/2	Tue 4/7/26
7	Task #1. Expansion of ARO Study	4 mons	Wed 4/8/26	Tue 7/28/26
8	Task #2. Adequacy of Reserve Fund	4 mons	Wed 4/8/26	Tue 7/28/26
9	Task #3. Allocating Foregone Profits	5 mons	Tue 6/10/25	Mon 10/27/25
10	Task #4. Property Tax and Other Revenue	8 mons	Wed 4/8/26	Tue 11/17/26
11	Task #5. Trapps Study Sensitivity Analysis	4 mons	Wed 4/8/26	Tue 7/28/26

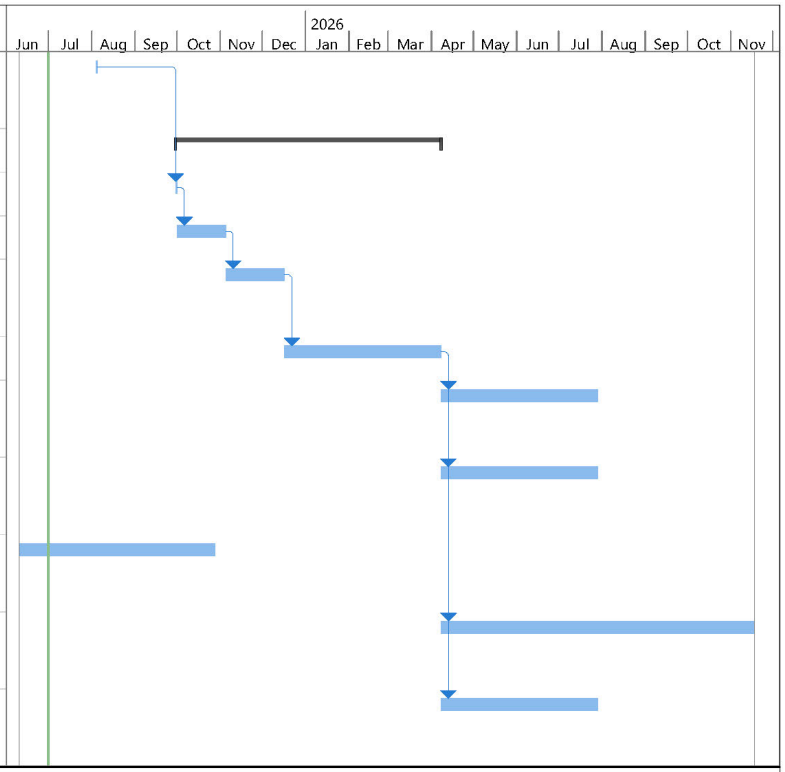

Figure 4.2-1. Anticipated Schedule for Completion of RFQ Scope

4.3 List of Recommended Consultants to Develop RFQ

The following list of consultants have the qualifications and expertise to develop an RFQ to address each of the studies listed in Section 4.1 as well as conduct the necessary analyses. While there are numerous consultants with experience in the Oil and Gas Industry, we've focused our suggestions on those with particular experience in the Southern California region and/or the unique issues to be addressed in Long Beach. Recommended consultants are listed in alphabetical order. Note that the potential exists for consultants to have a conflict of interest and these issues would need to be worked out between the specific consultant and the City of Long Beach.

- Capital Matrix Consulting
- Catalyst Environmental Solutions
- Cornerstone Engineering
- ERM
- Evans and Walker
- Exponent
- Geosyntec
- Integral
- Moffatt and Nichol
- Trinity Consultants