CITY OF LONG BEACH
Gas & Oil
DEPARTMENT

C-13

ROBERT DOWELL
DIRECTOR

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March 21, 2017

HONORABLE MAYOR AND CITY COUNCIL
City of Long Beach
California

RECOMMENDATION:

Approve and adopt the Long Beach Unit Annual Plan (July 1, 2017 - June 30, 2018) and the Program Plan (July 1, 2017 – June 30, 2022). (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, and amended Chapter 138 require the City and the Contractor, California Resources Long Beach, Inc. (CRLBI), 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 City staff, 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 F. Anthony on February 23, 2017 and by Revenue Management Officer Geraldine Alejo on February 28, 2017.

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, 2017. To meet that requirement, City Council approval is requested on March 21, 2017.

FISCAL IMPACT

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

SUGGESTED ACTION:

Approve recommendation.

Respectfully submitted,

ROBERT DOWELL
DIRECTOR OF LONG BEACH GAS AND OIL

BD:kmt

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

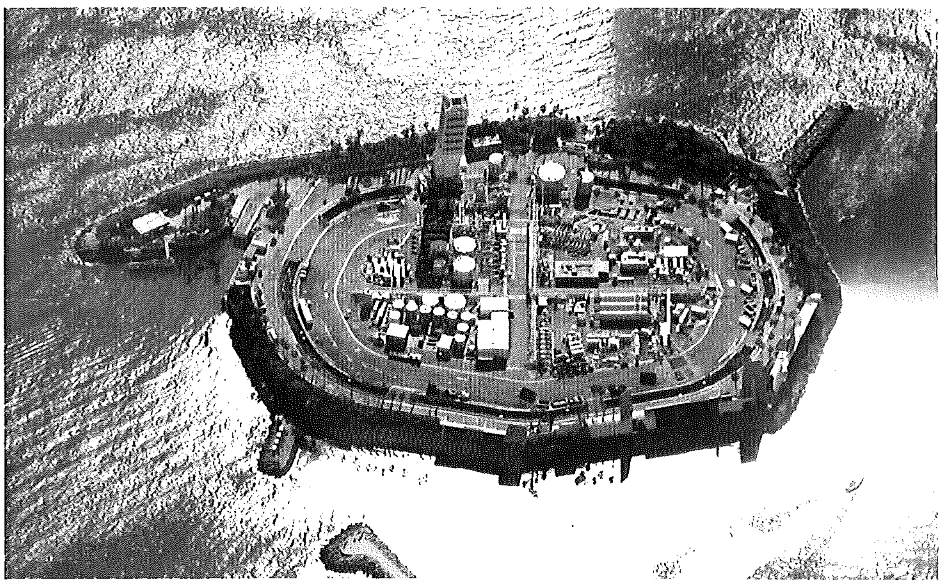
APPROVED:

PATRICK H. WEST
CITY MANAGER

Long Beach Unit

THUMS Long Beach Company

(Agent for Field Contractor)



ANNUAL PLAN

July 1, 2017 through June 30, 2018

ANNUAL PLAN

July 1, 2017 through June 30, 2018

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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, 2017 through June 30, 2018 ("FY18"). 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 2017 – 2018 ($ Million)**
Development Drilling	$ 70.7
Operating Expense	$ 92.8
Facilities, Maintenance, and Plant	$ 53.6
Unit Field Labor and Administrative	$ 43.0
Taxes, Permits, and Administrative Overhead	$ 29.9
Total	$289.9

A. Plan Basis

This Plan was developed based on the parameters outlined in the Program Plan for the period July 2017 through June 2022 and provides current and updated estimates of volumes, drilling activity and expenditures for FY18.

Volumes

Oil and gas production volumes are predicted to average 20.6 Mbopd and 7.9 MMcfd, respectively, in FY18. Water production for the period is expected to average 1,170 Mbwpd and water injection is expected to average 1,244 Mbwpd.

Revenue and Expenses

A projected oil price of $45.00/bbl Wilmington and gas price of $2/mcf will result in revenues of $344.2 million. Budgeted expenses for FY18 total $289.9 million. Projected net profit in FY18 is $54.3 million.

Drilling

This Plan allows for drilling approximately 45 new and redrilled development and/or replacement wells from existing cellars. The plan sets a drilling pace equivalent to approximately one and one half drilling rigs over the fiscal year. 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). Injection support for the drilling program will be provided through a combination of capital workovers (add pays and conversions), repair of failed injectors, and 5 new drill injectors. Regulatory challenges facing injection projects (e.g. possible SRT requirements) are manageable through injector completion design and strategic project selection. As per current operational practices, injection support will continue to maintain adequate I/G ratios to prevent subsidence and improve waterflood sweep efficiency.

Maintenance

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

CRC has a Mechanical Integrity and Quality Assurance (MIQA) program to assess and maintain critical equipment in order to protect the environment. The MIQA program is designed to meet internal and regulatory requirements and provide a high level of equipment integrity to reduce risk and increase reliability. Key elements include:

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

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

Projects will be undertaken to repair or replace equipment that has outlived its useful life. Items needing to be repaired or replaced include, but are not limited to, facilities piping, tanks, and vessels. These projects are consistent with past activities to keep the Unit facilities in safe operating condition and reflect a forecasted 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 the California Department of Fish and Wildlife.

Environmental and community outreach is also a fundamental part of THUMS program and each of the Islands received a Conservation Certification in 2016 by the Wildlife Habitat Council (WHC). This designation is awarded to facilities that provide for public education and involvement through wildlife related projects and learning opportunities on the facilities. In 2016, the THUMS Islands were presented by the WHC with the "Landscaping Project Award." These certifications and national award received by the WHC demonstrate THUMS continuing commitment to environmental stewardship and habitat conservation.

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

Economic Review

Project expenditures during the Plan period are subject to economic review through the Determination and Authority for Expenditure (AFE) processes. All existing wells are frequently reviewed in light of changing crude prices to determine if they are economic to operate. Well servicing work is justified on economics and other conditions consistent with good engineering, business, and operating practices.

CRC remains committed to careful 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 FY18	BUDGET SECOND QUARTER FY18	BUDGET THIRD QUARTER FY18	BUDGET FOURTH QUARTER FY18	BUDGET TOTAL FY18
ESTIMATED REVENUE					
Oil Revenue	$85.5	$85.2	$83.1	$84.7	$338.5
Gas Revenue	$1.4	$1.4	$1.4	$1.5	$5.8
TOTAL REVENUE	$87.0	$86.6	$84.5	$86.2	$344.3
ESTIMATED EXPENDITURES					
Development Drilling	$11.4	$11.4	$23.9	$23.9	$70.7
Operating Expense	$22.3	$22.8	$24.3	$23.4	$92.8
Facilities & Maintenance	$12.7	$12.3	$14.4	$14.2	$53.6
Unit Field Labor & Administration	$11.8	$9.2	$12.6	$9.4	$43.0
Taxes, Permits & Overhead	$7.7	$6.6	$8.4	$7.3	$29.9
TOTAL EXPENDITURES	$65.9	$62.3	$83.6	$78.2	$289.9
NET PROFIT	$21.1	$24.3	$0.9	$7.9	$54.3

