

March 23, 2021

C-5

HONORABLE MAYOR AND CITY COUNCIL
City of Long Beach
California

RECOMMENDATION:

Approve and adopt the Long Beach Unit Annual Plan (July 1, 2021 to June 30, 2022) and the Program Plan (July 1, 2021 to June 30, 2026). (Citywide)

DISCUSSION

In accordance with Chapter 138 of the Statutes of 1964, First Extraordinary Session, an Annual Plan and Program Plan (a five-year plan that is replaced every two years) of Development and Operations and Budget for the Long Beach Unit (LBU) must be adopted by the City of Long Beach (City) and approved by the State Lands Commission (SLC).

Chapter 941, California Legislature, 1991 Sessions, amended Chapter 138 and requires the City and the Field Contractor, California Resources Long Beach, Inc. (CRLBI), to prepare a one-year Annual Plan and Program Plan (Plans) every two years, which includes an itemized budget of intended expenditures.

The Plans provide for the further development of the LBU through the Agreement for Implementation of an Optimized Waterflood Program that was entered into in November 1991 as part of the above legislation. Preparation of the Plans is a joint effort by staff of the City's Energy Resources Department (Unit Operator), CRLBI (Field Contractor), and THUMS Long Beach Company (Agent for Field Contractor). Copies of the Plans are attached.

This matter was reviewed by Deputy City Attorney Richard F. Anthony on February 18, 2021 and by Revenue Management Officer Geraldine Alejo on March 3, 2021.

TIMING CONSIDERATIONS

Chapter 941, California Legislature, 1991 Sessions, also requires that the City submit formal copies of the Plans to the SLC for approval no later than March 23, 2021. To meet that requirement, City Council approval is requested on March 23, 2021.

FISCAL IMPACT

This recommendation has no staffing impact beyond the normal budgeted scope of duties and is consistent with existing City Council priorities. There is no fiscal or local job impact associated with this recommendation.

SUGGESTED ACTION:

Approve recommendation.

Respectfully submitted,



ROBERT M. DOWELL
DIRECTOR OF ENERGY RESOURCES

Attachments: Long Beach Unit Annual Plan
Long Beach Program Plan

APPROVED:



THOMAS B. MODICA
CITY MANAGER

Long Beach Unit

THUMS Long Beach Company (Agent for Field Contractor)



ANNUAL PLAN

July 1, 2021 through June 30, 2022



ANNUAL PLAN

July 1, 2021 through June 30, 2022

Table of Contents

	<u>Page</u>
Part I - Introduction.....	2
A. Plan Basis.....	3
B. Economic Projections.....	7
C. Major Planning Assumptions.....	8
Part II – Program Plan Schedules.....	9
A. Range of Production and Injection.....	9
B. Anticipated Redrill Completions.....	10
Part III – Itemized Budget of Expenditures.....	11
A. Development Drilling.....	11
B. Operating Expense	11
C. Facilities, Maintenance, and Plant.....	12
D. Unit Field Labor and Administrative.....	13
E. Taxes, Permits, and Administrative Overhead.....	13
Part IV – Definitions.....	14
A. Modifications	15
B. Supplements	15
C. Final Report and Closing Statement.....	16

Part I

Introduction

This Annual Plan (“Plan”) was developed to reflect anticipated activity levels during the fiscal period from July 1, 2021 through June 30, 2022 (“FY22”). 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:

Plan Category	Fiscal Year 2022 (\$ Million)
Development Drilling	\$ 33.6
Operating Expense	\$ 84.2
Facilities, Maintenance, and Plant	\$ 33.2
Unit Field Labor and Administrative	\$ 40.4
Taxes, Permits, and Administrative Overhead	\$ 27.7
Total	\$219.1

A. Plan Basis

This Plan was developed based on the parameters outlined in the draft Program Plan for the period July 2021 through June 2026 and provides current and updated estimates of volumes, activity levels and expenditures for FY22.

Volumes

Oil and gas production volumes are predicted to average 14.6 Mbopd and 6.5 MMcfpd, respectively, in FY22. Water production for the period is expected to average 919 Mbwpd and water injection is expected to average 971 Mbwpd.

Revenue and Expenses

A projected realized oil price of \$45.00/bbl and gas price of \$2.90/mcf are projected to result in revenues of \$247.0 million. Budgeted expenses for FY22 total \$219.1 million. Projected net profit in FY22 is \$27.9 million.

Drilling

This Plan is based upon 18 development replacement wells planned from existing cellars. The Plan sets a drilling pace equivalent to approximately 0.75 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 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 2B). 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 4 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 will be necessary 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 critical equipment in order to protect 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 has outlived 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 and reflect a forecasted field life of over 30 years.

