CITY OF LONG BEACH
Gas & Oil
DEPARTMENT

R-27

CHRISTOPHER J. GARNER
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March 3, 2015

HONORABLE MAYOR AND CITY COUNCIL
City of Long Beach
California

RECOMMENDATION:

Approve and adopt the Long Beach Unit Annual Plan (July 1, 2015 - June 30, 2016) and the Program Plan (July 1, 2015 - June 30, 2020). (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 and approved by the State Lands Commission (SLC).

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

The Annual Plan and Program Plan 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 is a joint effort by the staffs of the City of Long Beach, Gas and Oil Department (Unit Operator), CRLBI (Field Contractor), and THUMS Long Beach Company (Agent for Field Contractor). A copy of the Annual Plan and Program Plan is attached.

This matter was reviewed by Deputy City Attorney Richard Anthony on January 29, 2015 and by Budget Management Officer Victoria Bell on February 2, 2015.

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, 2015. To meet that requirement, City Council approval is requested on March 3, 2015.

FISCAL IMPACT

City Council approval of the Annual Plan and Program Plan for transmission to the California State Lands Commission has no fiscal impact or local job impact.

SUGGESTED ACTION:

Approve recommendation.

Respectfully submitted,

CHRISTOPHER J. GARNER
DIRECTOR OF LONG BEACH GAS AND OIL

CJG:Kmt

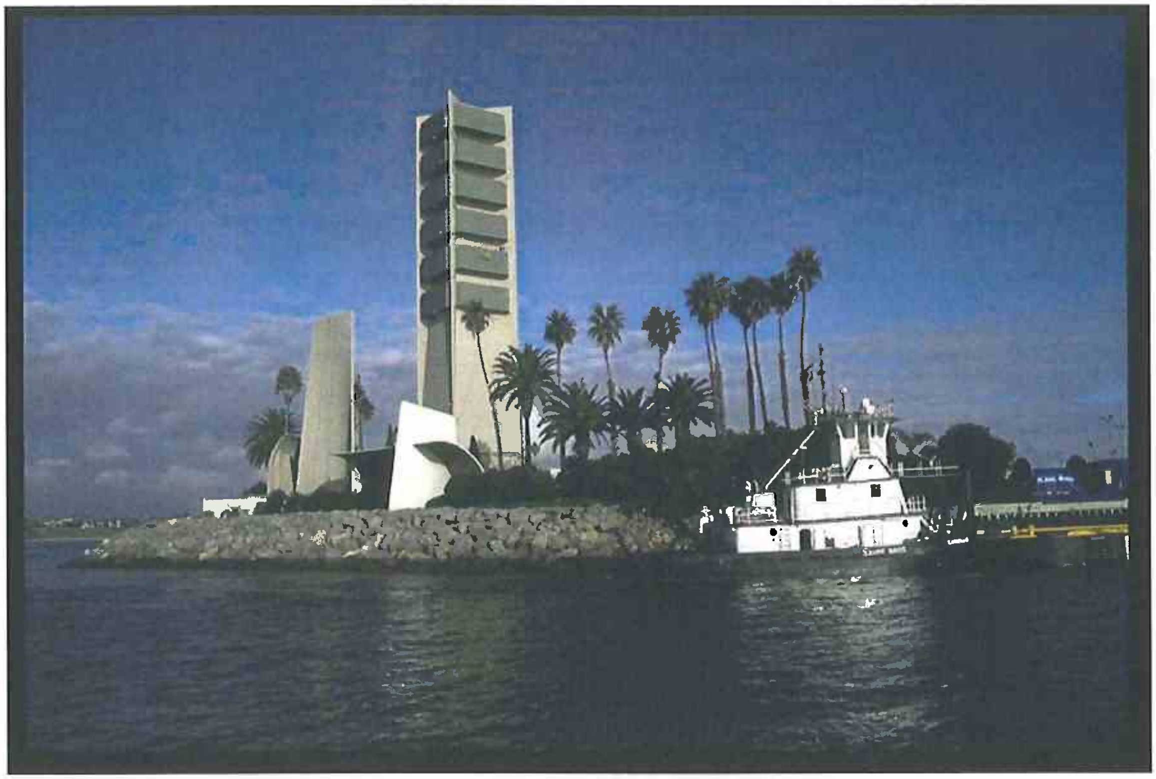
Attachments:
Long Beach Unit Annual Plan
Long Beach Unit Program Plan

APPROVED:

PATRICK H. WEST
CITY MANAGER

Long Beach Unit

THUMS Long Beach Company
(Agent for Field Contractor)



ANNUAL PLAN

July 1, 2015 through June 30, 2016

ANNUAL PLAN

July 1, 2015 through June 30, 2016

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Part I

Introduction

This Annual Plan ("Plan") was developed to reflect anticipated activity levels during the fiscal period from July 1, 2015 through June 30, 2016 ("FY16"). 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 2015 – 2016 ($ Million)
Development Drilling	$ 83.0
Operating Expense	$ 82.8
Facilities, Maintenance, and Plant	$ 79.9
Unit Field Labor and Administrative	$ 31.4
Taxes, Permits, and Administrative Overhead	$ 48.1
Total	$325.2

A. Plan Basis

This Plan was developed based on the parameters outlined in the Program Plan for the period July 2015 through June 2020 and provides current and updated estimates of volumes, drilling activity and expenditures for FY16.

Volumes

Oil and gas production volumes are predicted to average 21.9 Mbopd and 8.8 MMcfd, respectively, in FY16. Water production for the period is expected to average 1,095.8 Mbwpd and water injection is expected to average 1,174 Mbwpd.

Revenue and Expenses

A projected oil price of $45.00/bbl Wilmington and gas price of $3.75/mcf will result in revenues of $371 million. Budgeted expenses for FY16 total $325.2 million. Projected net profit in FY16 is $45.8 million.

Drilling

This Plan allows for drilling approximately 39 new and redrilled development and/or replacement wells. The plan is to use approximately one and one-half drilling rigs. The rig utilization could potentially change due to variations in oil price and program performance. Workover rigs will perform drilling preparation and completion work.

The locations of production and injection wells to be drilled or redrilled are consistent with those given in the Program Plan (see attached Part II, Schedule 2B).

Maintenance

Most of the major facility projects anticipated during the Plan period are required to maintain current equipment capabilities or to enhance operations. Other projects will be necessary to take advantage of 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 to the maximum extent possible. 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.

Many 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 Unit facilities in safe operating condition and reflect a forecast forward field life of 30-40 years.

Abandonment

Wells and facilities with no further economic use will be abandoned to reduce current and future Unit liability. This Plan provides funds for plugging wells to surface, in-zone, and conditional abandonments.

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. Key safety programs 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 all laws and regulations, including South Coast Air Quality Management District (AQMD) requirements, waste management and minimization, spill prevention plans and Business Emergency Plans (BEP's).

The effectiveness and compliance of the above programs are assured through various internal audit programs. In addition, numerous agencies conduct periodic audits, including the CA State Lands Commission, Department of Transportation, State Fire Marshal, AQMD, Environmental Protection Agency, Long Beach Fire and Health Departments, Port of Long Beach and City of Long Beach Gas & Oil Department.

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 California Department of Fish and Game.

Environmental and community outreach is also a fundamental part of THUMS program and each of the Islands is currently designated 'Corporate Lands for Learning' sites by the Wildlife Habitat Council. This designation is awarded to facilities that provide for public education and involvement through wildlife related projects and learning opportunities on the facilities.

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 management of subsidence related to its oil and gas production through strict adherence to existing regulations and voidage rules.

