CITY OF LONG BEACH
Gas & Oil
DEPARTMENT

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R-14

March 5, 2013

HONORABLE MAYOR AND CITY COUNCIL
City of Long Beach
California

RECOMMENDATION:

Approve the Long Beach Unit Annual Plan (July 1, 2013 - June 30, 2014) and the Program Plan (July 1, 2013 - June 30, 2018). (Citywide)

DISCUSSION

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

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

The Annual Plan and Program Plan provide for the further development of the LBU through the Agreement for Implementation of an Optimized Waterflood Program that was entered into in November 1991 as part of the above legislation. Preparation is a joint effort by the staffs of the City of Long Beach, Gas and Oil Department (Unit Operator), OLBI (Field Contractor), and THUMS Long Beach Company (Agent for Field Contractor). A copy of the Annual Plan and Program Plan is attached.

This matter was reviewed by Deputy City Attorney Richard Anthony on January 31, 2013 and by Budget Management Officer Victoria Bell on February 5, 2013.

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, 2013. To meet that requirement, City Council approval is requested on March 5, 2013.

FISCAL IMPACT

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

SUGGESTED ACTION:

Approve recommendation.

Respectfully submitted,

CHRISTOPHER J. GARNER
DIRECTOR OF LONG BEACH GAS AND OIL

CJG:kmt

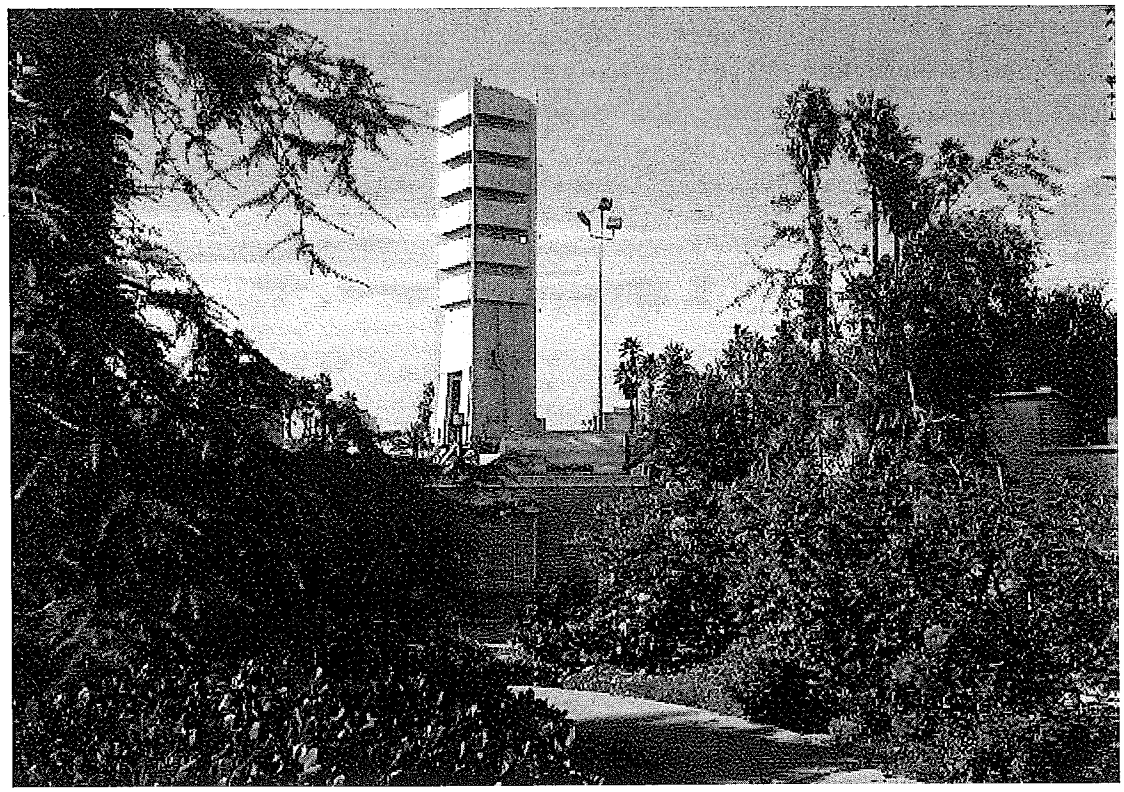
Attachments:
Long Beach Unit Annual Plan
Long Beach Unit Program Plan

APPROVED:

PATRICK H. WEST
CITY MANAGER

Long Beach Unit

THUMS Long Beach Company
(Agent for Field Contractor)



ANNUAL PLAN

July 1, 2013 through June 30, 2014

ANNUAL PLAN

July 1, 2013 through June 30, 2014

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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, 2013 through June 30, 2014 ("FY14"). 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 approved by the State of California, the City of Long Beach, and Atlantic Richfield Company, whose interest has been assigned to Occidental Petroleum Corporation.

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 2013 – 2014 ($ Million)
Development Drilling	$ 147.1
Operating Expense	$ 100.5
Facilities, Maintenance, and Plant	$ 87.8
Unit Field Labor and Administrative	$ 59.8
Taxes, Permits, and Administrative Overhead	$ 43.1
Total	$438.4

A. Plan Basis

This Plan was developed based on the parameters outlined in the Program Plan for the period July 2013 through June 2018 and provides current and updated estimates of volumes, drilling activity and expenditures for FY14.

Volumes

Oil and gas production volumes are predicted to average 24.3 Mbopd and 8.2 MMcfd, respectively, in FY14. Water production for the period is expected to average 1,080 Mbwpd and water injection is expected to average 1,162 Mbwpd.

Revenue and Expenses

A projected oil price of $65.00/bbl Wilmington and gas price of $4.00/mcf will result in revenues of $588 million. Budgeted expenses for FY14 total $438 million. Projected net profit in FY14 is $150 million.

Drilling

This Plan allows for drilling approximately 78 new and redrilled development and/or replacement wells. The plan is to use approximately three drilling rigs. The rig utilization could potentially change due to variations in oil price and program performance. Workover rigs will perform drilling preparation and completion work.

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

Maintenance

Most of the major facility projects anticipated during the Plan period are required to maintain current equipment capabilities or to enhance operations. Other projects will be necessary to take advantage of improvement opportunities and to address changes in the oil field operating environment.

The Unit has a Mechanical Integrity and Quality Assurance (MIQA) program to assess and maintain critical equipment. 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, repair or replacement. The program is supported through the use of a comprehensive database and work order system that provides control and management of all maintenance activities.

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

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

The Unit is committed to conducting all aspects of its business in a manner that provides for the safety and health of employees, contractors and the public, and safeguards the environment in which it operates. Key safety programs include incident reporting and investigation, safety meetings and training, Management of Change (MOC), Process Hazard Reviews (PHR), emergency response planning and drills, and a behavior based safety observation program. Key aspects of the Environmental program include compliance with AQMD requirements, waste management and minimization, spill prevention plans and Business Emergency Plans (BEP's).

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

Emergency response planning and preparedness is bolstered by partnering with Marine Spill Response Corporation (MSRC). MSRC is an independent, non-profit, national spill response company dedicated to rapid response to environmental incidents. In 2010, MSRC provided the single largest oil spill response effort for the BP Macondo incident. MSRC has a major west coast base of operations in the Port of Long Beach and their equipment and expertise is readily available for Unit emergencies and is incorporated in onsite training exercises. The training exercises also involve a close working relationship with the United States Coast Guard and California Department of Fish and Game.

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

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

The State Lands Commission completed a comprehensive Safety and Environmental audit of the Unit. This audit is intended to both verify and potentially improve the Unit performance in these areas. This audit consisted of approximately 10 months of field review and a final report. Funding is included in the fiscal plan to address any findings from this audit..

Economic Review

Project expenditures during the Plan period are subject to economic review through the Determination and Authority for Expenditure 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.

The Unit 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 FY14	BUDGET SECOND QUARTER FY14	BUDGET THIRD QUARTER FY14	BUDGET FOURTH QUARTER FY14	BUDGET TOTAL FY14
ESTIMATED REVENUE					
Oil Revenue	$146.4	$147.4	$142.0	$140.1	$576.0
Gas Revenue	$3.1	$3.1	$3.0	$2.9	$12.1
TOTAL REVENUE	$149.5	$150.5	$145.0	$143.1	$588.0
ESTIMATED EXPENDITURES					
Development Drilling	$29.8	$40.7	$35.5	$41.0	$147.1
Operating Expense	$25.7	$24.7	$24.5	$25.6	$100.5
Facilities & Maintenance	$20.7	$22.9	$22.1	$22.1	$87.8
Unit Field Labor & Administration	$12.4	$22.5	$12.5	$12.5	$59.8
Taxes, Permits & Overhead	$11.1	$10.7	$10.6	$10.6	$43.1
TOTAL EXPENDITURES	$99.8	$121.5	$105.3	$111.8	$438.4
NET PROFIT	$49.6	$29.0	$39.7	$31.3	$149.6

C. MAJOR PLANNING ASSUMPTIONS

	BUDGET FIRST QUARTER FY14	BUDGET SECOND QUARTER FY14	BUDGET THIRD QUARTER FY14	BUDGET FOURTH QUARTER FY14	BUDGET TOTAL FY14
OIL PRODUCTION					
PRODUCED (1000 BBL)	2,253	2,268	2,185	2,156	8,862
(AVERAGE B/D)	24,486	24,649	24,279	23,694	24,277
GAS PRODUCTION					
PRODUCED (1000 MCF)	766	771	743	733	3,013
(AVERAGE MCF/D)	8,325	8,380	8,255	8,056	8,254
WATER PRODUCTION					
PRODUCED (1000 BBL)	97,615	99,177	97,911	99,362	394,066
(AVERAGE B/D)	1,061,037	1,078,015	1,087,904	1,091,893	1,079,712
WATER INJECTION					
INJECTED (1000 BBL)	105,094	106,761	105,359	106,876	424,091
(AVERAGE B/D)	1,142,329	1,160,443	1,170,660	1,174,466	1,161,974
OIL PRICE ($/BBL)	$65.00	$65.00	$65.00	$65.00	$65.00
GAS PRICE ($/MCF)	$4.00	$4.00	$4.00	$4.00	$4.00