C. MAJOR PLANNING ASSUMPTIONS

	BUDGET FIRST QUARTER FY18	BUDGET SECOND QUARTER FY18	BUDGET THIRD QUARTER FY18	BUDGET FOURTH QUARTER FY18	BUDGET TOTAL FY18
OIL PRODUCTION					
PRODUCED (1000 BBL)	1,901	1,893	1,846	1,882	7,522
(AVERAGE B/D)	20,663	20,573	20,507	20,684	20,607
GAS PRODUCTION					
PRODUCED (1000 MCF)	722	719	720	734	2,895
(AVERAGE MCF/D)	7,852	7,818	7,998	8,067	7,933
WATER PRODUCTION					
PRODUCED (1000 BBL)	106,778	107,194	105,538	107,530	427,040
(AVERAGE B/D)	1,160,631	1,165,147	1,172,647	1,181,647	1,169,972
WATER INJECTION					
INJECTED (1000 BBL)	113,122	114,161	112,398	114,519	454,201
(AVERAGE B/D)	1,229,584	1,240,882	1,248,870	1,258,455	1,244,385
OIL PRICE ($/BBL)	$45.00	$45.00	$45.00	$45.00	$45.00
GAS PRICE ($/MCF)	$2.00	$2.00	$2.00	$2.00	$2.00

Part II

Program Plan Schedules

Schedule 2A
Range of Production and Injection
FY18-FY19
Long Beach Unit Program Plan, July 2017-June 2022

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2017/18	19.6 - 21.6	1,111 - 1,228	7.5 - 8.3	1,182 - 1,307

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2018/19	19.3 - 21.4	1,144 - 1,264	7.5 - 8.3	1,218 - 1,346

Schedule 2 B

Anticipated New and Redrilled Wells

Fiscal Year 18

Long Beach Unit Program Plan, July 2017-June 2022

		Producers					Injectors				
Reservoir	CRB	Grissom Min - Max	White Min - Max	Chaffee Min - Max	Freeman Min - Max	Pier J Min - Max	Grissom Min - Max	White Min - Max	Chaffee Min - Max	Freeman Min - Max	Pier J Min - Max
SG Tar		0 - 3	0 - 0	0 - 0	0 - 0	0 - 3	0 - 1	0 - 0	0 - 0	0 - 0	0 - 1
Ranger West	1	0 - 10	0 - 0	0 - 0	0 - 0	0 - 0	0 - 4	0 - 0	0 - 0	0 - 0	0 - 0
	2	0 - 6	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0
	3	0 - 4	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0
	4	0 - 10	0 - 0	0 - 0	0 - 0	0 - 0	0 - 4	0 - 0	0 - 0	0 - 0	0 - 0
	5	0 - 10	0 - 0	0 - 0	0 - 2	0 - 2	0 - 4	0 - 0	0 - 0	0 - 0	0 - 1
	6	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	7	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	8	0 - 0	0 - 0	0 - 0	0 - 2	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 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	13	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	36	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1
	37	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	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 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	23	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 - 5	0 - 0	0 - 0	0 - 0	0 - 10	0 - 2	0 - 0	0 - 0	0 - 0	0 - 4
	39	0 - 5	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0
	40	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	41	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	42	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	43	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	47	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
UP Ford	26	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	27	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	30	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	31	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	44	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	45	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	46	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
237	30										
		Total					Total				
		0 - 80					0 - 28				

Part III

Itemized Budget of Expenditures

A. Development Drilling $70.7MM

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 45 wells will be developed and/or replaced during the Plan year using a drilling pace equivalent to 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 well performance. This information will be reviewed and approved in accordance with the various unit agreements during regularly scheduled meetings.

B. Operating Expense $92.8MM

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 20.6 Mbopd, estimated gas production of 7.9 MMcfpd, water injection requirement of 1,244

Mbwpd, and water production of 1,170 Mbwpd. Anticipated operating expenses were based on operating three and a half workover rigs per month for servicing an average active well count of 778 producers and 470 injectors. These rigs will also be used for the completion of approximately 14 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 45 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 53 percent of the funds in this Category. Cost for electric power is based on estimated kilowatt usage of 795,000,000 KWh at an average rate of $0.0610/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 $53.6MM

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 74 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 26 percent of the funding in this Category is for facility repair and minor projects. The majority of the facility repair and project investment is on the Tank and Vessel maintenance program and the remaining investment is focused on inspection, maintenance and repair in support of the MIQA program. This work includes regulated pipeline inspection surveys and evaluation, inspection and repair of cathodic protection systems, and infrastructure piping integrity inspections not covered by regulatory control. Projects include expenditures related to replacement, relocation, or minor expansion of existing injection piping, oil and water pumps and other infrastructure related investments.

D. Unit Field Labor and Administrative $43.0MM

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 93 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 $29.9 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 58 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, 2018 the City of Long Beach shall present to the State Lands Commission a final report and closing statement of the FY18 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 FY18 shall contain a reconciliation by category as finally modified and the actual accomplishments, including:

1. New wells and redrills by zone.

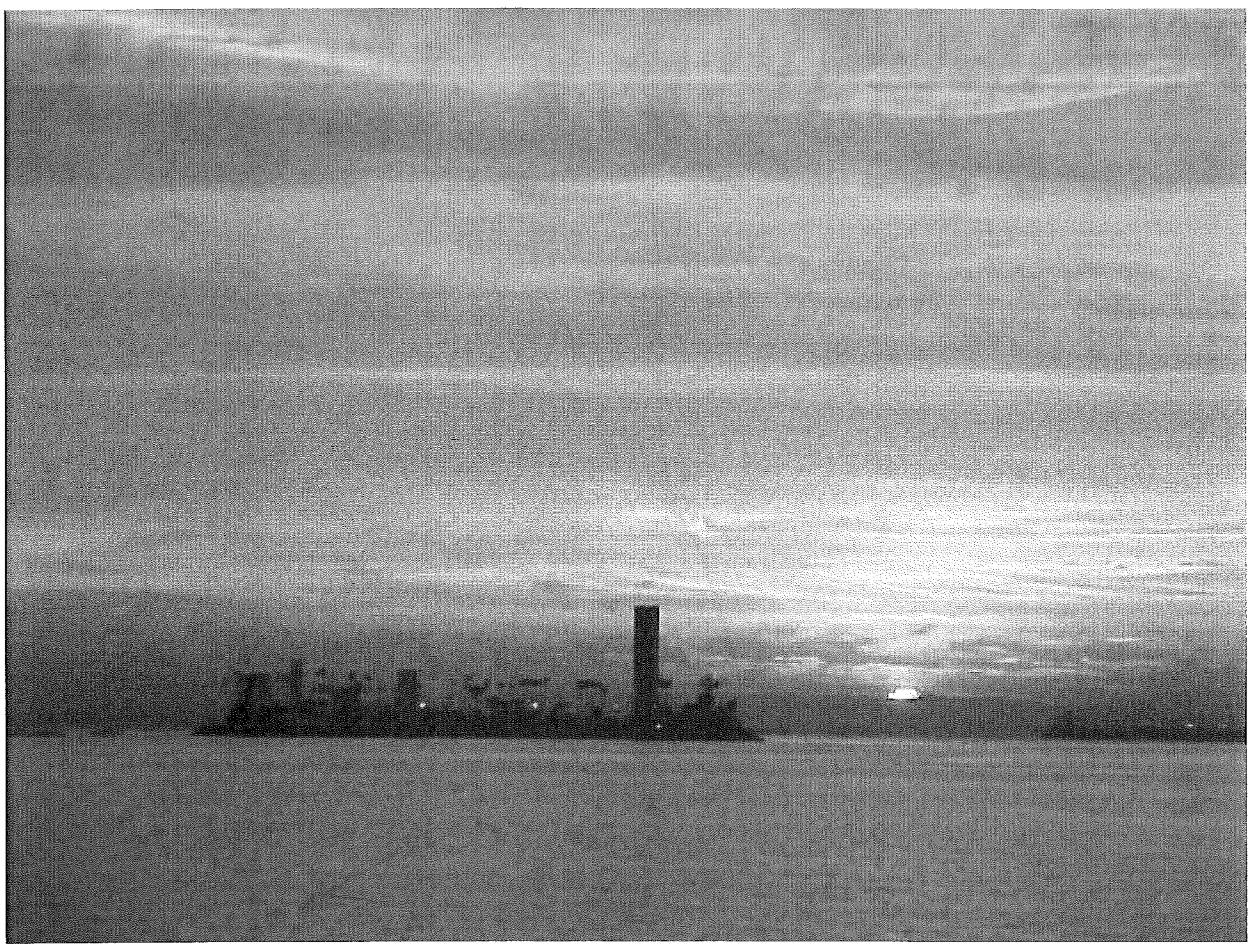
2. Facilities and capital projects.