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, contractors and the public, and safeguards the environment in which it operates. In 2019, the National Safety Council awarded CRC THUMS Operations with an Occupational Excellence Achievement Award for achieving a lost workday case incident rate better than 50 percent of the industry average. The National Safety Council also awarded CRC THUMS the Perfect Record Award which recognizes an operating area completing at least 12 consecutive months without a company employee receiving an occupational injury or illness that resulted in days away from work. These achievements are further demonstrated in the key safety programs, which include incident reporting and investigation, safety meetings and training, Management of Change (MOC), Process Hazard Reviews (PHR's), 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 (BEP's).

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, South Coast AQMD, 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 Certification in 2020 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.

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

(Data in Millions of Dollars)

	BUDGET FIRST QUARTER FY22	BUDGET SECOND QUARTER FY22	BUDGET THIRD QUARTER FY22	BUDGET FOURTH QUARTER FY22	BUDGET TOTAL FY22
<u>ESTIMATED REVENUE</u>					
Oil Revenue	\$61.5	\$60.8	\$59.0	\$58.8	\$240.1
Gas Revenue	\$1.8	\$1.8	\$1.7	\$1.7	\$6.9
TOTAL REVENUE	\$63.3	\$62.5	\$60.7	\$60.5	\$247.0
<u>ESTIMATED EXPENDITURES</u>					
Development Drilling	\$9.2	\$9.2	\$7.5	\$7.5	\$33.6
Operating Expense	\$21.1	\$21.3	\$20.7	\$21.3	\$84.2
Facilities & Maintenance	\$8.3	\$8.5	\$7.9	\$8.5	\$33.2
Unit Field Labor & Administration	\$10.1	\$10.3	\$9.7	\$10.3	\$40.4
Taxes, Permits & Overhead	\$8.7	\$5.3	\$8.5	\$5.3	\$27.7
TOTAL EXPENDITURES	\$57.4	\$54.6	\$54.3	\$52.9	\$219.1
<u>NET PROFIT</u>	\$5.9	\$8.0	\$6.4	\$7.7	\$27.9

C. MAJOR PLANNING ASSUMPTIONS

	BUDGET FIRST QUARTER <u>FY22</u>	BUDGET SECOND QUARTER <u>FY22</u>	BUDGET THIRD QUARTER <u>FY22</u>	BUDGET FOURTH QUARTER <u>FY22</u>	BUDGET TOTAL <u>FY22</u>
<u>OIL PRODUCTION</u>					
PRODUCED (1000 BBL)	1,366	1,351	1,310	1,308	5,335
(AVERAGE B/D)	14,852	14,682	14,557	14,370	14,616
<u>GAS PRODUCTION</u>					
PRODUCED (1000 MCF)	614	605	586	583	2,388
(AVERAGE MCF/D)	6,675	6,581	6,506	6,407	6,543
<u>WATER PRODUCTION</u>					
PRODUCED (1000 BBL)	86,394	84,642	82,627	81,871	335,534
(AVERAGE B/D)	939,070	920,026	918,075	899,679	919,272
<u>WATER INJECTION</u>					
INJECTED (1000 BBL)	91,211	89,374	87,291	86,375	354,252
(AVERAGE B/D)	991,429	971,462	969,898	949,179	970,554
OIL PRICE (\$/BBL)	\$45.00	\$45.00	\$45.00	\$45.00	\$45.00
GAS PRICE (\$/MCF)	\$2.90	\$2.90	\$2.90	\$2.90	\$2.90

Part II

Program Plan Schedules

Schedule 2A

Range of Production and Injection

Fiscal Year 22

Long Beach Unit Program Plan, July 2021-June 2026

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES											
	OIL MBOPD			WATER MBWPD		GAS MMCFPD		INJECTION MBWPD				
2022	13.6	-	15.3	855	-	965	6.1	-	6.9	903	-	1,019

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2022	1500	2500	2500	2500

Schedule 2 B
Anticipated Redrill Completions
Fiscal Year 22
Long Beach Unit Program Plan, July 2021-June 2026

Reservoir	CRB	Producers					Injectors				
		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		0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
Ranger West	1	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	2	0-0	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	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	5	0-0	0-0	0-0	0-0	0-3	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	0-0	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	0-0	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	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	15	0-0	0-0	0-1	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	16	0-0	0-0	0-1	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	17	0-0	0-0	0-1	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	0-4	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	21	0-0	0-0	0-11	0-0	0-0	0-0	0-0	0-3	0-0	0-0
	22	0-0	0-0	0-4	0-0	0-0	0-0	0-0	0-1	0-0	0-0
	33	0-0	0-0	0-2	0-0	0-0	0-0	0-0	0-1	0-0	0-0
		0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
Terminal	24	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	38	0-0	0-0	0-0	0-0	0-0	0-0	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
		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	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
		0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
		0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
237	30										
		Total					Total				
		0 - 28					0 - 5				

Part III

Itemized Budget of Expenditures

A. Development Drilling **\$33.6MM**

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 18 wells will be developed during the Plan year using a drilling pace equivalent to approximately 0.75 drilling rig. Additional funding might be required during the year for any additional drilling activity.