B. Economic Projections

(Data in Millions of Dollars)

	BUDGET FIRST QUARTER FY16	BUDGET SECOND QUARTER FY16	BUDGET THIRD QUARTER FY16	BUDGET FOURTH QUARTER FY16	BUDGET TOTAL FY16
ESTIMATED REVENUE					
Oil Revenue	$93.4	$90.6	$88.1	$86.9	$359.0
Gas Revenue	$3.1	$3.0	$2.9	$3.0	$12.0
TOTAL REVENUE	$96.5	$93.7	$91.1	$89.9	$371.0
ESTIMATED EXPENDITURES					
Development Drilling	$14.2	$14.6	$27.1	$27.1	$83.0
Operating Expense	$21.7	$19.3	$20.9	$20.9	$82.8
Facilities & Maintenance	$17.3	$17.8	$22.4	$22.4	$79.9
Unit Field Labor & Administration	$8.0	$8.0	$7.7	$7.7	$31.4
Taxes, Permits & Overhead	$12.6	$11.5	$12.6	$11.4	$48.1
TOTAL EXPENDITURES	$73.9	$71.3	$90.6	$89.5	$325.2
NET PROFIT	$22.5	$22.4	$0.5	$0.4	$45.8

C. MAJOR PLANNING ASSUMPTIONS

	BUDGET FIRST QUARTER FY16	BUDGET SECOND QUARTER FY16	BUDGET THIRD QUARTER FY16	BUDGET FOURTH QUARTER FY16	BUDGET TOTAL FY16
OIL PRODUCTION					
PRODUCED (1000 BBL)	2,074	2,014	1,959	1,932	7,978
(AVERAGE B/D)	22,547	21,890	21,761	21,228	21,856
GAS PRODUCTION					
PRODUCED (1000 MCF)	827	809	777	788	3,200
(AVERAGE MCF/D)	8,984	8,790	8,630	8,663	8,767
WATER PRODUCTION					
PRODUCED (1000 BBL)	99,523	100,144	99,076	101,189	399,932
(AVERAGE B/D)	1,081,768	1,088,527	1,100,839	1,111,968	1,095,775
WATER INJECTION					
INJECTED (1000 BBL)	106,705	107,307	106,102	108,317	428,430
(AVERAGE B/D)	1,159,835	1,166,375	1,178,915	1,190,295	1,173,855
OIL PRICE ($/BBL)	$45.00	$45.00	$45.00	$45.00	$45.00
GAS PRICE ($/MCF)	$3.75	$3.75	$3.75	$3.75	$3.75

Part II

Program Plan Schedules

Schedule 2 A

Range of Production and Injection
FY16
Long Beach Unit Program Plan, July 2015-June 2020

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2015/16	20.8 - 23.0	1,041.0 - 1,151	8.3 - 9.2	1,126 - 1,244

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2015/16	1500	2500	2500	2500

Schedule 2 B
Anticipated New and Redrilled Wells
Fiscal Year 16
Long Beach Unit Program Plan, July 2015-June 2020

Reservoir	CRB	Producers: Grissom Min - Max	Producers: White Min - Max	Producers: Chaffee Min - Max	Producers: Freeman Min - Max	Producers: Pier J Min - Max	Injectors: Grissom Min - Max	Injectors: White Min - Max	Injectors: Chaffee Min - Max	Injectors: Freeman Min - Max	Injectors: Pier J Min - Max
SG Tar		0 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Ranger West	1	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 3	0 - 0	0 - 0	0 - 0	0 - 0
	2	0 - 2	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 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	5	0 - 1	0 - 0	0 - 0	0 - 1	0 - 0	0 - 1	0 - 1	0 - 0	0 - 1	0 - 0
	7	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	8	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0
	9	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	10	0 - 0	0 - 3	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	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 - 1	0 - 0	0 - 0	0 - 0
	13	0 - 0	0 - 1	0 - 0	0 - 1	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
		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 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	15	0 - 0	0 - 4	0 - 0	0 - 0	0 - 0	0 - 0	0 - 3	0 - 0	0 - 0	0 - 0
	16	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	17	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	18	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	20	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	21	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	22	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0
	33	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
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 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	39	0 - 1	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
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	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 - 1	0 - 0	0 - 1	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 - 2	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 - 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	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		0 - 32					0 - 17				

Part III

Itemized Budget of Expenditures

A. Development Drilling $83.0MM

The Development Drilling category of expenditures encompasses all new well and 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 39 wells will be developed and/or replaced during the Plan year using approximately 1.5 drilling rigs.

Drilling and completing new wells, as well as redrilling and recompleting existing wells, account for 97 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 new well performance. This information will be reviewed and approved in accordance with the various unit agreements during regularly scheduled meetings.

B. Operating Expense $82.8MM

The Operating Expense category of expenditures encompasses the ongoing costs of day-to-day well production and injection operations necessary for producing, processing, and delivering crude oil and gas, and for all electric power charges. Expenses for this category are based on estimated oil production of 21.9 Mbopd, estimated gas production of 8.7 MMcfpd, water injection requirement of 1,174 Mbwpd, and water production of 1,095.8 Mbwpd. Anticipated operating expenses were based on operating four workover rigs per month for servicing an average active well count of 749 producers and 470 injectors. These rigs will also be used for the completion of approximately 25 investment wellwork projects. Abandonment well count will be determined as a function of drilling activity and the number of idle wells with no future use identified.

The day-to-day costs for production and injection well subsurface operations represent approximately 37 percent of the funding provided in this category. Included are funds for recompletions, routine well work, well conversions, in-zone plugs, conditional abandonments, and other charges incurred for well maintenance.

Electricity makes up 63 percent of the funds in this Category. Cost for electric power is based on estimated kilowatt usage of 748,100,000 KWh at an average rate of $0.070/KWh. This cost includes all sources of Unit electrical power, including all costs associated with the power plant and electric utility purchases.

C. Facilities, Maintenance, and Plant $79.9MM

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

Approximately 49 percent of the funding in this category is for general field and operating costs. This includes, but is not limited to, charges for general labor, equipment rentals, and materials for general maintenance (painting, welding, electrical, etc.) of all Unit systems, such as oil gathering, treating, storage, and transfer; gas gathering and treating; scale and corrosion control; produced water handling; waste disposal; leasehold improvements; electrical system; fresh water system; fire protection and safety; marine operations; and automotive equipment. Funds are also provided for chemical purchases and laboratory-related charges for chemical treatment of produced and injected fluids; gas processing charges; make-up water; security; transportation; small tools; and other miscellaneous field activities.

Approximately 51 percent of the funding in this Category is for facilities repair and improvement projects. Approximately 28% of the repair project category 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.

Improvement projects include spending for injection pumps, oil transfer pumps and other infrastructure related investments that position the Unit for longevity.

D. Unit Field Labor and Administrative $31.4MM

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 all CRC employees. These costs represent approximately 90 percent of the Category total.

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

E. Taxes, Permits, and Administrative Overhead $48.1 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 62 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 Gas and Oil 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, 2016 the City of Long Beach shall present to the State Lands Commission a final report and closing statement of the FY16 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.

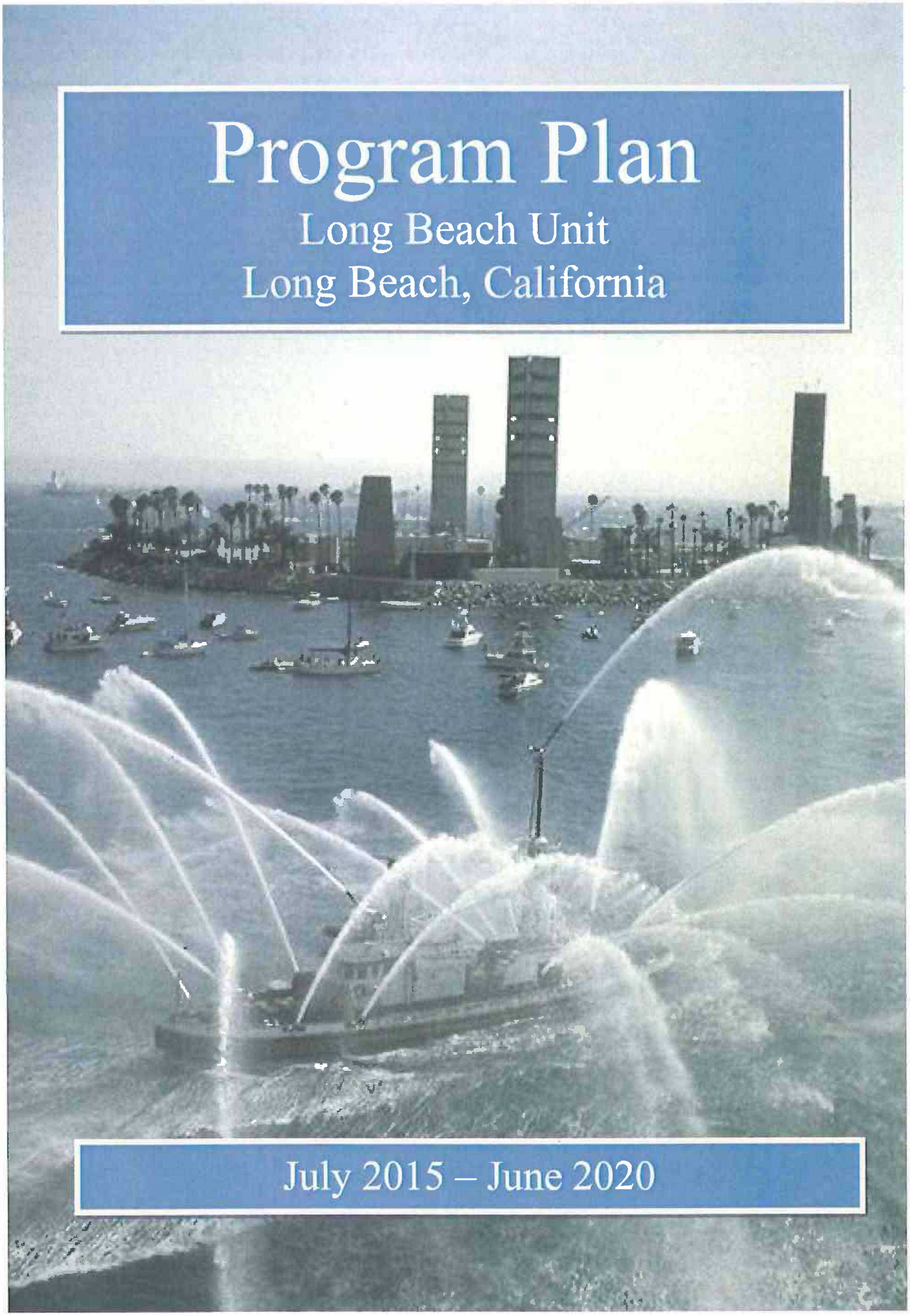
C. Final Report and Closing Statement

The final report and closing statement for FY16 shall contain a reconciliation by category as finally modified and the actual accomplishments, including:

1. New wells and redrills by zone.
2. Facilities and capital projects.
3. Production by zone.
4. Injection by zone.

Program Plan

Long Beach Unit
Long Beach, California



July 2015 – June 2020

PROGRAM PLAN

Long Beach Unit

July 2015 through June 2020

Prepared Jointly by:

Long Beach Gas and Oil Department
City of Long Beach
(Unit Operator)

California Resources Long Beach, Inc.
(Field Contractor)

THUMS Long Beach Company
(Agent for the Field Contractor)

February 2015

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Executive Summary

This Program Plan covers the period from July 1, 2015 through June 30, 2020. The purpose of the Plan is to describe key issues facing the Unit and to outline strategies for maximizing profitability while maintaining excellence in safety and environmental protection. This Plan is the culmination of a cooperative effort by the Long Beach Gas & Oil 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 drilling plans and projected rates of production and injection. The Plan also includes a discussion of key issues facing the Unit, plans for major facility 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 expenses associated with drilling 214 development and replacement wells over the life of the Program Plan. This schedule will result in a steady decline in oil production rate through the end of FY19/20. Unit production and injection rates are expected to average 21.9 Mbopd, 1,095.8 Mbwpd and 1,174 Mbwipd in FY16 and 20.2 Mbopd, 1,148.4 Mbwpd and 1,228.2 Mbwipd in FY17, respectively.

The anticipated development drilling activity is detailed in Exhibit B and the predicted rate curves are shown in Exhibits E and F. This drilling activity encompasses all locations: Pier J, and Islands , Freeman, Grissom and White with the use of Unit rigs T-3, T-5 and T-9, and if needed, 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 new drilling candidates throughout the Plan period. Decisions regarding future drilling activity will be influenced by the quality of the projects identified and prevailing economic conditions.

Facility improvement projects envisioned during the Plan include installation of injection pumps and completion of an oil-transfer pump project. These projects are intended to upgrade and ensure continued, efficient, fluid handling. Other work will focus on piping infrastructure on Island Chaffee. Other improvements are focused on right-sizing facility capacity limits to accommodate the forecast drilling program 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. The first year of the Program Plan also includes funds to design and install injection and vapor-recovery bearing equipment to reduce fresh-water usage.

Based on production from 39 development and replacement well projects planned for FY16 of the Program Plan and an oil price of $45.00 in FY16, $55.00 for FY17, $60.00 for FY18-20 and a gas price of $3.75/mcf, total revenue, expenditures, and net profits over the 5-year period of the Program Plan are projected to be $2,073.7 million, $1,769.5

million, and $304.1 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, 2015 through June 30, 2020. The purpose of this Plan is to describe key issues facing the Unit, and to outline strategies for maximizing profitability 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 drilling 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 an oil price of $45.00 in FY16, $55.00 for FY17, $60.00 for FY18-20 and a gas price of $3.75/mcf. This section also includes the schedules that will be incorporated into the FY16 and FY17 Annual Plans.

Introduction

History

The Long Beach Unit ("Unit") commenced operation April 1, 1965. Since its inception, a major requirement 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 1990's and has ranged between 1 and 3 rigs through 2005. A 3 rig program was utilized through most of 2014. Rig count and pace have been optimized for investment return within the constraints of oil price and the business environment. A rig count between one to two 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 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, Oxy Long Beach was renamed and included as California Resources Long Beach, Inc. in the establishment of a standalone California company, California Resources Corporation ("CRC"), and continues Field Contractor responsibilities.

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 development investment opportunities via the drilling and investment wellwork programs. Development 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. The Unit's Technology Plan identifies technology needs, impacts, and implementation issues. 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 the value from production is maximized. 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 at least once every two years, and obtaining well pressure surveys as required to assess formation pressures. This data forms the cornerstone for reservoir analysis of production trends. THUMS Development and Operations Divisions work jointly to ensure the needed data is obtained in the most cost-effective manner.
- Waterflood performance will be analyzed using standard industry techniques to differentiate between good and poor pattern performance and identify well enhancement opportunities. Techniques used will 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, profile modifications, new drill wells, and stimulations. 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 4-6% overbalance as required. Since July 2006, the LBGO Subsidence Division, along with the THUMS Reservoir Management Team 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 to support semi-annual ground elevation measurements.

Development Opportunities

The Unit has a strategy to invest and minimize the decline of the LBU's oil production rate. To support this strategy, development activities have 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, permanent profile modifications and well stimulation. 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 Reservoir Characterization Group, 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 maintains a Technology Plan that identifies technology needs, impacts, and implementation issues. Operational and technological areas addressed by the Plan 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

Drilling Schedule

The Program Plan projects development and replacement drilling to average approximately 39 wells in FY16 and 49 wells in FY17. This schedule can be met with approximately 1.5 rigs in FY16 and 2 rigs in FY17. Workover rigs will continue to be used for new well completions to capitalize on improved completion quality control and to provide better drilling rig efficiency.

Exhibit B shows the drilling plan by reservoir for the Program Plan period, and the required Schedules 1B and 2B show the anticipated range of development and replacement wells to be drilled into each cut-recovery block during FY16 and FY17. This drilling plan reflects the current understanding of new development well economics. The drilling candidate list is updated annually by the reservoir development teams. Drilling 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, drilling 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 FY16 and FY17, 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 case 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 10 to 13% per year for the existing wells and a lower decline in later years.

The incremental production contribution for new 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 new 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, electrical 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.

The most 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

The most 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

The Unit 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. Key safety programs include incident reporting and investigation, safety meetings and training, Management of Change (MOC), Process Hazard Reviews (PHR), emergency response planning and drills, and a behavior based safety observation program. Key aspects of the Environmental program include compliance with AQMD requirements, waste management and minimization, spill prevention plans and Business Emergency Plans (BEP's).

The effectiveness and compliance of the above programs are assured through internal audit programs. In addition, numerous agencies conduct periodic audits, including the DOT, State Fire Marshal, AQMD, EPA, local fire department and health departments, Port of Long Beach and City of Long Beach.

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. In 2010, MSRC provided the single largest oil spill response effort for the BP Macondo incident. MSRC has a major west coast base of operations in the Port of Long Beach and their equipment and expertise is readily available for Unit emergencies and is incorporated in onsite training exercises. The training exercises also involve a close working relationship with the United States Coast Guard and California Department of Fish and Wildlife.

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, THUMS continues to place emphasis on risk and system reviews and operational safeguards to assure reliable and compliant environmental performance.

In March 2013, the State Lands Commission (SLC) completed a comprehensive 13 month Safety and Environmental audit of the Unit. As noted in the SLC Executive Summary of the audit, the Unit was found to be in 'good condition' and 'free of conditions that represent undue risk'. The audit also noted a greater than 50% reduction in action items compared to the prior Unit audit. In September 2014, the SLC formally recognized the completion of the audit action items with agreement that the final 11 infrastructure improvements would be performed over several years by the continuation of the Unit's existing improvement program. Funding is included in the fiscal plan for these ongoing improvements.

Environmental Protection

The Unit is committed to the protection of the environment and has continued to include this as a key annual goal. All 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 will be 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 the 2015 and beyond, both THUMS 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 LBGO Subsidence Division, along with the THUMS Reservoir Management 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 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. This prudently reduces overall future abandonment liability as well as the potential for detrimental in-zone cross flow.

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 State Division of Oil, Gas and Geothermal Resources. 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 to be efficient in spending its operational funds. Emphasis is given to spending funds wisely, investing in opportunities with the best economic return, and continuing to look for ways to become more efficient in business operations. Employing effective cost management strategies will aid 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 Facility Operations group is accountable for electricity usage, operation of oil, gas and water treating facilities, chemical usage and acquisition of make-up water. Amine Plant operations, used to reduce produced-gas CO_2 levels, will be 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, wellbore maintenance, high demand for quality labor and equipment, increased labor rates, improving safety performance, reducing well failures, 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. 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. These additional equipment could include contract drilling rigs, workover rigs and 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 750 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.