3. Production by zone.

4. Injection by zone.

Program Plan

Long Beach Unit
Long Beach, California



July 2017 – June 2022

PROGRAM PLAN

Long Beach Unit

July 2017 through June 2022

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 2017

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Executive Summary

This Program Plan covers the period from July 1, 2017 through June 30, 2022. The purpose of the Plan is to describe key issues facing the Unit and to outline strategies for optimizing the economic recovery of resources while maintaining excellence in safety and environmental protection. This Plan is the culmination of a cooperative effort by the Long Beach 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 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 194 wells over the life of the Program Plan. This schedule will result in a steady decline in oil production rate through the end of FY21/22. Unit production and injection rates are expected to average 20.6 Mbopd, 1,170 Mbwpd and 1,244 Mbwipd in FY18 and 20.4 Mbopd, 1,204 Mbwpd and 1,282 Mbwipd in FY19, respectively.

The anticipated drilling activity is detailed in Exhibit B and the predicted rate curves are shown in Exhibits E and F. This drilling activity encompasses several locations: Pier J, and Islands, Freeman, and Grissom with the use of Unit rigs 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 project work during the program plan period will include projects to support mechanical integrity, safety and environmental, regulatory compliance, facility enhancement and optimization, and other typical oil field facility projects. These projects are intended to upgrade and ensure continued, efficient, fluid handling. The Plan also includes the replacement of pipeline rail crossings at Pier J, in collaboration with the Port of Long Beach. 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.

Based on production from 45 well projects planned for FY18 of the Program Plan and an oil price of $45 in FY18, $50 for FY19, $55 for FY20, and $60 for FY21-22 and a gas price of $2/mcf, total revenue, expenditures, and net profits over the 5-year period of the Program Plan are projected to be $1,899.7 million $1,476.8 million, and $422.9 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, 2017 through June 30, 2022. The purpose of this Plan is to describe key issues facing the Unit, and to outline strategies for optimizing the economic recovery of resources while maintaining excellence in safety and environmental protection.

This Plan is divided into four major sections:

- The *Introduction* provides a brief summary of the Unit history.
- The *Unit Reservoir Management Plan* section outlines strategies to be employed in reservoir development and management. An overview of the field-wide goals and strategies is provided. Appendix 1 contains a more detailed Reservoir Management Plan for the six reservoir areas: Ranger West/Tar, Ranger East, Terminal, UP Ford, 237 Zone and Shallow gas zone.
- The *Unit Forecasts* section summarizes planned Unit 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 a realized oil price of $45 in FY18, $50 for FY19, $55 for FY20, and $60 for FY21-22 and a realized gas price of $2/mcf. This section also includes the schedules that will be incorporated into the FY18 and FY19 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, then reduced over 2015 and 2016 to a half rig pace. Rig count and pace are continuously optimized for investment return within the constraints of oil price and the business environment. A rig count between one and 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 ("Oxy") bought all of Atlantic Richfield Company's stock in ALBI. As a result, the Field Contractor name was legally changed from ALBI to Oxy Long Beach, Inc. ("OLBI"). In late 2014, in conjunction with the separation of California Resources Corporation ("CRC") from Oxy, OLBI was renamed as California Resources Long Beach, Inc.

Unit Reservoir Management Plan

Goal

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

Reservoir Management Strategy

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

1. Maximize economic production from existing assets by the use of sound waterflood practices. This effort is focused on waterflood surveillance activities including well monitoring, flood performance analysis, and voidage management for subsidence control. In addition, a cross-functional effort is used to coordinate near and long-term planning. The work product of this effort is a full-field development plan, that is periodically updated as business and operational conditions warrant.
2. Assess and deliver additional 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 optimization of production. The reservoir management strategies for accomplishing this goal include well monitoring, flood performance analysis, and voidage management for subsidence control.

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

sweep, hydrocarbon throughput analysis and streamline and other reservoir simulation methodologies. Based on the analysis results, development opportunities will be identified and evaluated including re-completions, 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 a 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 in order 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 are focused on:

- Drilling injection wells targeting increased throughput in the less mature sand layers and improving zonal injection control. Drilling results to date have shown good success from injection wells drilled to re-establish injection patterns in the relatively underdeveloped areas of the field.
- Adding production wells: (1) in areas of unswept oil, (2) in lower productivity sands that cannot produce well in combination with higher productivity zones in long completions, (3) in areas of high oil saturations banked along sealing faults, and (4) in areas where improved injection warrants additional production capacity.
- Investing in wellwork projects that will increase the ultimate recovery of the field or require special planning and attention. Investment wellwork includes well conversions, recompletions, 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 corporate technical support, and local staff, the Long Beach Unit continues to assess, understand and refine its knowledge of the reservoir and develop new production opportunities.

Technology

Advances in drilling and completion technology continue to be a significant factor in realizing development drilling opportunities. Key technologies being developed and applied include horizontal well placement, water shut-off techniques, special design and extended reach wells, cased hole completions and low cost replacement wells. The Unit 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 drilling to average approximately 45 wells in FY18 and 60 wells in FY19. This schedule can be met with approximately 1.5 rigs in FY18 and 2 rigs in FY19. Workover rigs will continue to be used as applicable 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 FY18 and FY19. 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 FY18 and FY19, respectively. These forecasts were developed by combining a forecast of existing well performance with the expected results of the previously outlined development plan. The expected injection forecast shown in Exhibit D was generated based on the gross fluid rates from the production forecast. Graphs comparing historical and predicted field rate performance data are presented in Exhibits E and F. The plots clearly show the variability of historical rate data, necessitating the use of rate ranges to account for uncertainty in the rate projections.

The oil and water production forecast for the existing wells is based on a process that uses an extrapolation of wells within each reservoir summed together to yield a forecast of the existing wells' production for the entire Unit. For each well, the expected future oil and water rates are extrapolated from historical trends of oil and gross fluid rates vs. time and the trend of water-oil ratio vs. cumulative oil production using conventional decline curve techniques. The resulting prediction shows a near term exponential decline ranging from 9 to13% 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, electricity generation, taxes and make-up water sources. All can dramatically influence the success of the Unit, and as such, will be addressed with considerable effort and resources.

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

People

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

Health and Safety

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 the California Department of Fish and Wildlife.

Environmental and community outreach is also a fundamental part of THUMS program and each of the Islands received a Conservation Certification in 2016 by the Wildlife Habitat Council (WHC). This designation is awarded to facilities that provide for public education and involvement through wildlife related projects and learning opportunities on the facilities. In 2016, the THUMS Islands were presented by the WHC with the "Landscaping Project Award." These certifications and national award received by the WHC demonstrates THUMS continuing commitment to environmental stewardship and habitat conservation.

