Meeting Date: 04/07/23
Work Order Number: W17166
Staff: J. Abedi

Staff Report 71

GRANTEE:

City of Long Beach

REQUESTED ACTION:

The City has requested the Commission's acceptance of the Long Beach Unit Program Plan (July 1, 2023, through June 30, 2028), and the Annual Plan (July 1, 2023, through June 30, 2024), Long Beach Unit, Wilmington Oil Field, Los Angeles County

BACKGROUND:

The City of Long Beach (City), as Unit Operator and Trustee for the State, submitted the Program Plan (July 1, 2023, through June 30, 2028) and Annual Plan (July 1, 2023, through June 30, 2024) for the Long Beach Unit (Unit) to the Commission, as required by Chapter 138, Statutes of 1964, 1st Extraordinary Session, and Chapter 941, Statutes of 1991, and the Optimized Waterflood Program Implementation Agreement (OWPA). The Field Contractor for the Long Beach Unit is California Resources Long Beach, Inc. The operations for the Long Beach Unit are governed by Chapter 138 and Chapter 941, the OWPA, the Long Beach Unit Agreement, and the Long Beach Unit Operating Agreement.

On March 21, 2023, the Long Beach City Council adopted the proposed Program Plan and Annual Plan and authorized submittal to the Commission for its consideration. The Plans were submitted to Commission staff on March 22, 2023. As required by Chapter 941, the Commission has 45 days to review the Program Plan and the Annual Plan; otherwise, the Plans are deemed to be reviewed and accepted by the Commission.

Pursuant to Section 3 (a) of Chapter 941, the Commission reviews and may order revisions to the Program Plan for:

1. Consistency with good oil field practice;
2. Consistency with the OWPA;

3. Consistency with the Long Beach Unit and Unit Operating Agreements; or
4. Environmental and safety concerns.

The Commission reviews the Program Plan to ensure consistency with the categories identified above. Pursuant to the OWPA, any changes ordered by the Commission must be in writing and set forth, with specificity, the reasons for the changes. Similarly, the Commission's authority is limited to reviewing whether the Annual Plan is consistent with the Program Plan.

The City and the contractor must "revise the plan to incorporate the changes ordered by the Commission where the Commission has found the changes to be necessary to assure that the plan (1) is consistent with good oil field practice, (2) is consistent with the optimized waterflood program, (3) is consistent with the Long Beach Unit and Unit Operating Agreements, or (4) does not involve significant safety or environmental risk . The contractor or the City, or both, may apply to a court of competent jurisdiction for review of the changes ordered by the commission."[1]

PROGRAM PLAN:

The proposed Program Plan is a 5-year plan prepared by the City of Long Beach Energy Resources Department covering Fiscal Years 2023 through 2028. Preparation and submittal of the Program Plan began in 1991 as required by Chapter 941 and the OWPA. The purpose of the Program Plan is to describe how the OWPA, the Unit Agreement, and the Operating Agreement will be implemented during the upcoming 5-year period. The Program Plan addresses reservoir management objectives, results and performance of the prior year's development activities, methods of continuing field development, economic projections, and anticipated drilling schedules for the 5-year period. The Program Plan includes anticipated rates of production, Unit revenue, Unit expenditures, and Unit net income as projected by the City. The Program Plan is prepared every 2 years and modified as necessary to reflect changes in actual field performance, economic factors, and reservoir management practices. The previous Program Plan was accepted by the Commission at its April 2021 meeting (Item 40, April 27, 2021).

As presented by the City in the Long Beach Unit Program Plan, the economic projections for the period July 1, 2023, through June 30, 2028, are shown on the following table:

Table 1, Economic Projections for July 1, 2023 through June 30, 2028

[1] Section 3a, Chapter 941, Statutes of 1991

All Figures are in Millions of Dollars

PERIOD	TOTAL REVENUE	EXPENDITURES	NET INCOME
FY 2023-24	$358	$324	$34
FY 2024-25	$349	$316	$41
FY 2025-26	$348	$299	$56
FY 2026-27	$335	$280	$62
FY 2027-28	$323	$284	$46
Total	**$1,705**	**$1,502**	**$239**

ECONOMIC PROJECTIONS IN PROGRAM PLAN:

For Fiscal Years 2023-28, the City estimates the Long Beach Unit net income will be $239 million after total expenditures of $1.502 billion. This net income projection is based on the City's crude oil price forecast of $65 per barrel (bbl) in Fiscal Year 2023-24, and $65/bbl for Fiscal Year 2024-28, and a natural gas price of $3 per thousand cubic feet. Most of the net income will be from oil revenues. The City forecasts oil production to range from an average of 14,700 bbls/day in Fiscal Year 2023-24 to 13,600 bbls/day in Fiscal Year 2027-28. These rates assume the continuation of development activity to involve re-drilling a total of 102 wells from existing wellbores over the Program Plan period. Expenditure levels and the types of development projects may be adjusted as necessary to respond to fluctuations in oil price and other economic conditions. Pursuant to article 2, paragraph 2.07 of the OWPA, the Field Contractor may exceed any budget category in the Program Plan budget up to 20 percent without obtaining additional authority from the City and review by the Commission.

ANNUAL PLAN:

The proposed Annual Plan is a 1-year plan submitted by the City covering Fiscal Year 2023-24. The previous Annual Plan was accepted by the Commission at its April 2022 meeting (Item 51, April 26, 2022). The Annual Plan is an itemized budget of anticipated expenditures needed to carry out the Program Plan objectives. There are five expenditure categories in the Annual Plan: Development Drilling; Operating Expense; Facilities Maintenance and Plant; Unit Field Labor and Administrative; and, Taxes, Permits and Administrative Overhead. The proposed Annual Plan's total budgeted expenditure of $323.7 million represents about a 0.9 percent increase from the current Annual Plan for Fiscal Year 2022-23 budget of $320.7 million.

Oil Price Forecast:

In planning the expenditures needed to accomplish Long Beach Unit objectives, and the revenues needed to fund those expenditures, the City has used a crude oil price forecast of $65/bbl for Fiscal Year 2023-24. The City's approach for planning purposes ensures that revenues will be sufficient to pay for the Long Beach Unit's proposed expenditures and still provide net income to the State and the City's Field Contractor, California Resources Long Beach, Inc. and its agent, THUMS Long Beach Company, and the other working interest owners. Exhibit D (attached) shows the oil price volatility.

The $65/bbl oil price basis in the proposed plan, which is below the current actual price realized in recent months, yields a realistic projection of net income under the current oil price environment. The price of Long Beach Unit crude during first week of March 2023 was $78/bbl. At an average oil price of $65/bbl, staff estimates $34 million for the net income of the Unit in Fiscal Year 2023-24 based on the proposed expenditures.

Review of Program and Annual Plans:

As directed by Section 3 of Chapter 941, Statutes of 1991, staff has reviewed the proposed Program Plan and Annual Plan submitted by the City. The purpose of the Program Plan is for the Grantee, the City of Long Beach, and its contractor "…to describe key issues facing the Unit, and to outline strategies for optimizing the economic recovery of resources while maintaining excellence in safety and environmental protection." (See Exhibit B, Program Plan, Executive Summary, p. 1.) The Program Plan is essentially a strategic document, meaning that, as a matter of prudence, it should include considerations of probable risks to the operations from potential statutory, regulatory, and economic changes over the 5-year period. The proposed Program Plan only emphasizes immediate considerations for safety, health and environmental protection. For the Program Plan to be an effective planning tool, it should highlight foreseeable uncertainties and risks that would significantly alter unit operations.

Although the current Program Plan identifies "critical potential issues," challenges and risks under the "Issues and Projects" section, the overall economic and development projections do not take those scenarios into account. To address long-term considerations, staff recommends the Commission order the Program Plan to be revised to incorporate risk identification and analysis to provide the transparency necessary to evaluate the efficacy of current and future operations, including the following:

- SB 1137: Although SB 1137's implementation is currently stayed; it remains law and its implementation within the 5-year program is a significant possibility. According to a presentation by City staff, two of the four THUMS islands will be impacted by 3,200 ft set back requirement meaning that a significant portion of the unit's production may be affected as may the abilities to manage subsidence control. Because implementation of SB 1137 is probable within the 5-year period, good oil field practice, consistency with the agreements, and requirements of law intended to protect health and the environment requires that SB 1137 and its effects be assessed. Additionally, the City has a fiduciary obligation to identify probable operational, economic and fiscal impacts on the Unit operations if the law goes into effect. The Plan should address the possible impact of SB 1137 implementation in 2025 as it pertains to development plans, well and reservoir management and economic outlook.
- CalGEM Injection Gradients: CalGEM has provided direction on injection gradient control which may affect field management and economics. The Commission understands that CalGEM guidance and direction has remained consistent and as the regulatory body, a final order consistent with the guidance would have significant effects on Unit operations. For the same reasons as in SB 1137, the Program Plan must account for a scenario implementing CalGEM's guidance as it pertains to reservoir management and economic outlook.
- Power Plant Operations: The power plant lease expiration in 2024 poses a substantial risk to the Unit's economics as well as its ability to operate and produce oil. The Power Plant is a primary consumer of the Unit's gas production and its potential shut down, only one year into the Program Plan, poses significant risks to the Unit that must be assessed beyond a mere mention. A scenario analyzing the impacts to Unit economics and operations as well as risk reduction options is necessary to comport with good oil field practice, consistency with the agreements, and to prevent waste.
- Commodity Price Volatility: The last three years have seen two significant gas volatility events as well as significant variation in oil prices. The Program Plan should be more transparent about development and economic projections under various oil and gas unit prices. Various projections will also improve the consistency between the Program Plan and Annual Plans.
- Sea Level Rise: Sea level rise and other compounding climate impacts, including more frequent and intense storm surges, flooding, and erosion, pose threats to the Long Beach Unit's onshore and offshore oil and gas

infrastructure. Potential damages could cause significant public health, safety, and environmental impacts. The risks of subsidence further increase the LBU's vulnerability to sea level rise and climate impacts. According to OPC's 2018 Sea-Level Rise Guidance, the LBU should prepare for 1.0 feet of sea level rise by 2030, 1.7 feet by 2040, and 2.6 feet by 2050 (based on the 'extreme risk aversion' projections). Vulnerability assessments and adaptation strategies are needed to protect the public, the environment, and the oil and gas infrastructure through the end of the Unit's economic life and eventual decommissioning. The planning and implementation of these efforts should begin immediately and must be included in the Program Plan.

- Environmental Justice: The Long Beach Unit's oil and gas operations are a source of air pollution that affects the public health, safety, and environment of the surrounding communities in Long Beach. Based on 2020 data from the California Air Resources Board, THUMS Long Beach Company was responsible for emitting 27 tons of volatile organic compounds (VOCs), 34 tons of nitrous oxides (NOx), 16 tons of carbon monoxide (CO), and 13 tons of particulate matter (PM)[2].

  Long Beach's communities are already heavily exposed to pollution from the Ports of Los Angeles and Long Beach, traffic from Interstate 405, and other nearby industrial activities. According to CalEnviroScreen, many of the surrounding neighborhoods, especially those located north of the ports and Long Beach Unit, are ranked among the highest in the State (up to the 99th percentile) for their "pollution burden," an aggregate scoring of various forms of pollution[3]. Notably, these neighborhoods are highly exposed to particulate matter, diesel emissions, and toxic chemicals released from industrial sources. These forms of pollution are known to cause significant human health effects, including cancer, cardiovascular diseases, low birth weights and premature birth, and premature death.

  Consequently, many of these same neighborhoods also rank very high on CalEnviroScreen for health issues such as asthma and low birth weight, as well as many other population characteristics that increase vulnerabilities to pollution, including poverty, housing burdens, and unemployment. In the 2020 census, 72% of Long Beach's residents identified as Asian, Black, or

[2] https://ww2.arb.ca.gov/applications/facility-search-engine

[3] California Office of Environmental Health Hazard Assessment (OEHHA). (2021). CalEnviroScreen 4.0. https://oehha.ca.gov/media/downloads/calenviroscreen/report/calenviroscreen40reportf2021.pdf

Latino. Multiple studies have found that minority communities in California are disproportionately exposed to oil and gas extraction[4,5], and a community's exposure is highly correlated with health impacts[6].

The Program Plan identifies "People" as a critical potential issue, but limits the discussion of "People" to employees. The Program Plan should expand this discussion to include groups other than employees affected by Unit operations, such as surrounding impacted communities. Similarly, the "Environmental Protection" section of the Program Plan notes that "environmental and community outreach is also a fundamental part of THUMS program," and that "the Unit and CRC will continue to review opportunities to further this stewardship effort." More detail should be added to ensure against significant safety or environmental risks to those communities that are disproportionally impacted by the pollution burdens of the Long Beach Unit operations.

- Well Abandonment Plan: The Program Plan provides that the "Unit attempts to minimize the inventory of idle wells that have no further economic benefit." This is not a strong or definite statement, and no details are provided regarding the number of idle wells in the Unit, the number in the queue of wells to be plugged and abandoned, the number of idle wells plugged and abandoned each year, or the costs of those abandonments. Adding these details to the Program Plan would provide a better picture of the Unit's Well Abandonment Plan and would more sufficiently address the environmental and health and safety risks posed by idle wells. Moreover, in light of California's plan to phase out oil and gas production by 2045, the Program Plan should include a plan for reducing the number of all future well

[4] Gonzalez, D. J. X., Nardone, A., Nguyen, A. V., Morello-Frosch,R., & Casey, J. A. (2022). Historic redlining and the siting of oil and gas wells in the United States. In Journal of Exposure Science & Environmental Epidemiology (Vol. 33, Issue 1, pp. 76–83). Springer Science and Business Media LLC. https://doi.org/10.1038/s41370-022-00434-9
[5] González, D. J. X., Morton, C. M., Hill, L. A. L., Michanowicz, D. R., Rossi, R. J., Shonkoff, S. B. C., Casey, J. A., & Morello-Frosch, R. (2023). Temporal Trends of Racial and Socioeconomic Disparities in Population Exposures to Upstream Oil and Gas Development in California. In GeoHealth (Vol. 7, Issue 3). American Geophysical Union (AGU). https://doi.org/10.1029/2022gh000690
[6] Shamasunder B, Collier-Oxandale A, Blickley J, Sadd J, Chan M, Navarro S, Hannigan M, Wong NJ. Community-Based Health and Exposure Study around Urban Oil Developments in South Los Angeles. Int J Environ Res Public Health. 2018 Jan 15;15(1):138. doi: 10.3390/ijerph15010138. PMID: 29342985; PMCID: PMC5800237.

reworks. These well reworks are costly to the State. They typically include partial abandonment followed by re drilling and completion of the well in the desired zone, the majority of which is paid for out of the state's share of the net profits. This plan will also help with reducing the state's liability for final abandonment.

- Make-up Water Sources: The Program Plan identifies the sources of water used for the Unit, noting that "fresh water is used sparingly, primarily for utility purposes…" It would be more transparent to provide quantities or at least percentages of water used from each source in light of health and safety and environmental risks related to water shortages in the State.