The power plant also provides a means to flexibly optimize the choice of procurement or generation of electricity in a cost-effective manner.

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

The County of Los Angeles has historically significantly increased the assessed value of the Unit. However, given the current price environment, Ad Valorem taxes are estimated to remain flat for the Plan period. 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 Tidelands Oil Production Company produced water and Long Beach Water Department (LBWD) reclaimed water. 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 from the sale of oil and gas from six producing formations: Lower Pliocene shallow gas sands, Tar, Ranger West, Ranger East, Terminal, and UP Ford/237. The projected revenue during the Program Plan period is $2,073.7 million, based on a oil price of $45.00 in FY16, $55.00 for FY17, $60.00 for FY18-20 and a gas price of $3.75/mcf, and average daily oil and gas production as projected in Exhibit C. Projected revenue for FY16 is expected to be $371.0 million.

Cost Forecast

Total estimated expenditures for the first year of this Program Plan are consistent with the FY16 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 $1,769.5 million. The projected expenditures for FY16 are $325.2 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 $304.1 million. Unit profit for FY16 is expected to be $45.8 million. A schedule of annual projected revenue, expenditures, and net profit is given in Exhibit A.

Budget commitments for FY17 will be established based on actual results and additional insights gained during FY16.

Table 1

SUMMARY OF PRODUCTION AND INJECTION
AS OF DECEMBER 2014
JULY 2015 – JUNE 2020 PROGRAM PLAN, LONG BEACH UNIT

		Active Well Count		Average Rates for December 2014				Average Well Rates	
Reservoir	CRB	Producers	Injectors	BOPD	BWPD	BIPD	Wtr Cut	BOPD/Well	BIPD/Well
SG	65	-	-	-	-	-	-	-	-
	66	-	-	-	-	-	-	-	-
Tar	35	7	1	199	1,845	1,968	90%	28	1,968
Ranger	1	33	28	925	52,924	78,137	98%	28	2,791
West	2	33	15	1,069	47,509	46,722	98%	32	3,115
	3	41	22	1,437	86,009	77,275	98%	35	3,513
	4	61	34	1,971	140,454	130,608	99%	32	3,841
	5	35	27	1,300	84,419	91,528	98%	37	3,390
	7	17	6	381	21,922	16,611	98%	22	2,769
	8	15	10	494	23,254	27,760	98%	33	2,776
	9	13	9	368	13,479	17,957	97%	28	1,995
	10	23	19	662	29,541	35,919	98%	29	1,890
	11	12	6	491	13,913	12,378	97%	41	2,063
	12	10	5	271	9,475	11,130	97%	27	2,226
	13	9	6	270	17,090	15,929	98%	30	2,655
	36	26	24	886	42,281	70,462	98%	34	2,936
	37	5	9	253	14,659	27,632	98%	51	3,070
	Total	**340**	**221**	**10,977**	**598,774**	**662,016**	**98%**	**32**	**2,996**
Ranger	14	19	15	868	34,335	42,940	98%	46	2,863
East	15	42	19	1,509	70,826	66,287	98%	36	3,489
	16	16	6	448	14,236	13,097	97%	28	2,183
	17	27	13	896	25,599	23,976	97%	33	1,844
	18	9	16	395	14,998	25,752	97%	44	1,610
	20	15	6	625	17,726	11,728	97%	42	1,955
	21	26	22	1,214	46,126	44,665	97%	47	2,030
	22	14	7	354	12,159	10,440	97%	25	1,491
	32	-	2	-	-	3,611	0%	-	1,806
	33	24	18	913	41,903	37,237	98%	38	2,069
	Total	**192**	**124**	**7,222**	**277,908**	**279,733**	**97%**	**38**	**2,256**
Terminal	24	23	14	517	21,465	29,572	98%	22	2,112
	38	31	17	935	52,616	47,991	98%	30	2,823
	39	20	12	635	24,193	32,487	97%	32	2,707
	40	4	3	63	3,027	2,932	98%	16	977
	41	3	3	155	3,361	6,442	96%	52	2,147
	42	6	5	200	5,220	8,514	96%	33	1,703
	43	27	11	730	28,804	24,187	98%	27	2,199
	47	2	-	30	1,113	-	97%	15	-
	Total	**116**	**65**	**3,265**	**139,799**	**152,125**	**98%**	**28**	**2,340**
UP/Ford	26	-	1	-	-	922	0%	-	922
	27	16	6	490	10,023	9,662	95%	31	1,610
	31	8	2	120	4,611	1,978	97%	15	989
	44	5	8	91	3,203	7,061	97%	18	883
	45	23	14	843	17,698	20,069	95%	37	1,434
	46	23	9	854	23,677	13,346	97%	37	1,483
	Total	**75**	**40**	**2,398**	**59,212**	**53,038**	**96%**	**32**	**1,326**
237	30	-	-	-	-	-	-	-	-
LBU Total		723	450	23,862	1,075,693	1,146,912	98%	33	2,549

Exhibit A

ECONOMIC PROJECTIONS
July 1, 2015 through June 30, 2020 Program Plan
(Million Dollars)

	Fiscal 2015/16	Fiscal 2016/17	Fiscal 2017/18	Fiscal 2018/19	Fiscal 2019/20	Program Plan Period
Estimated Revenue						
Oil Revenue	$359.0	$406.4	$425.1	$415.6	$410.3	$2,016.5
Gas Revenue	$12.0	$11.7	$11.3	$11.1	$11.0	$57.1
Total Estimated Revenue	$371.0	$418.1	$436.4	$426.7	$421.4	$2,073.7
Estimated Expenditures	$325.2	$369.4	$370.3	$378.2	$326.4	$1,769.5
Net Income	$45.8	$48.8	$66.1	$48.5	$95.0	$304.1

Oil Price	$45.00	$55.00	$60.00	$60.00	$60.00	

Exhibit B

Anticipated Drilling Schedule
July 1, 2015 through June 30, 2020
(Number of Wells)

Fiscal Year	Ranger West	Ranger East	Terminal	U.P. Ford/ 237	Total Wells
2015/16	23	12	2	2	39
2016/17	33	6	7	3	49
2017/18	29	10	8	1	48
2018/19	36	1	5	8	50
2019/20	21	2	1	4	28

* See text for a description of the process that will be used to identify and approve all new locations
** Development drilling of proven, risked probable and possible replacement wells

[Type text]

Exhibit C

Range of Production Rates
July 2015-June 2020 Program Plan
Long Beach Unit

FISCAL YEAR	EXPECTED RANGE			EXPECTED RATE		
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	OIL MBOPD	WATER MBWPD	GAS MMCFPD
2015/16	20.8 - 23.0	1,041 - 1,151	8.3 - 9.2	21.9	1,095.8	8.7
2016/17	19.2 - 21.3	1,091 - 1,206	8.1 - 9.0	20.2	1,148.4	8.5
2017/18	18.4 - 20.4	1,130 - 1,249	7.9 - 8.7	19.4	1,189.6	8.3
2018/19	18.0 - 19.9	1,164 - 1,286	7.7 - 8.5	19.0	1,225.1	8.1
2019/20	17.8 - 19.6	1,193 - 1,318	7.6 - 8.4	18.7	1,255.6	8.0

Exhibit D

Range of Injection Rates
July 2015-June 2020 Program Plan
Long Beach Unit

FISCAL YEAR	WATER INJECTION RATE		RANGE OF INJECTION PRESSURES			
	RANGE MBWPD	EXPECTED MBWPD	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2015/16	1,126 - 1,244	1,174	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2016/17	1,177 - 1,301	1,228	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2017/18	1,218 - 1,346	1,271	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2018/19	1,253 - 1,385	1,307	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2019/20	1,283 - 1,418	1,339	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500

Exhibit E


Oil Rate Forecast
Jul-2015 TO Jun-2020
Long Beach Unit
Oil Rate BOPD
40000
35000
30000
25000
20000
15000
10000
5000
0
07/01/2000
07/01/2001
07/01/2002
07/01/2003
07/01/2004
07/01/2005
07/01/2006
07/01/2007
07/01/2008
07/01/2009
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07/01/2016
07/01/2017
07/01/2018
07/01/2019