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

Environmental Protection

The Unit is committed to the protection of the environment and has continued to include this as a key annual goal. 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 is conducted as areas of need are identified.

Environmental and community outreach is also a fundamental part of THUMS program and each of the Islands are currently certified by the Wildlife Habitat Council. In 2017 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 in order to support semi-annual ground elevation measurements.

Well Abandonment Plan

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

Wells with no further economic use are fully abandoned to reduce the Unit's future abandonment liability. Abandonment also eliminates the costs of performing periodic pressure tests of long-term idle well casings mandated by the 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 for operational cost efficiency. Emphasis is given to spending funds wisely, investing in opportunities with the best economic return, and continuing to look for ways to improve efficiency in business operations. Employing effective cost management strategies aids in achieving the Unit's goal of performing in the lowest cost per net barrel quartile for comparable operations. Cost management gains will continue to be aggressively pursued during the term of this Plan. Some of the areas where the Unit plans to place substantial focus include the following:

Operations: The 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 CO2 levels, are optimized in conjunction with Power Plant operations. Process optimization, best operating practices, and operating cost reductions will be focus areas. Improvements in electrical efficiency, optimization of make-up water sources, maintaining water quality, enhanced well surveillance, and improved coordination between operations, wellwork, and facility maintenance are expected outcomes over the Program Plan period.

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

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

Mechanical Integrity

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

Electricity Generation

Electricity is the single largest operational cost element for the Unit. Currently the Unit consumes approximately 795 million kWh per year, and is one of the largest single-site users of electricity in Southern California Edison's territory. Any change in the electrical rates or availability of electricity supply significantly affects the profitability of Unit operations.

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

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

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

Taxes

Historically, the County of Los Angeles has increased the assessed value of the Unit annually. 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 produced water from Tidelands Oil Production Company and reclaimed water from Long Beach Water Department (LBWD). Fresh water is used sparingly, primarily for utility purposes (drinking and hygiene uses). In addition, bearing-cooling projects have been put in place to further reduce use of fresh water.

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

Economic Summary

Revenue Forecast

Unit Revenue will be generated predominately from the sale of oil and gas from five producing formations: Tar, Ranger West, Ranger East, Terminal, and UP Ford/237. The projected revenue during the Program Plan period is $1,899.7 million, based on an oil price of $45 in FY18, $50 for FY19, $55 for FY20, and $60 for FY21-22 and a gas price of $2/mcf, and average daily oil and gas production as projected in Exhibit C. Projected revenue for FY18 is expected to be $344.3 million.

Cost Forecast

Total estimated expenditures for the first year of this Program Plan are consistent with the FY18 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 $1,476.8 million. The projected expenditures for FY18 are $289.9 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 $422.9 million. Unit profit for FY18 is expected to be $54.3 million. A schedule of annual projected revenue, expenditures, and net profit is given in Exhibit A.

Budget commitments for FY19 will be established based on actual results and additional insights gained during FY18.

Table 1

SUMMARY OF PRODUCTION AND INJECTION
AS OF NOVEMBER 2016
JULY 2017 – JUNE 2022 PROGRAM PLAN, LONG BEACH UNIT

		Active Well Count		Averge Rates for November 2016				Average Well Rates		
Reservoir	CRB	Producers	Injectors	BOPD	BWPD	BIPD	Wtr Cut	BOPD/Well	BWPD/Well	BIPD/Well
SG	65	-	-	-	-	-	-	-	-	-
	66	-	-	-	-	-	-	-	-	-
Tar	35	13.0	2	322	4,129	9,151	93%	25	318	4,031
Ranger	1	38.5	23.5	1,003	59,858	61,147	98%	26	1,555	2,602
West	2	31.5	17.0	1,158	48,465	50,657	98%	37	1,539	2,980
	3	38.0	29.0	1,259	83,785	95,995	99%	33	2,208	3,310
	4	52.7	32.9	1,668	140,957	130,152	99%	32	2,675	3,961
	5	34.0	25.8	1,173	86,779	96,634	99%	34	2,552	3,750
	7	13.9	8.0	387	23,400	23,366	98%	28	1,677	2,921
	8	16.6	10.0	465	27,333	25,545	98%	28	1,642	2,554
	9	12.0	7.0	313	14,251	12,887	98%	26	1,188	1,841
	10	22.5	21.0	629	30,313	38,827	98%	28	1,347	1,849
	11	11.5	4.0	344	11,868	8,581	97%	30	1,032	2,145
	12	9.6	4.3	199	10,499	8,084	98%	21	1,094	1,898
	13	9.9	7.5	254	17,813	14,885	99%	26	1,794	1,985
	36	26.0	21.0	910	53,521	65,280	98%	35	2,058	3,109
	37	5.0	8.0	218	14,322	23,068	98%	44	2,864	2,884
	Total	**322**	**219**	**9,980**	**623,163**	**655,107**	**98%**	**31**	**1,937**	**2,993**
Ranger	14	18.6	14.4	688	33,463	33,945	98%	37	1,796	2,361
East	15	42.2	22.8	1,270	72,130	80,656	98%	30	1,708	3,544
	16	20.0	8.2	501	18,857	17,743	97%	25	944	2,153
	17	25.9	16.0	739	24,907	29,585	97%	29	962	1,849
	18	11.0	17.0	293	16,937	32,125	98%	27	1,540	1,890
	20	14.5	6.0	435	13,375	12,029	97%	30	922	2,005
	21	27.5	24.1	1,015	54,724	56,921	98%	37	1,993	2,360
	22	13.5	6.5	293	12,136	11,480	98%	22	899	1,766
	32	0.5	2.0	15	292	3,824	95%	29	585	1,912
	33	30.6	21.0	779	43,769	41,103	98%	25	1,430	1,957
	Total	**204**	**138**	**6,028**	**290,590**	**319,409**	**98%**	**30**	**1,423**	**2,315**
Terminal	24	20.8	11.8	375	18,677	25,622	98%	18	900	2,177
	38	29.8	16.6	787	45,334	49,764	98%	26	1,521	3,000
	39	21.3	11.0	705	28,775	27,269	98%	33	1,350	2,479
	40	5.6	2.9	72	3,210	3,071	98%	13	578	1,074
	41	5.1	4.0	183	5,206	5,615	97%	36	1,025	1,404
	42	8.4	5.2	179	7,995	7,385	98%	21	952	1,431
	43	27.6	13.6	637	33,503	32,438	98%	23	1,212	2,380
	47	0.9	0.4	7	472	695	99%	7	497	1,830
	Total	**119**	**65**	**2,945**	**143,172**	**151,859**	**98%**	**25**	**1,198**	**2,322**
UP/Ford	26	-	1.0	-	-	911	-	-	-	911
	27	18.5	6.0	404	14,616	13,353	97%	22	790	2,225
	31	5.0	4.0	68	3,401	4,079	98%	14	680	1,020
	44	5.0	7.0	53	2,874	7,339	98%	11	575	1,048
	45	24.0	11.0	673	18,867	16,645	97%	28	786	1,513
	46	25.0	12.4	681	25,463	22,284	97%	27	1,021	1,791
	Total	**77**	**41**	**1,880**	**65,220**	**64,611**	**97%**	**24**	**842**	**1,559**
237	30	-	-	-	-	-	-	-	-	-
LBU Total		**736**	**466**	**21,155**	**1,126,274**	**1,200,138**	**98%**	**29**	**1,530**	**2,575**

Exhibit A

ECONOMIC PROJECTIONS
July 1, 2017 through June 30, 2022 Program Plan
(Million Dollars)