Part II

Program Plan Schedules

Schedule 2 A

Range of Production and Injection
FY 2014
Long Beach Unit Program Plan, July 2013-June 2018

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2013/14	23.1 - 25.5	1,026 - 1,134	7.8 - 8.7	1,112 - 1,229

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2013/14	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Schedule 2 B
Anticipated New and Redrilled Wells
Fiscal Year 13/14
Long Beach Unit Program Plan, July 2013-June 2018

Reservoir	CRB	Producers					Injectors				
		Grissom	White	Chaffee	Freeman	Pier J	Grissom	White	Chaffee	Freeman	Pier J
		Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max
Tar	35	0 - 1	0 - 2	0 - 0	0 - 0	0 - 0	0 - 1	0 - 2	0 - 0	0 - 0	0 - 0
SG		0 - 0	0 - 2	0 - 1	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0
Ranger West	1	0 - 5	0 - 0	0 - 0	0 - 0	0 - 0	0 - 7	0 - 0	0 - 0	0 - 0	0 - 0
	2	0 - 3	0 - 1	0 - 0	0 - 0	0 - 0	0 - 3	0 - 1	0 - 0	0 - 0	0 - 0
	3	0 - 7	0 - 1	0 - 0	0 - 0	0 - 0	0 - 2	0 - 1	0 - 0	0 - 0	0 - 2
	4	0 - 1	0 - 1	0 - 0	0 - 1	0 - 2	0 - 0	0 - 1	0 - 0	0 - 1	0 - 2
	5	0 - 0	0 - 0	0 - 0	0 - 1	0 - 2	0 - 0	0 - 0	0 - 0	0 - 1	0 - 2
	7	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0
	8	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	9	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	10	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	11	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	12	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	13	0 - 0	0 - 1	0 - 0	0 - 1	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	36	0 - 0	0 - 0	0 - 0	0 - 0	0 - 5	0 - 0	0 - 0	0 - 0	0 - 1	0 - 1
	37	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Ranger East	14	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	15	0 - 0	0 - 1	0 - 0	0 - 2	0 - 0	0 - 0	0 - 1	0 - 0	0 - 2	0 - 0
	16	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 1	0 - 0	0 - 0
	17	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0
	18	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0
	20	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0
	21	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0
	22	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0
	32	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	33	0 - 0	0 - 0	0 - 5	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Terminal	24	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 1	0 - 1	0 - 0	0 - 1	0 - 0
	38	0 - 1	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2
	39	0 - 1	0 - 1	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	40	0 - 1	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	41	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1
	42	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
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		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 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	27	0 - 0	0 - 1	0 - 1	0 - 1	0 - 0	0 - 0	0 - 1	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 - 1	0 - 1	0 - 0	0 - 0	0 - 2	0 - 0	0 - 1	0 - 0	0 - 0	0 - 1
	44	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 1	0 - 0
	45	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 1	0 - 1	0 - 0	0 - 0
	46	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0
237	30	0 - 1	0 - 0	0 - 2	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		Total					Total				
		0 - 89					0 - 62				

Part III

Itemized Budget of Expenditures

A. Development Drilling $147.1MM

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 78 wells will be developed and/or replaced during the Plan year and 26 investment wellwork projects will be carried out, using approximately two and half drilling rigs and two workover rigs, respectively.

Drilling and completing new wells, as well as redrilling and recompleting existing wells, account for 98 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 OXY Long Beach, Inc. (OLBI). These decisions will be influenced by contributions from reservoir engineering personnel, results from ongoing engineering studies, and new well performance. This information will be reviewed and approved in accordance with Unit Agreements during regularly scheduled Unit forums.

B. Operating Expense $100.5MM

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 24.3 Mbopd, estimated gas production of 8.3 MMcfpd, water injection requirement of 1,170 Mbwpd, and water production of 1,103 Mbwpd. Anticipated operating expenses were based on operating four workover rigs per month for servicing an average active well count of 765 producers and 467 injectors. 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 39 percent of the funding provided in this category. Included are funds for stimulation, recompletions, routine well work, well conversions, in-zone plugs, conditional abandonments, and other charges incurred for well maintenance.

Electricity makes up 48 percent of the funds in this Category. Cost for electric power is based on estimated kilowatt usage of 723,825,000 Kwh at an average rate of $0.067/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 $87.8MM

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

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

Approximately 51 percent of the funding in this Category is for facilities repair and improvement projects. Approximately 20% of the repair project category is focused on inspection, maintenance and repair in support of the MIQA program. This work includes regulated pipeline inspection surveys and evaluation, inspection and repair of cathodic protection systems, and infrastructure piping integrity inspections not covered by regulatory control.

Improvement projects include spending for the construction of the Pier J electrical distribution, Freeman 700-800 Cellars, Grissom Injection Pump and other infrastructure related investments that position the Unit for longevity.

D. Unit Field Labor and Administrative $59.8MM

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 THUMS employees. These costs represent approximately 94 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; Department of Transportation drug and alcohol testing; special management projects; and other miscellaneous support charges.

E. Taxes, Permits, and Administrative Overhead $43.1MM

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 59 percent of the Category total.

Funding is also provided in this Category for all Administrative Overhead (including Unit Operator billable costs and OLBI 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 OLBI, to the State Lands Commission in accordance with Article 2.06 of the Optimized Waterflood Program Agreement.

In addition, on or before October 1, 2014 the City of Long Beach shall present to the State Lands Commission a final report and closing statement of the FY14 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 OLBI, 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

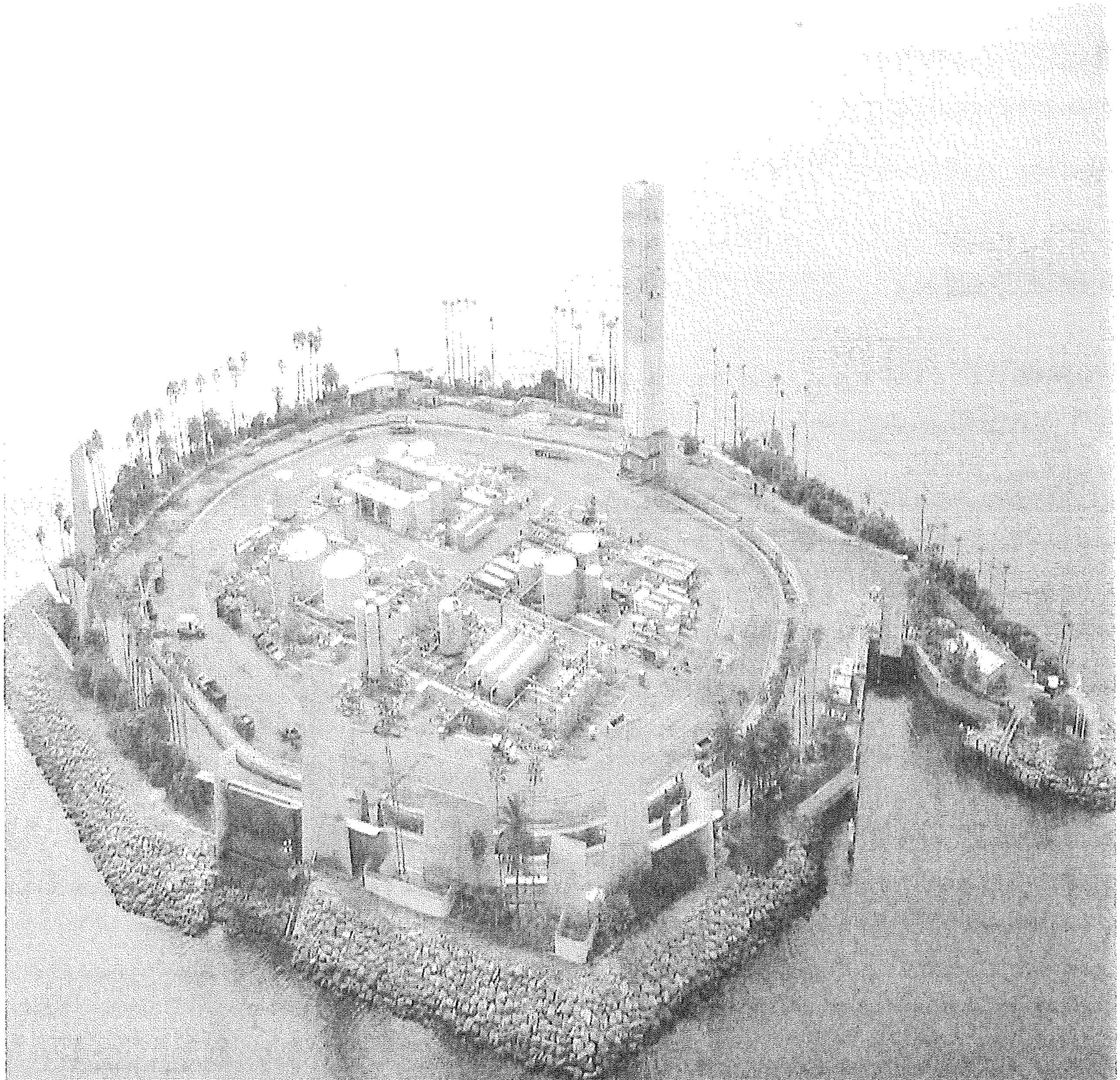
This Annual Plan contains all the investment and expense projects reasonably anticipated at the time the Plan was drafted and for which adequate detailed studies existed. Any significant and uncommon expenses not originally contemplated may be added to this budget or transferred by a supplement in accordance 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 FY14 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 2013 – June 2018

PROGRAM PLAN

Long Beach Unit

July 2013 through June 2018

Prepared Jointly by:

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

OXY Long Beach, Inc.
(Field Contractor)

THUMS Long Beach Company
(Agent for the Field Contractor)

February 2013

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Executive Summary

This Program Plan covers the period from July 1, 2013 through June 30, 2018. The purpose of the Plan is to describe key issues facing the Unit and to outline strategies for maximizing profitability while maintaining excellence in safety and environmental protection. This Plan is the culmination of a cooperative effort by the Long Beach Gas & Oil Department, City of Long Beach (Unit Operator), OXY Long Beach, Inc. (Field Contractor), and THUMS Long Beach Company (agent for the Field Contractor). The Program Plan meets requirements of Section 2.03 of the Optimized Waterflood Program Agreement ("OWPA").