ENVIRONMENTAL AND SAFETY REVIEW:

Commission staff conduct two programs to ensure adequate environmental and safety standards are maintained during Long Beach Unit production operations. Safety and Oil Spill Prevention Inspections test the alarm and control sensors and devices that activate each island's automatic shutdown system. These inspections are conducted monthly and ensure that the reliability of the alarm systems and emergency equipment is maintained. Safety and Oil Spill Prevention Audits complement the monthly inspection program by performing technical analyses of safety system design, equipment specifications and conditions that are impracticable to inspect or evaluate on a monthly basis. Safety management programs and contingency and emergency response plans are also reviewed for adequacy as part of the audits. Together, the monthly inspection and safety audit programs ensure that the facilities meet the Best Achievable Protection standard mandated by Public Resources Code section 8755. These audits are repeated at 5-year intervals by staff engineers on all state oil and gas production facilities.

The last audit report on the Long Beach Unit was completed in July 2020. The safety audit included a Safety Assessment of Management Systems procedure (SAMS). The SAMS procedure was first developed in 1997 as a joint industry project intended to bridge the existing research on human and organizational error factors to a practical field application in safety and environmental protection. The procedure assesses the degree of integration of corporate safety management programs throughout the organization through a series of interviews of a cross section of company and contract field workers, engineers, and management. Topics in nine areas of safety management, guided by sets of structured questions, are discussed with each employee, and a ranking of the degree of integration and maturity of corporate programs is constructed from the responses. Results of both the physical and human factors audit were good, demonstrating a high degree of corporate commitment to conducting operations safely and protecting the environment.

Overall, past Safety and Pollution Prevention Inspections and Audits have found the Long Beach Unit facilities, safety systems, and equipment to be of safe design and in good condition.

OTHER PERTINENT INFORMATION:

1. Staff maintains direct involvement in ongoing Long Beach Unit development activities and the planning of future activities. Staff's involvement includes, among other things, monthly meetings of an engineering committee, on-site inspector presence in the field, reservoir management consultation with the City and the Field Contractor, analysis of drilling safeguards involving blowout prevention equipment certification, oil spill prevention exercises, and subsidence monitoring and prevention.

2. This action is consistent with the "Meeting Evolving Public Trust Needs" Strategic Focus Area of the Commission's 2021-2025 Strategic Plan.

3. The Commission's review of the Program Plan and Annual Plan for consistency with the criteria defined in Statutes of 1991, Chapter 941 and the associated contracts, and any ordered revisions, is not a discretionary action within the meaning of CEQA because the review and acceptance is a determination of whether there has been conformity with applicable statutes, ordinances, regulations, or other fixed standards and not an approval of a discretionary project or entitlement issued by the Commission. (Pub. Resources Code, 21080 subd. (a), Cal. Code Regs., tit. 14, § 15357.) "The key question is whether the public agency can use its subjective judgment to decide whether and how to carry out or approve a project." (Cal. Code Regs., tit. 14, § 15357.)

   Because the oil and gas operations at issue occur on lands granted by the California Legislature to the City of Long Beach, over which the Commission lacks direct authority, the Commission does not have discretion to "use its subjective judgment to decide whether and how to carry out" the City's oil and gas operations; instead, the Commission reviews the plans for consistency with the statutes and contracts that direct the larger operations. The Commission's review of the Program Plan and Annual Plan also does not authorize oil and gas operations, which were already authorized by the Legislature through Chapter 138, Statutes of 1964; Chapter 941, Statutes of 1991; and the associated contracts. CEQA does not apply to the Commission's examination of the Program Plan and Annual Plan, as the review does not constitute approval of a discretionary project.

   Moreover, the Commission's review and acceptance of the Program Plan is a normal, intrinsic part of the ongoing Unit operation, which was approved prior to CEQA, and is statutorily exempt from CEQA as part of an ongoing project.[7] Oil development occurred rapidly in the Unit following the enactment of Chapter 138 in 1964, with development of all essential facilities between 1965 and 1970, and a peak in production in August 1969, at 148,495 barrels per day. Oil production since 1969 has continued but declined naturally over time. Neither the Program Plan nor the development activities described therein expand or modify the underlying activity that was approved previously, and prior to CEQA, as described in Chapter 138 of the Statutes of 1964, and as further described in Chapter 941 of the Statutes of 1991. Commission review of plans of development and operation for the Unit is expressly required in Section 5(a) of Chapter 138, and Section 3 of Chapter 941. Because Commission review of Program and Annual Plans is squarely within the scope of the pre-CEQA original project, the Commission's review and ordered revisions or acceptance of the Program Plan and Annual Plan is statutorily exempt from CEQA, pursuant to the California Code of Regulations, Title 14, section 15261. Commission review of the Program Plan and Annual Plan is further categorically exempt as pertaining to existing facilities, pursuant to the California Code of Regulations, Title 14, section 15301.

4. Finally, review and acceptance of the Long Beach Unit Program Plan and Annual Plan is not a project as defined by the California Environmental Quality Act because it is an administrative action that will not result in direct or indirect physical changes in the environment.

   Authority: Public Resources Code section 21065 and California Code of Regulations, title 14, section 15378, subdivision (b)(5).

EXHIBITS:

A. Letter from the City of Long Beach submitting the Long Beach Unit Program Plan and Annual Plan to the Commission
B. Long Beach Unit Program Plan (July 2023 - June 2028)
C. Long Beach Unit Annual Plan (July 1, 2023 through June 30, 2024)
D. Oil Price Comparison (Graph and Average Price Chart Fiscal Year 2018-2023)

[7] Pub. Resources Code sections 21169 – 21171; 14 CCR section 15261; *N. Coast Rivers All. v. Westlands Water Dist.* (2014) 227 Cal.App.4th 832, 864.

RECOMMENDED ACTION:

It is recommended that the Commission:

AUTHORIZATION:

Pursuant to Section 3, Chapter 941, Statutes of 1991, order the Program Plan and Annual Plan to be revised to incorporate risk identification and analysis to provide the transparency necessary to evaluate the efficacy of current and future operations including: 1) SB 1137; 2) CalGEM Injection Gradients; 3) Power Plant Operations; 4) Commodity Price Volatility; 5) Sea Level Rise; 6) Environmental Justice; 7) Well Abandonment Plan; and 8) Make-Up Water Sources; and as more fully described in this staff report.

EXHIBIT A

W17166

CITY OF LONG BEACH
ENERGY RESOURCES

2400 EAST SPRING STREET • LONG BEACH, CA 90806
(562) 570-2000 • www.longbeach.gov

March 22, 2023

Ms. Shahed Meshkati
Division of Mineral Resources Management
California State Lands Commission
301 E. Ocean Blvd., Suite 550
Long Beach, CA 90802-4331

SUBJECT: **SUBMISSION OF THE LONG BEACH UNIT ANNUAL PLAN (JULY 1, 2023 - JUNE 30, 2024) AND PROGRAM PLAN (JULY 1, 2023 – JUNE 30, 2028)**

Dear Ms. Meshkati,

The City of Long Beach, as Unit Operator of the Long Beach Unit, and in accordance with Chapter 138, Section 5, Chapter 941, Section 3, and the Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, Article 2, submits one copy each of the Long Beach Unit Annual Plan (July 1, 2022 through June 30, 2023) and Program Plan (July 1, 2023 through June 30, 2028).

The Plans were approved by the Long Beach City Council on March 21, 2023. If you have any questions, please contact Mr. Bob Dowell at (562) 570-2001.

Sincerely,

ROBERT DOWELL, DIRECTOR
LONG BEACH ENERGY RESOURCES DEPARTMENT

BD:kmt

Enclosures

cc: J. Lucchesi, California State Lands Commission
J. Hilton, California Resources Long Beach, Inc.
R. Anthony, City of Long Beach

EXHIBIT B

W 17166

Program Plan

Long Beach Unit
Long Beach, California

July 2023 – June 2028

Program Plan

Long Beach Unit (“Unit”)

July 2023 through June 2028

Prepared Jointly by:

Long Beach Energy Resources Department
City of Long Beach
(Unit Operator)

California Resources Long Beach, Inc.
(Field Contractor)

THUMS Long Beach Company
(Agent for the Field Contractor)

February 2023

TABLE OF CONTENTS

Executive Summary

This Program Plan covers the period from July 1, 2023 through June 30, 2028. The purpose of the Plan is to describe key issues facing the Unit and to outline strategies for optimizing the economic recovery of resources while maintaining excellence in safety and environmental protection. This Plan is the culmination of a cooperative effort by the Long Beach Energy Resources Department (LBER), City of Long Beach (Unit Operator), California Resources Long Beach, Inc. (Field Contractor), and THUMS Long Beach Company (agent for the Field Contractor). The Program Plan meets the requirements of Section 2.03 of the Optimized Waterflood Program Agreement ("OWPA").

The Program Plan describes the Unit reservoir management strategies to be implemented under the OWPA, including activity plans and projected rates of production and injection. The Plan also includes a discussion of key issues facing the Unit, plans for major projects and initiatives to be implemented during the Plan period, and anticipated revenues and profits. The format is similar to the previous Program Plan.

The Plan includes investment associated with 102 development replacement completions over the life of the Program Plan. This schedule will result in a modest decline in oil production rate through the end of FY28. Unit production and injection rates are expected to average 14.7 Mbopd, 1,032 Mbwpd and 1,072 Mbwipd in FY24 and 14.7 Mbopd, 1,020 Mbwpd and 1,060 Mbwipd in FY25.

The anticipated activity is detailed in Exhibit B and the predicted rate curves are shown in Exhibits E and F. This activity encompasses several locations: Pier J, and Islands Freeman, Grissom, White, and Chaffee with the use of Unit rigs T-5, T-9, T-3 and as required, augmented with the use of other rig assets, workover rigs, and coiled tubing units. The purchase or rental of additional peripheral equipment to maintain safe and efficient operations may be required. It is possible that development results, continuous reservoir review, improved Unit seismic data, and production history will yield additional development candidates throughout the Plan period. Decisions regarding future activity levels will be influenced by the quality of the projects identified and prevailing economic conditions.

Facility project work during the program plan period will include projects to support mechanical integrity, safety and environmental, regulatory compliance, facility enhancement and optimization, and other typical oil field facility projects. These projects are intended to upgrade and ensure continued, efficient, fluid handling and replacement of pipeline rail crossings, in collaboration with the Port of Long Beach. Other improvements are focused on right-sizing facility capacity limits to accommodate the forecast throughout all 5 years of the Program Plan period. These investments result in enhancement of revenue streams, lower maintenance and operational costs, and improved safety and environmental performance.

Based on production from 33 replacement well projects planned for FY24 of the Program Plan and an oil price of $65/bbl during the 5-year program period, and a gas price of $3.00/mcf, total revenue, expenditures, and net profits over the 5-year period of the Program Plan are projected to be $1,741 million, $1,502 million, and $239 million, respectively. A schedule of projected revenue, expenditures, and net profits by year is given in Exhibit A. Expenditure levels and project mix will be adjusted as needed to respond to fluctuations in oil price and other economic conditions.

Overview

This Program Plan covers the period from July 1, 2023 through June 30, 2028. The purpose of this Plan is to describe key issues facing the Unit, and to outline strategies for optimizing the economic recovery of resources while maintaining excellence in safety and environmental protection.

This Plan is divided into four major sections:

- The *Introduction* provides a brief summary of the Unit history.

- The *Unit Reservoir Management Plan* section outlines strategies to be employed in reservoir development and management. An overview of the field-wide goals and strategies is provided. The Appendix contains a more detailed Reservoir Management Plan for the six reservoir areas: Ranger West/Tar, Ranger East, Terminal, UP Ford, 237 Zone and Shallow gas zone.

- The *Unit Forecasts* section summarizes planned Unit activity as well as projected production and injection rates during the Program Plan period.

- The *Issues and Projects* section describes the key issues facing the Unit. Key goals in the areas of people, safety, environmental protection, profitability, and subsidence control are described, as are plans for meeting those goals. Initiatives to manage costs through improved business and operating practices are described. Plans for maintaining and improving the field infrastructure, abandoning unusable wells, and managing external influences on the Unit are also described.

- The *Economic Summary* section provides a forecast of Unit revenues, expenditures, and profits anticipated during the Plan period, assuming a realized oil price of $65/bbl during the 5-year program period and a realized gas price of $3.00/mcf. This section also includes the schedules that will be incorporated into the FY24 and FY25 Annual Plans.

Introduction

The Long Beach Unit (Unit) commenced operation April 1, 1965. Since its inception, a major principle of Unit operations has been to minimize the impact on the environment and to comply with all applicable environmental laws and regulations. No oil-related subsidence has occurred since the inception of the Unit, although minor positive and negative elevation fluctuations have been observed. An active elevation monitoring system is in place and remedial measures would start immediately if significant elevation change was detected.

Development drilling began in July 1965. Initial development activity peaked with 20 rigs operating in 1968. This high level of drilling activity continued into early 1970. Drilling activity continued to fluctuate depending on the price environment. Activity increased again in 1982, when sub-zone development was initiated to improve oil recovery by completion of wells in sands with high remaining oil saturation. This level of activity was held until early 1986 when drilling activity again began to decline due to low oil price (no drilling rig activity occurred from mid-March 1987 until August 1987). Development activity slowly increased through the early 1990s and ranged between one and three rigs through 2014, then reduced over 2015-2017 to a half rig pace. A significant drop in prices resulted in pausing the drilling program in 2020. Drilling resumed in 2021 and is anticipated to continue through most of the next five years. A rig count ranging from 0.75 to one is assumed for the Program Plan. Rig count and pace are continuously optimized for investment return within the constraints of oil price and the business environment.

On January 1, 1992, ARCO Long Beach, Inc. (ALBI) became the sole Field Contractor, having acquired interests from all previous Field Contractor companies. On the same date, the OWPA also took effect. On January 1, 1995, the term of the Contractors' Agreement was extended through the end of the Unit's economic life, in accordance with the OWPA. Consequently, THUMS Long Beach Company (THUMS) will continue in its capacity as agent for the Field Contractor beyond the original contract term of April 1, 2000.

In April 2000, Occidental Petroleum Corporation (Oxy) bought all Atlantic Richfield Company's stock in ALBI. As a result, the Field Contractor name was legally changed from ALBI to Oxy Long Beach, Inc. (OLBI). In late 2014, in conjunction with the separation of California Resources Corporation (CRC) from Oxy, OLBI was renamed as California Resources Long Beach, Inc.

Unit Reservoir Management Plan

Goal

The goal of the Unit Reservoir Management Plan is to maximize the economic recovery of oil and gas from the Unit, while ensuring stable surface elevations, through the application of sound engineering practices. This will be achieved by utilizing existing Unit assets to maximize short and long-term economic benefit, optimizing the Unit's waterflood depletion strategies, identifying investment opportunities, and delivering the expected results.

Reservoir Management Strategy

The Unit's Reservoir Management strategy consists of three elements:

1. Maximize economic production from existing assets by the use of sound waterflood practices. This effort is focused on waterflood surveillance activities including well monitoring, flood performance analysis, and voidage management for subsidence control. In addition, a cross-functional effort is used to coordinate near and long-term planning. The work product of this effort is a full-field development plan, that is periodically updated as business and operational conditions warrant.
2. Assess and deliver additional redevelopment investment opportunities via the drilling and investment wellwork programs. Redevelopment activities are currently focused on capturing bypassed, unswept oil and increasing waterflood throughput in less mature areas.
3. Implement new technologies to decrease costs, improve efficiencies, and develop unproven reserves. Enhanced oil recovery applications will be considered for implementation if economically and technically viable.