	Fiscal 2017/18	Fiscal 2018/19	Fiscal 2019/20	Fiscal 2020/21	Fiscal 2021/22	Program Plan Period
Estimated Revenue						
Oil Revenue	$338.5	$371.6	$387.2	$396.0	$379.3	$1,872.6
Gas Revenue	$5.8	$5.8	$5.5	$5.1	$4.9	$27.2
Total Estimated Revenue	$344.3	$377.4	$392.7	$401.1	$384.2	$1,899.7
Estimated Expenditures	$289.9	$323.6	$281.7	$288.6	$293.1	$1,476.8
Net Income	$54.3	$53.9	$111.1	$112.6	$91.1	$422.9

Oil Price	$45.00	$50.00	$55.00	$60.00	$60.00	

Exhibit B

Anticipated Drilling Schedule
July 1, 2017 through June 30, 2022
(Number of Wells)

FISCAL YEAR	Tar V	Ranger West	Ranger East	Terminal	UP Ford/237	Total Wells
2017/18	5	33	0	7	0	45
2018/19	0	49	2	9	0	60
2019/20	0	16	10	3	0	29
2020/21	0	0	23	7	0	30
2021/22	0	0	23	7	0	30

* 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

Exhibit C

Range of Production Rates
July 2017-June 2022 Program Plan
Long Beach Unit

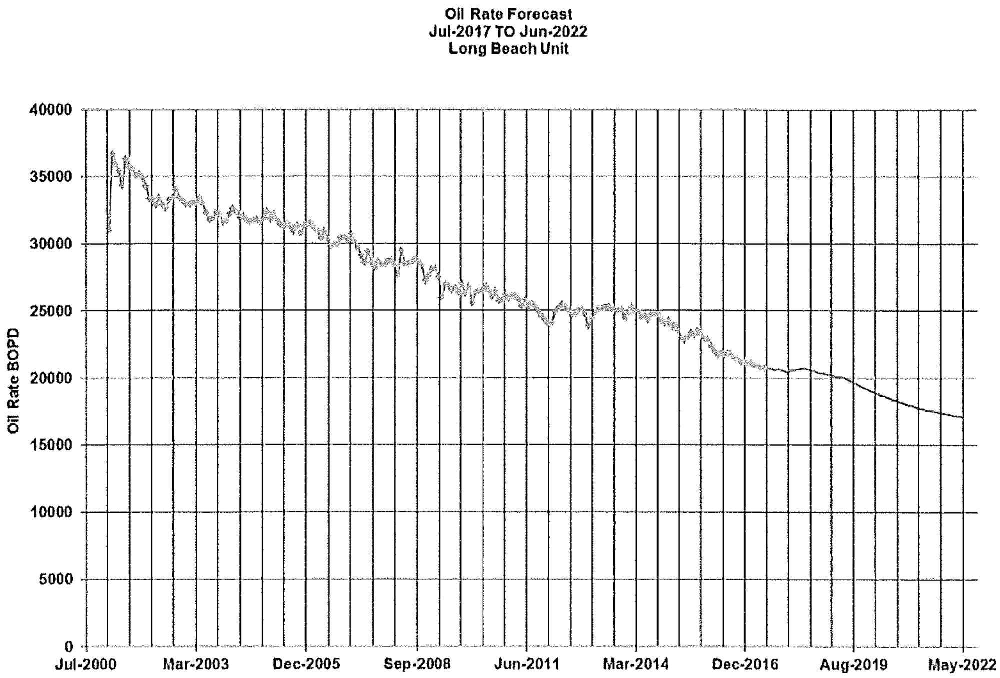
FISCAL YEAR	EXPECTED RANGE									EXPECTED RATE		
	OIL MBOPD			WATER MBWPD			GAS MMCFPD			OIL MBOPD	WATER MBWPD	GAS MMCFPD
2017/18	19.6	-	21.6	1,111	-	1,228	7.5	-	8.3	20.6	1,170	7.9
2018/19	19.3	-	21.4	1,144	-	1,144	7.5	-	8.3	20.4	1,204	7.9
2019/20	18.3	-	20.2	1,172	-	1,172	7.1	-	7.9	19.2	1,234	7.5
2020/21	17.2	-	19.0	1,186	-	1,186	6.7	-	7.4	18.1	1,248	7.1
2021/22	16.5	-	18.2	1,203	-	1,203	6.4	-	7.1	17.3	1,266	6.8

Exhibit D

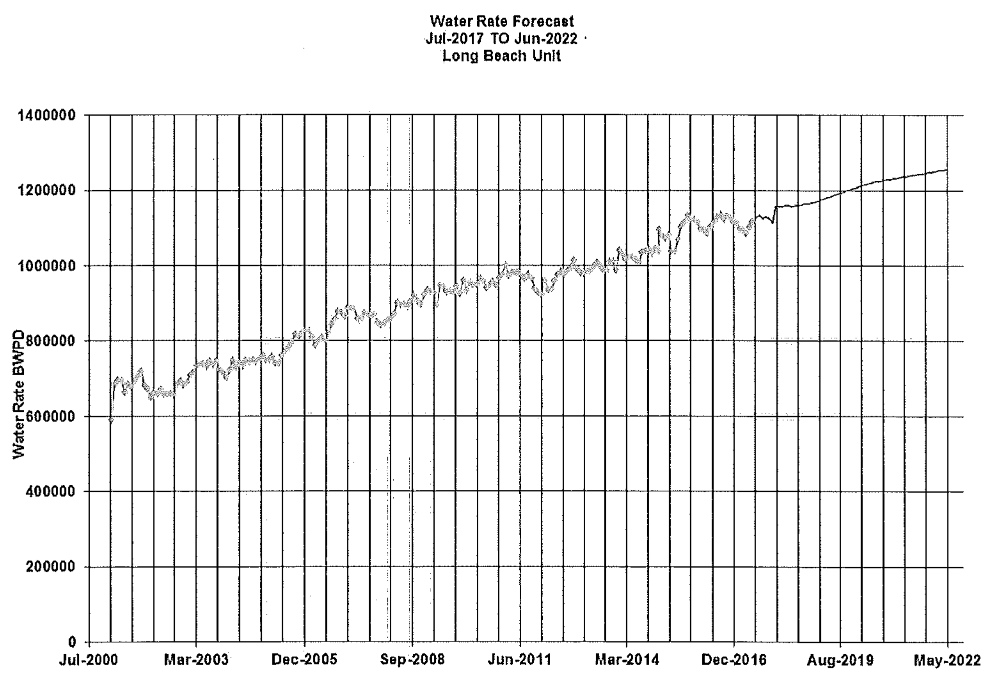
Range of Injection Rates
July 2017-June 2020 Program Plan
Long Beach Unit

FISCAL YEAR	WATER INJECTION RATE				RANGE OF INJECTION PRESSURES			
	RANGE MBWIPD			EXPECTED MBWIPD	TAR PSI	RANGER PSI	TERMINAL PSI	U.P./FORD PSI
2017/18	1,182	-	1,306	1,244	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2018/19	1,218	-	1,346	1,282	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2019/20	1,248	-	1,380	1,314	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2020/21	1,263	-	1,396	1,330	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500
2021/22	1,281	-	1,416	1,349	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 2500