Drilling and completing wells account for 89 percent 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 **\$84.2MM**

The Operating Expense category of expenditures encompasses the ongoing costs of day-to-day well production and injection operations necessary for producing,

Approximately 18 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 \$40.4MM

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 83 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 \$27.7 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; for the 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 60 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, 2022 the City of Long Beach shall present to the State Lands Commission a final report and closing statement of the FY22 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 FY22 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.

Program Plan

Long Beach Unit
Long Beach, California



July 2021 – June 2026

PROGRAM PLAN

Long Beach Unit (“Unit”)

July 2021 through June 2026

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 2021

TABLE OF CONTENTS

PROGRAM PLAN2

EXECUTIVE SUMMARY2

OVERVIEW.....4

INTRODUCTION.....5

 HISTORY5

UNIT RESERVOIR MANAGEMENT PLAN6

 GOAL.....6

 RESERVOIR MANAGEMENT STRATEGY6

 PRODUCTION AND SURVEILLANCE6

 DEVELOPMENT OPPORTUNITIES7

 TECHNOLOGY7

UNIT FORECASTS9

 ACTIVITY SCHEDULE9

 RATE FORECASTS9

ISSUES AND PROJECTS10

 PEOPLE.....10

 HEALTH AND SAFETY.....10

 ENVIRONMENTAL PROTECTION.....11

 SUBSIDENCE CONTROL.....10

 WELL ABANDONMENT PLAN.....12

 COST MANAGEMENT12

 MECHANICAL INTEGRITY13

 ELECTRICITY GENERATION13

 TAXES13

 MAKE-UP WATER SOURCES14

ECONOMIC SUMMARY.....14

 REVENUE FORECAST14

 COST FORECAST14

 PROFIT FORECAST14

 TABLE 115

 EXHIBIT A.....16

 EXHIBIT B.....17

 EXHIBIT C18

 EXHIBIT D18

 EXHIBIT E.....19

 EXHIBIT F.....20

 SCHEDULE 1 A.....21

 SCHEDULE 1 B.....22

 SCHEDULE 2 A.....23

 SCHEDULE 2 B.....24

APPENDIX 125

 RANGER WEST / TAR26

 RANGER EAST30

 TERMINAL ZONE33

 UPF ZONE37

 237 ZONE40

 SHALLOW GAS.....42

Executive Summary

This Program Plan covers the period from July 1, 2021 through June 30, 2026. 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, 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 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 114 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 FY26. Unit production and injection rates are expected to average 14.6 Mbopd, 919 Mbwpd and 971 Mbwipd in FY22 and 14.1 Mbopd, 868 Mbwpd and 916 Mbwipd in FY23.

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 18 development replacement well projects planned for FY22 of the Program Plan and an oil price of \$45 in FY22 and \$47-\$53 for FY23-26, and a gas price of \$2.90/mcf, total revenue, expenditures, and net profits over the 5-year period of the Program Plan are projected to be \$1,279 million, \$1,101 million, and \$178 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, 2021 through June 30, 2026. 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. Appendix 1 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 *Major 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 \$45 in FY22 and \$47-\$53 for FY23-26 and a realized gas price of \$2.90/mcf. This section also includes the schedules that will be incorporated into the FY22 and FY23 Annual Plans.

Introduction

History

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 subsidence monitoring system is in place and remedial measures would start immediately if significant subsidence 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 1 and 3 rigs through 2014, then reduced over 2015-2017 to a half rig pace. A significant drop in prices resulted in pausing the drilling program early 2020. Rig count and pace are continuously optimized for investment return within the constraints of oil price and the business environment. A rig count of ranging from 0.75 to one is assumed for the Program Plan.

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 of 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 immature 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 4-6% 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, water shut-off techniques, 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.

Unit Forecasts

Activity Schedule

The Program Plan projects recompletions to average approximately 18 development replacement wells in FY22 and 24 development replacement wells in FY23. This schedule can be met with approximately 0.75 rig in FY22 and 1 rig in FY23. Workover rigs will continue to be used as applicable for well completions to capitalize on improved completion quality control and to provide better drilling rig efficiency.

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 FY22 and FY23. 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 FY22 and FY23, 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 vs. time and the trend of water-oil ratio vs. cumulative oil production using conventional decline curve techniques. The resulting prediction shows a near term exponential decline ranging from 9 to 13% per year for the existing wells and a lower decline in later years.