Each of these strategies is discussed in more detail below. Specific strategies and goals for each reservoir are included in the Appendix.

Production and Surveillance

A major goal of the Unit's reservoir management plan is to ensure optimization of production. The reservoir management strategies for accomplishing this goal include well monitoring, flood performance analysis, and voidage management for subsidence control.

- Well monitoring activities include monthly testing of production wells, daily monitoring of injection well pressures and volumes, acquiring injection well profiles annually and obtaining well pressure surveys as required to assess formation pressures. This data forms the cornerstone for reservoir analysis of production trends. THUMS Surface and Subsurface departments work jointly to ensure the necessary data is obtained in the most cost-effective manner.
- Waterflood performance is analyzed using standard industry techniques to differentiate between good and poor pattern performance and to identify well enhancement opportunities. Techniques used include decline curve analysis, material balance, volumetrics, bubble maps, well pass through data, waterflood sweep, hydrocarbon throughput analysis and streamline and other reservoir

simulation methodologies. Based on the analysis results, development opportunities will be identified and evaluated including re-completions and profile modifications. In addition, as wells fail, the analysis results will be used to justify well maintenance work such as liner replacements, wellbore repairs, and pump changes. The maintenance work program is managed and executed by the Wellwork group.

- To ensure pressure maintenance and reduce the potential for subsidence, an optimal I/G ratio is managed, which normally ranges between a 4% to 6% overbalance, as required. Since July 2006, the LBER Subsidence Division, along with the THUMS Subsurface and Well Surveillance Leaders have been periodically modifying the voidage accounting rules to ensure stable ground elevations (subsidence and dilation), while providing prudent operational flexibility to improve waterflood management. A collaborative effort is used on the methodology for the voidage account, and to identify key wells to survey for bottomhole pressures in order to support semi-annual ground elevation measurements.

Redevelopment Opportunities

The Unit has a strategy to invest and minimize the decline of the LBU's oil production rate. To support this strategy, redevelopment activities are focused on:

- Drilling injection wells targeting increased throughput in the less mature sand layers and improving zonal injection control. Drilling results to date have shown good success from injection wells drilled to re-establish injection patterns in the relatively underdeveloped areas of the field.
- Adding production wells: (1) in areas of unswept oil, (2) in lower productivity sands that cannot produce well in combination with higher productivity zones in long completions, (3) in areas of high oil saturations banked along sealing faults, and (4) in areas where improved injection warrants additional production capacity.
- Investing in wellwork projects that will increase the ultimate recovery of the field or require special planning and attention. Investment wellwork includes well conversions, recompletions, and permanent profile modifications. The investment wellwork program is still one of the Unit's most successful programs, adding reserves at comparatively low cost. The investment wellwork program will continue at a healthy pace throughout the upcoming Plan period.

The Long Beach Unit has embarked on an effort to improve reservoir characterization across the Unit. With the assistance of CRC's corporate technical support, and local staff, the Long Beach Unit continues to assess, understand and refine its knowledge of the reservoir and develop new production opportunities.

Technology

Advances in drilling and completion technology continue to be a significant factor in realizing development drilling opportunities. Key technologies being developed and applied include horizontal well placement, special design and extended reach wells, cased hole completions and low-cost replacement wells. The Unit is continuously identifying technology needs, impacts, and implementation issues as a regular part of its operations. Operational and technological focus areas include wellwork and drilling, facilities, reservoir (profile control, behind-pipe-oil detection, conformance evaluation software tools, reservoir modeling software tools, 3D reservoir characterization), and Health, Environmental and Safety training. Enhanced oil recovery applications will be considered for implementation if economically and technically viable. One other technology that is being implemented are permanent magnet motors for ESPs. These motors have been incorporated on a handful of ESPs and are experiencing 5-15% electrical efficiency gains. These motors could benefit the Unit with reduced electrical loads and subsequently lower operating costs.

Unit Forecasts

Activity Schedule

The Program Plan projects recompletions to average approximately 33 replacement wells in FY24 and 25 replacement wells in FY25. This schedule can be met with approximately one drilling rig.

Exhibit B shows the completion and redrilling plan by reservoir for the Program Plan period, and the required Schedules 1B and 2B show the anticipated range of development replacement wells to be drilled into each cut-recovery block during FY24 and FY25. This plan reflects the current understanding of development well economics. The candidate list is updated annually by the reservoir development teams. Projects are submitted to Voting Parties for approval at least 2-4 months ahead of the planned spud date. Individual well AFEs are submitted subsequently. The economics of each well are fully investigated at that time, and changes in key factors such as oil price, cost, or candidate quantity and quality may result in changes to the overall plan.

Rate Forecasts

Exhibit C shows the Unit production forecasts for the Plan period, and the required Schedules 1A and 2A show the anticipated rates for FY24 and FY25, respectively. These forecasts were developed by combining a forecast of existing well performance with the expected results of the previously outlined development plan. The expected injection forecast shown in Exhibit D was generated based on the gross fluid rates from the production forecast. Graphs comparing historical and predicted field rate performance data are presented in Exhibits E and F. The plots clearly show the variability of historical rate data, necessitating the use of rate ranges to account for uncertainty in the rate projections.

The oil and water production forecast for the existing wells is based on a process that uses an extrapolation of wells within each reservoir summed together to yield a forecast of the existing wells' production for the entire Unit. For each well, the expected future oil and water rates are extrapolated from historical trends of oil and gross fluid rates over time and the trend of water-oil ratio versus cumulative oil production using conventional decline curve techniques. The resulting prediction shows a near-term exponential decline ranging from 9 to13% per year for the existing wells and a lower decline rate in later years.

The incremental production contribution for development wells is calculated by adding together type well forecasts for each project. The type wells are determined by reservoir area and completion type. The engineers managing individual reservoir pools determine type wells for their areas based on historical performance. Depending on available data, type wells are built by reservoir, by pool, or by cut-recovery block. The producer type wells are based on recent development wells determining an average initial production rate and decline rate. The type well rates are combined with the development drilling schedule to generate the expected rate contribution for development wells. The total Unit production forecast is the sum of the existing well and development well forecasts. The Unit water production forecast was derived as the difference between the gross fluid and oil production rates.

Issues and Projects

Several major issues must be considered when planning Unit strategies. These issues include consideration for people, health and safety, environmental protection, subsidence control, well abandonment, cost management, expansion of production infrastructure, shallow and deep gas development, electricity generation, taxes and make-up water sources. All can dramatically influence the success of the Unit, and as such, will be addressed with considerable effort and resources.

Some of the more critical potential issues anticipated during the Program Plan period are discussed below. Actual operating practice will be adjusted in accordance with future economic circumstances, practical considerations, regulatory requirements, and any unforeseen situations that may arise.

People

An important asset of the Unit is its employee resource and the ability of these employees to work together toward organizational goals. The Unit will strive to maintain a diverse workforce of employees who are positioned in the right job and who are well qualified to perform that job in a superior manner. Effective teamwork is expected of all Unit employees, as well as open communication, mutual respect, and individual accountability. Developing and enhancing job skills through training, education, and job experience will be emphasized through the Plan period.

Health, Environment, and Safety (HES)

CRC is committed to conducting all aspects of its business in a manner that provides for the safety and health of employees, service providers and the public, and safeguards the environment in which it operates. Key aspects of the safety programs, which include incident reporting and investigation, safety meetings and training, Management of Change, Process Hazard Reviews, emergency response planning and drills, and a behavior-based safety observation program. Key aspects of the environmental program include compliance with applicable laws and regulations, including South Coast Air Quality Management District (SCAQMD) requirements, waste management and minimization, spill prevention plans and Business Emergency Plans.

The effectiveness and compliance of the above programs are assessed through various internal audit programs. In addition, numerous agencies conduct periodic audits, including the CA State Lands Commission, Department of Transportation, State Fire Marshal, SCAQMD, California Geologic Energy Management Division (CalGEM), Environmental Protection Agency, Long Beach Fire and Health Departments, Port of Long Beach and City of Long Beach Energy Resources Department. CRC THUMS participated in the re-occurring 5-year Safety and Oil Spill Audit, the main objective of which is to ensure that oil and gas production facilities are operated in a safe and environmentally sound manner. The audit, which started in 2017, was completed July 15, 2020 and showed that CRC THUMS has had continuous improvement in reducing findings and risk from previous audits and embraces the responsibility to provide and maintain a safe and healthy work environment for all employees, and the community.

Emergency response planning and preparedness is bolstered by partnering with Marine Spill Response Corporation (MSRC). MSRC is an independent, non-profit, national spill response company dedicated to rapid response to environmental incidents. MSRC has a major west coast base of operations in the Port of Long Beach and its equipment and expertise are readily available for emergencies and are incorporated in onsite training exercises. The training exercises also involve a close working relationship with the United States Coast Guard and the California Department of Fish and Wildlife.

Environmental and community outreach is also a fundamental part of operations and each of the Islands received a Conservation Recertification in 2022 by the Wildlife Habitat Council (WHC). This certification is awarded to facilities that provide for public education and involvement through wildlife related projects and learning opportunities on the facilities. The certifications received by the WHC demonstrate the Unit's continuing commitment to environmental stewardship and habitat conservation.

Projects relating to safety, environmental issues, or other situations necessary for meeting compliance with code, permit, or regulatory requirements will continue to be implemented under this Plan in accordance with all Unit agreements. In addition, CRC places additional emphasis on risk and system reviews and operational safeguards to assure reliable and compliant environmental performance.

Environmental Protection

The Unit is committed to the protection of the environment and has continued to include this as a key annual goal. Operations are conducted to minimize environmental impacts and comply with all applicable laws, regulations, and policies and environmental assessments are undertaken by Unit personnel and outside organizations to assure this compliance and level of performance.

Precautions to prevent uncontrolled discharges are a high priority. Each Island has oil spill response booms and deployment equipment for rapid containment. Response drills are conducted regularly to continually improve the effectiveness of personnel and equipment, and to test coordination with other agencies. Refinements to the response process and equipment will be made when necessary.

Personnel awareness is also essential for an effective Environmental Program. Training is conducted routinely to meet all regulatory requirements and environmental awareness.

Environmental and community outreach is also a fundamental part of THUMS program and each of the Islands are currently certified by the WHC. In 2022 and beyond, both the Unit and CRC will continue to review opportunities to further this stewardship effort.

Subsidence Control

A major goal during the operation and development of the Unit is the continued prevention of subsidence related to oil and gas production. Since the oil reservoir zones of the Wilmington Oil Field are susceptible to compaction, injection rates must be managed, and reservoir pressures must be maintained to prevent subsidence.

Currently, injection-voidage targets are maintained in eleven reservoir pools in the Tar, Ranger and Terminal Zones to ensure pressure maintenance and reduce the potential for subsidence.

Since July 2006, the LBER Subsidence Division, along with the THUMS Subsurface Team and Well Surveillance Leaders, have been periodically modifying the voidage management guidelines to ensure stable ground elevations, while providing prudent operational flexibility to improve waterflood management. A collaborative effort is used on the methodology for the voidage account, and to identify key wells to survey for bottomhole pressures in order to support semi-annual ground elevation measurements.

Well Abandonment Plan

The Unit attempts to minimize the inventory of idle wells that have no further economic benefit. Each plugback of an idle well reduces the ultimate liability for that well to the cost of completing the surface abandonment, reducing overall future abandonment liability.

Wells with no further economic use are fully abandoned to reduce the Unit's future abandonment liability. Abandonment also eliminates the costs of performing periodic pressure tests of long-term idle well casings mandated by the CalGEM. Unit engineers regularly review idle wells and evaluate their potential value to the Unit. Those found to have little or no value are added to the queue of wells to be plugged or abandoned. The Unit plans provide funding for both in-zone and mud-line abandonments that will allow the Unit to reduce its abandonment liability.

Cost Management

The Unit continuously strives for operational cost efficiency. Emphasis is given to spending funds wisely, investing in opportunities with the best economic return, and continuing to look for ways to improve efficiency in business operations. Employing effective cost management strategies aids in achieving the Unit’s goal of performing in the lowest cost per net barrel quartile for comparable operations. Cost management gains will continue to be aggressively pursued during the term of this Plan. Some of the areas where the Unit plans to place substantial focus include the following:

Operations: The Surface and Operations Resources groups are accountable for electricity usage, operation of oil, gas and water treating facilities, chemical usage and acquisition of make-up water. Amine Plant operations, used to reduce produced-gas CO_2 levels, are optimized in conjunction with Power Plant operations. Process optimization, best operating practices, and operating cost reductions will be focus areas. Improvements in electrical efficiency, optimization of make-up water sources, maintaining water quality, enhanced well surveillance, and improved coordination between operations, wellwork, and facility maintenance are expected outcomes over the Program Plan period.

Maintenance Wellwork and Drilling Operations: In order to reduce overall Unit development costs, several challenges will be addressed during the Program Plan period. These include rig resource allocation, rig equipment availability, wellbore maintenance, quality labor and equipment demand, labor rate increases, safety performance improvements, well failure reductions, and injector profile optimization projects. Several teams are focused on these areas of the business.

Drilling/Wellwork Equipment: Future drilling activity can be accomplished on Pier J, and Islands Chaffee and Freeman with the use of Unit Rig T-9 and land rig as required. Activity on Grissom can be accomplished with Unit Rig T-5. Activity on Island White can be accomplished with Unit Rig T-3. Additional drilling methods or equipment will be considered for lowering drilling costs on all locations. This additional equipment could include contract drilling rigs, workover rigs, coiled tubing units, and the use of top drive components.

Mechanical Integrity

The Unit has developed a comprehensive mechanical integrity program to ensure operations are conducted in a safe and environmentally sound manner and to ensure the long-term sustainability of Unit infrastructure. The mechanical integrity program includes preventive maintenance, inspections, repairs, and replacements of Unit piping, electrical, and other infrastructure equipment. Routine inspections, repairs, and replacements are expected during the Program Plan period.

Electricity Generation

Electricity is the single largest operational cost element for the Unit. Currently, the Unit consumes approximately 683 million kWh per year and is one of the largest single-site users of electricity in Southern California Edison's territory. Any change in the electrical rates or availability of electricity supply significantly affects the profitability of Unit operations.

The Unit constructed a 45MW power generation plant in an effort to increase the California in-state generation supply, as well as insulate the Unit from the risks of electricity supply disruptions and escalating wholesale electric costs. The plant commenced operations in FY02/03.

In addition to power generation, the power plant provides a means to flexibly optimize the choice of procurement or generation of electricity in a cost-effective manner. It also allows the Unit to maximize electricity cost savings via Southern California Edison's Base Interruptible Program.

The land lease for the LBU power plant is expiring in July 2024. Lease extension negotiations stalled when the current landowner entered into a sales agreement for the property. A new lease has not been secured with the incoming buyer. Failure to secure a new lease will result in removal of the existing facility and the option of relocating the plant or installing a sales pipeline to SoCal Gas. Costs could exceed $40MM.