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

The Plan includes expenses associated with drilling 344 development and replacement wells over the life of the Program Plan. This schedule will result in a steady decline in oil production rate through the end of FY17/18. Unit production and injection rates are expected to average 24.3 Mbopd, 1,079.7 Mbwpd and 1,170.2 Mbwipd in FY13/14 and 23.2 Mbopd, 1,117.4 Mbwpd and 1,209.1 Mbwipd in FY14/15, respectively.

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

Facility improvement projects envisioned during the Plan include completion of the Freeman 700-800 cellar culvert piping project and procurement and installation of a new injection pump at Is. Grissom. These projects are intended to upgrade and ensure continued, efficient, fluid handling. Other work will focus on electrical infrastructure improvements at Pier J which will provide additional well capacity required to support the planned development program. Other improvements are focused on right-sizing facility capacity limits to accommodate the forecast drilling program throughout all 5 years of the Program Plan period. These investments result in enhancement of revenue streams, lower maintenance and operational costs, and improved safety and environmental performance. The first year of the Program Plan also includes funds to design and install replacement skim-basin liners to allow the Unit to meet regulatory requirements.

Based on production from 78 development and replacement well projects planned for FY13/14 of the Program Plan and an average oil price of $65.00/bbl, total revenue, expenditures, and net profits are projected to be $588.0 million, $438.4 million, and $149.6 million, respectively. Over the five-year Program Plan period, cumulative total revenue, expenditures, and net profit are expected to reach $2,775.6 million, $2,151.7 million, and $623.9 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, 2013 through June 30, 2018. The purpose of this Plan is to describe key issues facing the Unit, and to outline strategies for maximizing profitability while maintaining excellence in safety and environmental protection.

This Plan is divided into four major sections:

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

- The *Unit Reservoir Management Plan* section outlines strategies to be employed in reservoir development and management. An overview of the field-wide goals and strategies is provided. Appendix 1 contains a more detailed Reservoir Management Plan for the six reservoir areas: Ranger West/Tar, Ranger East, Terminal, UP Ford, 237 Zone and Shallow gas zone .

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

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

- The *Economic Summary* section provides a forecast of Unit revenues, expenditures, and profits anticipated during the Plan period, assuming an oil price of $65.00/bbl during the Program Plan period and gas price of $4.00/mcf. This section also includes the schedules that will be incorporated into the FY13/14 and FY14/15 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. Generally, a 2-rig pace has been maintained, excepting for times when opportunities arise and are pursued (for example, due to the price environment or 237-zone exploration). A rig count between two to three is assumed for the Program Plan.

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

In April 2000, Occidental Petroleum Corporation bought all of Atlantic Richfield Company's stock in ALBI. As a result, the Field Contractor name was legally changed from ALBI to OXY Long Beach, Inc. (OLBI).

Unit Reservoir Management Plan

Goal

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

Reservoir Management Strategy

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

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

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

Production and Surveillance

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

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

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

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

Development Opportunities

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

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

The Long Beach Unit has embarked on an effort to improve reservoir characterization across the Unit. With the assistance of Oxy's Worldwide Reservoir Characterization Group, and local staff, the Long Beach Unit continues to assess, understand and refine its knowledge of the reservoir and develop new production opportunities.

Technology

Advances in drilling and completion technology continue to be a significant factor in realizing development drilling opportunities. Key technologies being developed and applied include horizontal well placement, water shut-off techniques, special design and extended reach wells, cased hole completions and low cost replacement wells. The Unit maintains a Technology Plan that identifies technology needs, impacts, and implementation issues. Operational and technological areas addressed by the Plan include wellwork and drilling, facilities, reservoir (profile control, behind-pipe-oil detection, conformance evaluation software tools, reservoir modeling software tools, 3D reservoir characterization), and Health, Environmental and Safety training. Enhanced oil recovery applications will be considered for implementation if economically and technically viable.

Unit Forecasts

Drilling Schedule

The Program Plan projects development and replacement drilling to average approximately 78 wells per year for FY13/14 and FY14/15. This schedule can be met with approximately 3 Unit drilling rigs running continuously. Workover rigs will continue to be used for new well completions to capitalize on improved completion quality control and to provide better drilling rig efficiency.

Exhibit B shows the drilling plan by Unitized Formation 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 FY13/14 and FY14/15. 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 FY13/14 and FY14/15, respectively. These forecasts were developed by combining a forecast of existing well performance with the expected results of the previously outlined development plan. The expected case injection forecast shown in Exhibit D was generated based on the gross fluid rates from the production forecast. Graphs comparing historical and predicted field rate performance data are presented in Exhibits E and F. The plots clearly show the variability of historical rate data, necessitating the use of rate ranges to account for uncertainty in the rate projections.

The oil and water production forecast for the existing wells is based on a process that uses an extrapolation of wells within each Unitized Formation summed together to yield a forecast of the existing wells' production for the entire Unit. For each well, the expected future oil and water rates are extrapolated from historical trends of oil and gross fluid rates vs. time and the trend of water-oil ratio vs. cumulative oil production using conventional decline curve techniques. The resulting prediction shows a near term exponential decline ranging from 10 to 13% per year for the existing wells.

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.

Major Issues and Projects

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

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

People

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

Health and Safety

The Unit is committed to conducting all aspects of its business in a manner that provides for the safety and health of employees, contractors and the public, and safeguards the environment in which it operates. Key safety programs include incident reporting and investigation, safety meetings and training, Management of Change (MOC), Process Hazard Reviews (PHR), emergency response planning and drills, and a behavior based safety observation program. Key aspects of the Environmental program include compliance with AQMD requirements, waste management and minimization, spill prevention plans and Business Emergency Plans (BEP's).

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

Emergency response planning and preparedness is bolstered by partnering with Marine Spill Response Corporation (MSRC). MSRC is an independent, non-profit, national spill response company dedicated to rapid response to environmental incidents. In 2010, MSRC provided the single largest oil spill response effort for the BP Macondo incident. MSRC has a major west coast base of operations in the Port of Long Beach and their equipment and expertise is readily available for Unit emergencies and is incorporated in onsite training exercises. The training exercises also involve a close working relationship with the United States Coast Guard and California Department of Fish and Game.

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

The State Lands Commission completed a comprehensive Safety and Environmental audit of the Unit. This audit is intended to both verify and potentially improve the Unit performance in these areas. This audit consisted of approximately 10 months of field review and a final report. Funding is included in the fiscal plan to address any findings from this audit.

Environmental Protection

The Unit is committed to the protection of the environment, and as such has identified this as a key goal. All operations are conducted to minimize environmental impacts and comply with all applicable laws, regulations, and policies.

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

Personnel awareness is also essential for an effective Environmental Program. Training will be conducted routinely to meet all regulatory requirements and other environmental awareness training will be conducted as areas of need are identified.

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

The Unit continues to strive to improve the environmental record attained by its employees and is proud of its accomplishments, including the Wildlife Habitat Council Certification of all four THUMS Islands. To ensure continued compliance, environmental assessments are undertaken by Unit personnel and outside organizations.

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 RMT and Well Surveillance Leaders, have been periodically modifying the voidage accounting rules to ensure stable ground elevations, while providing prudent operational flexibility to improve waterflood management. A collaborative effort is used on the methodology for the voidage account, and to identify key wells to survey for bottomhole pressures to support semi-annual ground elevation measurements.

Well Abandonment Plan

The Unit attempts to minimize the inventory of idle wells that have no further economic benefit. Each plugback of an idle well reduces the ultimate liability for that well to the cost of completing the surface abandonment. This prudently reduces overall future abandonment liability as well as the potential for detrimental in-zone cross flow.

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

Cost Management

The Unit continuously strives to be efficient in spending its operational funds. Emphasis is given to spending funds wisely, investing in opportunities with the best economic return, and continuing to look for ways to become more efficient in business operations. Employing effective cost management strategies will aid in achieving the Unit's goal of performing in the lowest cost per net barrel quartile for comparable operations. Cost management gains will be aggressively pursued during the term of this Plan. Some of the areas where the Unit plans to make substantial gains 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, will be optimized in conjunction with Power Plant operations. Process optimization, best operating practices, and operating cost reductions will be focus areas. Improvements in electrical efficiency, optimization of make-up water sources, maintaining water quality, enhanced well surveillance, and improved coordination between operations, wellwork, and facility maintenance are expected outcomes over the Program Plan period.

Maintenance Wellwork and Drilling Operations: In order to reduce overall Unit development costs, several challenges will be addressed during the Program Plan period. These include rig resource allocation, rig equipment, wellbore maintenance, high demand for quality labor and equipment, increased labor rates, improving safety performance, reducing well failures, and complex formation injection and pressure profile optimization projects. Several teams have been formed to focus on these areas of the business.

Drilling/Wellwork Equipment: Future drilling activity can be accomplished on Pier J, and Islands Chaffee and Freeman with the use of Unit Rig T-9. Activity on Grissom can be accomplished with Unit Rig T-5. Activity on Island White can be accomplished with Unit

Rig T-3. Additional drilling methods or equipment will be considered for lowering drilling costs on all locations. These additional equipment could include contract drilling rigs, workover rigs and coiled tubing units and the use of top drive components.

Mechanical Integrity

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

Expansion of Pier J Electrical Infrastructure

Expansion of current electrical facility will be needed to provide electrical capacity for the field development during the Program Plan period at the Pier J facilities. The existing electrical service capacity is sufficient to handle the current load but will not be able to handle future development. Activities to help achieve capacity expansion include new SCE 66KV service substation, transformers, electrical switchgears, motor control centers, and conduits. The planned expansion will also optimize system reliability by providing back-up service to minimize production downtime in the event of a primary electrical service failure. This Plan includes funding to complete the upgrades needed to meet the anticipated drilling activity.

Electricity Generation

Electricity is the single largest cost element for the Unit. Currently the Unit consumes approximately 720 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 47MW power generation plant in an effort to increase the California in-state generation supply, as well as insulate the Unit from the risks of electricity supply disruptions and escalating wholesale electric costs. The plant commenced operations in FY02/03.

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

Efforts will also focus on electrical production equipment efficiency. Injection pumps will utilize power monitoring devices to identify opportunities for improving their electrical efficiency. Work will also continue with the Unit's submersible pump supplier to identify opportunities for reducing power usage on submersible pumps.