Exhibit E

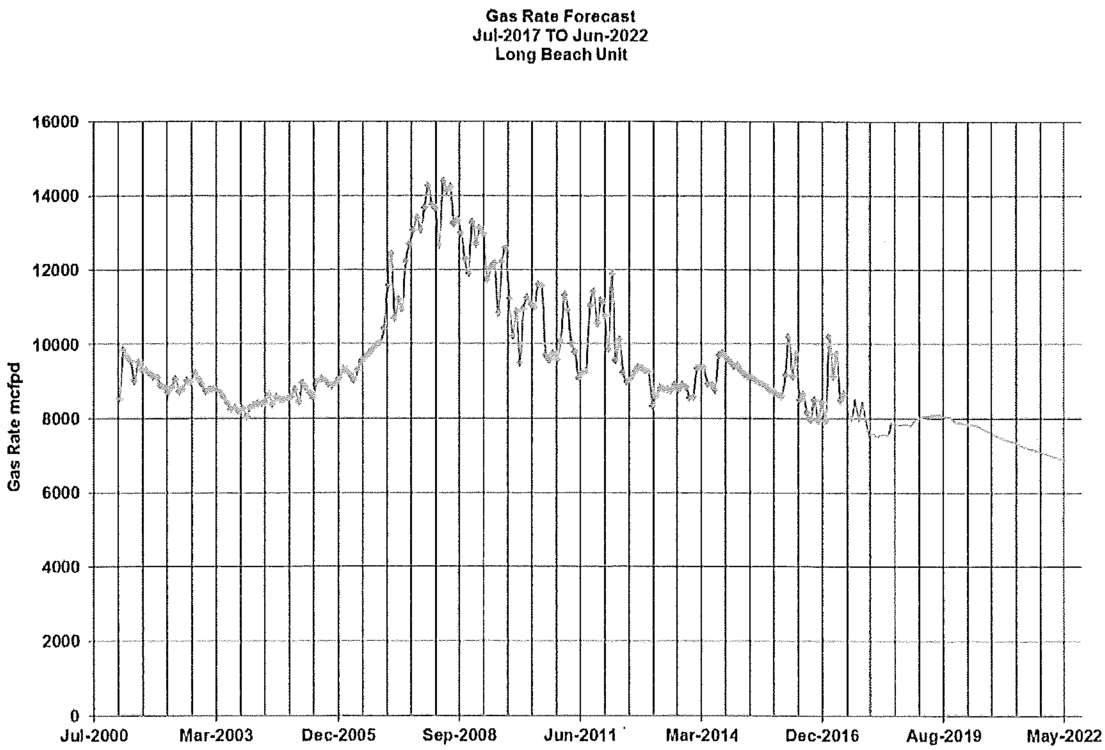


Oil Rate Forecast
Jul-2017 TO Jun-2022
Long Beach Unit
Oil Rate BOPD
40000
35000
30000
25000
20000
15000
10000
5000
0
Jul-2000
Mar-2003
Dec-2005
Sep-2008
Jun-2011
Mar-2014
Dec-2016
Aug-2019
May-2022



Water Rate Forecast
Jul-2017 TO Jun-2022
Long Beach Unit
Water Rate BWPD
1400000
1200000
1000000
800000
600000
400000
200000
0
Jul-2000
Mar-2003
Dec-2005
Sep-2008
Jun-2011
Mar-2014
Dec-2016
Aug-2019
May-2022

Exhibit F


Gas Rate Forecast
Jul-2017 TO Jun-2022
Long Beach Unit
Gas Rate mcfpd
16000
14000
12000
10000
8000
6000
4000
2000
0
Jul-2000
Mar-2003
Dec-2005
Sep-2008
Jun-2011
Mar-2014
Dec-2016
Aug-2019
May-2022

Schedule 1 A

Range of Production and Injection
FY 18
Long Beach Unit Program Plan, July 2017-June 2022

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2017/18	19.6 - 21.6	1,111 - 1,228	7.5 - 8.3	1,182 - 1,307

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2017/18	1500	2500	2500	2500

Schedule 1 B

Anticipated Development and Replacement Locations
Fiscal Year 18
Long Beach Unit Program Plan, July 2017-June 2022

		Producers					Injectors				
Reservoir	CRB	Grissom Min - Max	White Min - Max	Chaffee Min - Max	Freeman Min - Max	Pier J Min - Max	Grissom Min - Max	White Min - Max	Chaffee Min - Max	Freeman Min - Max	Pier J Min - Max
SG Tar		0 - 3	0 - 0	0 - 0	0 - 0	0 - 3	0 - 1	0 - 0	0 - 0	0 - 0	0 - 1
Ranger West	1	0 - 10	0 - 0	0 - 0	0 - 0	0 - 0	0 - 4	0 - 0	0 - 0	0 - 0	0 - 0
	2	0 - 6	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0
	3	0 - 4	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0
	4	0 - 10	0 - 0	0 - 0	0 - 0	0 - 0	0 - 4	0 - 0	0 - 0	0 - 0	0 - 0
	5	0 - 10	0 - 0	0 - 0	0 - 2	0 - 2	0 - 4	0 - 0	0 - 0	0 - 0	0 - 1
	6	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	7	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	8	0 - 0	0 - 0	0 - 0	0 - 2	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 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	13	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	36	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1
	37	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	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 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	23	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 - 5	0 - 0	0 - 0	0 - 0	0 - 10	0 - 2	0 - 0	0 - 0	0 - 0	0 - 4
	39	0 - 5	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0
	40	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	41	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	42	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	43	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	47	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
UP Ford	26	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	27	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	30	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	31	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	44	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	45	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	46	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
237	30										
		Total					Total				
		0 - 80					0 - 28				

Schedule 2 A

Range of Production and Injection
FY 19
Long Beach Unit Program Plan, July 2017-June 2022

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2018/19	19.3 - 21.4	1,144 - 1,264	7.5 - 8.3	1,218 - 1,346

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2018/19	1500	2500	2500	2500

Schedule 2 B

Anticipated Development and Replacement Locations
Fiscal Year 19
Long Beach Unit Program Plan, July 2017-June 2022

		Producers					Injectors				
Reservoir	CRB	Grissom Min - Max	White Min - Max	Chaffee Min - Max	Freeman Min - Max	Pier J Min - Max	Grissom Min - Max	White Min - Max	Chaffee Min - Max	Freeman Min - Max	Pier J Min - Max
SG											
Tar		0 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 1
Ranger West	1	0 - 4	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0
	2	0 - 9	0 - 0	0 - 0	0 - 0	0 - 0	0 - 3	0 - 0	0 - 0	0 - 0	0 - 0
	3	0 - 4	0 - 0	0 - 0	0 - 0	0 - 1	0 - 1	0 - 0	0 - 0	0 - 0	0 - 1
	4	0 - 10	0 - 0	0 - 0	0 - 0	0 - 0	0 - 3	0 - 0	0 - 0	0 - 0	0 - 0
	5	0 - 10	0 - 0	0 - 0	0 - 4	0 - 1	0 - 3	0 - 0	0 - 0	0 - 2	0 - 1
	6	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	7	0 - 0	0 - 0	0 - 0	0 - 4	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0
	8	0 - 0	0 - 0	0 - 0	0 - 4	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	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 - 4	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0
	13	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	36	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1
	37	0 - 0	0 - 0	0 - 0	0 - 4	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
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 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	23	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 - 5	0 - 0	0 - 0	0 - 0	0 - 3	0 - 2	0 - 0	0 - 0	0 - 0	0 - 1
	39	0 - 4	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	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 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	42	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	43	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	47	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
UP Ford	26	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	27	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	30	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	31	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	44	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	45	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	46	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
237	30										
		Total					Total				
		0 - 76					0 - 31				

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.