Efforts will also focus on electrical production equipment efficiency. Injection pumps will utilize power monitoring devices to identify opportunities for improving their electrical efficiency. Electrical efficiency improvements are recognized by Southern California Edison through their efficiency rebate program. Work will also continue with the Unit's submersible pump supplier to identify opportunities for reducing power usage on submersible pumps which include permanent magnet motors.

Taxes

Historically, the County of Los Angeles has increased the assessed value of the Unit annually. Ad Valorem taxes are estimated to increase modestly with future price increase. Determination of actual tax levies will be based on assessor valuation, driven by oil price and cost projections.

Make-up Water Sources

A reliable source of water to be used for injection is vital to the success of the Unit. Water injected into the formations serves two purposes: 1) controlling subsidence and 2) enhancing oil recovery. In order to meet voidage targets, make-up water is purchased from sources outside the Unit. The Unit’s primary make-up water sources include produced water from Tidelands Oil Production Company (Tidelands) and reclaimed water from Long Beach Water Department. Fresh water is used sparingly, primarily for utility purposes (drinking and hygiene uses). In addition, bearing-cooling projects have been put in place to further reduce use of fresh water.

THUMS is working closely with Tidelands to anticipate water needs and sources to satisfy the injection needs in the Unit.

Regulatory

In 2022, Senate Bill 1137 (SB 1137) was proposed to California legislation. SB 1137 prohibits most new or modified oil and gas wells within 3,200 feet of specific locations. It also requires existing wells in these areas to meet specified health, safety, and environmental requirements. The bill passed the California State Assembly and California State Senate in late August and was signed into law in September. A referendum challenging the law collected enough signatures to stay the law until the next general election in 2024 where the public will vote on the bill. If the bill becomes a law, it will likely adversely affect the development plans and maintenance on wells that require permitted operations on wells in Island Grissom, Island White, and Pier J. Incremental operating costs are also anticipated due to the additional monitoring requirements of the law.

Additionally, during the Underground Injection Control Project by Project review by CalGEM, the validity of the maximum allowable injection pressure was questioned and, in particular, the injection gradient. CRC and the City of Long Beach have had numerous meetings with CalGEM and have presented a plethora of data to support current injection gradients which have been in place since the start of injection. CalGEM is yet to come to a conclusion on this matter. If the injection gradient is lowered, it would limit the Unit’s ability to inject water and subsequently reduce produced volumes.

Economic Summary

Revenue Forecast

Unit revenue will be generated predominately from the sale of oil and gas from five producing formations: Tar, Ranger West, Ranger East, Terminal, and UP Ford/237. The projected revenue during the Program Plan period is $1,741 million, based on an oil price of $65/bbl, a gas price of $3.00/mcf, and average daily oil and gas production as projected in Exhibit C. Projected revenue for FY24 is expected to be $358 million.

Cost Forecast

Total estimated expenditures for the first year of this Program Plan are consistent with the FY24 Annual Plan. Costs in subsequent years are projected by establishing a relationship between current costs and the variables believed to be principally responsible for driving future costs by category. The most leveraging cost drivers overall are the levels of gross fluid production and injection, discretionary activity levels (e.g., drilling, abandonment, and major projects), and the number of wells and facilities that are active at a given time.

Based on the projected production rates, injection rates and activity levels, total expenditures during the Program Plan period are expected to be $1,502 million. The projected expenditures for FY24 are $324 million. Costs in future years will be refined upon completion of ongoing studies and projects and also be affected by changes and adjustments that may result from the economic conditions.

Profit Forecast

Based on the above revenue and cost forecasts, Unit profit during the Program Plan period is projected to be $239 million. Unit profit for FY24 is expected to be $34 million. The schedule of annual projected revenue, expenditures, and net profit is given in Exhibit A.

Budget commitments for FY25 will be established based on actual results and additional insights gained during FY24.

Table 1

SUMMARY OF PRODUCTION AND INJECTION

AS OF DECEMBER 2022
JULY 2023 – JUNE 2028 PROGRAM PLAN, LONG BEACH UNIT

Reservoir	CRB	Active Producer Count	Active Injector Count	Avg Rate Dec. '22 BOPD	Avg Rate Dec. '22 BWPD	Avg Rate Dec. '22 BIPD	Wtr. Cut	Average BOPD/ Well	Average BWPD/ Well	Average BIPD/ Well
SG	65	0	0	0	0	0	-	0	0	0
	66	0	0	0	0	0	-	0	0	0
Tar	35	7	2	126	3,855	11,661	97%	18	551	4,962
Ranger	1	23	20	487	35,257	54,288	99%	22	1,567	2,714
West	2	35	11	846	51,112	36,840	98%	25	1,482	3,349
	3	40	23	895	79,721	80,408	99%	22	1,976	3,496
	4	45	30	973	108,410	118,487	99%	21	2,395	3,907
	5	28	19	969	66,848	65,996	99%	35	2,387	3,505
	7	14	7	295	21,643	21,573	99%	20	1,500	3,082
	8	14	9	250	23,985	19,511	99%	18	1,744	2,295
	9	7	6	162	9,501	10,085	98%	23	1,357	1,681
	10	19	16	374	26,325	28,085	99%	20	1,423	1,812
	11	10	5	200	10,739	6,875	98%	21	1,130	1,528
	12	7	5	141	9,461	5,111	99%	20	1,333	1,022
	13	8	8	197	15,569	16,407	99%	24	1,862	2,188
	36	20	16	478	43,437	46,894	99%	24	2,172	3,025
	37	5	8	195	13,417	24,128	99%	39	2,683	3,016
	Total	**274**	**181**	**6,460**	**515,425**	**534,687**	**99%**	**24**	**1,879**	**2,960**
Ranger	14	10	11	301	22,403	25,927	99%	29	2,144	2,469
East	15	33	20	851	61,609	71,102	99%	25	1,845	3,555
	16	16	6	394	16,829	15,063	98%	24	1,042	2,511
	17	26	12	562	30,323	29,003	98%	22	1,171	2,522
	18	9	11	235	14,542	26,232	98%	26	1,616	2,385
	20	20	6	539	25,425	17,732	98%	28	1,304	3,224
	21	39	27	1,176	70,338	69,409	98%	30	1,796	2,530
	22	13	6	275	14,559	13,119	98%	22	1,147	2,212
	32	1	2	9	357	4,441	98%	18	714	2,960
	33	23	17	551	43,036	45,952	99%	24	1,904	2,785
	Total	**189**	**116**	**4,891**	**299,421**	**317,979**	**98%**	**26**	**1,581**	**2,745**
Terminal	24	20	12	240	21,550	29,182	99%	12	1,052	2,348
	38	35	16	786	58,129	50,856	99%	23	1,668	3,178
	39	23	11	492	26,454	34,788	98%	21	1,155	3,163
	40	7	2	58	4,395	1,666	99%	9	671	833
	41	3	2	57	4,393	6,805	99%	20	1,525	3,402
	42	7	4	92	8,213	5,512	99%	12	1,110	1,378
	43	24	12	388	31,785	27,590	99%	16	1,319	2,362
	47	0	0	4	368	0	99%	8	819	
	Total	**120**	**59**	**2,116**	**155,288**	**156,398**	**99%**	**18**	**1,298**	**2,646**
UP/ Ford	26	0	1	0	0	580	-	0	0	580
	27	14	5	223	10,882	8,469	98%	16	796	1,882
	31	3	3	22	1,673	2,469	99%	7	558	823
	44	4	7	34	2,622	7,479	99%	9	656	1,068
	45	22	8	407	13,483	7,424	97%	18	613	928
	46	23	9	380	19,387	13,391	98%	17	857	1,483
	Total	**65**	**33**	**1,066**	**48,046**	**39,812**	**98%**	**16**	**736**	**1,224**
237	30	0	0	0	0	0	-	0	0	0
LBU Total		**656**	**391**	**14,659**	**1,022,034**	**1,060,537**	**99%**	**22**	**1,559**	**2,716**

Exhibit A

ECONOMIC PROJECTIONS

July 1, 2023 through June 30, 2028 Program Plan

(Million Dollars)

	Fiscal 2023/24	Fiscal 2024/25	Fiscal 2025/26	Fiscal 2026/27	Fiscal 2027/28	Program Plan Period
Estimated Revenue						
Oil Revenue	$350	$349	$348	$335	$323	**$1,705**
Gas Revenue	$7	$7	$7	$7	$7	**$36**
Total Estimated Revenue	$358	$356	$355	$342	$330	**$1,741**
Estimated Expenditures	$324	$316	$299	$280	$284	**$1,502**
Net Income	$34	$41	$56	$62	$46	**$239**
Oil Price $/bbl	$ 65.00	$ 65.00	$ 65.00	$ 65.00	$ 65.00	

Exhibit B

Anticipated Completion & Redrill Schedule
July 1, 2023 through June 30, 2028
(Number of Wells)

FISCAL YEAR	Tar V	Ranger West	Ranger East	Terminal	UP Ford/237	Total Wells
2023/24	**1**	**18**	**5**	**8**	**1**	**33**
2024/25	0	10	6	5	4	25
2025/26	0	5	12	1	1	19
2026/27	0	0	15	1	1	17
2027/28	0	4	2	2	0	18

Exhibit C

Range of Expected Production Rates
July 2023-June 2028 Program Plan
Long Beach Unit

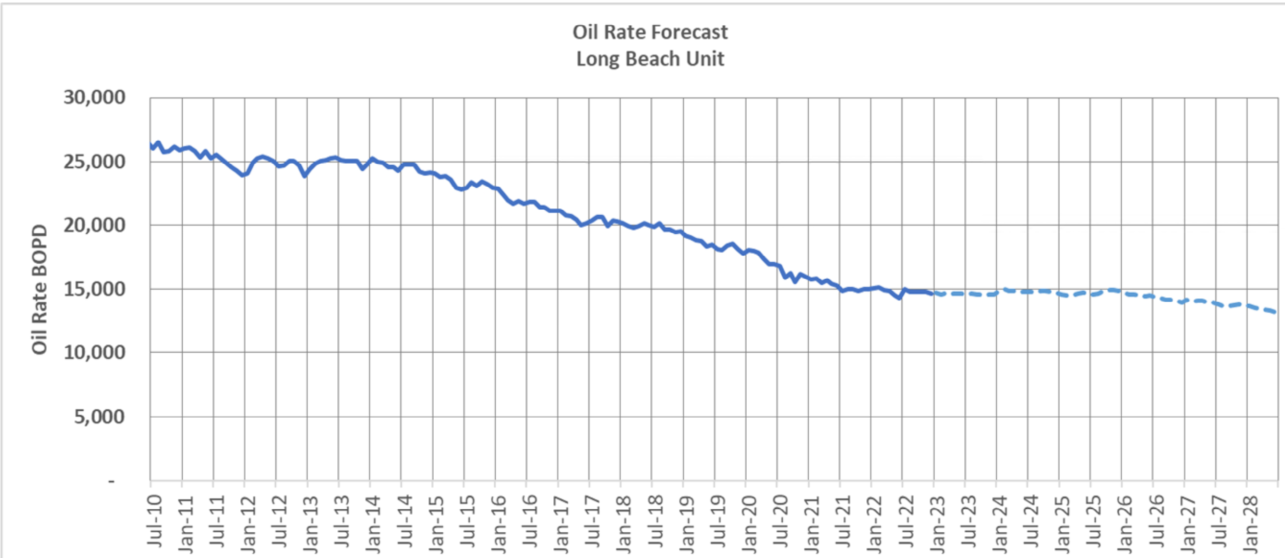
FISCAL YEAR	OIL RANGE MBOPD	WATER RANGE MBWPD	GAS RANGE MMCFPD	OIL RATE MBOPD	WATER RATE MBWPD	GAS RATE MMCFPD
2023/24	13.7 – 15.5	960 – 1,083	6.3 – 7.1	14.73	1,032	6.8
2024/25	13.7 – 15.4	949 – 1,071	6.3 – 7.1	14.70	1,020	6.8
2025/26	13.6 – 15.4	947 – 1,069	6.3 – 7.1	14.67	1,018	6.7
2026/27	13.1 – 14.8	910 – 1,027	6.0 – 6.8	14.10	978.4	6.5
2027/28	12.6 – 14.3	876 – 989	5.8 – 6.6	13.60	942.3	6.2

Exhibit D

Range of Injection Rates
July 2023-June 2028 Program Plan
Long Beach Unit

FISCAL YEAR	WATER INJECTION RANGE (MBWIPD)	EXPECTED WATER INJECTION (MWIPD)	TAR PRESSURE RANGE (PSI)	RANGER PRESSURE RANGE (PSI)	TERINAL PRESSURE RANGE (PSI)	UP/FORD PRESSURE RANGE (PSI)
2023/24	997 – 1,126	1,072	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2024/25	986 – 1,113	1,060	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2025/26	984 – 1,111	1,058	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2026/27	945 – 1,067	1,017	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2027/28	911 – 1,028	979	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500