Taxes

The County of Los Angeles has significantly increased the assessed value of the Unit. Estimation of taxes for the Plan period assume an annual 4% increase, although determination of actual tax levies will be based on assessor valuation, driven by oil price and cost projections.

Make-up Water Sources

A reliable source of water to be used for injection is vital to the success of the Unit. Water injected into the formations serves two purposes: 1) controlling subsidence and 2) enhancing oil recovery. In order to meet voidage targets, make-up water is purchased from sources outside the Unit. The Unit's primary make-up water sources include Tidelands Oil Production Company produced water and Long Beach Water Department (LBWD) reclaimed water. The Unit evaluated the usage of reclaimed water because of quality issues related to Tidelands water and the high cost and potential for interruptions in supply of the LBWD fresh water. This evaluation resulted in the Unit installing facilities to utilize reclaimed water supplied by the LBWD. Reclaimed water provides a long-term source of make-up water at a lower cost than fresh potable water.

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

Economic Summary

Revenue Forecast

Unit Revenue will be generated from the sale of oil and gas from six producing formations: Lower Pliocene shallow gas sands, Tar, Ranger West, Ranger East, Terminal, and UP Ford/237. The projected revenue during the Program Plan period is $2,775.6 million, based on a $65.00/bbl oil price and $4.00/mcf gas price, and average daily oil and gas production as projected in Exhibit C. Projected revenue for FY13/14 is expected to be $588.0 million.

Cost Forecast

Total estimated expenditures for the first year of this Program Plan are consistent with the FY13/14 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 $2,151.7 million. The projected expenditures for FY13/14 are $438.4 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 $623.9 million. Unit profit for FY13/14 is expected to be $149.6 million. A schedule of annual projected revenue, expenditures, and net profit is given in Exhibit A.

Budget commitments for FY14/15 will be established based on actual results and additional insights gained during FY13/14.

Table 1

SUMMARY OF PRODUCTION AND INJECTION
AS OF OCTOBER 2012
JULY 2013 – JUNE 2018 PROGRAM PLAN, LONG BEACH UNIT

		Active Well Count:		Average Rates for October 2012				Average Well Rates	
Reservoir	CRB	Producers	Injectors	BOPD	BWPD	BIPD	Wtr Cut	BOPD/ Well	BIPD/ Well
SG	65	0	0	0	0	0	0%	-	-
	66	0	0	0	0	0		-	-
Tar	35	4	1	53	694	1,365	93%	13	1,365
Ranger	1	39	26	1,025	54,648	64,344	98%	26	2,475
West	2	28	14	991	40,992	40,304	98%	35	2,879
	3	33	26	1,280	65,922	82,030	98%	39	3,155
	4	62	27	2,195	120,628	98,504	98%	35	3,648
	5	33	25	1,663	81,632	86,076	98%	50	3,443
	7	18	7	493	24,175	21,100	98%	27	3,014
	8	14	8	388	22,199	21,897	98%	28	2,737
	9	13	6	409	12,891	8,868	97%	31	1,478
	10	24	21	897	32,710	43,684	97%	37	2,080
	11	12	5	506	13,165	10,335	96%	42	2,067
	12	10	5	344	10,438	10,841	97%	34	2,168
	13	9	5	261	16,405	11,481	98%	29	2,296
	36	19	18	701	32,891	54,017	98%	37	3,001
	37	5	8	221	11,103	20,141	98%	44	2,518
	Total	**323**	**202**	**11,427**	**540,493**	**574,987**	**98%**	**35**	**2,846**
Ranger	14	17	14	614	24,133	38,341	98%	36	2,739
East	15	46	21	1,488	59,691	59,195	98%	32	2,819
	16	19	8	512	17,064	15,215	97%	27	1,902
	17	28	13	1,006	23,136	26,876	96%	36	2,067
	18	13	13	313	14,413	29,643	98%	24	2,280
	20	10	5	349	10,004	12,890	97%	35	2,578
	32	1	2	28	1,405	5,525	98%	28	2,763
	33	30	20	1,189	50,213	43,479	98%	40	2,174
	21	38	23	1,366	55,710	54,642	98%	36	2,376
	22	17	6	415	14,748	12,587	97%	24	2,098
	Total	**219**	**125**	**7,280**	**270,517**	**298,393**	**97%**	**33**	**2,387**
Terminal	24	28	18	627	20,536	28,706	97%	22	1,595
	38	35	19	957	50,593	54,774	98%	27	2,883
	39	27	12	871	29,175	28,264	97%	32	2,355
	40	5	6	90	3,138	4,821	97%	18	804
	41	5	3	223	6,050	6,142	96%	45	2,047
	42	8	5	183	6,904	8,759	97%	23	1,752
	43	36	16	855	31,148	25,412	97%	24	1,588
	47	4	1	12	573	-	98%	3	-
	Total	**148**	**80**	**3,818**	**148,117**	**156,878**	**97%**	**26**	**1,961**
UP/Ford	26	0	1	-	-	1,176	0%	-	1,176
	27	18	15	705	15,416	17,006	96%	39	1,134
	31	9	4	94	3,634	4,302	98%	10	1,076
	44	5	6	89	2,622	4,912	97%	18	819
	45	22	13	632	14,488	11,402	96%	29	877
	46	25	16	660	18,835	18,209	97%	26	1,138
	Total	**79**	**55**	**2,180**	**54,995**	**57,007**	**96%**	**28**	**1,036**
237	30	1	0	-	139,636	-	97%	-	-
	LBU Total	774	463	24,758	1,154,452	1,088,630	98%	32	2,351

Exhibit A

ECONOMIC PROJECTIONS
July 1, 2013 through June 30, 2018 Program Plan
(Million Dollars)

	Fiscal 2013/14	Fiscal 2014/15	Fiscal 2015/16	Fiscal 2016/17	Fiscal 2017/18	Program Plan Period
Estimated Revenue						
Oil Revenue	$576.0	$551.2	$543.5	$527.6	$520.5	$2,718.7
Gas Revenue	$12.1	$11.5	$11.4	$11.0	$10.9	$56.9
Total Estimated Revenue	$588.0	$562.7	$554.9	$538.6	$531.4	$2,775.6
Estimated Expenditures	$438.4	$435.8	$419.4	$425.9	$432.2	$2,151.7
Net Income	$149.6	$126.9	$135.5	$112.7	$99.2	$623.9

Exhibit B

Anticipated Drilling Schedule
July 1, 2013 through June 30, 2018
(Number of Wells)

FISCAL YEAR	RANGER WEST	RANGER EAST	TERMINAL	U.P. FORD/ 237	TOTAL WELLS
2013/14	49	16	10	4	78
2014/15	52	8	12	7	79
2015/16	28	23	10	6	66
2016/17	18	30	1	10	59
2017/18	24	26	0	12	62

* 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 2013-June 2018 Program Plan
Long Beach Unit

FISCAL YEAR	EXPECTED RANGE			EXPECTED RATE		
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	OIL MBOPD	WATER MBWPD	GAS MMCF PD
2013/14	23.1 - 25.5	1,026 - 1,134	7.8 - 8.7	24.3	1,080	8.3
2014/15	22.1 - 24.4	1,062 - 1,173	7.5 - 8.3	23.2	1,117	7.9
2015/16	21.8 - 24.1	1,094 - 1,210	7.4 - 8.2	22.9	1,152	7.8
2016/17	21.1 - 23.3	1,114 - 1,232	7.2 - 7.9	22.2	1,173	7.6
2017/18	20.8 - 23.0	1,144 - 1,264	7.1 - 7.8	21.9	1,204	7.4

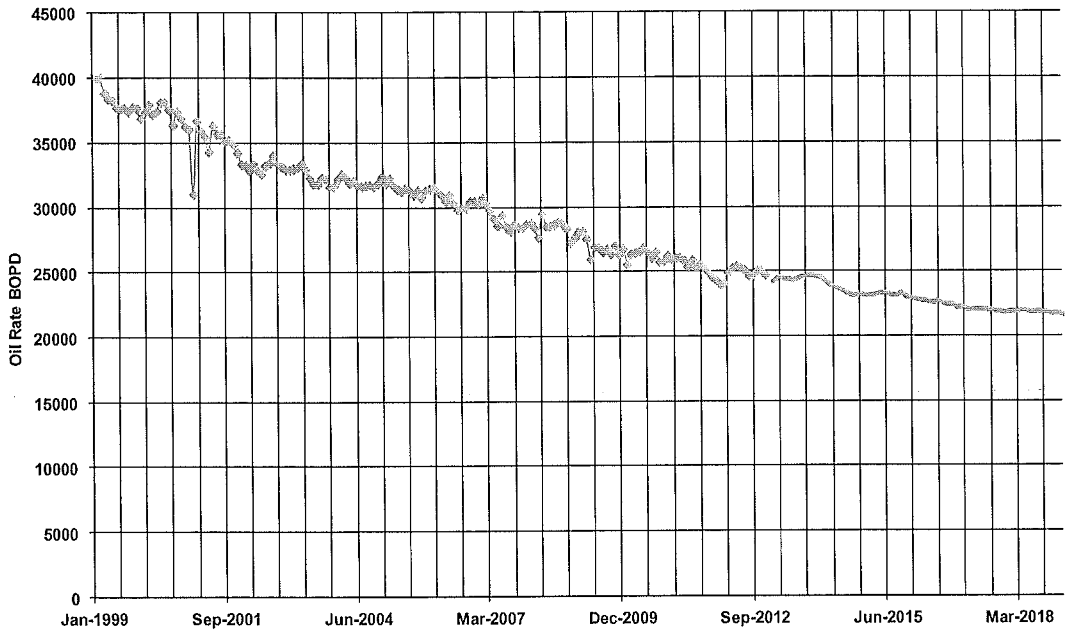
Exhibit D

Range of Injection Rates
July 2013-June 2018 Program Plan
Long Beach Unit

FISCAL YEAR	WATER INJECTION RATE		RANGE OF INJECTION PRESSURES			
	RANGE MBWPD	EXPECTED MBWPD	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2013/14	1,112 - 1,229	1,170	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2014/15	1,149 - 1,270	1,209	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2015/16	1,183 - 1,308	1,245	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2016/17	1,204 - 1,330	1,267	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2017/18	1,235 - 1,365	1,300	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Exhibit E