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 BOPD. The completion types consist of vertical (S3/T sands), slant (S3/T sands), and horizontal wells (S3 sand). The waterflood consists 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.

Status

The Ranger West/Tar production rates as of November 2016 were 9,980 BOPD and 623,163 BWPD (98.3% water cut) from 322 producers. November 2016 injection was 655,107 BWPD from 220 injectors. Average active well rates were 32 BOPD and 1,888 BWPD for producers and 3,001 BWPD for injectors. Ranger West currently has 66 inactive wells that have not been plugged in zone. 53 of these wells are being evaluated for repair, conversion or redrill.

Recovery through November 2016 was 520 MMBO (33% OOIP). While the base production in Ranger West reservoir has been declining at around 11% per year, the active development program in 2014-2016 has added an average of approximately 1,795 BOPD annually.

Wilmington Tar V has 13 active producing (7 horizontals) wells and 2 injectors. November 2016 production is approximately 322 BOPD and 4,129 BWPD (92% 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 November 2016, only about 2.2 MMBO of oil was recovered (6% OOIP), and less than one hydrocarbon pore volume of water injected.

Calendar Years 2015 and 2016 Activities and Results

Since publication of the last Program Plan, 13 producers (8 horizontal, 5 other) and 2 injectors have been drilled and completed in the Ranger West and Tar V pools.

The average initial stabilized rate (3 month average) for the producers drilled in the Ranger West Pool was 81 BOPD with initial rates ranging from 27 BOPD to 208 BOPD. This rate was higher than the anticipated average rate of 65 BOPD. The average initial stabilized production rate was 112 BOPD for the horizontal completions and 58 BOPD for the other 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 2015 were 2289 BWIPD compared with the expected rate of 2312 BWIPD. The 2016 projects performed above AFE. Average well injection rates of 2012 completions averaged 2779 BWIPD compared to an expected 2292 BWIPD. Overall, Projects completed from 2015-2016 outperformed AFE expectations.

During the 2015-2016 Plan period, a total of 9 injector development (investment) wellwork jobs were also completed. All of the projects were Ranger zone selective recompletions/add pay projects targeting bypassed oil sands. The injector development wellwork projects included three add-pay conversions to dual string injection and six profile modification add-pay projects. The injection work targeted increasing water throughput in selective sands and pattern areas. Injection development wellwork projects contributed an average incremental injection of about 1,767 BWIPD per well at an average cost of approximately $233K per 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. In 2015 and 2016, six additional Tar horizontal wells were drilled and completed. The 2014-16 Tar campaign's per well 90-day oil/gross rate average was approximately 96N/534G.

Reservoir Management Objectives

The primary reservoir management objective is to maximize the profitability of the Ranger West pool. Maximum profitability will be achieved through increasing recovery in underdeveloped blocks by identifying optimal locations for development drilling/investment wellwork combined with the right placement of injection water. Throughput objectives are to reach an HPVI target of at least 6.0 for each sand in all CRB's. As of December 2016, 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 cross-flow. Risk of subsidence will be minimized in all reservoir management actions.

Strategies

The Ranger West development plan includes drilling an additional 9 development wells and performing approximately 3 investment wellwork projects in CY17. 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 CRBs in Ranger West. In summary, waterflood optimization of the more mature crestal and south flanking blocks will be achieved through injector and producer profile control, pattern realignment, and capturing bypassed pockets of oil through horizontal drilling and cased-hole recompletions. In the less mature northern blocks, waterflood optimization will be achieved through (1) infill drilling and recompletions to improve pattern throughput, and (2) injector profile modifications to better balance injection between high permeability and low permeability sands.

Because of the Tar zone's poor mobility ratios (~450 CP viscosity), the plan is to keep injectors at least 1,500' away from producers. To overcome the high viscosity, where possible, these horizontal wells will be drilled at least 2,000' in length with a spacing of approximately 250' between the wells. The optimal drilling orientation is alternating toe/heel. The additional injection needed to support the new wells will come from lower cost add-pay injection well work - there are many Ranger and below penetrator options.

Critical Issues

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

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

Ranger East
Reservoir Management Plan

History

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

Production from Ranger East began in April 1967. However, several initial wells encountered relatively low reservoir pressures, and full production was delayed until enough pressure support was established to reduce the high producing gas-oil ratios. The waterflood program was initiated immediately, based primarily on peripheral injection. Line drive injectors were subsequently added in some areas, mainly along the crest of the structure. Early efforts to inject into and produce from full-zone completions were not fully effective, as flow was dominated by well-developed and high permeability F0, F, or M1 sand units high in the vertical section. A 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 structural crest of the reservoir and the southern flank, which has seen good pressure support and sweep from the peripheral injectors. Similarly, the crestal areas have benefited from a combination of down-dip support from the injectors along the southern flank and direct support from line drive injectors. Pressure support and recovery efficiencies in crestal CRB's 15, 22, 32, and 33 are expected to be high, though somewhat lower than in CRB-21 due to complex faulting and reduced sweep efficiency.

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

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

Status

As of November 2016, Ranger East production is 6,028 BOPD and 290,590 BWPD from 204 active producers. Total water injection is 319,409 BWPD into 138 active injectors. Average active well rates are 28 BOPD and 1,405 BWPD for producers and 2,429 BWPD for injectors. Ranger East currently has 34 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 November 2016 is 259.2 MMBO (32.9% OOIP). Since the last reporting period in December 2014, the total oil production has been steadily dropping due to the reduced drilling activity which is being driven by lower crude prices. Excluding development, base decline has been approximately 13% over the last two years.

Calendar Years 2015 and 2016 Activities and Results

Since publication of the last Program Plan, 7 producers (3 horizontal/slants and 4 conventional vertical wells) and 1 injector (dual string vertical cased injector) 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 108 BOPD with initial rates ranging from 42 BOPD to 250 BOPD. The injection well drilled during the 2015-2016 period was selectively perforated in specific intervals with historically low waterflood throughput and relatively high remaining oil saturation. The injection well met injectivity expectations with an average injection rate of 2500 BWPD.

During the 2015-2016 Plan period, a total of 6 development (investment) wellwork jobs were also completed (1 producer and 5 injectors). The injector development wellwork projects included 4 convert to injectors and 1 profile modification/add pay project. The injection work targeted increasing water throughput in selective sands and pattern areas. Injection development wellwork projects contributed an average of 3,000 bpd of injection per well at an average cost of about $128,000 per job.

Maintenance wellwork continues to play a major role in maximizing Ranger East base production. During 2015-2016, approximately 37 producer maintenance wellwork projects at a cost of about $96,000/job were performed. 102 injector maintenance projects were also completed at an average cost of about $150,000/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 48.8. 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 performed 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 ensures that maximum productivity is achieved from the wells. Finally, producers are recompleted when economic quantities of unswept oil are identified.

Strategies

The Ranger East development plan includes drilling additional 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. Some investment wellwork projects have been identified and these projects will target insufficiently swept pay.

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

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

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

Critical Issues

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

- Updating the Ranger East eclipse simulation model with 2015-2016 production and development projects
- 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 (primarily R90N)

Terminal Zone
Reservoir Management Plan

History

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

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

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

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

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

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

Status

As of November 2016, the total production from the Terminal zone is 2,945 BOPD and 143,172 BWPD resulting in an average WOR of 49. There are currently 119 active producers. Terminal zone injection for November 2016 is 151,859 BWIPD from 65 wells. Average active well rates were 25 BOPD and 1,198BWPD for producers and 2,322 BWIPD for injectors. Five Terminal wells are currently mechanically idle and potentially capable of being reactivated with further investment. Evaluations of repair and/or conversion options as well as uphole potential are currently underway for these wells.