The incremental production contribution for development wells is calculated by adding together type wells. 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 injector type wells are based on average injection rates, peak offset oil and gross response measured in effected wells and reserves. 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 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, contractors and the public, and safeguards the environment in which it operates. In 2019, the National Safety Council awarded CRC THUMS Operations with an Occupational Excellence Achievement Award for achieving a lost workday case incident rate better than 50 percent of the industry average. The National Safety Council also awarded CRC THUMS the Perfect Record Award which recognizes an operating area completing at least 12 consecutive months without a company employee receiving an occupational injury or illness that resulted in days away from work. These achievements are further demonstrated in the key safety programs, which include incident reporting and investigation, safety meetings and training, Management of Change (MOC), Process Hazard Reviews (PHR's), 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 (BEP's).

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, South Coast AQMD, 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 Certification in 2020 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 will be conducted routinely to meet all regulatory requirements and other environmental awareness training is conducted as areas of need are identified.

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 2021 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 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 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 California Geologic Energy Management Division (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 CO₂ 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 have been formed to focus 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 665 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 (BIP).

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.

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 and reclaimed water from Long Beach Water Department (LBWD). 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.

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 \$1,279 million, based on an oil price of \$45 in FY22 and \$47-53 for FY23-26 and a gas price of \$2.90/mcf, and average daily oil and gas production as projected in Exhibit C. Projected revenue for FY22 is expected to be \$247 million.

Cost Forecast

Total estimated expenditures for the first year of this Program Plan are consistent with the FY22 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 \$1,101 million. The projected expenditures for FY22 are \$219 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 \$178 million. Unit profit for FY22 is expected to be \$28 million. A schedule of annual projected revenue, expenditures, and net profit is given in Exhibit A.

Budget commitments for FY23 will be established based on actual results and additional insights gained during FY22.

Table 1 (Planning/Ops)

**SUMMARY OF PRODUCTION AND INJECTION
AS OF DECEMBER 2020
JULY 2021 – JUNE 2026 PROGRAM PLAN, LONG BEACH UNIT**

Reservoir	CRB	Active Well Count		Average Rates for December 2020				Average Well Rates		
		Producers	Injectors	BOPD	BWPD	BIPD	Wtr Cut	BOPD/Well	BWPD/Well	BIPD/Well
SG	65	-	-	-	-	-	-	-	-	-
	66	-	-	-	-	-	-	-	-	-
Tar	35	8	2	140	3,475	6,947	96%	17	434	2,977
Ranger	1	28	21	687	44,369	55,558	98%	25	1,613	2,646
West	2	37	14	1,115	59,242	45,709	98%	31	1,623	3,386
	3	37	23	1,049	76,523	80,982	99%	28	2,068	3,478
	4	47	28	1,183	104,176	111,326	99%	25	2,217	3,959
	5	30	17	921	67,210	64,417	99%	31	2,240	3,716
	7	15	7	363	21,996	18,706	98%	25	1,517	2,672
	8	11	9	249	15,834	17,785	98%	24	1,508	2,092
	9	7	6	170	8,075	9,569	98%	24	1,154	1,595
	10	16	18	388	20,342	27,005	98%	25	1,312	1,543
	11	10	5	245	10,518	6,716	98%	26	1,107	1,493
	12	5	5	115	6,048	4,993	98%	26	1,344	999
	13	10	7	208	15,049	12,997	99%	22	1,584	2,000
36	21	16	648	41,551	50,170	98%	31	1,979	3,136	
37	5	8	214	14,527	22,295	99%	43	2,905	2,787	
Total		275	182	7,555	505,461	528,230	99%	27	1,838	2,899
Ranger	14	10	10	272	16,069	21,565	98%	29	1,691	2,270
	15	37	19	998	61,669	65,943	98%	27	1,690	3,483
	16	13	5	330	16,590	13,775	98%	25	1,276	2,755
	17	26	12	538	26,999	23,004	98%	21	1,038	2,000
	18	7	12	207	12,337	34,549	98%	30	1,762	2,879
	20	14	4	354	14,592	13,121	98%	25	1,042	3,280
	21	31	23	1,040	59,390	62,294	98%	34	1,947	2,760
	22	13	4	304	15,232	12,988	98%	23	1,172	3,247
	32	1	2	11	373	3,402	97%	22	746	2,268
	33	25	14	490	37,104	40,779	99%	20	1,514	2,913
Total		175	103	4,544	260,355	291,419	98%	26	1,492	2,829
Terminal	24	20	13	293	18,904	26,771	98%	15	953	2,137
	38	35	17	920	55,787	54,261	98%	26	1,579	3,113
	39	22	12	528	27,094	31,943	98%	24	1,232	2,662
	40	6	2	83	3,661	1,881	98%	15	666	940
	41	3	3	116	4,055	4,569	97%	41	1,431	1,523
	42	6	5	124	7,451	8,129	98%	21	1,242	1,626
	43	24	13	453	30,288	24,259	99%	19	1,262	1,924
47	2	-	6	428	-	99%	3	234	-	
Total		117	65	2,523	147,668	151,814	98%	22	1,259	2,351
UP/Ford	26	-	1	-	-	465	-	-	-	465
	27	13	3	242	10,415	8,196	98%	18	791	2,569
	31	4	3	21	1,973	2,282	99%	6	538	761
	44	3	7	28	1,877	7,167	99%	9	626	1,024
	45	21	8	398	13,339	8,790	97%	19	635	1,099
	46	25	8	495	22,813	12,513	98%	20	901	1,631
Total		66	30	1,185	50,417	39,413	98%	18	762	1,320
237	30	-	-	-	-	-	-	-	-	
LBU Total		641	382	15,946	967,376	1,017,824	98%	25	1,509	2,664