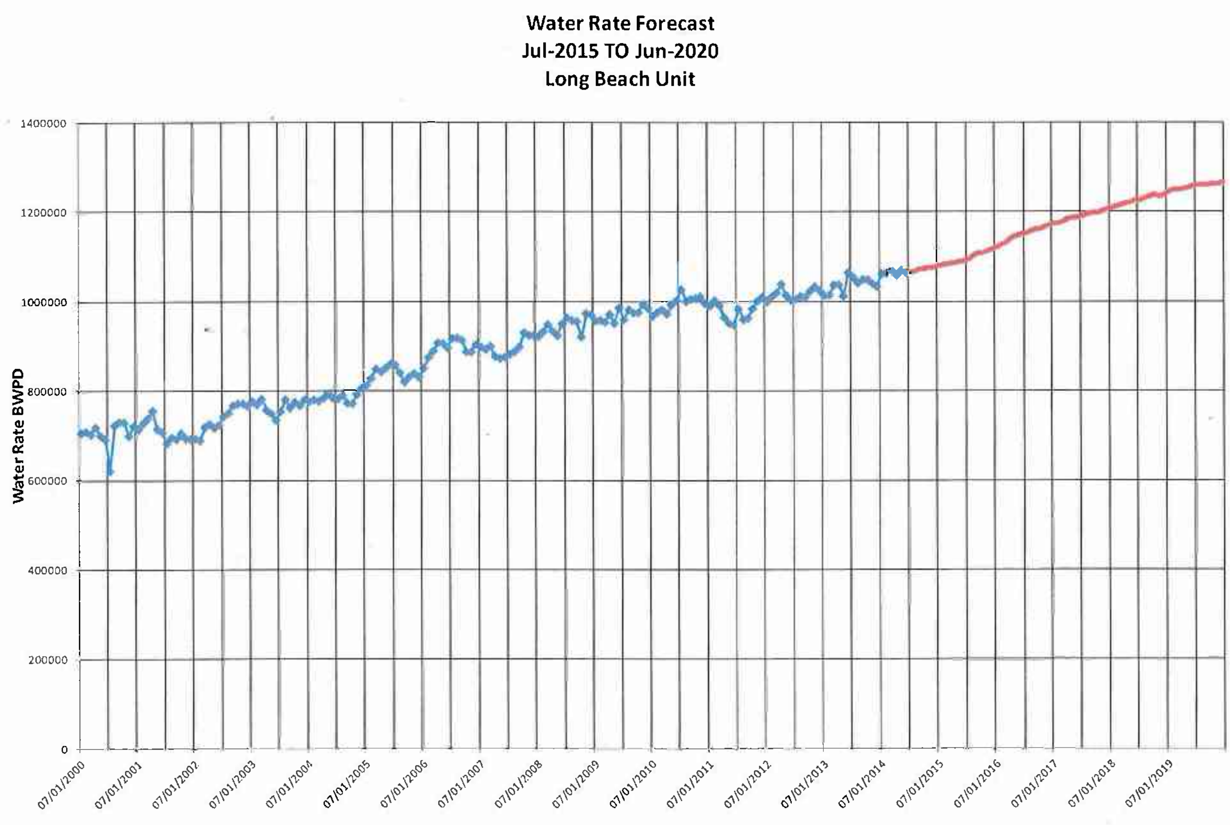
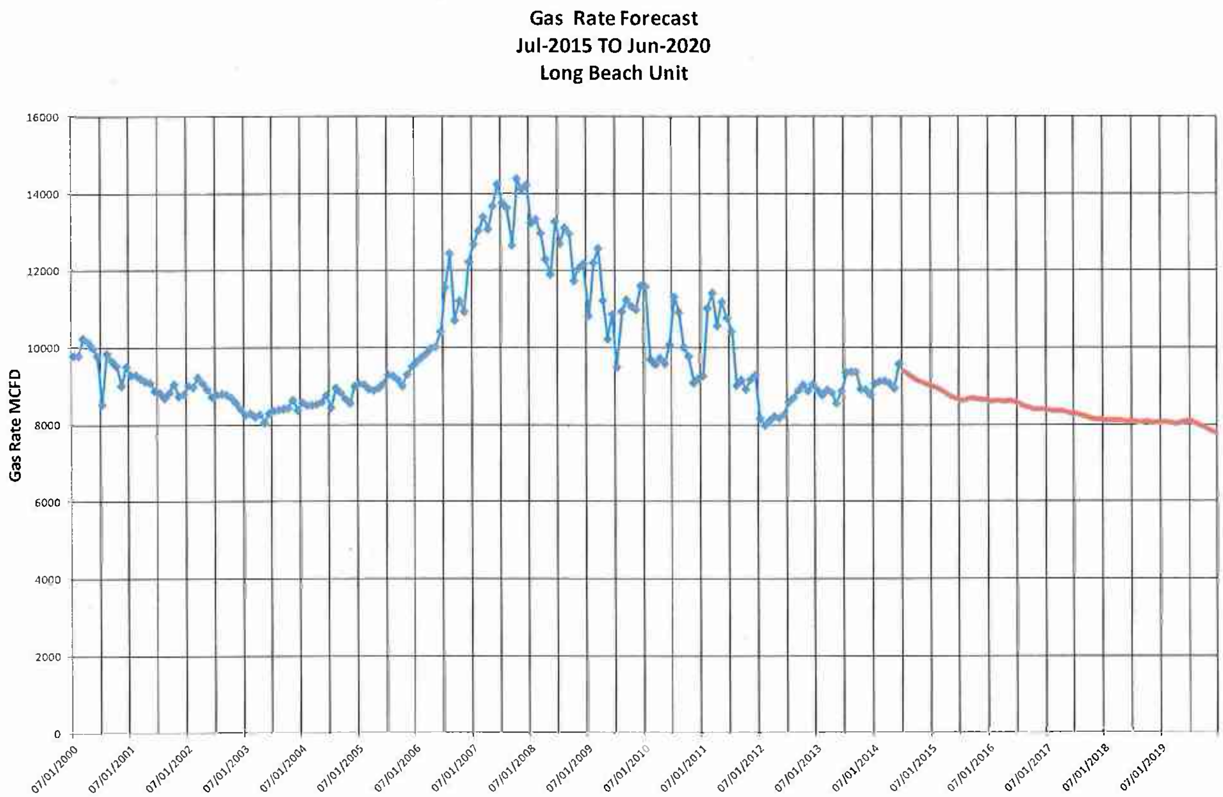

Water Rate Forecast
Jul-2015 TO Jun-2020
Long Beach Unit
Water Rate BWPD
1400000
1200000
1000000
800000
600000
400000
200000
0
07/01/2000
07/01/2001
07/01/2002
07/01/2003
07/01/2004
07/01/2005
07/01/2006
07/01/2007
07/01/2008
07/01/2009
07/01/2010
07/01/2011
07/01/2012
07/01/2013
07/01/2014
07/01/2015
07/01/2016
07/01/2017
07/01/2018
07/01/2019

Exhibit F


Gas Rate Forecast
Jul-2015 TO Jun-2020
Long Beach Unit
Gas Rate MCFD
16000
14000
12000
10000
8000
6000
4000
2000
0
07/01/2000
07/01/2001
07/01/2002
07/01/2003
07/01/2004
07/01/2005
07/01/2006
07/01/2007
07/01/2008
07/01/2009
07/01/2010
07/01/2011
07/01/2012
07/01/2013
07/01/2014
07/01/2015
07/01/2016
07/01/2017
07/01/2018
07/01/2019

Schedule 1 A

Range of Production and Injection
FY 16
Long Beach Unit Program Plan, July 2015-June 2020

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2015/16	20.8 - 23.0	1,041.0 - 1,151	8.3 - 9.2	1,126 - 1,244

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2015/16	1500	2500	2500	2500

Schedule 1 B

Anticipated Development and Replacement Locations
Fiscal Year 16
Long Beach Unit Program Plan, July 2015-June 2020

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 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Ranger West	1	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 3	0 - 0	0 - 0	0 - 0	0 - 0
	2	0 - 2	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 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	5	0 - 1	0 - 0	0 - 0	0 - 1	0 - 0	0 - 1	0 - 1	0 - 0	0 - 1	0 - 0
	7	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	8	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0
	9	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	10	0 - 0	0 - 3	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	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 - 1	0 - 0	0 - 0	0 - 0
	13	0 - 0	0 - 1	0 - 0	0 - 1	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
		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 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	15	0 - 0	0 - 4	0 - 0	0 - 0	0 - 0	0 - 0	0 - 3	0 - 0	0 - 0	0 - 0
	16	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	17	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	18	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	20	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	21	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	22	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0
	33	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
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 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	39	0 - 1	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 - 1	0 - 0	0 - 1	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 - 2	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 - 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	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 - 32					0 - 17				

Schedule 2 A

Range of Production and Injection

FY 17

Long Beach Unit Program Plan, July 2015-June 2020

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES										
	OIL MBOPD			WATER MBWPD			GAS MMCFPD			INJECTION MBWPD	
2016/17	19.2	-	21.3	1,091.0	-	1,205.9	8.1	-	9.0	20.3	8.5

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2016/17	1500	2500	2500	2500

Schedule 2 B

Anticipated Development and Replacement Locations
Fiscal Year 17
Long Beach Unit Program Plan, July 2015-June 2020