Cumulative production through November 2016 totaled 153.41 MMBO (35.18% OOIP). Excluding development, base decline has been approximately 11 % over the past two years.

Calendar Years 2015 and 2016 Activities and Results

Since publication of the last Program Plan, 1 producer (cased-hole completion vertical) has been drilled and completed in the Terminal pool.

The average initial stabilized rate (3 month average) for the vertical producer drilled is 56 BOPD with initial rates ranging from 30 BOPD to 75 BOPD. The average expected rate is 60 BOPD (the completion strategy of this project was changed due to drilling issues).

During the 2015-2016 Plan period, a total of 2 development (investment) wellwork jobs were also completed (two producers). The investment projects were selective recompletions/add pay projects. Overall, the producer development wellwork has returned an average of 55 BOPD/job at a cost of $400,000 per job. 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.

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. Current plan is to target the center part of upper terminal reservoir where there is minimal depletion. Several investment wellwork projects are also planned. These objectives will be met by utilizing the various Unit programs currently in-place. The best 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 and 39 is to gather pressure data and saturations to improve recovery and vertical conformance due to the block's waterflood maturity and highly layered system. In addition, a highly selective drilling program will be conducted to target bypassed oil via Z and HXC horizontals. The reservoir management goal for UT6 CRB-39 is to increase the overall level of development through infill drilling in this less mature block. Increased throughput and optimization of vertical and areal conformance will increase recovery in the block. The development strategy for UT7 includes crestal injection to augment the current peripheral injection configuration due to the area's highly faulted nature. Finally, injection and infill development in Fault Block 90 will continue to be tailored to the improved understanding of fault compartmentalization.

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

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

Critical Issues

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

- Update the Terminal East and West streamline models with the latest production, completion and log data. Complete the updated history match on the Terminal West model.
- Improve vertical conformance in UT6 CRB-38/39 through the selective drilling of 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 in TE & update seismic data in TE).
- Improve structural understanding in TE90 with the reprocessing of the seismic data. With the new interpretation, improve fault play vertical/horizontal exploitation.
- Evaluate the feasibility of Z and HXC horizontals primarily in CRB 38.
- 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 identifying producer acid candidates (Terminal has the most successful acid jobs among East Reservoir projects).
- Optimize injection by utilizing the results of the improved Streamsim Surveillance model.

UPF Zone
Reservoir Management Plan

History

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

The UP-Ford reservoir is complex from both reservoir and operational perspectives. Since it underlies the Ranger and Terminal zones, 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 because of the sensitive nature of the formation.

From the late 1990's, success in pattern waterflood development in the Tract II area was achieved through the adoption of non-damaging drilling and completion techniques. As a result, UP-Ford oil production rate reached a 20-year high (6978 STB/D oil) during early 1998. During the early 2000's, attempts to further 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 the 2010's, multiple stimulated wells and open hole slotted liner hybrid completions have shown promise in increasing UPF oil production.

Status

The UP-Ford production rates in November 2016 were 1,880 BOPD and 65,220 BWPD (96.1% water cut) from 77 producers. November 2016 injection averaged 64,611 BWIPD from 41 injectors. Average active well rates were 24 BOPD and 842 BWPD for producers and 1,559 BWIPD for injectors

UP-Ford currently has 4 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 November 2016 was 108.5 MMBO (24.9% OOIP). For the January 2015 to November 2016 period the base potential production in UP-Ford reservoir declined 18% annually, with a steeper decline in 2015 caused by wells drilled in 2014, and a shallowing decline in 2016. Maintenance wellwork continues to play a major role in maximizing UP-Ford base production.

Calendar Years 2015 and 2016 Activities and Results

Since publication of the last Program Plan, no producers or injectors have been drilled and completed in the UP-Ford pool.

Reservoir Management Objectives

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

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

Strategies

The development plan for UP-Ford moving forward includes continued activity in this reservoir. Due to the downturn in oil price, most of the development activity will be focused on maintaining base production, increasing injector conformance and drilling 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. 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 northern CRB 45 with infill producers and injectors to improve the low recovery factor and support CRB 46 development wells by fixing current injectors
- Further leverage well design and completion alternatives for increasing infill well deliverability.
- Horizontal/slant wells are drilled in AE, AK1 and AO sands currently and will be further tested in AF, AI, AM and AR sands in the future.
- Continue to refine non-reservoir-damaging procedures to complete and work over wells and determine injection water quality requirements.
- Increase pressure support in the upper reservoir sands utilizing in-zone injectors and conformance improvement projects for existing injection wells through stimulation and mechanical methods.
- Continue to delineate the Northern down-dip extent of UP-Ford CRB 44 and CRB 45.
- Incorporate any new structural understandings from the reprocessed seismic data towards improved development and reservoir management.

237 Zone
Reservoir Management Plan

History

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

The Hot Shale member of the Lower 237 Zone is a world-class oil source rock. It is correlative with the Nodular Shale of the western Los Angeles Basin. It probably contributed most of the oil trapped within the Long Beach Unit. The Hot Shale contains 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 1,800 BOPD.

The first 237 Zone well was completed in 1968 at an initial rate of 1,050 BOPD. Twenty more wells have been completed in the LBU. All wells reported oil and gas shows while drilling through the lower 237 Zone. Six of the wells were economic, one was marginally economic, twelve were uneconomic and the most recent two are still being evaluated. One of the wells was a mechanical failure and did not properly evaluate the lower 237 Zone. The uneconomic wells may have been damaged during drilling or lacked sufficient permeability to be productive. Through November 2016, cumulative production from the 237 Zone/acoustic basement is 4.28 MMBO.

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

Status

C355 and C252 were drilled from 2009 to 2011 with not much success. C348 was drilled in 2012 with some success but due to high temperature it was not feasible to keep the ESP running and it's currently down. There is no current production from 237 zone.

Reservoir Management Objectives and Studies

In 2014, the 237 Reservoir Management Team completed a study with a focus on trying to understand what makes an economic 237 producer as opposed to an uneconomic producer. All 237 wells in the LBU were studied. Timing, geologic/structural location, formation open to completion, completion type, completion angle, initial production and cumulative production were all 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." The plan forward is to combine all studies and draft a blueprint for 237 future development.

Critical Issues

- Reprocess/Reinterpret LBU seismic data with a focus on the 237 Shale zones and Seismic basement.
- Re-evaluate economics and risk on C-348 and review plan to red-drill C250.
- 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.

The bulk of the Shallow Gas reserves reside below Island Grissom with additional proven developed reserves accessible from Island White. Gas shows have been found in wellbores originating on Island Chaffee and Pier J. Development of Shallow Gas reserves began from Island Grissom due to the availability of commercially identifiable reserves for development from this location. Shallow Gas production commenced May 18, 2006 from one well. Development of Shallow Gas from Island White was initiated on February 15, 2010. To date 8 wells have been recompleted as Shallow Gas producers (7 on Island Grissom, 1 on Island White) and one horizontal well has been drilled. As of December 2016, because of economics, the remaining shallow gas zone producer B-403 was shut-in and plugged.

Status

Cumulative Grissom production through 2016 totals over 5.2 BCFG (approximately 69.7% OGIP) in excess of initially estimated ultimate recovery expected to reach over 4.4 BCFG (61.0% OGIP) in 2011 for the Grissom Gas reservoir. Cumulative White Gas production amounts to over 400 MMCF.

Reservoir Management Objectives

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

Strategies

The development plan, when natural gas prices exceed approximately $6/MCF, 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, low 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.