Exhibit A

ECONOMIC PROJECTIONS July 1, 2021 through June 30, 2026 Program Plan (Million Dollars)

	Fiscal 2021/22	Fiscal 2022/23	Fiscal 2023/24	Fiscal 2024/25	Fiscal 2025/26	Program Plan Period
Estimated Revenue						
Oil Revenue	\$240	\$241	\$247	\$254	\$263	\$1,246
Gas Revenue	\$7	\$7	\$6	\$6	\$6	\$32
Total Estimated Revenue	\$247	\$248	\$254	\$261	\$270	\$1,279
Estimated Expenditures	\$219	\$224	\$220	\$219	\$218	\$1,101
Net Income	\$28	\$23	\$34	\$41	\$51	\$178
Oil Price \$/bbl	\$ 45.00	\$ 47.00	\$ 49.00	\$ 51.00	\$ 53.00	

Exhibit B

Anticipated Completion & Redrill Schedule July 1, 2021 through June 30, 2026 (Number of Wells)

FISCAL YEAR	Tar V	Ranger West	Ranger East	Terminal	UP Ford/237	Total Wells
2021/22	0	0	18	0	0	18
2022/23	0	4	15	1	4	24
2023/24	0	3	12	1	8	24
2024/25	3	6	7	8	0	24
2025/26	0	14	7	3	0	24

Exhibit C

Range of Production Rates July 2021-June 2026 Program Plan Long Beach Unit

FISCAL YEAR	EXPECTED RANGE						EXPECTED RATE					
	OIL MBOPD			WATER MBWPD			GAS MMCFPD					
2021/22	13.6	-	15.3	855	-	965	6.1	-	6.9	14.6	919	6.5
2022/23	13.1	-	14.8	808	-	912	5.8	-	6.5	14.1	868	6.2
2023/24	12.8	-	14.5	778	-	879	5.6	-	6.3	13.8	837	6.0
2024/25	12.7	-	14.3	761	-	860	5.5	-	6.2	13.7	819	5.9
2025/26	12.7	-	14.3	750	-	846	5.4	-	6.1	13.6	806	5.8

Exhibit D

Range of Injection Rates July 2021-June 2026 Program Plan Long Beach Unit

FISCAL YEAR	WATER INJECTION RATE			RANGE OF INJECTION PRESSURES				
	RANGE MBWIPD			EXPECTED MWIPD	TAR PSI	RANGER PSI	TERMINAL PSI	U.P./FORD PSI
2021/22	903	-	1,019	971	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2022/23	852	-	962	916	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2023/24	820	-	926	882	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2024/25	802	-	905	862	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2025/26	789	-	891	848	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500