Reservoir	CRB	Producers					Injectors				
		Grissom	White	Chaffee	Freeman	Pier J	Grissom	White	Chaffee	Freeman	Pier J
		Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max
SG Tar		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2
Ranger West	1	0 - 4	0 - 0	0 - 0	0 - 0	0 - 0	0 - 6	0 - 0	0 - 0	0 - 0	0 - 0
	2	0 - 3	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0
	3	0 - 3	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2
	4	0 - 1	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 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 1
	7	0 - 0	0 - 0	0 - 0	0 - 1	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 - 1	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 - 2	0 - 1
	37	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	0 - 0	0 - 0	0 - 0	0 - 0
Ranger East	14	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	15	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	16	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	17	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	18	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	20	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	21	0 - 0	0 - 0	0 - 0	0 - 5	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0
	22	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	33	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		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 - 2	0 - 0	0 - 0	0 - 0	0 - 2	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0
	40	0 - 1	0 - 0	0 - 0	0 - 1	0 - 0	0 - 2	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 - 1	0 - 0	0 - 0	0 - 0	0 - 4	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 - 2	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	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 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	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 - 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	0 - 0	0 - 0	0 - 0	0 - 0
237	30	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		Total					Total				
		0 - 37					0 - 25				

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 24-56. In the less mature northern blocks, oil recoveries range from 27-32% with WORs of 26-27.

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 CRB's 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.

The Ranger West pool is also peripherally flooded from the north and south aquifers. The southern aquifer appears to be bounded allowing peripheral injection to be effective in supporting up-dip producers. The northern aquifer appears to be unbounded providing less effective support from aquifer injection (based on production performance, pressure histories, and full-field reservoir simulation studies).

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 through point exits 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.

Since 1992, a successful development drilling program in CRB-1 has resulted in increased water throughput and oil production. CRB-1 oil production increased from a low of 2690 BOPD in April 1992 to a high of 6350 BOPD in September 1994. Additional development is needed to further optimize the waterflood patterns in CRB-1.

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 STB/D. The completion types consist of vertical (S3/T sand), slant (S3/T sands), and horizontal wells (S3 sand). The waterflood consist of only one injector on the south 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. The injection/production and pressure history indicates an active aquifer is present.

Status

The Ranger West/Tar production rates at the end of December 2014 were 11.0 MBOPD and 598.8 MBWPD (98.2% water cut) from 340 producers. December 2014 injection was 662.0 MBWPD from 221 injectors. Average active well rates were 32 BOPD and 1761 BWPD for producers and 2996 BWPD for injectors. Ranger West currently has 58 inactive wells that have not been plugged in zone. 53 of these wells are being evaluated for repair, conversion or redrill.

Recovery through December 2014 was 514 MMBO (32.6% OOIP). While the base production in Ranger West reservoir has been declining at around 11% per year, the active development program in 2013-2014 has added an average of approximately 1293 BOPD annually.

Wilmington Tar V has seven active producing (two horizontals) wells and one injector. December 2014 production is approximately 199 BOPD and 1845 BWPD (90.3% water cut). The simulation model estimates OOIP of about 39 million barrels and eight million barrels of oil remaining in the S3/T sands (about 4 MMBO each). As of December 2014, only about 2 MMBO of oil was recovered (5% OOIP), and less than one hydrocarbon pore volume of water injected.

Calendar Years 2013 and 2014 Activities and Results

Since publication of the last Program Plan, 46 producers (14 horizontal, 21 conventional, 4 hybrid, and 7 cased-hole completions) and 18 injectors have been drilled and completed in the Ranger West pool.

The average initial stabilized rate (3 month average) for the producers drilled in the Ranger West Pool is 69 BOPD with initial rates ranging from 4 BOPD to 153 BOPD. This rate is better than the anticipated average rate of 67 BOPD. The average initial stabilized production rate is 99 BOPD for the horizontal completions, 65 BOPD for the conventional completions, 29 BOPD for the cased-hole completions, and 43 BOPD for the hybrid completions. The injection wells drilled during this period were selectively perforated in specific intervals with historically low waterflood throughput and relatively high remaining oil saturation. Average well injection rates in 2013 were 2289 BWIPD compared with the expected rate of 2312 BWIPD. In 2014 projects performed above AFE. Average well injection rates of 2012 completions averaged 2779 BWIPD compared to an expected 2292 BWIPD. Overall, Projects completed from 2013-2014 outperformed AFE expectations.

During the 2013-2014 Plan period, a total of 22 development (investment) wellwork jobs were also completed (8 producers and 14 injectors). Three of the producer development projects were selective recompletions/add pay projects and five were recompletions to the Ranger zone targeting bypassed oil sands. Overall, the producer development wellwork has been successful, averaging about 17 BOPD/job at a cost of $471,125 per job. The injector development wellwork projects included seven convert to injectors and seven profile modifications and add pay projects. The injection work targeted increasing water throughput in selective sands and pattern areas. Injection development wellwork projects contributed an average of 2615 BWIPD of injection per well at an average cost of $320,500 per job.

Maintenance wellwork continues to play a major role in maximizing Ranger West base production. During 2013-2014, approximately 88 producer maintenance wellwork projects at a cost of $75,281/job were performed. 187 injector maintenance projects were also completed at an average cost of $14,052/job.

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. Wells A642 and A753 January 2015, production rates are 57N/594G and 66N/528G respectively.

Reservoir Management Objectives

The primary reservoir management objective is to maximize the profitability of the Ranger West pool. Maximum profitability will be achieved by increasing recovery in underdeveloped blocks through 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 CRB's. As of December 2014, 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 CRB's up to 48% in other CRB's. By ensuring that each sand reaches an HPVI target of at least 6.0, oil recoveries for individual sands should reach a minimum of 30-33% for an overall recovery in excess of 40% for the Ranger West sand. In the more mature blocks, maximum profitability will be achieved through minimizing the volume of low value water cycling, directing water to the remaining economic reservoir targets and targeting by-passed oil pockets with development drilling and investment wellwork projects. In the absence of economic options, idle wells will be abandoned to reduce future abandonment liabilities and reservoir crossflow. Risk of subsidence will be minimized in all reservoir management actions.

Strategies

The Ranger West development plan includes drilling an additional 23 development wells and performing 13 investment wellwork projects in FY15/16. The development plan will be implemented under the guidance of the reservoir management objectives discussed above. The best new drilling and 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 CRB's 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.

Because of the TAR zones 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, drill these horizontal wells at least 2,000' in length and keep approximately 250' spacing between the wells. The optimal drilling orientation is alternating toe/heel. The additional injection needed to support the new wells is planned to 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 thru G6), by using dual-string and selectively perforated injectors.
- Optimize the Ranger West waterflood through subzoning 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 look for 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, 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, primarily 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 subzoning 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 southern flank and the structural crest of the reservoir. The aquifer along the southern flank is effectively bounded, and the adjacent CRB-21 area has seen good pressure support and sweep from the peripheral injectors. Similarly, the crestal areas have benefited from a combination of downdip support from the aquifer 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 aquifer is not well bounded and communicates with the Seal Beach field downstructure. A significant portion of the peripheral injection in CRB's 14, 16, 17, and 18 has been lost to the aquifer, 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 leaseline between Ranger East and the Belmont Offshore field, loss of reserves probably occurred until after the Belmont Field ceased producing in 1992.

Status

As of December 2014, Ranger East production is 7,222 BOPD and 277,908 BWPD from 192 active producers. Total water injection is 279,133 BWPD into 124 active injectors. Average active well rates are 38 BOPD and 1,447 BWPD for producers and 2,256 BWPD for injectors. Ranger East currently has 37 wells that are mechanically idle but are capable of reactivation with further investment. The team is currently evaluating the repair and/or conversion options for these wells.

Cumulative oil production as of December 2014 is 254.3 MMBO (32.3% OOIP). Since the last reporting period in November 2012, the total oil production has remained relatively flat including development. Excluding development, base decline has been approximately 15% over the last two years.

Calendar Years 2013 and 2014 Activities and Results

Since publication of the last Program Plan, 34 producers (10 horizontal/slants and 24 conventional vertical wells) and 14 injectors (2 single string vertical cased injectors and 12 dual string vertical cased injectors) have been drilled and completed in the Ranger East pool.

The average initial stabilized rate (3 month average) for the producers drilled in the Ranger East Pool is 81 BOPD with initial rates ranging from 20 BOPD to 530 BOPD. The injection wells drilled during the 2013-2014 period were selectively perforated in specific intervals with historically low waterflood throughput and relatively high remaining oil saturation. Most of the injection wells met injectivity expectations with an average injection rate of 2200 BWPD.