Oil Rate Forecast
Jul-2013 TO Jun-2018
Long Beach Unit



Water Rate Forecast
Jul-2013 TO Jun-2018
Long Beach Unit

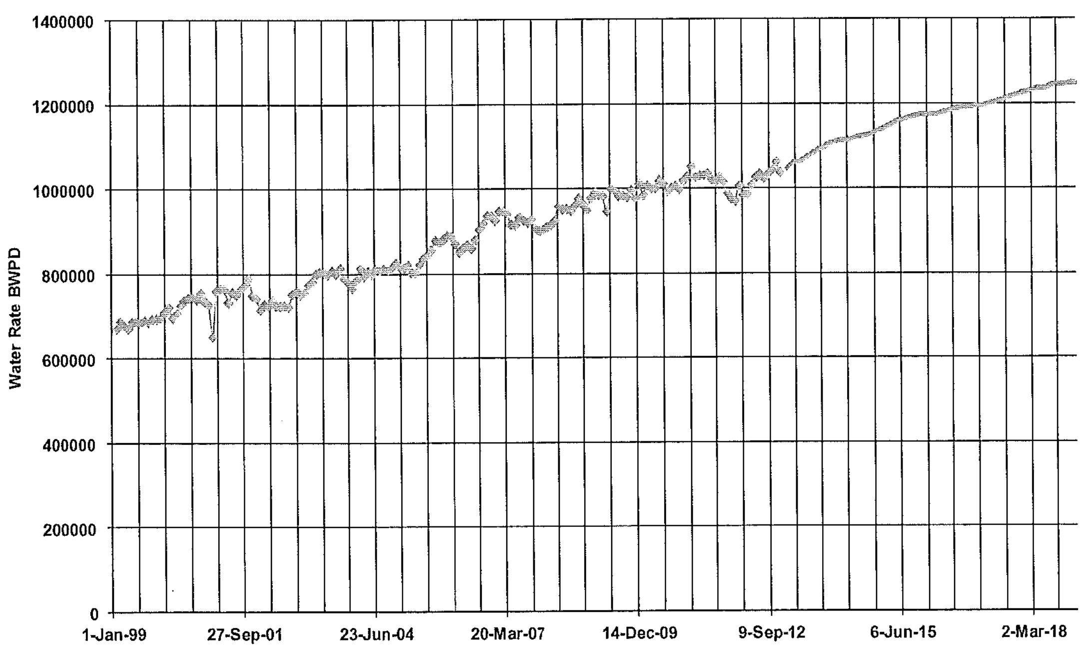
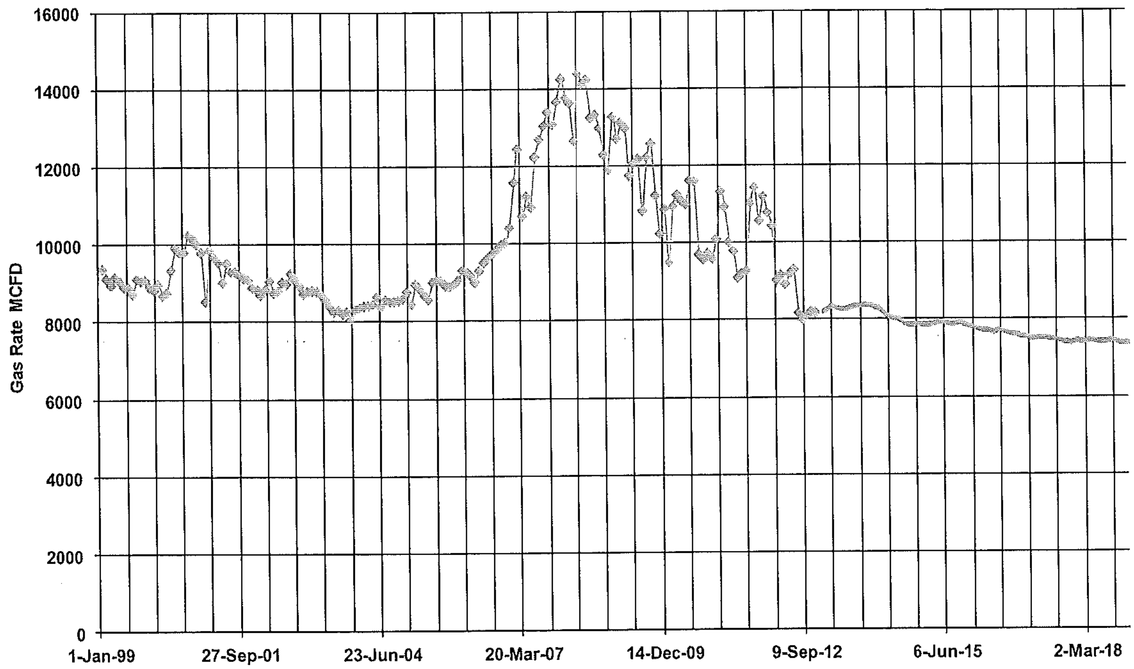


Exhibit F

Gas Rate Forecast
Jul-2013 TO Jun-2018
Long Beach Unit



Schedule 1 A

Range of Production and Injection
FY 2013/14
Long Beach Unit Program Plan, July 2013-June 2018

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2013/14	23.1 - 25.5	1,026 - 1,134	7.8 - 8.7	1,112 - 1,229

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2013/14	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Schedule 1 B

Anticipated Development and Replacement Locations
Fiscal Year 13/14
Long Beach Unit Program Plan, July 2013-June 2018

Reservoir	CRB	Producers					Injectors				
		Grissom	White	Chaffee	Freeman	Pier J	Grissom	White	Chaffee	Freeman	Pier J
		Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max
Tar	35	0 - 1	0 - 2	0 - 0	0 - 0	0 - 0	0 - 1	0 - 2	0 - 0	0 - 0	0 - 0
SG		0 - 0	0 - 2	0 - 1	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0
Ranger West	1	0 - 5	0 - 0	0 - 0	0 - 0	0 - 0	0 - 7	0 - 0	0 - 0	0 - 0	0 - 0
	2	0 - 3	0 - 1	0 - 0	0 - 0	0 - 0	0 - 3	0 - 1	0 - 0	0 - 0	0 - 0
	3	0 - 7	0 - 1	0 - 0	0 - 0	0 - 0	0 - 2	0 - 1	0 - 0	0 - 0	0 - 2
	4	0 - 1	0 - 1	0 - 0	0 - 1	0 - 2	0 - 0	0 - 1	0 - 0	0 - 1	0 - 2
	5	0 - 0	0 - 0	0 - 0	0 - 1	0 - 2	0 - 0	0 - 0	0 - 0	0 - 1	0 - 2
	7	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0
	8	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	9	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	10	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	11	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	12	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	13	0 - 0	0 - 1	0 - 0	0 - 1	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	36	0 - 0	0 - 0	0 - 0	0 - 0	0 - 5	0 - 0	0 - 0	0 - 0	0 - 1	0 - 1
	37	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Ranger East	14	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0
	15	0 - 0	0 - 1	0 - 0	0 - 2	0 - 0	0 - 0	0 - 1	0 - 0	0 - 2	0 - 0
	16	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 1	0 - 0	0 - 0
	17	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0
	18	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0
	20	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0
	21	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0
	22	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0
	32	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	33	0 - 0	0 - 0	0 - 5	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Terminal	24	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 1	0 - 1	0 - 0	0 - 1	0 - 0
	38	0 - 1	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2
	39	0 - 1	0 - 1	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	40	0 - 1	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	41	0 - 0	0 - 0	0 - 0	0 - 0	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1
	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 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	47	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
UP Ford	26	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	27	0 - 0	0 - 1	0 - 1	0 - 1	0 - 0	0 - 0	0 - 1	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 - 1	0 - 1	0 - 0	0 - 0	0 - 2	0 - 0	0 - 1	0 - 0	0 - 0	0 - 1
	44	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 1	0 - 0
	45	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 1	0 - 1	0 - 0	0 - 0
	46	0 - 0	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0	0 - 0
		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 1	0 - 0
237	30	0 - 1	0 - 0	0 - 2	0 - 2	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		Total					Total				
		0 - 89					0 - 62				

Schedule 2 A

Range of Production and Injection

FY 2014/15

Long Beach Unit Program Plan, July 2013-June 2018

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2014/15	22.1 - 24.4	1,062 - 1,173	7.5 - 8.3	1,149 - 1,270

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2014/15	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Schedule 2 B

Anticipated Development and Replacement Locations

Fiscal Year 14/15

Long Beach Unit Program Plan, July 2013-June 2018

		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
Tar	35	0 - 1	0 - 2				0 - 1	0 - 1			
SG											
Ranger West	1	0 - 4					0 - 5				
	2	0 - 7	0 - 1				0 - 2	0 - 1			
	3	0 - 4	0 - 1					0 - 1			0 - 3
	4		0 - 1		0 - 1	0 - 1		0 - 1			0 - 1
	5				0 - 2	0 - 7				0 - 2	0 - 3
	7				0 - 4					0 - 2	
	8										
	9		0 - 1					0 - 1			
	10		0 - 1					0 - 1			
	11		0 - 1					0 - 1			
	12		0 - 1					0 - 1			
	13		0 - 1		0 - 1			0 - 1			
	36					0 - 2					0 - 1
	37				0 - 1						
Ranger East	14		0 - 1					0 - 1			
	15		0 - 1		0 - 4			0 - 1		0 - 2	
	16		0 - 1					0 - 1			
	17			0 - 1					0 - 1		
	18			0 - 1					0 - 1		
	20			0 - 1					0 - 1		
	21			0 - 1	0 - 2				0 - 1		
	22			0 - 1					0 - 1		
	32			0 - 1					0 - 1		
	33			0 - 2					0 - 1		
Terminal	24		0 - 1					0 - 1			
	38	0 - 2				0 - 1	0 - 1				
	39	0 - 2	0 - 1				0 - 1	0 - 1			
	40	0 - 1	0 - 1				0 - 1	0 - 1			
	41					0 - 2					0 - 1
	42										
	43			0 - 1	0 - 1				0 - 1	0 - 1	
	47			0 - 1					0 - 1		
UP Ford	26			0 - 1					0 - 1		
	27		0 - 1	0 - 1	0 - 1			0 - 1	0 - 1		
	30				0 - 2						
	31		0 - 1					0 - 1			
	44										
	45			0 - 1					0 - 1		
	46		0 - 1		0 - 2			0 - 1		0 - 1	
237	30			0 - 1	0 - 2				0 - 1		
		Total					Total				
		0 - 90					0 - 59				

Appendix 1

Ranger West / Tar
Reservoir Management Plan

History

The Ranger West reservoirs are comprised of the Ranger 6 and Ranger 7 fault blocks. Ranger West is the largest pool in the Unit with 1.6 billion barrels of original oil in place (OOIP). The first pool developed at field startup in late 1965, Ranger West contains a contrasting mix of mature and under-developed blocks. The crestal and southern blocks are generally more mature than the northern blocks in the Ranger West area. In the more mature crestal and southern blocks, waterflood recovery is generally high (34-48% OOIP) with water-oil ratios (WOR's) ranging from 24-56. In the less mature northern blocks, oil recoveries range from 27-32% with WORs of 26-27.