Exhibit E


Oil Rate Forecast
Long Beach Unit
30,000
25,000
20,000
15,000
10,000
5,000
-
Oil Rate BOPD
Jul-10
Jan-11
Jul-11
Jan-12
Jul-12
Jan-13
Jul-13
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Jul-14
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Jul-15
Jan-16
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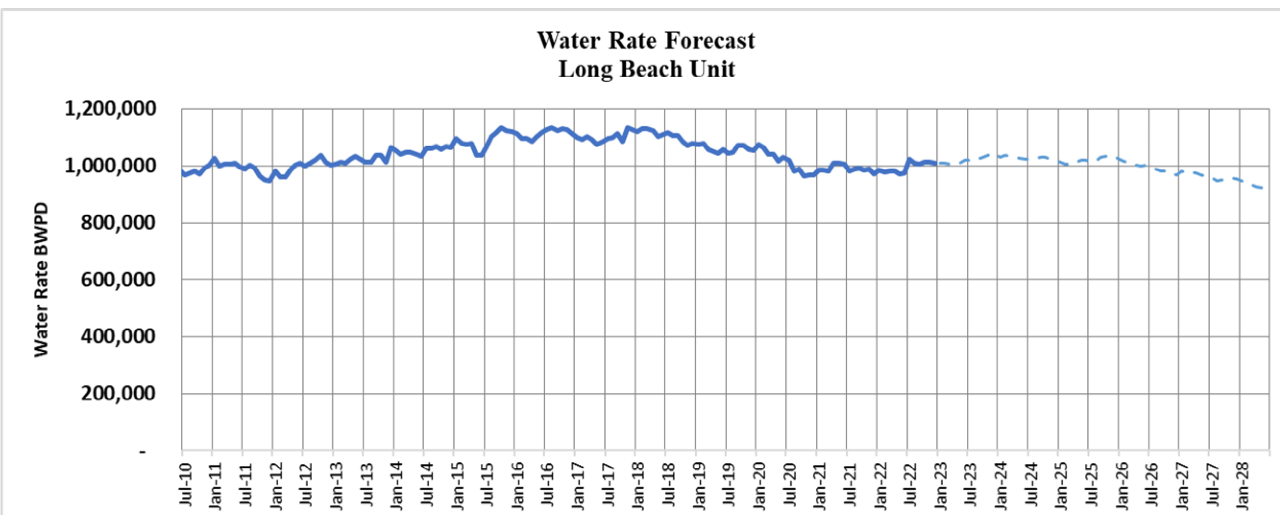
Water Rate Forecast
Long Beach Unit
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800,000
600,000
400,000
200,000
-
Water Rate BWPD
Jul-10
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Jul-11
Jan-12
Jul-12
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Jul-14
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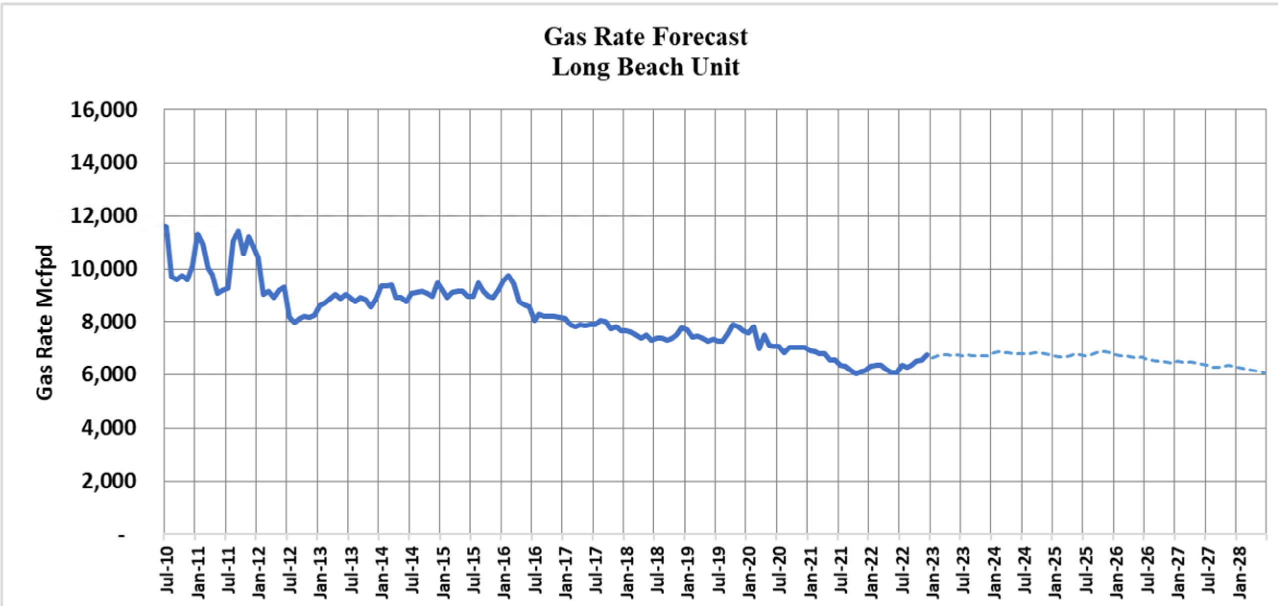
Exhibit F



Schedule 1A

Range of Production and Injection
FY24
Long Beach Unit Program Plan, July 2023-June 2028

FISCAL YEAR	OIL RANGE MBOPD	WATER RANGE MBWPD	GAS RANGE MMCFPD	INJECTION RANGE MBWIPD
2023/24	13.7 – 15.5	960 – 1,083	6.3 – 7.1	997 – 1,126

FISCAL YEAR	TAR INJECTION PRESSURE (PSI)	RANGER INJECTION PRESSURE (PSI)	TERMINAL INJECTION PRESSURE (PSI)	UP/FORD INJECTION PRESSURE (PSI)
2023/24	1,500	2,500	2,500	2,500

Schedule 1B

Anticipated Redrill Completions; Fiscal Year 24
Long Beach Unit Program Plan, July 2023-June 2028

		Producers	Producers	Producers	Producers	Producers		Injectors	Injectors	Injectors	Injectors	Injectors
Reservoir	**CRB**	**Grissom Min - Max**	**White Min - Max**	**Chaffee Min - Max**	**Freeman Min - Max**	**Pier J Min - Max**		**Grissom Min - Max**	**White Min - Max**	**Chaffee Min - Max**	**Freeman Min - Max**	**Pier J Min - Max**
SG												
Tar	35	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 1
Ranger West	1	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	2	0 - 4	0 - 0	0 - 0	0 - 0	0 - 0		0 - 1	0 - 0	0 - 0	0 - 0	0 - 0
	3	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	4	0 - 4	0 - 0	0 - 0	0 - 0	0 - 1		0 - 1	0 - 0	0 - 0	0 - 0	0 - 1
	5	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	6	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	7	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	8	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	9	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	10	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	11	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	12	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	13	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	36	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	37	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Ranger East	14	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	15	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	16	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	17	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	18	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	20	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	21	0 - 0	0 - 0	0 - 3	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	22	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	33	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Terminal	24	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	38	0 - 3	0 - 0	0 - 0	0 - 0	0 - 0		0 - 1	0 - 0	0 - 0	0 - 0	0 - 0
	39	0 - 3	0 - 0	0 - 0	0 - 0	0 - 0		0 - 1	0 - 0	0 - 0	0 - 0	0 - 0
	40	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	41	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	42	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	43	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	47	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
UP Ford	26	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	27	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	30	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	31	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	44	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	45	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	46	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
237	30	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
				Total						Total		
				0 - 33						0 - 6		

Schedule 2 A

Range of Production and Injection

FY 25

Long Beach Unit Program Plan, July 2023-June 2028

FISCAL YEAR	OIL RANGE MBOPD	WATER RANGE MBWPD	GAS RANGE MMCFPD	INJECTION RANGE MBWIPD
2024/25	13.7 – 15.4	949 – 1,071	6.3 – 7.1	986 – 1,113

FISCAL YEAR	TAR INJECTION PRESSURE (PSI)	RANGER INJECTION PRESSURE (PSI)	TERMINAL INJECTION PRESSURE (PSI)	UP/FORD INJECTION PRESSURE (PSI)
2024/25	1,500	2,500	2,500	2,500

Schedule 2 B

Anticipated Redrill Completions; Fiscal Year 25
Long Beach Unit Program Plan, July 2023-June 2028

		Producers	Producers	Producers	Producers	Producers		Injectors	Injectors	Injectors	Injectors	Injectors
Reservoir	CRB	Grissom	White	Chaffee	Freeman	Pier J		Grissom	White	Chaffee	Freeman	Pier J
		Min - Max	Min - Max	Min - Max	Min - Max	Min - Max		Min - Max	Min - Max	Min - Max	Min - Max	Min - Max
SG												
Tar	35	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Ranger West	1	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	2	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	3	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	4	0 - 0	0 - 3	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	5	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	6	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	7	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	8	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	9	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	10	0 - 0	0 - 4	0 - 0	0 - 0	0 - 0		0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	11	0 - 0	0 - 4	0 - 0	0 - 0	0 - 0		0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	12	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	13	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	36	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	37	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Ranger East	14	0 - 0	0 - 3	0 - 0	0 - 0	0 - 0		0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	15	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	16	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	17	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	18	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	20	0 - 0	0 - 0	0 - 4	0 - 0	0 - 0		0 - 0	0 - 0	0 - 1	0 - 0	0 - 0
	21	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	22	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	33	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Terminal	24	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	38	0 - 0	0 - 3	0 - 0	0 - 0	0 - 0		0 - 1	0 - 0	0 - 0	0 - 0	0 - 0
	39	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	40	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	41	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	42	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	43	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	47	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
UP Ford	26	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	27	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	30	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	31	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	44	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	45	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	46	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
237	30	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
				Total						Total		
				0 - 33						0 - 6		

Appendix

Ranger West / Tar

Reservoir Management Plan

History

The Ranger West reservoirs are comprised of the Ranger 6 and Ranger 7 fault blocks. Ranger West is the largest pool in the Unit with 1.6 billion barrels of original oil in place (OOIP). The first pool developed at field startup in late 1965, Ranger West contains a contrasting mix of mature and under-developed blocks. The crestal and southern blocks are generally more mature than the northern blocks in the Ranger West area. In the more mature crestal and southern blocks, waterflood recovery is generally high (34-48% OOIP) with water-oil ratios (WOR's) ranging from 32-136. In the less mature northern blocks, oil recoveries range from 27-38% with WORs of approximately 17-139.

The Ranger West waterflood was originally implemented using a 3-1 staggered line drive (SLD) pattern containing three rows of producers for each row of injectors. There are twelve cut-recovery blocks (CRB's) still using this pattern framework. The only exceptions are CRB-8, which lies between 2 faults on the crest, and CRBs 1 and 10, which were re-configured through development drilling as injector-centered patterns (1992-1994). In 1986, 70 offset row producers were shut-in because of relatively high water cuts and high operating costs. This left only the center row producers in some blocks, converting these patterns to a classic line drive with exaggerated spacing between producers and injectors. This skewed pattern provides a slow rate of recovery at a reduced, but still relatively high, theoretical areal sweep efficiency.

There are three main completion intervals in Ranger West: the F0, the F-X, and X-HX1 (Lower Ranger). More recently, traditional X-HX1 completions have been modified to target sands of similar injection throughput and permeability including Mn, M1 and H1 sands historically completed in the F-X wells. Over the majority of the Ranger West pool, the F0 is the thickest and most dominant sand package. Original wells used full-zone, open-hole gravel packs across all three intervals. The more permeable F0 sand received the majority of the injected water resulting in bypassed oil within the F0 and throughout the lower zones. The Subzone Redevelopment Program, from 1980-1984, was successful in diverting injection and production to the F-X and Lower Ranger intervals by selectively completing only those subzones. Ranger West production increased 4,000 BOPD during 1980-1984 from this effort. Pockets of bypassed oil throughout the Ranger West area continue to be the target of horizontal wells, injection realignment/conversions, and selective recompletions.

In Ranger West, from 2001 to 2018, a very successful thirty-five well F0 horizontal drilling campaign was executed. This campaign targeted the upper F0 sand attic oil (~15 to 35 ft. oil column). The 90-day average oil rate per well from the 2019-2020 campaign is approximately 90 BOPD.

The Wilmington Tar V reservoir covers approximately 200 acres of inter-bedded sands, siltstones, and shales with a typical interval height of 180' gross and 70' net. Production began in 1967 and has ranged from 15 BOPD to 330 BOPD. The completion types consist of vertical (S3/T sands), slant (S3/T sands), and horizontal wells (S3 sand). The waterflood consists of two injectors on the south flank and one 1,000 foot horizontal injector on the north flank. The plan is to extend this south flank injection into a peripheral waterflood around the northeast and southeast flanks utilizing injection conversions of idle Ranger and below wells. This strategy recognizes that the southern S3 sand O/W contact is at about 2,350 ft whereas the northern O/W contact is at about 2,150 ft.

Future Tar V drilling plans are a continuation of the successful S3 horizontal redevelopment program during 2014-16.

Status

The Ranger West/Tar production rates as of December 2022 were 6,460 BOPD and 515,425 BWPD (99% water cut) from 274 producers. December 2022 injection was 534,687 BWPD from 181 injectors. Average active well rates were 24 BOPD and 1,879 BWPD for producers and 2,960 BWPD for injectors.

Recovery through December 2022 was approximately 537 MMBO (34% OOIP). The base production in Ranger West reservoir has been declining at around 10% per year.

Wilmington Tar V has 7 active producing wells and 2 injectors. December 2022 production is approximately 126 BOPD and 3,855 BWPD (97% water cut). Estimated floodable OOIP is about 23.8 million barrels, the majority of which resides in the S Sand. As of December 2022, only 2.6 MMBO of oil has been recovered (about 11% OOIP), from an injected hydrocarbon pore volume of 1.75. Future efforts to increase the waterflood throughput and economic oil recovery will utilize low-cost injection conversion of idle Ranger and below penetrators.

Calendar Years 2021 and 2022 Activities and Results

Since publication of the last Program Plan, no producers have been drilled and completed in the Ranger West and Tar V pools.

The average initial stabilized rate for the 2019 and 2020 campaigns (90-day average) drilled in the Ranger West Pool was 90 BOPD with initial rates ranging from 10 BOPD to 387 BOPD (well A-647). The average initial stabilized production rate was 144 BOPD for the horizontal completions and 38 BOPD for the other completion types. Overall, projects completed from 2019-2020 outperformed AFE expectations.

Before the 2014 drilling campaign, the last Tar well drilled was in 2007. In early 2014, a reservoir simulation model was built that identified seven horizontal S3 sand drill well candidates. In August and September 2014, two S3 sand horizontal wells (A642 and A753) were drilled and completed. Wells A642 and A753 peak rates were approximately 251 BOPD, 664 BGPD and 242 BOPD, 701 BGPD respectively. In 2015 and 2016, six additional Tar horizontal wells were drilled and completed with a 90-day production rate of 104 BOPD.

Reservoir Management Objectives

The primary reservoir management objective is to maximize the profitability of the Ranger West pool. Maximum profitability will be achieved through increasing recovery in underdeveloped blocks by identifying optimal locations for development drilling/investment wellwork combined with the right placement of injection water. Throughput objectives are to reach an HCPVI target of at least 6.0 for each sand in all CRBs. As of December 2022, HPVIs range from 1 to more than 10 on an individual sand basis. As a result, oil recoveries range from values as low as 30% in some CRBs up to 50% in other CRBs. By ensuring that each sand reaches an HPVI target of at least 6.0, oil recoveries for individual sands should reach a minimum of 30-33% for an overall recovery in excess of 40% for the Ranger West sand. In the more mature blocks, maximum profitability will be achieved through minimizing the volume of low value water cycling, directing water to the remaining economic reservoir targets and targeting by-passed oil pockets with development drilling and investment wellwork projects. In the absence of economic options, idle wells will be abandoned to reduce future abandonment liabilities and reservoir cross-flow. Risk of subsidence will be minimized in all reservoir management actions.

Strategies

The Ranger West development plan includes completing 4 development wells and performing approximately 10 investment wellwork projects per year in FY22 and 23. The development plan will be implemented under the guidance of the reservoir management objectives discussed above. The best investment wellwork locations will be evaluated and selected for inclusion in the drilling and wellwork programs based on a combination of economic and strategic criteria. Projects will be reviewed carefully to ensure that only projects that will be profitable even in low price environments are executed. Pool reviews/reservoir studies, conducted on an ongoing basis, will be used as the foundation for identifying the best drilling and wellwork opportunities and to monitor progress towards achieving reservoir management goals.

Key reservoir management strategies have been developed for each of the CRBs in Ranger West. In summary, waterflood optimization of the more mature crestal and south flanking blocks will be achieved through injector and producer profile control, pattern realignment, and capturing bypassed pockets of oil through horizontal drilling and cased-hole recompletions. In the less mature northern blocks, waterflood optimization will be achieved through (1) infill drilling and recompletions to improve pattern throughput, and (2) injector profile modifications to better balance injection between high permeability and low permeability sands.

Specific F0 horizontal recompletions will continue to be part of the future development plan. Future candidates will be selected based on the following general characteristics: ideally greater than 100 feet of new completion interval, greater than 100 feet between the new and original perforation intervals, greater than 400 feet from active or historic injection, and new pay should be closer to the confining FO shale than the original completion.