Exhibit E

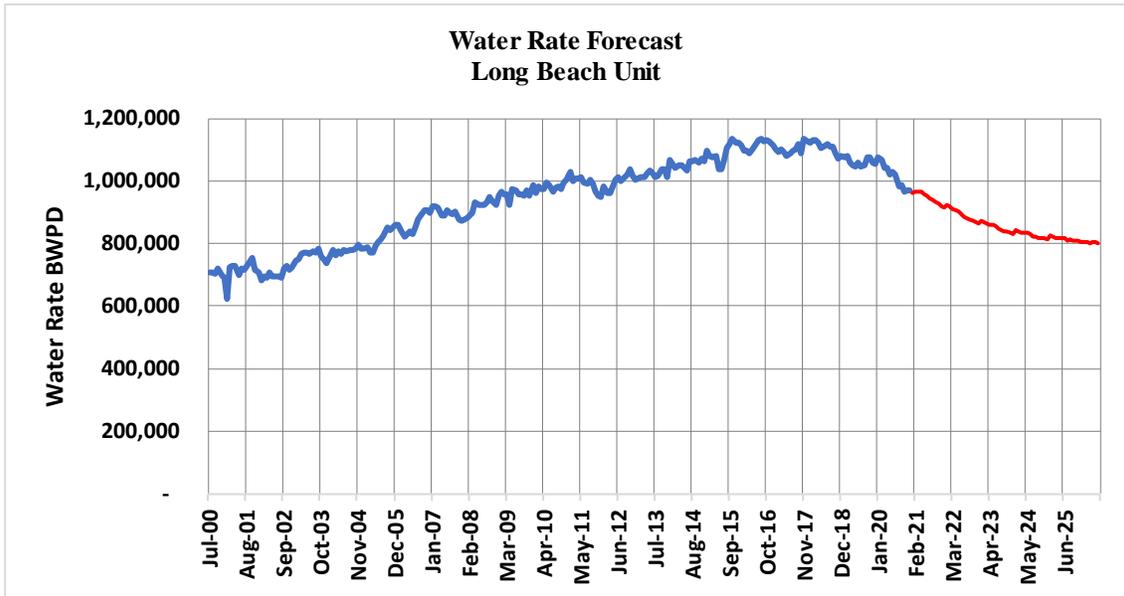
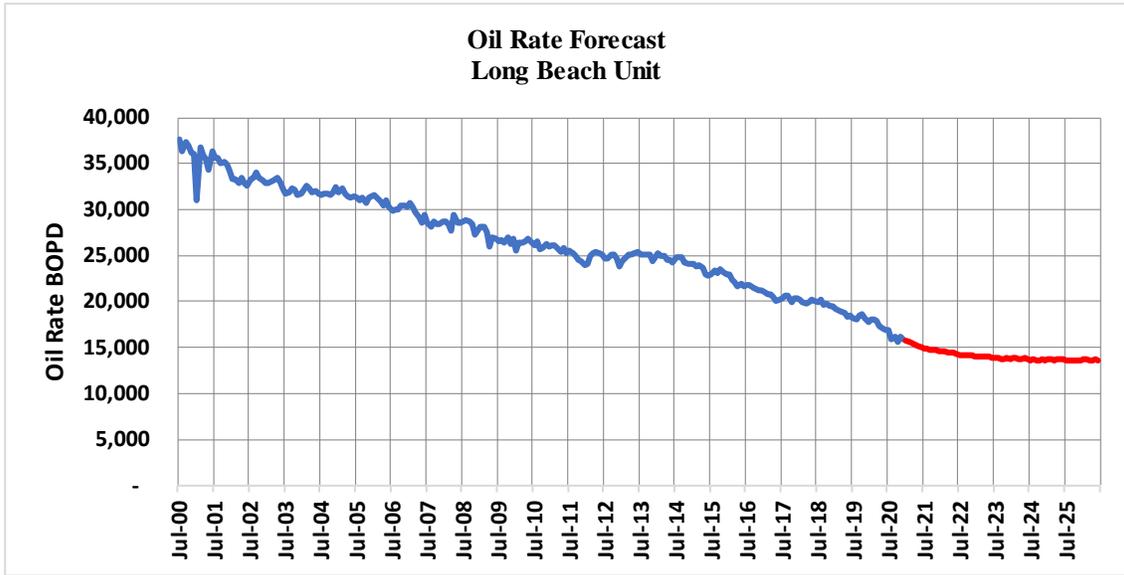
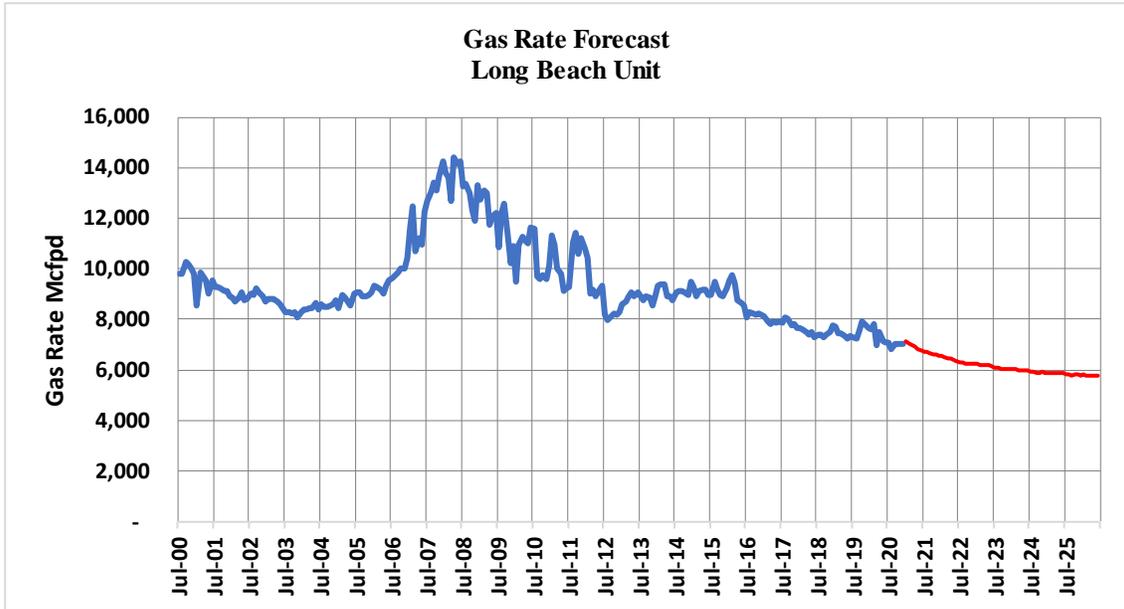