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

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

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

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

Status

The Ranger West/Tar production rates in October 2012 were 11.4 MBOPD and 540.5 MBWPD (97.9% water cut) from 323 producers. October 2012 injection averaged 574.9 MBWPD from 202 injectors. Average active well rates were 34 BOPD and 1510 BWPD for producers and 2515 BWPD for injectorsRanger West currently has 60 inactive wells that have not been plugged in zone. 52 of these wells are being evaluated for repair, conversion or redrill.

Recovery through November 2012 was 505.7 MMBO (32.1% OOIP). While the base production in Ranger West reservoir has been declining at around 11% per year, the active development program in 2011-2012 has added an average of approximately 987 BOPD annually.

Calendar Years 2011 and 2012 Activities and Results

Since publication of the last Program Plan, 36 producers (14 horizontal, 17 conventional, and 5 cased-hole completions) and 18 injectors have been drilled and completed in the Ranger West pool.

The average initial stabilized rate (3 month average) for the producers drilled in the Ranger West Pool is 104 BOPD with initial rates ranging from 4 BOPD to 408 BOPD. This rate is better than the anticipated average rate of 68 BOPD. The average initial stabilized production rate is 156 BOPD for the horizontal completions, 69 BOPD for the conventional completions and 50 BOPD for the cased-hole 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. Wells drilled during 2011 were required by the permitting agency to stay within 100' of the previous wellbore. Four of the six injectors drilled and completed in 2011 have underperformed. Average well injection rates are 1725 BWIPD compared with the expected rate of 2395 BWIPD. Drilled injection wells completed in 2012 have been either restrained by the 100' offset rule which applied for 2011 drill projects or are temporarily restrained to a 0.7 psi/ft gradient. As a result, injection in 2012 projects also underperformed, but are expected to improve when the gradient is increased to the approved waterflood gradient. Average well injection rates of 2012 completions averaged 901 BWIPD compared to an expected 2556 BWIPD. Projects completed in this time period have underperformed on average with injection rates.

During the 2011-2012 Plan period, a total of 17 development (investment) wellwork jobs were also completed (8 producers and 9 injectors). Six of the producer development projects were selective recompletions/add pay projects and two were recompletions to the Ranger zone targeting bypassed oil sands. Overall, the producer development wellwork has been successful, averaging about 42 BOPD/job at a cost of $305,366 per job. The injector development wellwork projects included three successful, one unsuccessful convert to injectors and four profile modifications and add pay projects. The injection work targeted increasing water throughput in selective sands and pattern areas. Injection development wellwork projects contributed an average of 2123 BWIPD of injection per well at an average cost of $207,898 per job.

Maintenance wellwork continues to play a major role in maximizing Ranger West base production. During 2011-2012, approximately 49 producer maintenance wellwork projects at a cost of $86,664/job were performed. 204 injector maintenance projects were also completed at an average cost of $18,401/job.

Reservoir Management Objectives

The primary reservoir management objective is to maximize the profitability of the Ranger West pool. Maximum profitability will be achieved by increasing recovery in underdeveloped blocks through identifying optimal locations for development drilling/investment wellwork combined with the right placement of injection water. Throughput objectives are to reach an HPVI target of at least 6.0 for each sand in all CRB's. As of November 2012, HPVIs range from 1 to more than 10 on an individual sand basis. As a result, oil recoveries range from values as low as 27% in some CRB's up to 48% in other CRB's. By ensuring that each sand reaches an HPVI target of at least 6.0, oil recoveries for individual sands should reach a minimum of 30-33% for an overall recovery in excess of 40% for the Ranger West sand. In the more mature blocks, maximum profitability will be achieved through minimizing the volume of low value water cycling, directing water to the remaining economic reservoir targets and targeting by-passed oil pockets with development drilling and investment wellwork projects. In the absence of economic options, idle wells will be abandoned to reduce future abandonment liabilities and reservoir crossflow. Risk of subsidence will be minimized in all reservoir management actions.

Strategies

The Ranger West development plan includes drilling an additional 49 development wells and performing 5 investment wellwork projects in FY13/14. The development plan will be implemented under the guidance of the reservoir management objectives discussed above. The best new drilling and investment wellwork locations will be evaluated and selected for inclusion in the drilling and wellwork programs based on a combination of economic and strategic criteria. Projects will be reviewed carefully to ensure that only projects that will be profitable even in low price environments are executed. Pool reviews/reservoir studies, conducted on an ongoing basis, will be used as the foundation for identifying the best drilling and wellwork opportunities and to monitor progress towards achieving reservoir management goals.

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

Critical Issues

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

- Continue throughput optimization in under-injected sands; generally the lower sands (Mn thru G6).
- Optimize the Ranger West waterflood through subzoning into upper and lower floods where it is economically effective.
- Continue application of horizontal well technology including additional infill F0 horizontals in blocks 3, 4, and 5, and the crestal area of Ranger 7, and look for horizontal well opportunities in lower F0 lobes (F01 & F02) in all areas. In addition utilize slant wells as another way to optimize depletion from these sands.
- Evaluate the completion methods to deliver optimum productivity including continued improvement of open hole gravel packed slotted liners and cased hole selective completions including fracture stimulations.
- Implement low cost replacement drilling options for failed wells, particularly for injectors with poor conformance and limited repair options.
- Update the geologic and reservoir description in Tar V and develop a depletion plan.
- Continue to update and optimize streamline reservoir models to evaluate depletion optimization in Ranger West. Update the geologic model in Petrel.

Ranger East
Reservoir Management Plan

History

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

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

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

Although peripheral injection along the northern flank provides a row of back-up injection, this injection has been less effective because the aquifer is not well bounded and communicates with the Seal Beach field downstructure. A significant portion of the peripheral injection in CRB's 14, 16, 17, and 18 has been lost to the aquifer, particularly during the early field life when withdrawal from the Seal Beach field was higher. Pressure support has thus been limited in these areas, and both the current and projected recoveries are relatively low. The remaining reserves in these areas constitute the major redevelopment target in Ranger East.

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

Status

As of October 2012, Ranger East production is 7280 BOPD and 270,517 BWPD from 219 active producers. Total water injection is 298,393 BWPD into 125 active injectors. Average active well rates are 32 BOPD and 1196 BWPD for producers and 2379 BWPD for injectorsRanger East currently has 18 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. Additionally, there are 7 wells that have been identified as "uneconomic to repair" that have yet to be plugged in zone.

Cumulative oil production as of November 2012 is 249.0 MMBO (31.6% OOIP). Since the last reporting period in November 2010, oil production, the total oil production has remained relatively flat including development. Within the last 3 months, production has increased by approximately 9% due to successful development. Excluding development, base decline has been approximately 7.6% over the last two years.

Calendar Years 2011 and 2012 Activities and Results

Since publication of the last Program Plan, 24 producers (3 horizontal/slants, 20 conventional openhole gravel packs, and 1 cased-hole completion) and 12 injectors (3 single string vertical cased injectors and 9 dual string vertical cased injectors) have been drilled and completed in the Ranger East pool.

The average initial stabilized rate (3 month average) for the producers drilled in the Ranger East Pool is 85 BOPD with initial rates ranging from 31 BOPD to 378 BOPD. The average expected rate is 63 BOPD. The injection wells drilled during the 2011-2012 period were selectively perforated in specific intervals with historically low waterflood throughput and relatively high remaining oil saturation. Most of the injection wells met injectivity expectations with an average injection rate of 2100 BWPD. Injectivity was hurt in some injectors by the new requirement of an injection gradient for new wells of 0.7 psi/foot.

During the 2011-2012 Plan period, a total of 16 development (investment) wellwork jobs were also completed (6 producers and 10 injectors). All of the producer development projects were selective recompletions/add pay projects targeting bypassed oil sands. Overall, the producer development wellwork has been successful, with the four successful projects averaging about 30.5 BOPD/job at a cost of $337,000 per job. One project was not successful. The last project is still stabilizing. The injector development wellwork projects included three convert to injectors and seven profile modifications/add pay projects. The injection work targeted increasing water throughput in selective sands and pattern areas. Injection development wellwork projects contributed an average of 2085 bpd of injection per well at an average cost of about $258,000 per job. One injector add pay project was unsuccessful due to mechanical failure.

Maintenance wellwork continues to play a major role in maximizing Ranger East base production. During 2011-2012, approximately 109 producer maintenance wellwork projects at a cost of about $78,500/job were performed. 301 injector maintenance projects were also completed at an average cost of about $15,200/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 37.1. The injection target volume is greater than 6.0 hydrocarbon pore volumes into each sand before reaching a producing WOR of 100. Injection throughput has been challenged by the difficulty of maintaining good vertical profile control. Another challenge is the optimal placement of injectors in the highly faulted Ranger East pool. Producer to injector conversions and injector recompletions have been done to improve sweep efficiency.

Production rates are maximized by selective acidization of active wells, or in conjunction with other wellwork. In addition, increasing pump size and using variable speed drives to increase well drawdown assure that maximum productivity is achieved from the wells. Finally, producers are recompleted when economic quantities of unswept oil are identified.