Because of the Tar zone’s poor mobility ratios (~450 CP viscosity), the plan is to keep injectors at least 800 ft away from producers. To overcome the high viscosity, where possible, these horizontal wells will be drilled at least 1,250 ft. in length with a spacing of approximately 250’ between the wells. The optimal drilling orientation is alternating toe/heel based on reservoir simulation results. The additional injection needed to support the new completions will come from lower cost add-pay injection well conversions using idle Ranger and below penetrator wellbores.

Critical Issues

Key areas of focus for the Program Plan period include the following:

- Continue throughput optimization in under-injected sands, generally the lower sands (Mn through G6), by using dual-string and selectively perforated injectors.
- Optimize the Ranger West waterflood through sub-zoning into upper and lower floods where it is economically effective.
- Continue application of horizontal well technology including additional infill F0 and Tar horizontals in blocks 3, 4, 5, 35 and the crestal area of Ranger 7, and identify horizontal well opportunities in lower F0 lobes (F01 & F02) in all areas. In addition, utilize slant wells as another way to optimize depletion from these sands.
- Mitigate water influx from poorly saturated sands and target high saturation zones by utilizing hybrid wells, cased-hole wells, x-pack/multi-x-pack completions, horizontal wells, multilaterals, and slant wells.
- Implement low-cost replacement drilling options for failed wells, particularly for injectors with poor conformance and limited repair options.
- Continue to update and optimize streamline reservoir models to evaluate depletion optimization in Ranger West. Update the geologic model in Petrel.

Ranger East

Reservoir Management Plan

History

The Ranger East area is comprised of the three major fault blocks east of the Long Beach Unit fault: Ranger 8A/8B, Ranger 90N, and Ranger 90S. To facilitate reservoir analysis, the fault blocks are further broken down into cut-recovery blocks (CRB's) along injection rows or significant faults, as appropriate.

Production from Ranger East began in April 1967. However, several initial wells encountered relatively low reservoir pressures, and full production was delayed until enough pressure support was established to reduce the high producing gas-oil ratios. The waterflood program was initiated immediately, based primarily on peripheral injection. Line drive injectors were subsequently added in some areas, mainly along the crest of the structure. Early efforts to inject into and produce from full-zone completions were not fully effective, as flow was dominated by well-developed and high permeability F0, F, or M1 sand units high in the vertical section. A sub-zoning program in the early 1980's significantly improved the flood by decreasing the amount of interval open in each well, and substantially enhanced the response in the Lower Ranger sands.

This development strategy has been effective along the structural crest of the reservoir and the southern flank, which has seen good pressure support and sweep from the peripheral injectors. Similarly, the crestal areas have benefited from a combination of down-dip support from the injectors along the southern flank and direct support from line drive injectors. Pressure support and recovery efficiencies in crestal CRB's 15, 22, 32, and 33 are expected to be high, though somewhat lower than in CRB-21 due to complex faulting and reduced sweep efficiency.

Although peripheral injection along the northern flank provides a row of back-up injection, this injection has been less effective because the producing reservoirs are in pressure communication with the Seal Beach field down-structure. A significant portion of the peripheral injection in CRB's 14, 16, 17, and 18 has been diverted down dip, particularly during the early field life when withdrawal from the Seal Beach field was higher. Pressure support has thus been limited in these areas, and both the current and projected recoveries are relatively low. The remaining reserves in these areas constitute the major redevelopment target in Ranger East.

In addition to injection losses to the north, a significant amount of oil was lost to the eastern flank to the Belmont Offshore field. The Belmont Offshore field produced for about 13 years before the Ranger East began development. Although a row of injectors was placed along the lease line between Ranger East and the Belmont Offshore field, loss of reserves probably occurred until after the Belmont Field ceased production in 1992.

Status

As of December 2022 Ranger East production is 4,891 BOPD and 299,421 BWPD from 189 active producers. Total water injection is 317,979 BWPD into 116 active injectors. Average active well rates are 26 BOPD and 1,581BWPD for producers and 2,745 BWPD for injectors.

Cumulative oil production as of December 2022 is 270 MMBO (33% OOIP). Since the last reporting period, oil production has been dropping due to the reduced drilling activity which is being driven by lower crude prices. Excluding development, base decline has been approximately 11% over the last two years.

Calendar Years 2021 and 2022 Activities and Results

Since publication of the last Program Plan, 18 horizontal and eight vertical producers have been drilled and completed in the Ranger East pool.

The average stabilized rate (3-month average) for the producers drilled in the Ranger East Pool is 876 BOPD. Two injectors were drilled during this period but have not been completed.

During the 2021-22 period, (investment) wellwork jobs were limited due to injector permitting constraints. There is a queue of injector add pays and injector conversions with CalGEM but are effectively in a standstill until the UIC Project by Project review is complete. The proposed injector development wellwork projects were add pays in zone targeting low pressure and support for development projects. The injection work targeted increasing water throughput in selective sands and pattern areas. Maintenance wellwork continues to play a major role in maximizing Ranger East base production.

Reservoir Management Objectives

The primary goal of the reservoir management plan is to maximize the profitability and economic oil recovery from the Ranger East pool. This can be accomplished by developing proper waterflood pattern closure, providing adequate injection throughput into all the individual sand intervals in each pattern, reducing water cycling in swept zones where possible, and maximizing well productivity. Current WOR in the three major fault blocks averages 50. The injection target volume is greater than 6.0 hydrocarbon pore volumes into each sand before reaching a producing WOR of 100. Injection throughput has been challenged by the difficulty of maintaining good vertical profile control.

Production rates are maximized by selective removal of near wellbore damage, most often due to fines migration and scale, from producers. In addition, increasing pump size and using variable speed drives to increase well drawdown ensures that maximum productivity is achieved from the wells. Finally, producers are recompleted when economic quantities of unswept oil are identified.

Strategies

The Ranger East development plan includes drilling additional redevelopment wells on Chaffee, Freeman, and White. A continued focus is on F0, FJ and M1 horizontals in

Ranger East. Some investment wellwork projects have been identified and these projects will target insufficiently swept pay.

Base Optimization meetings will be conducted regularly to identify well work, conversion, and infill opportunities. Reservoir studies are being performed to develop long term depletion plans and to reliably forecast future reservoir performance.

The updated Ranger East simulation model was built and rolled out in 2014 using the Eclipse software. The new model was developed to improve the reservoir characterization of Ranger East, to improve the estimate of net pay and OOIP. The goals of the simulation model are to understand flux into or out of the Unit, identify hydrocarbon hot spots, manage waterflooding, optimize the Ranger East depletion plan and assist in well planning. In addition, the goal is to use post-processing of the streamline data to identify opportunities to improve injection pattern balancing and sweep.

The profitability of the development plan will be maximized by reducing costs where possible and prudent. The focus will be on using existing wellbores, correcting injection profiles with workovers or remedial wellwork where possible, returning idle producers to production, shutting in high WOR producers and potentially adding or stimulating non-productive intervals. Existing wells will continue to be redrilled when warranted. A successful wellwork program will continue to be critical to Ranger East success. Strong communications between individuals in operations and engineering will be maintained through joint involvement in block reviews and joint review of wellwork opportunities and priorities.

Critical Issues

Redevelopment of the Ranger East area is continuing. The primary development goals for the Plan period include:

- Complete Plan of depletion (POD)/ surveillance sessions studies by CRB for Ranger 90N/90S and R8A/B.
- Develop proper waterflood pattern closure and improve the injection throughput into under-injected sands by wellwork, drilling, and removal of near wellbore damage (i.e. fines, scale).
- Select the optimal injector drilling locations by utilizing the results of the improved streamline simulation model.
- Evaluate the feasibility of and begin development of horizontal wells in the M1 (primarily R90N)
- Reduce the WOR on high WOR wells through mechanical or chemical water shut off projects on the injector or producer.

Terminal Zone

Reservoir Management Plan

History

The Terminal zone is about 1,000 feet thick and its productive limits cover an area about four miles long and two miles wide within the Unit. The LBU fault divides the Terminal into the Upper and Lower Terminal zones on the west side of the field from the Terminal East (TE) zone on the east side.

The Terminal Zone was first developed in 1965 on the west side of the LBU fault in Upper Terminal VI (UT6). Water injection commenced with initial production utilizing a peripheral injection flood configuration. Early injectors were drilled down structure from the productive limits of the oil column. Development of Terminal East began in 1967, and the last block to be flooded was Upper Terminal VII (UT7) starting in 1985.

Wells on the west side of the field have generally been completed in Upper Terminal sands, in either the HX1-Y4 or Y4-AA intervals; however, a few wells include the less prolific Lower Terminal AA-ADL sands.

Terminal East wells are completed in either the upper Y-A or AA-ADL intervals. In the middle 1980’s, some Terminal East wells were completed as dedicated sub-zone producers and injectors in the AC-AD interval.

The sub-zone development program targeted reserves in these deeper interbedded sands. AC-ADL zone reserves were not fully recovered in the original full-zone completions due to competition from the upper, more prolific intervals.

Early wells were completed with gravel packed slotted liners and water zones were excluded with cemented blank liner sections/ isolation packers. Water exclusion and selective injection became more important as the waterflood matured and the more permeable reservoir sands watered out. In the early 1980's cased hole completions were utilized to improve water exclusion and sand control. The current cased hole completion program typically includes conventional perforating and wire-wrapped screens.

Status

As of December 2022, the total production from the Terminal zone is 2,116 BOPD and 155,288 BWPD from 120 active producers. Terminal zone injection for December 2022 is 156,398 BWIPD from 59 wells. Average active well rates were 18 BOPD and 1,298 BWPD for producers and 2,646 BWIPD for injectors. Five Terminal wells are currently mechanically idle and potentially capable of being reactivated with further investment. Evaluations of repair and/or conversion options as well as uphole potential are currently underway for these wells.

Cumulative production through December 2022 totaled 164 MMBO (39% OOIP). Excluding development, base decline has been approximately 8% per year over the past two years.

Calendar Years 2021 and 2022 Activities and Results

Since publication of the last Program Plan, no new well was drilled and completed in the Terminal pool.

During the 2021-2022 Plan period, a total of 4 development (investment) wellwork jobs were also completed. The investment projects were selective recompletions/add pay projects. Maintenance wellwork continues to play a major role in maximizing Terminal base production.

Reservoir Management Objectives

Future plans for development and management of the reservoir are guided by the objective of maximizing profitability while ensuring stable surface elevations. Development will be driven by identifying the best well locations and by optimizing the placement of injected water within voidage constraints while minimizing uneconomic water cycling.

Production and injection infill well locations will be identified and drilled to recover oil banked near faults, to improve areal sweep efficiency and to increase reservoir throughput. Profile modification will be attempted to reduce thief intervals and improve vertical conformance. Recovery from existing wells will be optimized to ensure maximum economic value. Completion techniques will be specialized for each well to increase injectivity, minimize reservoir damage, and reduce high decline rates.

Strategies

The Terminal Zone development plan includes drilling additional development drilling wells on various locations (Grissom, White, Freeman, and Pier J). Note that some projects are reachable from more than one location. Current plan is to target the center part of upper terminal reservoir and horizontals along the seismic D fault in CRB 43, where there is minimal depletion. Several investment wellwork projects are also planned. These objectives will be met by utilizing the various Unit programs currently in-place. The best production and injection infill completion candidates will be evaluated and selected for inclusion in the drilling schedule based on economic and strategic development criteria. Pool reviews will be conducted regularly to identify well work, conversion, and infill opportunities. Reservoir studies are being performed to develop long term depletion plans and to reliably forecast future reservoir performance.

Key reservoir management strategies have been formulated for each Terminal reservoir pool. The focus strategy for UT6 CRB-38 and 39 is to gather pressure data and saturations to improve recovery and vertical conformance due to the block's waterflood maturity and highly layered system. In addition, a highly selective drilling program will be conducted to target bypassed oil via HXC horizontals in UT06 and AC and AA horizontals in TE. The reservoir management goal for UT6 CRB-39 is to increase the overall level of development through infill drilling in this less mature block. Increased throughput and optimization of vertical and areal conformance will increase recovery in the block. The development strategy for UT7 includes crestal injection to augment the current peripheral injection configuration due to the area’s highly faulted nature. Finally, injection and infill development in Fault Block 90 will continue to be tailored to the improved understanding of fault compartmentalization and target bypassed oil in AA and AC sands.

Reservoir studies incorporating seismic interpretation will help fine tune future drilling requirements. Throughput analyses will be performed in those areas with the greatest development potential to quantify injection requirements. A detailed review of existing well histories and performance during pool reviews will help identify candidates for well work to improve management of the reservoir.

The focus will be on using existing wellbores, correcting injection profiles with workovers or remedial wellwork where possible, returning idle producers to production, shutting in high WOR producers and potentially adding or stimulating non-productive intervals. A successful wellwork program will continue to be critical to Terminal success. Strong communications between individuals in operations and engineering will be maintained through joint involvement in block reviews and joint review of wellwork opportunities and priorities. The team will actively seek out and advocate cost reduction strategies while meeting reservoir objectives.

Critical Issues

The following key points summarize the development goals for the Program Plan period:

- Update the Terminal East and West streamline models with the latest production, completion and log data. Complete the updated history match on the Terminal West model.
- Improve vertical conformance in UT6 CRB-38/39 through the selective drilling of cased hole producers, injectors, and conformance-improving workovers.
- Identify areas of bypassed oil and develop via horizontal completions in Terminal West & East (using the recent UPF pass through in TE & update seismic data in TE).
- Evaluate the feasibility of AA and AC horizontals primarily in TE.
- Effectively manage and optimize the waterflood in different areas between peripheral and infill injection strategies.
- Complete/continue Plan of Depletion (POD) studies by CRB for TE.
- Develop proper waterflood pattern closure and improve the injection throughput into under-injected sands by wellwork, drilling, and removal of near wellbore damage (i.e. fines, scale).

UPF Zone

Reservoir Management Plan

History

Much of the UP-Ford Zone's historical production is attributable to natural water drive from the AX sand, which was believed to have been watered-out over almost the entire field by the early 1980's. Recent development has been focused on developing AX oil at structurally high positions in CRB 45 and 46. These wells had very high IP rates. Sands above the AX have been historically less prolific owing to several factors, including lower formation permeability, thin-bedded discontinuous shaly sands which are prone to formation damage due to a high clay content, a lack of adequate injection support, and damaging completion and workover techniques.

The UP-Ford reservoir is complex from both reservoir and operational perspectives. Since it underlies the Ranger and Terminal zones, wells are more expensive to drill because of the depth and the pressure difference in Ranger and Terminal sands. In addition, higher reservoir temperatures and lower total fluid production rates shorten pump run times relative to the other reservoirs of the Unit. Non-damaging fluids are required during drilling and workover operations because of the sensitive nature of the formation.