During the 2013-2014 Plan period, a total of 21 development (investment) wellwork jobs were also completed (12 producers and 9 injectors). All of the producer development projects were selective recompletions/add pay projects targeting bypassed oil sands. Overall, the producer development wellwork has been successful with the projects averaging about 33 BOPD/job at a cost of $406,000 per job. The injector development wellwork projects included 6 convert to injectors and 3 profile modifications/add pay projects. The injection work targeted increasing water throughput in selective sands and pattern areas. Injection development wellwork projects contributed an average of 1,800 bpd of injection per well at an average cost of about $207,000 per job.

Maintenance wellwork continues to play a major role in maximizing Ranger East base production. During 2013-2014, approximately 97 producer maintenance wellwork projects at a cost of about $86,000/job were performed. 341 injector maintenance projects were also completed at an average cost of about $16,900/job.

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 38.4. 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. Another challenge is the optimal placement of injectors in the highly faulted Ranger East pool. Producer to injector conversions and injector recompletions have been done to improve sweep efficiency.

Production rates are maximized by selective acidization of active wells, or in conjunction with other wellwork. In addition, increasing pump size and using variable speed drives to increase well drawdown assure 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 development drilling wells on Chaffee, Freeman, and White. A new focus is on F0, FJ and M1 horizontals to try and prove up this technology in Ranger East. Several investment wellwork projects are also planned. These projects will target insufficiently swept pay.

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.

This year a new Ranger East simulation model was built using Eclipse software. The new model was undertaken 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 with 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 new model is currently being fine tuned and should be fully operational within the next few months.

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:

- Finish new Ranger East eclipse simulation model.
- Complete Plan of depletion (POD) 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 prudent application of acid stimulation, wellwork, and drilling.
- 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.

Terminal Zone
Reservoir Management Plan

History

The Terminal zone is about 1000 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 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 in the aquifer, 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 2014, the total production from the Terminal zone is 3,265 BOPD and 139,799 BGPD resulting in an average WOR of 43. There are currently 116 active producers. Terminal zone injection for December 2014 is 152,125 BWIPD from 65 wells. Average active well rates were 28 BOPD and 1,205 BWPD for producers and 2,340 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 2014 totaled 151.1 MMBO (32.6% OOIP (436 MMBO- D&M 2005)). Excluding development, base decline has been approximately 12 % over the past two years.

Calendar Years 2013 and 2014 Activities and Results

Since publication of the last Program Plan, nine producers (four cased-hole completion verticals, five open-hole completion Horizontals) and four injectors (one single string, three dual-string injector) have been drilled and completed in the Terminal pool. Eight wells have been drilled in Terminal West (including all five horizontals and three injectors) and the other two wells have been drilled in Terminal East.

The average initial stabilized rate (3 month average) for the vertical producers drilled is 55 BOPD with initial rates ranging from 20 BOPD to 108 BOPD. The average expected rate is 71 BOPD (note the completion strategy of some projects have been changed due to the pressure distribution which reduced the expected rate to a lower number). The average initial stabilized rate (3 month average) for the horizontal producers drilled is 55 BOPD with initial rates ranging from 40 BOPD to 131 BOPD. The average expected rate is 73 BOPD. The injection wells drilled during the 2013-2014 period were selectively perforated in specific intervals with historically low waterflood throughput and relatively high remaining oil saturation. The average initial injection rate is 2050 BWIPD.

During the 2013-2014 Plan period, a total of 4 development (investment) wellwork jobs were also completed (two producers, two injectors). The investment projects were selective recompletions/add pay projects. Overall, the producer development wellwork has returned an average of 75 BOPD/job at a cost of $400,000 per job. The injector wellwork projects were an add pay that increased the reservoir energy in TE faultblock 90S. 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 new 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. An improved history match is currently being worked on for the Terminal West model. This will improve our capabilities in managing the asset and comes at an opportune time as we plan to drill development projects from Island Grissom and Pier J in the short-term future.

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 new 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. Several investment wellwork projects are also planned. These objectives will be met by utilizing the various Unit programs currently in-place. The best new production and injection infill well 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 is to improve 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 in a vertically spaced manner. 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 also be focus areas for 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.

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. 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:

- Annually 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 in 1st half of 2015.
- Improve vertical conformance in UT6 CRB-38 through selective drilling of new cased hole producers, injectors, and conformance-improving workovers.

- Identify areas of bypassed oil and exploit via horizontal completions in Terminal West & East. (using the recent UPF pass through (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 exploitation.
- 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 UT6.
- Develop proper waterflood pattern closure and improve the injection throughput into under-injected sands by prudent application of acid stimulation, wellwork, and drilling.
- Continue on finding producer acid candidates (Terminal has the most successful acid jobs among East Reservoir Management Team).
- Optimize injection by utilizing the results of the improved Streamsim Surveillance model.

UPF Zone
Reservoir Management Plan

History

The UP-Ford Zone has produced 98.3 MMSTB oil to date and current active well counts are 75 producers and 40 injectors. Much of the 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 exploiting AX oil at structurally high positions in CRB 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 owing 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, new 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 owing to the sensitive nature of the formation.

From the late 1990's, success in pattern waterflood development in the Tract II area was achieved through 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 exploit 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 2010's, multiple stimulated wells and open hole slotted liner hybrid completions have shown promise in increasing UPF oil production. Production entering 2014 was nearly 3900 BOPD. In 2014, several open hole slotted liner wells were drilled exploiting the AX sands. Despite the drilling of the several wells daily production has declined by 1500 BOPD from 3900-2400 BOPD.

Status

The UP-Ford production rates in December 2014 were 2,398 BOPD and 59,212 BWPD (96.1% water cut) from 75 producers. December 2014 injection averaged 53,038 BWIPD from 40 injectors. Average active well rates were 32 BOPD and 789 BWPD for producers and 1,326 BWIPD for injectors

UP-Ford currently has 8 wells that are mechanically idle and capable of being reactivated with further investment. These wells are being evaluated for repair and/or conversion.

Recovery through December 2014 was 98.3 MMBO (19% OOIP). For the January to December 2013 period, the base potential production in UP-Ford reservoir has declined at 7% annually and for the January to December 2014 period, the base potential production in UP-Ford reservoir has declined at 23% annually. Maintenance wellwork continues to play a major role in maximizing UP-Ford base production.

Calendar Years 2013 and 2014 Activities and Results

Since publication of the last Program Plan, 12 producers (4 open-hole slotted liner completions, and 8 cased-hole completions) and 1 cased hole completion) and 1 injector have been drilled and completed in the UP-Ford pool.

The average initial stabilized rate (3 month average) for the producers drilled in the UP-Ford pool is 168 BOPD with initial rates ranging from 403 BOPD to 30 BOPD. This rate is more than the anticipated average initial rate of 78 BOPD.

During the 2013-2014 Plan period, 5 development (investment) wellwork jobs were also completed. These successful add pay completions resulted in a stabilized project incremental rate of 35 STB/D.

Reservoir Management Objectives

The goal of the UP-Ford Reservoir Management Plan is to maximize the profitability of the reservoir. As the recovery mechanism is waterflood, we have to increase the waterflood efficiency by increasing throughput ratio, injection efficiency and volumetric sweep. There are three areas of focus with respect to attaining this goal. First is to maintain the base production and injection rates in existing wells through reactive and proactive wellwork. The second objective is to effectively stimulate and waterflood sands above the AU through selective completion and stimulation techniques. 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. The third area of focus is to enhance the producer-injector conformance which 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 in FY15/16 includes continued activity in this reservoir. Due to the downturn in oil price, most of the development activity will be focused on maintaining base production, increasing injector conformance and drilling of low risk high reward producers/injectors. Potential new production and injection infill well candidates will be evaluated and the best will be selected for inclusion in the drilling schedule based on economic and strategic development criteria. 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. In FY15/16 the model will be further upgraded based on most recent understanding of the geological framework and properties. 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. Completion techniques will continue to be refined in an attempt to reduce treatment 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 CRB 44 and northern CRB 45 with infill producers and injectors to improve low recovery factor.
- Further leverage well design and completion alternatives for increasing infill well deliverability.
- 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-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 through stimulation and mechanical methods.
- Continue to delineate the Northern down-dip extent of UP-Ford CRB 44 and CRB 45.
- Study and evaluate the potential of UP-Ford 98.
- Incorporate any new structural understandings from the reprocessed seismic data towards improved development and reservoir management.

237 Zone

Reservoir Mangement 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 a 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. This facies tends 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 2.98 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 1.35 MMBO from two LBU wells, one of which had a flowing IP of 1800 BOPD.

The first 237 Zone well was completed in 1968 at an initial rate of 1050 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 permeabilityto be productive. Through December 2014, 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 2014 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 currently 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 structure high, 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, it having only produced 40 barrels of oil before dying. Multiple acid treatments failed to establish production. This well probably lacks adequate permeability.