Exhibit F



Schedule 1 A

Range of Production and Injection

FY 22

Long Beach Unit Program Plan, July 2021-June 2026

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES											
	OIL MBOPD			WATER MBWPD			GAS MMCFPD			INJECTION MBWPD		
2022	13.6	-	15.3	855	-	965	6.1	-	6.9	903	-	1,019

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2022	1500	2500	2500	2500

Schedule 1 B

Anticipated New Completions & Redrills Fiscal Year 22 Long Beach Unit Program Plan, July 2021-June 2026

Reservoir	CRB	Producers					Injectors				
		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		0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
Ranger West	1	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	2	0-0	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	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	5	0-0	0-0	0-0	0-0	0-3	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	0-0	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	0-0	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	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	15	0-0	0-0	0-1	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	16	0-0	0-0	0-1	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	17	0-0	0-0	0-1	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	0-4	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	21	0-0	0-0	0-11	0-0	0-0	0-0	0-0	0-3	0-0	0-0
	22	0-0	0-0	0-4	0-0	0-0	0-0	0-0	0-1	0-0	0-0
	33	0-0	0-0	0-2	0-0	0-0	0-0	0-0	0-1	0-0	0-0
		0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
Terminal	24	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	38	0-0	0-0	0-0	0-0	0-0	0-0	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
		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	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
		0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
		0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
237	30										
		Total					Total				
		0 - 28					0 - 5				

Schedule 2 A

Range of Production and Injection FY 23

Long Beach Unit Program Plan, July 2021-June 2026

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2022/23	13.1 - 14.8	808 - 912	5.8 - 6.5	852 - 962

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2022/23	1500	2500	2500	2500

Schedule 2 B

Anticipated New Completions & Redrills Fiscal Year 23 Long Beach Unit Program Plan, July 2021-June 2026

Reservoir	CRB	Producers					Injectors				
		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		0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
Ranger West	1	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	2	0-0	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	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	5	0-0	0-0	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	0-0	0-0	0-2	0-0	0-0	0-0	0-0	0-1	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	0-0	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	0-1	0-0	0-0	0-0	0-0	0-0	0-0
37	0-0	0-0	0-0	0-1	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	0-2	0-0	0-0	0-0	0-0	0-0	0-0
	16	0-0	0-1	0-0	0-3	0-0	0-0	0-0	0-1	0-0	0-0
	17	0-0	0-0	0-11	0-0	0-0	0-0	0-0	0-2	0-0	0-0
	18	0-0	0-0	0-2	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	20	0-0	0-0	0-2	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	21	0-0	0-0	0-4	0-4	0-0	0-0	0-0	0-1	0-1	0-0
	22	0-0	0-0	0-0	0-2	0-0	0-0	0-0	0-0	0-0	0-0
	33	0-0	0-0	0-3	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	0-0	0-0	0-0	0-0	0-0	0-0	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	0-1	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	0-1	0-2	0-0	0-0	0-0	0-1	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	0-1	0-1	0-0	0-0	0-0	0-0	0-0	0-0	0-0
	46	0-0	0-0	0-6	0-1	0-0	0-0	0-0	0-1	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 - 51					0 - 8				

Appendix 1

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 ft. horizontal injector on the north flank. The plan is to extend this south flank injection into a peripheral waterflood. The location of 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.

Status

The Ranger West/Tar production rates as of December 2020 were 7,555 BOPD and 505,461 BWPD (99% water cut) from 275 producers. December 2020 injection was 528,230 BWPD from 182 injectors. Average active well rates were 27 BOPD and 1,838 BWPD for producers and 2,899 BWPD for injectors.