From the late 1990's, success in pattern waterflood development in the Tract II area was achieved through the adoption of non-damaging drilling and completion techniques. As a result, UP-Ford oil production rate reached a 20-year high (6978 STB/D oil) during early 1998. During the early 2000's, attempts to further develop these strategies in the upper UP-Ford sands were not successful because of the lack of adequate injection support. During a two-year development break, the reservoir description was completely redone, and completion techniques were reviewed. A new Petrel geological model and Frontsim reservoir simulation model were built and history-matched in 2005. In the 2010's, multiple stimulated wells and open hole slotted liner hybrid completions have shown promise in increasing UPF oil production.

Status

The UP-Ford production rates in December 2022 were 1,066 BOPD and 48,046 BWPD (98% water cut) from 65 producers. December 2022 injection averaged 39,812 BWIPD from 33 injectors. Average active well rates were 16 BOPD and 736 BWPD for producers and 1,224 BWIPD for injectors.

Recovery through December 2022 was 112 MMBO (25% OOIP). Excluding development, base decline has been approximately 11% over the past two years. Maintenance wellwork continues to play a major role in maximizing UP-Ford base production.

Calendar Years 2021 and 2022 Activities and Results

Since publication of the last Program Plan, four producers have been drilled and completed in the UP-Ford pool, which includes one redrill. The average initial stabilized rate (3-month average) for the producers drilled is 68 bopd matching the expected rates and the redrill well in 2022 has an average rate of 40 bopd.

Reservoir Management Objectives

The goal of the UP-Ford Reservoir Management Plan is to maximize the profitability of the reservoir by increasing waterflood efficiency. This will be accomplished by increasing throughput ratio, injection efficiency and volumetric sweep. There are three areas of focus with respect to attaining this goal. Proactive and reactive wellwork will maintain base production and injection rates in existing wells. Selective completion techniques will target sands above the AU. Most of the remaining oil is in these thinner, lower permeability sands, which will only achieve economic production rates with improved completion techniques and/or additional pressure support. Finally, enhancing producer-injector conformance will improve sweep efficiency.

Reservoir simulation models will be used to confirm infill locations. Production and injection infill well locations will be identified and drilled to recover oil banked near faults and oil bypassed between producer rows. Profile modifications will be attempted to improve vertical conformance. Completion techniques will be modified to increase injectivity, minimize reservoir damage, and reduce sanding.

Strategies

The development plan for UP-Ford moving forward includes continued activity in this reservoir. Due to the downturn in oil price, most of the development activity was focused on maintaining base production, increasing injector conformance and drilling low risk high reward producers/injectors. Potential production and injection infill completion candidates will be evaluated, and the best will be selected for inclusion in the drilling schedule based on economic and strategic development criteria. OHSL completions are being evaluated in different parts of the reservoir to see if it’s an economic reliable option for depleting UPF sands. The three OHSL wells drilled in UP-Ford 90 fault block in 2018-2022 showed promising results. Reservoir studies are ongoing to develop long term depletion plans and to reliably forecast future reservoir performance.

The key strategy for realizing optimal development of the UP-Ford zone is understanding its complex reservoir description. Geologic studies addressing sand quality, continuity and distribution, as well as reservoir faulting and stratigraphy, are critical to this effort. Reservoir models combining the best reservoir description and well performance data will help identify regions of high remaining oil saturation as well as regions with sub-optimal waterflood. The current reservoir model will be updated with a focus on adequate characterization of thin bedded sections.

UP-Ford 8 and 90 fault blocks have a reservoir flow model, but additional work needs to be performed to calibrate it better so the results from the development forecast could be used with confidence. The UP-Ford 98 block needs further study utilizing seismic, well log, core and production performance data to quantify future development opportunities as its recovery factor is low. Reservoir description studies will be performed to locate and map the most likely areas of sand development.

The in-zone injection program will expand to improve flood performance in the upper, less mature, reservoir sands. Intelligent and novel completion techniques are being evaluated for capital workover add pays and new completions to increase recovery. Technologies are being tested in CRC and refined to reduce costs while maintaining or improving effectiveness.

Critical Issues

To refine the development plans, focus will be on the following key issues during the Program Plan period:

- Develop northern CRB 45 with infill and fault play producers and injectors to improve the low recovery factor and support CRB 46 development wells by fixing current injectors
- Further leverage well design and completion alternatives for increasing infill well deliverability.
- Full zone and sub zone open hole slotted liner completions are being evaluated.
- Far reach new technologies are being evaluated for UPF add pays as part of the capital workover program.
- Horizontal/slant wells are drilled in AE, AK1 and AO sands currently and will be further tested in AF, AI, AM and AR sands in the future.
- Continue to refine non-reservoir-damaging procedures to complete and work over wells and determine injection water quality requirements.
- Increase pressure support in the upper reservoir sands utilizing in-zone injectors and conformance improvement projects for existing injection wells
- Continue to delineate the Northern down-dip extent of UP-Ford CRB 44 and CRB 45.
- Incorporate any new structural understandings from the reprocessed seismic data towards improved development and reservoir management.

237 Zone
Reservoir Management Plan

History

The 237 Zone underlies the UP-Ford Zone and comprises two distinct sub-zones, an upper clastic interval and a lower shale interval. The lower 237 Zone shale is further subdivided into the Hot Shale and Basal Shale members.

The Hot Shale member of the Lower 237 Zone is a world-class oil source rock. It is correlative with the Nodular Shale of the western Los Angeles Basin. It probably contributed most of the oil trapped within the Long Beach Unit. The Hot Shale contains poorly developed foraminite facies, but this has not been specifically targeted to date.

The Basal Shale is also a good, but lesser quality source rock. It has numerous thin dolomitic interbeds and thin quartz cemented sandstones. These facies tend to be more productive. It is extremely thick in the eastern LBU where it is determined from 3D seismic to be up to 1600 feet thick. This is ten times thicker than the average thickness found across the western Los Angeles Basin.

About 3.0 MMBO has been produced from the 237 Zone shale members from six commercial wells within the LBU. Acoustic basement underlies the 237 Zone shales. These rocks include the Miocene San Onofre Breccia and Cretaceous/Jurassic Catalina Schist basement. These reservoirs have contributed an additional 1.3 MMBO from two LBU wells, one of which had a flowing IP of 1,800 BOPD.

The first 237 Zone well was completed in 1968 at an initial rate of 1,050 BOPD. Twenty more wells have been completed in the LBU. All wells reported oil and gas shows while drilling through the lower 237 Zone. Six of the wells were economic, one was marginally economic, twelve were uneconomic and the most recent two are still being evaluated. One of the wells was a mechanical failure and did not properly evaluate the lower 237 Zone. The uneconomic wells may have been damaged during drilling or lacked sufficient permeability to be productive. Through December 2020, cumulative production from the 237 Zone/acoustic basement is 4.3 MMBO.

In 2006, a 237 team was formed to re-evaluate the unconventional shale play. Using seismic coherency mapping and structural trend measurements taken at local outcrops, well C-250 was proposed. This was the first 237 zone well drilled in the LBU in over 11 years. C-250 targeted the Hot Shale and Basal Shale with acoustic basement as a secondary target. It was completed in December 2007 and flowed for seven months at rates between 750 and 300 BOPD with only a 2 percent water cut. A pump was installed in July 2008 and the well-made 1240 BOPD. Cumulative oil production through the end of December 2016 from well C-250 is 313 MBO. The well is currently idle as there is an ESP cable that needs to be fished out of the well. It has been determined that fishing operations have a very high probability of being unsuccessful, therefore a plan to side track C-250 is being evaluated.

In FY08/09, two additional 237 zone wells were drilled from Island Freeman. These were ranked 3rd and 4th out of five proposed wells to build on the commercial C-250 discovery. They were drilled early in the program owing to cost savings related to rig moves. They targeted a previously drilled high structure, thought to have remaining potential. Well D-720A made 1,440 BWPD and 15 BOPD from the original completion of the lower part of the Basal Shale. It was recompleted in the upper part of the Basal Shale and became a 320 BOPD well.

D-562A was a non-commercial well, having only produced 40 barrels of oil before dying. Multiple near wellbore cleanouts failed to establish production. This well probably lacks adequate permeability.

C355 and C252 were drilled from 2009 to 2011 with not much success. C348 was drilled in 2012 with some success but due to high temperature it was kept down from 2015-2018.

In April 2021, a reciprocating ESP (RESP) was installed in C348; however, the design was not able to economically produce the well. There is no current production from the 237 zone.

Reservoir Management Objectives and Studies

In 2014, the 237 Reservoir Management Team completed a study with a focus on trying to understand what makes an economic 237 producer as opposed to an uneconomic producer. All 237 wells in the LBU were studied. Timing, geologic/structural location, formation open to completion, completion type, completion angle, initial production and cumulative production were all considered. It appears that the formation opens to production, timing, structural position and the completion types are all factors contributing to the economics of an LBU 237 producer. Predicting an economic producer however can be summarized as follows: “The first producer in a fault block, which penetrates greater fracture density (associated with areas of maximum structural flexure) and produces from basement rock will generally be the best producer. Subsequent wells will perform worse than the first. This is likely related to a relatively quick recovery of oil from the fracture network and slow recharge of that network.” The plan forward is to combine all studies and draft a blueprint for 237 future development.

The LBU seismic data is currently being reprocessed to visualize the major fault structure in the 237 zone and relation to historical well locations. Once the reprocessed seismic data is analyzed, a plan of depletion will be developed for the 237 zone with a concept targeting the LBU fault structure where it is believed the most natural fractures exist.

Critical Issues

- Reprocess/Reinterpret LBU seismic data with a focus on the 237 Shale zones and Seismic basement. Re-evaluate economics and risk to review and plan to re-drill C250.
- Identify additional opportunities in structures that may not have been developed.
- Leverage past studies in evaluating truly “unconventional” opportunities in 237.
- Plan a pilot program to test these unconventional opportunities.

Shallow Gas

Reservoir Management Plan

History

An agreement between the State of California, City of Long Beach, and OLBI regarding the development of shallow and deep gas reserves was finalized in 2006.

The bulk of the Shallow Gas reserves reside below Island Grissom with additional proven developed reserves accessible from Island White. Gas shows have been found in wellbores originating on Island Chaffee and Pier J. Development of Shallow Gas reserves began from Island Grissom due to the availability of commercially identifiable reserves for development from this location. Shallow Gas production commenced May 18, 2006 from one well. Development of Shallow Gas from Island White was initiated on February 15, 2010. To date 8 wells have been recompleted as Shallow Gas producers (7 on Island Grissom, 1 on Island White) and one horizontal well has been drilled. As of December 2020, because of economics, the remaining shallow gas zone producer B-403 remains shut-in and plugged.

Status

Cumulative Grissom production through December 2020 totals over 5.9 BCFG (approximately 70% OGIP) in excess of initially estimated ultimate recovery expected to reach over 4.4 BCFG (61.0% OGIP) in 2011 for the Grissom Gas reservoir. The last producing well B-403Z sanded July 2016. Cumulative White Gas production amounts to over 700 MMCF.

Reservoir Management Objectives

The overriding goal of the Shallow Gas Reservoir Management Plan is to maximize the profitability of the reservoir. Three objectives must be attained to achieve this goal. The first is to understand long-term reservoir energy support through pressure monitoring. Understanding the rate of withdrawal to pressure change in the reservoir is fundamental to quantifying recoverable reserves. Secondly, all small gas “stringers” should be tested for viable productivity, which will add to development opportunities and increase the reserves volume if they are commercially productive. Lastly, focus must be on utilizing the most ideally situated idle wellbores for Shallow Gas development to maintain a low-cost development and maximize recovery through existing assets.

Strategies

The A14 and A16 sands are the most prolific. Reservoir studies are being conducted to better understand the connectivity of the shows and extent of the gas in place. These studies will utilize seismic, well logs, and cased-hole reservoir sampling data to quantify extensional development opportunities.

The key strategy for realizing optimal development of the Shallow Gas reservoir is to understand the lateral continuity of the smaller sand sequences. Geologic studies addressing structural uncertainty, continuity and distribution, as well as reservoir faulting and stratigraphy, are critical to this effort.

EXHIBIT C

W 17166

Long Beach Unit

THUMS Long Beach Company

(Agent for Field Contractor)

ANNUAL PLAN

July 1, 2023 through June 30, 2024

ANNUAL PLAN

July 1, 2023 through June 30, 2024

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Part I – Introduction

This Annual Plan (“Plan”) was developed to reflect anticipated activity levels during the fiscal period from July 1, 2023 through June 30, 2024 (“FY24”). It is being submitted as required by Section 5(a) of Chapter 138, Statutes of 1964, First Extraordinary Session, and as revised by passage of Assembly Bill 227 (Chapter 941, Statutes of 1991) and the Optimized Waterflood Program Agreement executed by the State of California, the City of Long Beach, and California Resources Long Beach, Inc. (“CRC”), the Field Contractor.

This Plan provides for drilling, producing, water injection, and other associated activities from offshore and onshore locations. The budget for these activities is grouped into the following five major categories:

Fiscal Year 2024 Plan Category	**($ Million)**
Development Drilling	58.3
Operating Expense	138.4
Facilities, Maintenance, and Plant	58.1
Unit Field Labor and Administrative	38.6
Taxes, Permits, and Administrative Overhead	30.3
Total	323.7

A. Plan Basis

This Plan was developed based on the parameters outlined in the draft Program Plan for the period July 2023 through June 2028 and provides current and updated estimates of volumes, activity levels and expenditures for FY24.

Volumes

Oil and gas production volumes are predicted to average 14.7 Mbopd and 6.8 MMcfpd, respectively, in FY24. Water production for the period is expected to average 1,032 Mbwpd and water injection is expected to average 1,072 Mbwipd.

Revenue and Expenses

A projected realized oil price of $65/bbl and gas price of $3.00/mcf are projected to result in revenues of $357.8 million. Budgeted expenses for FY24 total $323.7 million. Projected net profit in FY24 is $34.0 million.

Drilling

This Plan is based upon 33 replacement wells planned from existing cellars. The Plan sets a drilling pace equivalent to approximately 1.25 drilling rig over the fiscal year. The rig utilization could potentially change due to variations in oil price and program performance and additional funding might be required during the fiscal year. Workover rigs will perform drilling preparation and completion work.

The locations of production and injection wells are consistent with those given in the Program Plan (see attached Part II, Schedule 1B). Injection support for the drilling program will be provided through a combination of capital workovers (add pays and conversions), return to injection of idle injectors, and drill injectors. As per current operational and regulatory practices, injection support will continue to maintain adequate Injection-to-Gross (I/G) ratios to prevent subsidence and improve waterflood sweep efficiency.

Maintenance

The majority of the facility projects anticipated during the Plan period are required to maintain current equipment capabilities or to increase efficiency of current operations. Other projects are planned to take advantage of technological and other improvement opportunities and to address changes in the oil field operating environment.

CRC has a Mechanical Integrity and Quality Assurance (“MIQA”) program to assess and maintain facility equipment and piping in order to ensure safety of personnel, operations, and/or the environment. The MIQA program is designed to meet internal and regulatory requirements and provide a high level of equipment integrity to reduce risk and increase reliability. Key elements include:

- Identification, evaluation, and determination of what equipment and/or process components are critical (i.e., their failure or malfunction could adversely affect the safety of personnel, operations, and/or the environment).
- A process to ensure equipment and components comply with material specifications, design and construction codes or standards thus providing a measure of safety and reliability.
- Methodologies for inspecting, testing and maintaining the equipment and documenting such action.