Strategies

The Ranger East development plan includes drilling an additional 16 development drilling wells on Chaffee in 2013 and early 2014 before the drilling rig moves to Freeman. A new focus is on F0, F and M1 horizontals and slants to try and prove up this technology in Ranger East. Several investment wellwork projects are also planned. These projects will target insufficiently swept pay. When the drilling rig moves to Freeman in 2014, there will be additional drilling in the Ranger East, targeting mainly Ranger 90S and Ranger 8A projects.

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.

An update of the Ranger East geologic description and streamline reservoir model was completed in 2007. The geologic study was undertaken to improve the reservoir characterization of Ranger East, to improve the estimate of net pay and OOIP and to provide the framework for the simulation model. The goals of the simulation model are to understand flux into or out of the Unit, identify hydrocarbon hot spots, manage waterflooding, optimize the Ranger East depletion plan and assist with well planning. In addition, the goal is to use post-processing of the streamline data to identify opportunities to improve injection pattern balancing and sweep. The low ultimate recovery in some blocks indicates a greater amount of study is needed to maximize recovery in Ranger East. In 2013, it is planned to rebuild the Ranger East geomodel and use it to develop a new simulation model to improve our ability to manage the asset.

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:

- Rebuild the Ranger East geomodel and simulation models in 2013/2014.
- Complete reservoir depletion 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 selective fracturing of mid and lower Ranger zones to improve productivity and ultimately reserves.
- Evaluate the feasibility of and begin development of high-angle slant wells in the M1 in the eastern part of the pool similar to the Belmont Upper completions.
- Evaluate the best strategy for completing targeting the F0, either slants or horizontals.
- Redevelop bypassed areas down-dip.

Terminal Zone
Reservoir Management Plan

History

The Terminal zone is about 1000 feet thick and its productive limits cover an area about four miles long and two miles wide within the Unit. The LBU fault divides the Terminal into the Upper and Lower Terminal zones on the west side of the field from the Terminal East zone on the east side.

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

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

Terminal East wells are completed in either the upper Y-A or AA-ADL intervals. In the middle 1980's, some Terminal East wells were completed as dedicated sub-zone producers and injectors in the AC-AD interval. The sub-zone development program targeted reserves in these deeper interbedded sands. AC-ADL zone reserves were not fully recovered in the original full-zone completions due to competition from the upper, more prolific intervals.

Early wells were completed with gravel packed slotted liners and water zones were excluded with cemented blank liner sections. 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 or the use of frac technology.

Status

As of October 2012, the total production from the Terminal zone is 3,818 BOPD and 148 MBWPD resulting in an average WOR of 39. There are currently 148 active producers. Terminal zone injection for October 2012 is 157 MBWIPD from 80 wells. Average active well rates were 24 BOPD and 871 BWPD for producers and 1,861 BWIPD for injectorsTwelve 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 is currently underway for these wells.

Cumulative production through November 2012 totaled 145.4 MMBO (33.9% OOIP). Successful infill drilling and well work activities have partially offset the underlying Terminal zone oil production decline rate of 7.9%/year (including development).

Calendar Years 2011 and 2012 Activities and Results

Since publication of the last Program Plan, five producers (four cased-hole, one open-hole completions) and three injectors (two single string, one dual-string injector) have been drilled and completed in the Terminal pool. These eight development wells have been balanced across the field with four being in Terminal West and four in Terminal East.

The average initial stabilized rate (3 month average) for the producers drilled is 53 BOPD with initial rates ranging from 35 BOPD to 82 BOPD. The average expected rate is 58 BOPD. The injection wells drilled during the 2011-2012 period were selectively perforated in specific intervals with historically low waterflood throughput and relatively high remaining oil saturation. The average initial injection rate is 2250 BWIPD.

During the 2011-2012 Plan period, a total of 4 development (investment) wellwork jobs were also completed (three producers, one injector). The investment projects were selective recompletions/add pay projects. Overall, the producer development wellwork has returned an average of 60 BOPD/job at a cost of $460,000 per job. The injector wellwork project was an injection conversion that increased the reservoir energy in TE faultblock eight. Maintenance wellwork continues to play a major role in maximizing Terminal base production.

Reservoir Management Objectives

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

In 2004 and 2005, a reservoir study was conducted to improve the geological and reservoir description of the Terminal Zones and better define the estimation of OOIP. This project resulted in the creation of a streamline reservoir simulation model for the Terminal East area and a second model for Terminal West. These models are and will continue to be used as a directional tool to identify opportunities to maximize recovery from the reservoir. An improved history match is currently being worked on for the Terminal West model. This will improve our capabilities in managing the asset and comes at an opportune time as we plan to drill development projects from Island Grissom and Pier J in the short-term future.

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

Strategies

The Terminal Zone development plan for FY 13/14 assumes ten drilling projects and several investment workover projects. These objectives will be met by utilizing the various Unit programs currently in-place. The best new production and injection infill well candidates will be evaluated and selected for inclusion in the drilling schedule based on economic and strategic development criteria. Pool reviews will be conducted regularly to identify well work, conversion, and infill opportunities. Reservoir studies are being performed to develop long term depletion plans and to reliably forecast future reservoir performance.

Key reservoir management strategies have been formulated for each Terminal reservoir pool. The focus strategy for UT6 CRB-38 is to improve vertical conformance due to the block's waterflood maturity and highly layered system. In addition, a highly selective drilling program will be conducted to target bypassed oil in a vertically spaced manner. The reservoir management goal for UT6 CRB-39 is to increase the overall level of development through infill drilling in this less mature block. Increased throughput and optimization of vertical and areal conformance will also be focus areas for the block. Horizontal wells have performed well in UT6 (both CRB 38 and 39) over the last decade. Much of the future development will consist of targeted, horizontal exploitation. The development strategy for UT7 includes crestal injection to augment the current peripheral injection configuration due to the area's highly faulted nature. Terminal 8A development will include the in-boarding of additional injection projects to achieve throughput targets, and increase reservoir energy in the southern portion of the faultblock. Finally, injection and infill development in Fault Block 90 will continue to be tailored to the improved understanding of fault compartmentalization.

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

In order to optimize well performance, completion techniques will continue to include larger perforating guns, gravel pack and frac and pack technology when applicable. Open hole completions will also be utilized, particularly in subzoned projects. Fracture stimulation technology in the lower sands of the Terminal zone will continue to be applied on a case by case basis to provide sand control and improve well deliverability in sensitive, low permeability formations. The team will actively seek out and advocate cost reduction strategies while meeting reservoir objectives.

Critical Issues

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

- Annually update the Terminal East and West streamline models with the latest production, completion and log data. Complete the updated history match on the Terminal West model in 1Q-2Q 2013.

- Improve vertical conformance in UT6 CRB-38 through selective drilling of new cased hole producers, injectors, and conformance-improving workovers, particularly from the southern, peripheral injection system.
- Identify areas of bypassed oil and exploit via horizontal completions in Terminal West CRB 38 and 39; HXO, HXC horizontals have been very successful. We want to further that program and potentially add additional sands.
- When it makes sense economically, strategically develop thinly bedded Lower Terminal East sands independently of more permeable zones characterized by higher water saturations.
- Optimize crestal injection in UT7 to augment the current peripheral injection configuration.
- Increase reservoir throughput in Terminal 8A through injection well drilling and conversions, particularly in the southern portion of the CRB where lower pressures exist.
- Improve structural understanding in TE90 with the reprocessing of the seismic data. With the new interpretation, improve fault play vertical/horizontal exploitation.
- Optimize development in Terminal 90N by better understanding sealing nature of the C608 fault by using the latest seismic, pressure, production, and stratigraphic data.
- Effectively manage and optimize the waterflood in different areas between peripheral and infill injection strategies.

UP-Ford

Reservoir Management Plan

History

The UP-Ford Zone has produced 105.1 MMSTB oil to date and current active well counts are 72 producers and 52 injectors. Much of the historical production is attributable to natural water drive from the AX sand, which watered-out over almost the entire field by the early 1980's. Sands above the AX have been historically less prolific owing to several factors, including: lower formation permeability, thin-bedded discontinuous shaly sands which are prone to formation damage owing to a high clay content, a lack of adequate injection support and damaging completion and workover techniques.

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

From the late 1990's, success in pattern waterflood development in the Tract II area was achieved through adoption of non-damaging drilling and completion techniques, and the fracture stimulation program. 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. New Petrel geological model and Frontsim reservoir simulation model were built and history-matched in 2005. The drilling and workover program is continuing with many benefits being realized from hydraulic fracturing completion techniques.

Status

The UP-Ford production rates in October 2012 were 2,180 BOPD and 54,995 BWPD (96.2% water cut) from 79 producers. October 2012 injection averaged 57,007 BWIPD from 55 injectors. Average active well rates were 20 BOPD and 639 BWPD for producers and 1,0372 BWIPD for injectors

UP-Ford currently has eight 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 2012 was 105.1 MMBO (19.0% OOIP). For the January to November 2012 period, the base potential production in UP-Ford reservoir has declined at 12% annually. Maintenance wellwork continues to play a major role in maximizing UP-Ford base production.

Calendar Years 2011 and 2012 Activities and Results

Since publication of the last Program Plan, five producers (one open-hole, four cased-hole completions) and one injector have been drilled and completed in the UP-Ford pool.

The average initial stabilized rate (3 month average) for the producers drilled in the UP-Ford pool is 52 BOPD with initial rates ranging from 10 BOPD to 125 BOPD. This rate is less than the anticipated average initial rate of 73 BOPD.

The injector development project consisted of a sidetrack redrill of a failed injector in CRB 44. The injection work targeted increasing water throughput in selective sands in that cut recovery block.

During the 2011-2012 Plan period, one development (investment) wellwork job was also completed (cased-hole frac add pay). This successful multi-stage frac add pay, resulted in a stabilized project incremental rate of 100 STB/D.

Reservoir Management Objectives

The goal of the UP-Ford Reservoir Management Plan is to maximize the profitability of the reservoir. As the recovery mechanism is waterflood, we have to increase the waterflood efficiency by increasing throughput ratio, injection efficiency and volumetric sweep. There are three areas of focus with respect to attaining this goal. First is to maintain the base production and injection rates in existing wells through reactive and proactive wellwork. The second objective is to effectively stimulate and waterflood sands above the AU through selective completion and stimulation techniques. Most of the remaining oil is in these thinner, lower permeability sands, which will only achieve economic production rates if their deliverability can be enhanced through fracture stimulation or horizontal/slant completion and their pressures be increased through waterflooding. The third area of focus is to enhance the producer-injector conformance which will improve sweep efficiency.