Recovery through December 2020 was approximately 533 MMBO (34% OOIP). The base production in Ranger West reservoir has been declining at around 10% per year. The active development program in 2019-2020 was small due to significant drop in oil prices.

Wilmington Tar V has 8 active producing wells and 2 injectors. December 2020 production is approximately 140 BOPD and 3,475 BWPD (96% water cut). The simulation model estimates OOIP of about 39 million barrels and approximately eight million barrels of oil remaining in the S3/T sands (about 4 MMBO each). As of December 2020, only about 2.5 MMBO of oil was recovered (about 6% OOIP), and less than one hydrocarbon pore volume of water injected.

Calendar Years 2019 and 2020 Activities and Results

Since publication of the last Program Plan, 6 producers (3 horizontal, 3 vertical) have been drilled and completed in the Ranger West and Tar V pools.

The average initial stabilized rate (90-day average) for the producers 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.

A new capital workover strategy consisting of recompleting F0 horizontals in unperforated F0 pay was performed on 6 wells in 2019 and 2020. This workover program was marginally economic with 50 bopd incremental oil and 1300 bgpd gross reduction.

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 251N/664G and 242N/701G respectively. In 2015 and 2016, six additional Tar horizontal wells were drilled and completed with a 90-day production rate of 104 BOPD. The current Tar V production rate is approximately 140 BOPD/3,615 BOPD/25WOR

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 HPVI target of at least 6.0 for each sand in all CRBs. As of December 2020, HPVIs range from 1 to more than 10 on an individual sand basis. As a result, oil recoveries range from values as low as 27% in some CRBs up to 48% 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 bypassed 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 1,500' 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. The additional injection needed to support the new completions will come from

lower cost add-pay injection well work - there are many Ranger and below penetrator options.

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, and 5, 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 2020 Ranger East production is 4,544 BOPD and 260,355 BWPD from 175 active producers. Total water injection is 291,419 BWPD into 103 active injectors. Average active well rates are 26 BOPD and 1,492 BWPD for producers and 2,829 BWPD for injectors.

Cumulative oil production as of December 2020 is 267 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 2019 and 2020 Activities and Results

Since publication of the last Program Plan, 6 horizontal producers and 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 82 BOPD. One injector was drilled during this period.

During the 2019-20 period, a total of 4 development (investment) wellwork jobs were also completed (3 producer and 1 injector). The 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:

- Updating the Ranger East eclipse simulation model with 2015-2020 production and development projects.
- 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 2020, the total production from the Terminal zone is 2,523 BOPD and 147,668 BWPD from 117 active producers. Terminal zone injection for December 2020 is 151,814 BWIPD from 65 wells. Average active well rates were 22 BOPD and 1,259 BWPD for producers and 2,351 BWIPD for injectors. Four 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 2020 totaled 158 MMBO (37% OOIP). Excluding development, base decline has been approximately 12% over the past two years.

Calendar Years 2019 and 2020 Activities and Results

Since publication of the last Program Plan, 6 producers (4 horizontals and 2 verticals) have been drilled and completed in the Terminal pool.

The average initial stabilized rate (3-month average) for the producers drilled is 40 BOPD matching the expected rates.

During the 2019-2020 Plan period, a total of 2 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.

In 2004 and 2005, a reservoir study was conducted to improve the geological and reservoir description of the Terminal Zones and better define the estimation of OOIP. This project resulted in the creation of a streamline reservoir simulation model for the Terminal East area and a second model for Terminal West. These models are and will continue to be used as a directional tool to identify opportunities to maximize recovery from the reservoir.

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. The streamline models will be used to optimize the waterflood and generate development projects for depletion planning. 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).
- Improve structural understanding in TE90 with the reprocessing of the seismic data. With the new interpretation, improve fault play vertical/horizontal development.
- 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).
- Optimize injection by utilizing the results of the improved Streamsim Surveillance model.

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 have 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 2020 were 1,185 BOPD and 50,417 BWPD (98% water cut) from 66 producers. December 2020 injection averaged 39,413 BWIPD from 30 injectors. Average active well rates were 18 BOPD and 762 BWPD for producers and 1,320 BWIPD for injectors

Recovery through December 2020 was 111 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 2019 and 2020 Activities and Results

Since publication of the last Program Plan, three producers have been drilled and completed in the UP-Ford pool. The average initial stabilized rate (3-month average) for the producers drilled is 68 BOPD matching the expected rates.

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 two OHSL wells drilled in UP-Ford 90 fault block in 2018 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 in an attempt 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 December 2018, a new pump designed for high temperature was installed in C348; however, the motor would turn off after a few days due to overload conditions. There is no current production from 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 on C-348 and review 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.