The MIQA program is an integral piece of the overall flow of maintenance, from inspection/testing through maintenance and, when necessary, repairs or replacement. The program is supported through the use of a comprehensive database and work order system that provides control and management of all maintenance activities.

Projects will be undertaken to repair or replace equipment that is nearing its useful life. Items needing to be repaired or replaced include, but are not limited to, facilities piping, tanks, and vessels. These projects are consistent with past activities to keep the Long Beach Unit ("Unit") facilities in safe operating condition.

Abandonment

Wells and facilities with no further economic use will be abandoned to reduce the long-term Unit liability. This Plan provides funds for plugging wells to surface, in-zone, and conditional abandonments to maintain compliance with the CalGEM Idle Well Management Plan program (PRC 3206).

Safety, Environmental, and Regulatory Compliance

CRC is committed to conducting all aspects of its business in a manner that provides for the safety and health of employees, service providers and the public, and safeguards the environment in which it operates. Key aspects of the safety programs, which include incident reporting and investigation, safety meetings and training, Management of Change, Process Hazard Reviews, emergency response planning and drills, and a behavior-based safety observation program. Key aspects of the environmental program include compliance with applicable laws and regulations, including South Coast Air Quality Management District (SCAQMD) requirements, waste management and minimization, spill prevention plans and Business Emergency Plans.

The effectiveness and compliance of the above programs are assessed through various internal audit programs. In addition, numerous agencies conduct periodic audits, including the CA State Lands Commission, Department of Transportation, State Fire Marshal, SCAQMD, Environmental Protection Agency, Long Beach Fire and Health Departments, Port of Long Beach and City of Long Beach Energy Resources Department. CRC THUMS participated in the re-occurring 5-year Safety and Oil Spill Audit, the main objective of which is to ensure that oil and gas production facilities are operated in a safe and environmentally sound manner. The audit, which started in 2017, was completed July 15, 2020 and showed that CRC THUMS has had continuous improvement in reducing findings and risk from previous audits and embraces the responsibility to provide and maintain a safe and healthy work environment for all employees, and the community.

Emergency response planning and preparedness is bolstered by partnering with Marine Spill Response Corporation (MSRC). MSRC is an independent, non-profit, national spill response company dedicated to rapid response to environmental incidents. MSRC has a major west coast base of operations in the Port of Long Beach and its equipment and expertise are readily available for emergencies and are incorporated in onsite training exercises. The training exercises also involve a close working relationship with the United States Coast Guard and the California Department of Fish and Wildlife.

Environmental and community outreach is also a fundamental part of THUMS program and each of the Islands are currently certified by the Wildlife Habitat Council. In 2022 and beyond, both the Unit and CRC will continue to review opportunities to further this stewardship effort.

Projects relating to safety, environmental issues, or other situations necessary for meeting compliance with code, permit, or regulatory requirements will continue to be implemented under this Plan in accordance with all Unit agreements. In addition, CRC places additional emphasis on risk and system reviews and operational safeguards to assure reliable and compliant environmental performance.

In 2022, Senate Bill 1137 (SB 1137) was proposed to California legislation. SB 1137 prohibits most new or modified oil and gas wells within 3,200 feet of specific locations. It also requires existing wells in these areas to meet specified health, safety, and environmental requirements. The bill passed the California State Assembly and California State Senate in late August and was signed into law in September. A referendum challenging the law collected enough signatures to stay the law until the next general election in 2024 where the public will vote on the bill. If the bill becomes a law, it will likely adversely affect the development plans and maintenance on wells that require permitted operations on wells in Island Grissom, Island White, and Pier J. Incremental operating costs are also anticipated due to the additional monitoring requirements of the law.

Economic Review

Project expenditures during the Plan period are subject to economic review through the Determination and Authority for Expenditure ("AFE") processes. All existing wells are frequently reviewed in light of changing crude prices to determine if they are economic to operate. Well servicing work is justified on economics and other conditions consistent with good engineering, business, and operating practices. CRC remains committed to careful prevention of subsidence through strict adherence to existing regulations and voidage-driven injection requirements.

B. Economic Projections

Table 1, Economic Projections by quarter for FY24

All Figures are in Millions of Dollars

	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	TOTAL FY24
ESTIMATED REVENUE					
Oil Revenue	87.4	87.3	88.1	87.5	350.3
Gas Revenue	1.9	1.9	1.9	1.9	7.4
TOTAL REVENUE	89.2	89.1	90.0	89.4	357.8
ESTIMATED EXPENDITURES					
Development Drilling	10.8	13.3	18.3	15.8	58.3
Operating Expense	36.0	33.3	34.6	34.6	138.4
Facilities & Maintenance	14.5	14.5	14.5	14.5	58.1
Unit Field Labor & Administration	8.9	9.1	10.6	10.0	38.6
Taxes, Permits & Overhead	8.6	6.4	8.8	6.5	30.3
TOTAL EXPENDITURES	78.8	76.7	86.9	81.4	323.7
NET PROFIT	10.5	12.5	3.1	8.0	34.0

C. Major Planning Assumptions

Table 2, Major Planning Assumptions by quarter for FY24

	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	TOTAL FY24
OIL PRODUCTION					
PRODUCED (1000 BBL)	1,344	1,343	1,356	1,347	5,390
(AVERAGE B/D)	14,613	14,596	14,899	14,800	14,727
GAS PRODUCTION					
PRODUCED (1000 MCF)	618	618	624	620	2,479
(AVERAGE MCF/D)	6,722	6,714	6,854	6,808	6,774
WATER PRODUCTION					
PRODUCED (1000 BBL)	94,386	95,704	94,088	93,462	377,640
(AVERAGE B/D)	1,025,932	1,040,257	1,033,934	1,027,059	1,031,803
WATER INJECTION					
INJECTED (1000 BBL)	98,087	99,469	97,813	97,146	392,515
(AVERAGE B/D)	1,066,161	1,081,184	1,074,863	1,067,540	1,072,444
OIL PRICE ($/BBL)	$65.00	$65.00	$65.00	$65.00	$65.00
GAS PRICE ($/MCF)	$3.00	$3.00	$3.00	$3.00	$3.00

Part II – Program Plan Schedules

Schedule 1A

Range of Production and Injection Fiscal Year 24

Long Beach Unit Program Plan, July 2023-June 2028

FISCAL YEAR	OIL RANGE MBOPD	WATER RANGE MBWPD	GAS RANGE MMCFPD	INJECTION RANGE MBWIPD
2023/24	13.7 – 15.5	960 – 1,083	6.3 – 7.1	997 – 1,126

FISCAL YEAR	TAR INJECTION PRESSURE (PSI)	RANGER INJECTION PRESSURE (PSI)	TERMINAL INJECTION PRESSURE (PSI)	UP/FORD INJECTION PRESSURE (PSI)
2023/24	1,500	2,500	2,500	2,500

Schedule 1B

Anticipated Redrill Completions Fiscal Year 24

Long Beach Unit Program Plan, July 2023-June 2028

		Producers	Producers	Producers	Producers	Producers		Injectors	Injectors	Injectors	Injectors	Injectors
Reservoir	**CRB**	**Grissom Min - Max**	**White Min - Max**	**Chaffee Min - Max**	**Freeman Min - Max**	**Pier J Min - Max**		**Grissom Min - Max**	**White Min - Max**	**Chaffee Min - Max**	**Freeman Min - Max**	**Pier J Min - Max**
SG												
Tar	35	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 1
Ranger West	1	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	2	0 - 4	0 - 0	0 - 0	0 - 0	0 - 0		0 - 1	0 - 0	0 - 0	0 - 0	0 - 0
	3	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	4	0 - 4	0 - 0	0 - 0	0 - 0	0 - 1		0 - 1	0 - 0	0 - 0	0 - 0	0 - 1
	5	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	6	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	7	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	8	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	9	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	10	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	11	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	12	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	13	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	36	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	37	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Ranger East	14	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	15	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	16	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	17	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	18	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	20	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	21	0 - 0	0 - 0	0 - 3	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	22	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	33	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Terminal	24	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	38	0 - 3	0 - 0	0 - 0	0 - 0	0 - 0		0 - 1	0 - 0	0 - 0	0 - 0	0 - 0
	39	0 - 3	0 - 0	0 - 0	0 - 0	0 - 0		0 - 1	0 - 0	0 - 0	0 - 0	0 - 0
	40	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	41	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	42	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	43	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	47	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
UP Ford	26	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	27	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	30	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	31	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	44	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	45	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	46	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
237	30	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
				Total						Total		
				0 - 33						0 - 6		

Part III – Itemized Budget of Expenditures

A. Development Drilling $58.3MM

The Development Drilling category of expenditures encompasses all replacement well drilling activity, as well as maintenance and replacement of drilling equipment within the Unit. Funds for development drilling are based on the assumption that 33 wells will be developed during the Plan year using a drilling pace equivalent to approximately 1.25 drilling rig. Additional funding might be required during the year for any incremental drilling activity.

Drilling and completing wells account for majority of the funding provided in this category. Included in these activities is funding for rig move-in, drilling and casing, completion activities, drilling rig in-zone plugs and conditional abandonments, and unscheduled activity (fishing operations, cement squeezing, special logging, contract drilling services).

Exact specifications regarding the distribution of wells, bottom hole locations, and completion intervals will be determined by CRC. These decisions will be influenced by contributions from reservoir engineering personnel, results from ongoing engineering studies, and well performance. This information will be reviewed and approved in accordance with the various unit agreements during regularly scheduled meetings.

B. Operating Expense $138.4MM

The Operating Expense category of expenditures encompasses the ongoing costs of day-to-day well production and injection operations necessary for producing, processing, and delivering crude oil and gas, and for all electric power charges. Expenses for this category are based on estimated oil production of 14.7 Mbopd, estimated gas production of 6.8 MMcfpd, water injection requirement of 1,072 Mbwipd, and water production of 1,032 Mbwpd. Anticipated operating expenses were based on operating five workover rigs per month for servicing an average active well count of 600 producers and 370 injectors. These rigs will also be used for the completion of investment wellwork projects. Funding for idle well testing is also included under this category.

The day-to-day costs for production and injection well subsurface operations represent approximately 32 percent of the funding provided in this category. Included are funds for recompletions, routine well work, well conversions, in-zone plugs, conditional abandonments, and other charges incurred for well maintenance.

Electricity makes up 62 percent of the funds in this category. This cost includes all sources of Unit electrical power, including costs associated with the power plant and electric utility purchases.

C. Facilities, Maintenance, and Plant $58.1MM

The Facilities, Maintenance, and Plant category of expenditures encompasses costs for maintenance, repairs, upgrades, additions of surface facilities and pipelines, and costs for general field services.

Approximately 20 percent of the funding in this category is for general field and operating costs. This includes, but is not limited to, charges for general labor, equipment rentals, and materials for general maintenance (painting, welding, electrical, etc.) of all Unit systems, such as oil gathering, treating, storage, and transfer; gas gathering and treating; scale and corrosion control; produced water handling; waste disposal; leasehold improvements; electrical system; fresh water system; fire protection and safety; marine operations; and automotive equipment. Funds are also provided for chemical purchases and laboratory-related charges for chemical treatment of produced and injected fluids; gas processing charges; make-up water; security; transportation; small tools; and other miscellaneous field activities.

Approximately 40 percent of the funding in this category is for facility repair and minor projects. The majority of the facility repair and project investment is on the Tank and Vessel maintenance program and the remaining investment is focused on inspection, maintenance and repair in support of the MIQA program. This work includes regulated pipeline inspection surveys and evaluation, inspection and repair of cathodic protection systems, and infrastructure piping integrity inspections not covered by regulatory control. Projects include expenditures related to replacement, relocation, or minor expansion of existing injection piping, oil and water pumps and other infrastructure related investments.

D. Unit Field Labor and Administrative $38.6MM

The Unit Field Labor and Administrative category of expenditures encompasses costs for Unit personnel and other Unit support activities.

Funding for Unit personnel includes costs of salaries, wages, benefits, training, and expenses of CRC employees. These costs represent approximately 90 percent of the category total.

Funding for Unit support activities includes, but is not limited to, costs for professional and temporary services necessary for the completion of support activities; charges for data processing; computer hardware and software; communications; office rent; general office equipment and materials; drafting and reprographic services; DOT drug and alcohol testing; special management projects; and other miscellaneous support charges.

E. Taxes, Permits, and Administrative Overhead $30.3 MM

The Taxes, Permits, and Administrative Overhead category of expenditures includes funds for specific taxes, permits, licenses, land leases, and all administrative overhead costs for the Unit.

Funding is provided for taxes levied on personal property, mining rights, and oil production; Petroleum and Gas Fund Assessment; annual well permits and renewals; Conservation Committee of California Oil and Gas Producers Assessment; California Oil Spill Response, Prevention, and Administration fee; land leases; and pipeline right-of-way costs. These costs represent approximately 57 percent of the category total.

Funding is also provided in this category for all Administrative Overhead (including Unit Operator billable costs and CRC billable costs) as called for in Exhibit F of the Unit Operating Agreement.

Part IV – Definitions

This Annual Plan may be Modified or Supplemented after review by the State Lands Commission for consistency with the current Program Plan. All Modifications and Supplements to this plan will be presented by the Long Beach Energy Resources Department, City of Long Beach, acting with the consent of CRC, to the State Lands Commission in accordance with Article 2.06 of the Optimized Waterflood Program Agreement.

In addition, on or before October 1, 2024 the City of Long Beach shall present to the State Lands Commission a final report and closing statement of the FY24 Annual Plan, in accordance with the provision in Section 10 of Chapter 138.

A. Modifications

The City of Long Beach, acting with the consent of CRC, has the authority to cause the expenditures of funds for Unit Operations in excess of the amount set forth in the budget included in the Annual Plan, provided, however, that no such expenditure shall be incurred that would result in any category of expenditures set forth in the budget to exceed 120 percent of the budgeted amount for that category. A budget modification would be required for any expenditures which would cause a budget category to exceed its budgeted amount by 120 percent.

Any transfer of funds between budget categories or an augmentation or decrease of the entire budget may be accomplished by a budget modification in accordance with section 5(g) of Chapter 138 and Article 2.06 of the Optimized Waterflood Program Agreement.

Investment, facilities, and management expense projects commenced in prior budget periods, which are to be continued during the current budget period, may be added to this budget by a modification in accordance with Article 2.06 of the Optimized Waterflood Program Agreement.

B. Supplements

This Annual Plan contains all the investment and expense projects reasonably anticipated at the time the Plan was drafted and for which adequate detailed studies existed. Any significant and uncommon expenses not originally contemplated may be added to this budget or transferred by a supplement in accordance with Article 2.06 of the Optimized Waterflood Program Agreement. The amount of the supplement shall include sufficient funds to complete the projects.

C. Final Report and Closing Statement

The final report and closing statement for FY24 shall contain a reconciliation by category as finally modified and the actual accomplishments, including:

1. Redrill completions by zone.
2. Facilities and capital projects.
3. Production by zone.
4. Injection by zone.

EXHIBIT D

W 17166

Oil Price Comparison

City of Long Beach - Energy Resources