The C-355, was drilled in FY09/10 as our first 237 zone completion through cemented liner. It was plagued by drilling and mechanical issues and a side track was necessary. The sidetrack was approximately 850 feet short of planned TD when the drill string became irrevocably stuck. Good oil shows were encountered in both well bores. The well was put on production but it was difficult keeping this well producing as the pump rather quickly draws down the fluid level.

Two additional wells have been drilled from Island Chaffee in the calendar year of 2011 and 2012. These two concepts were targeted as step-outs to the commercial C-250 well. Each of these wells will include new play elements including a previously untested stratigraphic interval or a new position on structure.

C252 was drilled in late 2011 and was completed in 2012 in the Basal Shale. The well, while showing some signs of deliverability after the stimulation treatment, tested very poorly with low intake pressure in the pump

The objective of the C348, drilled in late 2012, is to evaluate the Lower Basal Shale/Basement seismically-defined coherency anomaly. An initial rate of 60 BOPD, 390 gross and 60 MSCF gas was obtained. There is an opportunity to complete upper basal shale and other sands left behind pipe, the plan is to perforate and run high temperature equipment on this well. Well is currently cycling due to high temperature.

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 taken into account. It appears that the formation open 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 flexture), 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."

Critical Issues

- Reprocess/Reinterpret LBU seismic data with a focus on the 237 Shale zones and Seismic basement.
- Keep pump running in C-348 and evaluate production performance.
- Identify additional opportunities in structures that may not have been exploited.
- Incorporate all 237 wells (west Wilmington included) into 2014 study to gain cleared insight into overall 237 performance.
- 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. This Plan contains funding necessary for wellwork associated with producing these reserves, basic facility modifications necessary for production operations, and the gas production associated with the project.

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.

Status

The Shallow Gas reservoirs consist of 5 primary sand bodies: A10, A14, A16, A18 and A20. The Grissom Gas is the dominant Shallow Gas accumulation, with the majority of the historic production coming from the A14 and A16 sands. To date five of the eight wells have been completed in the A16, one in the A20 and three in the A14. With four wells producing out of the A16 sand a stabilized production rate was maintained at 5,000 mcf/d. This rate was maintained until June 2008 when Well A-268 watered out. Well A-260 followed and watered out as forecasted in September 2008. In January of 2009, well A-271 watered out. From this point, production rate for Grissom Shallow Gas production was averaging 4,200 mcf/d, with production from two active producers, Well A-301 (horizontal in A16 sand) and Well A-313 (A14 sand completion) which was returned to production after an inner liner was installed. In February of 2009, Well A310 completed in the A20 sands was successfully stimulated after a year of non-production. Shallow Gas production sharply declined in October of 2009 when horizontal well A-301 watered out; this event was shortly followed by the recompletion of well A-271 in the A14 sand. From October of 2009 to February of 2010, Grissom Gas production averaged 2500 mscf/d.

In February of 2010, B-403 was recompleted in the A-20 sands as the first step in the development of the White Shallow Gas accumulation with positive results early on. However, higher CO_2 content in the White Shallow Gas stream forced Facilities department to reduce/curtail the White Gas rate out of concern for subsea lines. In April of 2010, Well A-268 was recompleted in the A14 sand. During the February 2010 - July 2010, the total Shallow Gas rate was averaging 2300 mscf/d until subsea line repairs and facility maintenance forced the shut down of the Shallow Gas production. Upon completion of the repairs and maintenance work, production resumed from wells A-271, A-301 and A-310 at an average rate of 2200 mscf/d, the bulk of the production coming from well A-271. Production dropped sharply to 350 mscf/d in February of 2011 when well A-271 watered out. In July 2011, A-271 and B-403 were successfully recompleted, respectively in the upper lobe of the A14 sand and in the A16 sand, averaging a production of 3000 mscf/d. Fine sand production created issues with well B-403 which ceased to produce in January 2012. Production from well A-271 stopped for similar reason. Up-hole recompletions are being considered in other wells. B-403 was RTP on December 2014 and is currently doing 500 mscf/d. Daily rate by sand and cumulative production can be seen in Figure 1.

Cumulative Grissom production through July 2012 totals 5.133 BCFG (69.7% OGIP) in excess of initially estimated ultimate recovery expected to reach 4.33 BCFG (61.0% OGIP) in 2011 for the Grissom Gas reservoir. To date, White Gas cumulative production amounts to 356 MMCF. Underlying aquifer support within the reservoir will affect total gas recovered.

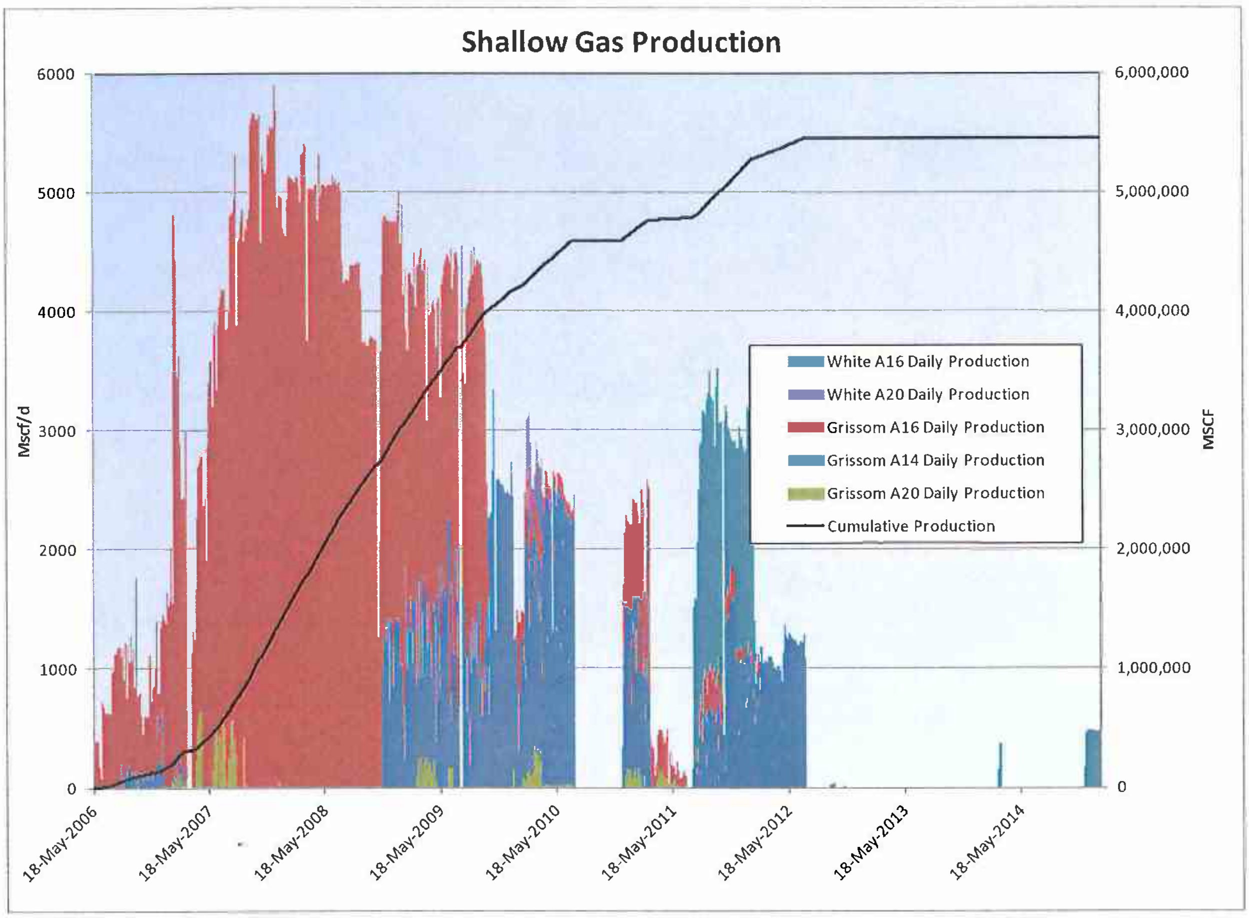


Figure 1: Shallow Gas production by sand

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 monitoring of aquifer influx and pressure measurement. 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, we must focus on utilizing the most ideally situated idle wellbores for Shallow Gas development to maintain a low cost development and maximize recovery through existing assets.

It has been found that sand control is needed in order to maintain the required production rates. Sand control has been installed on previously sanded wells.

Strategies

The development plan consists in the up-hole recompletions of the existing Grissom and White gas wells as they water out, mostly in the A14 sands, and one recompletion in the A10 sand in the White Gas accumulation. Reservoir studies may be done at a later date on the Pier J and Chaffee gas to better understand the connectivity of the shows and extent of the gas in place. These studies will utilize seismic, well log, and cased hole reservoir sampling data to quantify extensional development opportunities. However, lower gas prices have pushed most of those studies back.

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. This effort is ongoing.