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

Strategies

The development plan for UP-Ford in FY13/14 includes continued activity in this reservoir, particularly as we conclude drilling campaigns from Island White and Chaffee and prepare for a move to Island Freeman in 2014. The various Unit programs currently in place will be utilized to help achieve the development objectives stated above. 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. Logs such as 3-D resistivity image logs will be run to better understand the thin bedded sands.

UP-Ford 8 and 90 fault blocks have a reservoir flow model but additional work needs to be performed to calibrate it better so the results from the development forecast could be used with confidence. In FY13/14 the model will be further upgraded based on most recent understanding of the geological framework and properties. The UP-Ford 98 block needs further study utilizing seismic, well log, core and production performance data to quantify future development opportunities as its recovery factor is low. Reservoir description studies will be performed to locate and map the most likely areas of sand development.

The in-zone injection program will expand to improve flood performance in the upper, less mature, tight reservoir sands. Fracture stimulation techniques will continue to be refined in an attempt to reduce treatment costs while maintaining or improving effectiveness. Horizontal/slant wells will be drilled as an alternative to fracture stimulation to reduce costs and variable performance.

Critical Issues

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

- Develop CRB 44 with infill wells to improve low recovery factor.
- Further exploit alternatives for increasing infill well deliverability primarily through hydraulic fracturing as well as high angle and horizontal completions.
- Continue to improve frac designs and frac field implementation; evaluate new technologies (i.e. coiled tubing) that could allow increased stages and more expedient, cost effective stimulation
- Horizontal/slant wells are drilled in AK1 sands currently and will be further tested in AE, AF, AI, AM, AO, AR sands in the future.
- Continue to refine non-damaging procedures to complete and work over wells and determine injection water quality requirements.
- Increase pressure support in the upper reservoir sands utilizing in-zone injectors and conformance improvement projects for existing injection wells through stimulation and mechanical methods.
- Continue to delineate the Northern down-dip extent of UP-Ford CRB 44 and CRB 45.
- Evaluate and better understand the development potential of the Horst block along the LBU Fault in CRB 27.

- Evaluate the development potential of the deep sands AU2 through AZ and manage risk when testing deep concepts.
- Study and evaluate the potential of UP-Ford 98.
- Incorporate any new structural understandings from the reprocessed seismic data towards improved development and reservoir management.

237 Shale 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 have higher fracture density than the Hot Shale and has been 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 2.92 MMBO has been produced from the fractured shales of both 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 fractured reservoirs have contributed an additional 1.35 MMBO from two LBU wells, one of which had a flowing IP of 1800 BOPD.

The first 237 Zone well was completed in 1968 at an initial rate of 1050 BOPD. Twenty more wells have been completed in the LBU. All wells reported oil and gas shows while drilling through the lower 237 Zone. Six of the wells were economic, one was marginally economic, twelve were uneconomic and the most recent two are still being evaluated. One of the wells was a mechanical failure and did not properly evaluate the lower 237 Zone. The uneconomic wells may have been damaged during drilling or lacked sufficient fracture systems to be productive. Through November 2012, cumulative production from the 237 Zone/acoustic basement is 4.3 MMBO.

In 2006 a 237 team was formed to re-evaluate the fractured shale play. Using seismic coherency mapping and fracture 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 November 2012 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. Wellwork to recover the fish is scheduled to take place in 2013.

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 a meaningful fracture network.

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

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

The C252, drilled in 2011, was frac'd in mid-2012 in two stages in the Basal Shale. The well, while showing some signs of deliverability after the stimulation treatment, tested very poorly with low intake pressure in the pump Additional wellwork is pending at the end of 2012.

The objective of the C348, drilled in late 2012, is to evaluate the Lower Basal Shale/Basement seismically-defined coherency anomaly. An initial rate of 60 BOPD, 390 gross and 60 MSCF gas was obtained. Additional 237 intervals may be added uphole in the future.

Critical Issues

To fully understand the 237 reservoir and to refine future development plans, the focus will be on key reservoir issues during the current phase of exploratory/delineation drilling:

- Evaluation of open hole log and mud-log data acquired during drilling to better refine our completion design.
- Continued integration of reservoir performance, stress-field analysis, and geological understanding to high-grade future drilling targets.
- Core the first of the next two wells to determine if the reservoir is a single or dual porosity system and to evaluate the reservoir potential of the thin sands interbedded in the Basal Shale member.

Shallow Gas

Reservoir Management Plan

History

An agreement between the State of California, City of Long Beach, and OLBI regarding the development of shallow and deep gas reserves was finalized in 2006. This Plan contains funding necessary for wellwork associated with producing these reserves, basic facility modifications necessary for production operations, and the gas production associated with the project.

The bulk of the Shallow Gas reserves reside below Island Grissom with additional proven developed reserves accessible from Island White. Gas shows have been found in wellbores originating on Island Chaffee and Pier J. Development of Shallow Gas reserves began from Island Grissom due to the availability of commercially identifiable reserves for development from this location. Shallow Gas production commenced May 18, 2006 from one well. Development of Shallow Gas from Island White was initiated on February 15, 2010. To date 7 wells have been recompleted as Shallow Gas producers (6 on Island Grissom, 1 on Island White) and one horizontal well has been drilled.

Status

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

In February of 2010, B-403 was recompleted in the A-20 sands as the first step in the development of the White Shallow Gas accumulation with positive results early on. However, higher CO_2 content in the White Shallow Gas stream forced Facilities department to reduce/curtail the White Gas rate out of concern for subsea lines. In April of 2010, Well A-268 was recompleted in the A14 sand. During the February 2010 - July 2010, the total Shallow Gas rate was averaging 2300 mscf/d until subsea line repairs and facility maintenance forced the shut down of the Shallow Gas production. Upon completion of the repairs and maintenance work, production resumed from wells A-271, A-301 and A-310 at an average rate of 2200 mscf/d, the bulk of the production coming from well A-271. Production dropped sharply to 350 mscf/d in February of 2011 when well A-271 watered out. In July 2011, A-271 and B-403 were successfully recompleted, respectively in the upper lobe of the A-14 sand and in the A16 sand, averaging a production of 3000 mscf/d. Fine sand production created issues with well B-403 which ceased to produce in January 2012. Production from well A-271 stopped for similar reason. Both wells are currently idle. Up-hole recompletions are being considered in other wells. Daily rate by sand and cumulative production can be seen in Figure 1.

Cumulative Grissom production through July 2012 totals 5.133 BCFG (69.7% OGIP) in excess of initially estimated ultimate recovery expected to reach 4.33 BCFG (61.0% OGIP) in 2011 for the Grissom Gas reservoir. To date, White Gas cumulative production amounts to 311 MMCF. Including White Gas production the ultimate recovery was expected to reach 6.344 BCFG (61.0% OGIP including both Grissom and White accumulations) by 2015. Underlying aquifer support within the reservoir will affect total gas recovered.

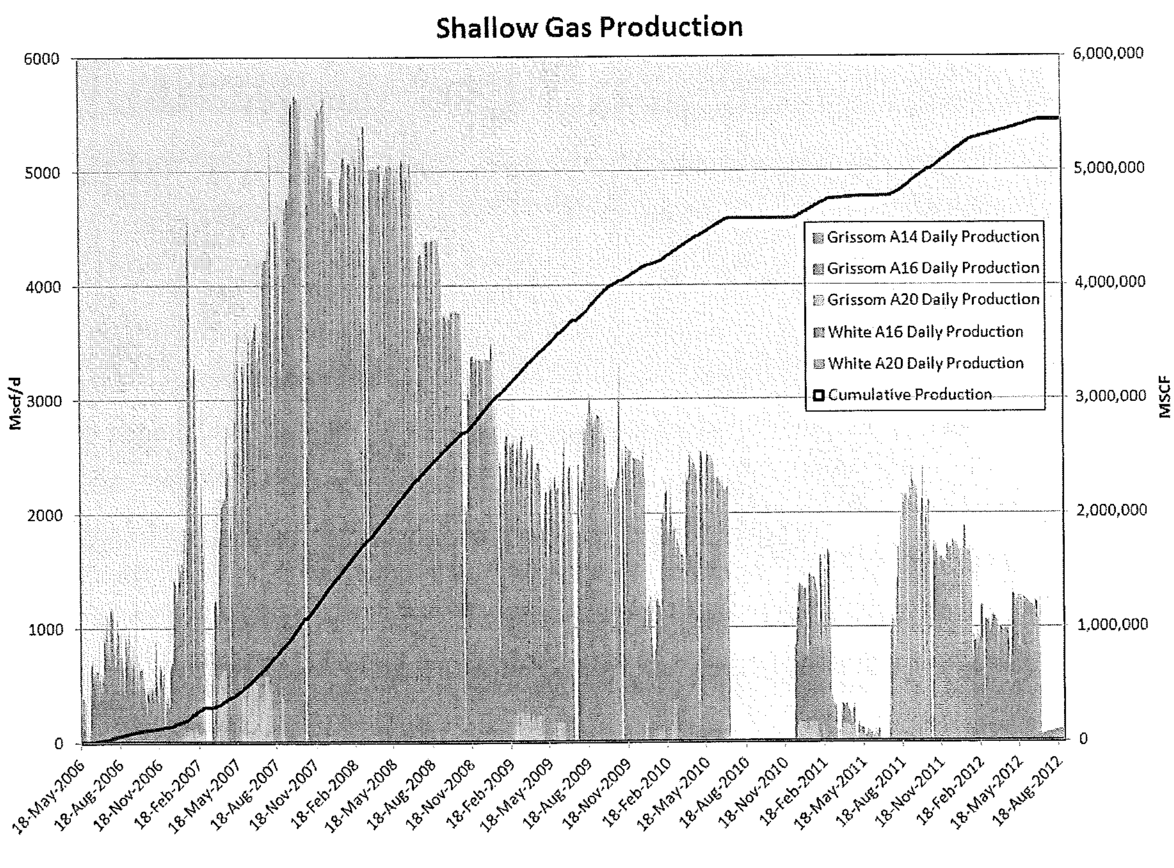


Figure 1: Shallow Gas production by sand

Reservoir Management Objectives

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

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

Strategies

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

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