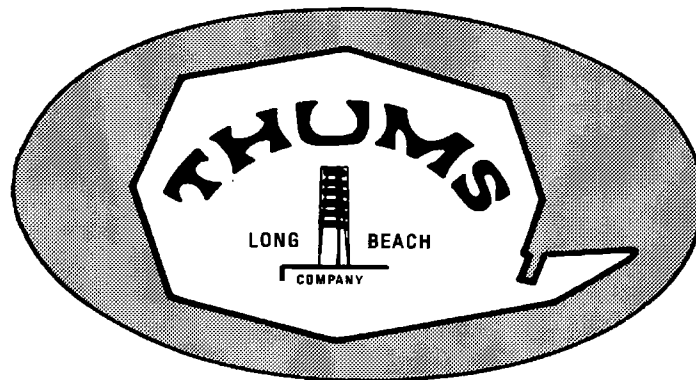


Long Beach Unit

Thums Long Beach Company
(Agent for Field Contractor)

ANNUAL PLAN

July 1, 2005 through June 30, 2006



ANNUAL PLAN

July 1, 2005 through June 30, 2006

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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, 2005 through June 30, 2006 ("FY05/06"). 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) 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 2005 – 2006 (\$ Million)
Development Drilling	\$ 70.0
Operating Expense	\$ 96.3
Facilities, Maintenance, and Plant	\$ 46.8
Unit Field Labor and Administrative	\$ 37.9
Taxes, Permits, and Administrative Overhead	\$ 21.0
Total	\$272.0

A. Plan Basis

This Plan was developed based on the parameters outlined in the Program Plan for the period July 2005 through June 2010 and provides current estimates of volumes, drilling activity and expenditures for FY05/06.

Volumes

Oil production for FY05/06 is expected to average 32.2 Mbopd within a range of 29.0 to 33.8 Mbopd. Gas production is expected to average 8.4 MMcfd within a range of 7.6 to 8.9 MMcfd. Water production for the period is expected to average 805 Mbwpd within a range of 724 to 845 Mbwpd. Water injection is expected to average 905 Mbwpd within a range of 815 to 950 Mbwpd.

Revenue and Expenses

A projected oil price of \$28.00/bbl and gas price of \$5.50/mcf will result in revenues of \$345.8 million. Based on a budgeted expense level of \$272.0 million, this will result in a net profit of \$73.8 million.

Drilling

This Plan allows for drilling approximately 60 new and redrilled development and/or replacement wells. It is expected that this will be accomplished by using the T-9 drilling rig at Island Chaffee, Freeman and Pier J, the T-3 drilling rig at Island White, and the T-5 drilling rig at Island Grissom during the Annual Plan term. A workover rig will do drilling preparation and completion work. Locations of production and injection wells to be drilled or redrilled are presented in Part II, Schedule 1B of this Plan.

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.

Many projects will be undertaken to repair or replace equipment that has outlived its useful life. Items needing to be repaired or replaced include facilities piping, tanks, and vessels. These projects are consistent with past activities to keep the Unit facilities in safe operating condition.

Abandonments

Wells and facilities with no further economic use will be abandoned to reduce current and future Unit liability. This Plan provides funds for both in-zone plugs and conditional abandonments with approximately \$1.5 million in spending for the Plan period.

Safety, Environmental, and Regulatory Compliance

Projects relating to safety and environmental issues and others necessary for meeting compliance with code, permit, or regulatory requirements will continue to be undertaken.

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 both on economics and conditions consistent with good engineering, business, and operating practices.

B. Economic Projections

(Data in Millions of Dollars)

	BUDGET FIRST QUARTER <u>FY05/06</u>	BUDGET SECOND QUARTER <u>FY05/06</u>	BUDGET THIRD QUARTER <u>FY05/06</u>	BUDGET FOURTH QUARTER <u>FY05/06</u>	BUDGET TOTAL <u>FY05/06</u>
<u>ESTIMATED REVENUE</u>					
Oil Revenue	\$82.4	\$82.9	\$81.5	\$82.1	\$328.9
Gas Revenue	<u>\$4.2</u>	<u>\$4.3</u>	<u>\$4.2</u>	<u>\$4.2</u>	<u>\$16.9</u>
TOTAL REVENUE	\$86.6	\$87.2	\$85.7	\$86.3	\$345.8
<u>ESTIMATED EXPENDITURES</u>					
Development Drilling	\$17.5	\$17.5	\$17.5	\$17.5	\$70.0
Operating Expense	\$21.9	\$32.4	\$20.9	\$21.1	\$96.3
Facilities & Maintenance	\$11.4	\$10.9	\$12.0	\$12.5	\$46.8
Unit Field Labor & Administration	\$9.2	\$9.2	\$10.2	\$9.3	\$37.9
Taxes, Permits & Overhead	<u>\$5.1</u>	<u>\$5.6</u>	<u>\$5.2</u>	<u>\$5.1</u>	<u>\$21.0</u>
TOTAL EXPENDITURES	\$65.1	\$75.6	\$65.8	\$65.5	\$272.0
<u>NET PROFIT</u>	\$21.5	\$11.6	\$19.9	\$20.8	\$73.8

C. MAJOR PLANNING ASSUMPTIONS

	BUDGET FIRST QUARTER <u>FY05/06</u>	BUDGET SECOND QUARTER <u>FY05/06</u>	BUDGET THIRD QUARTER <u>FY05/06</u>	BUDGET FOURTH QUARTER <u>FY05/06</u>	BUDGET TOTAL <u>FY05/06</u>
<u>OIL PRODUCTION</u>					
PRODUCED (1000 BBL)	2,943	2,960	2,910	2,933	11,746
(AVERAGE B/D)	31,988	32,174	32,339	32,227	32,181
<u>GAS PRODUCTION</u>					
PRODUCED (1000 MCF)	771	776	763	768	3,078
(AVERAGE MCF/D)	8,383	8,430	8,472	8,443	8,432
<u>WATER PRODUCTION</u>					
PRODUCED (1000 BBL)	72,635	72,602	73,133	73,558	291,928
(AVERAGE B/D)	789,513	789,154	812,586	808,327	804,557
<u>WATER INJECTION</u>					
INJECTED (1000 BBL)	81,942	82,913	82,008	83,539	330,402
(AVERAGE B/D)	890,667	901,230	911,202	918,012	905,211
OIL PRICE (\$/BBL)	\$28.00	\$28.00	\$28.00	\$28.00	\$28.00
GAS PRICE (\$/MCF)	\$ 5.50	\$ 5.50	\$ 5.50	\$ 5.50	\$ 5.50

Part II

Program Plan Schedules

Schedule 1 A

Range of Production and Injection

FY 2005/06

Long Beach Unit Program Plan, July 2005-June 2010

RANGE OF PRODUCTION AND INJECTION RATES

FISCAL YEAR	OIL MBOPD		WATER MBWPD		GAS MMCFPD		INJECTION MBWPD	
2005-06	29.0	- 33.8	724	- 845	7.6	- 8.9	815	- 950

RANGE OF PRODUCTION AND INJECTION RATES

FISCAL YEAR	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2005-06	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

SCHEDULE 1B
ANTICIPATED NEW AND REDRILLED WELLS
FISCAL YEAR 2005-06

LONG BEACH UNIT PROGRAM PLAN, JULY 2005 – JUNE 2010

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	Sc	0	0								0	0									0	0	
Ranger West	1	0	0	0	0							2	7										
	2	2	7									1	2										
	3	3	9	0	0							1	2								0	0	
	4	0	0	0	1			0	0			0	0	0	1						0	0	
	5	0	0					0	0												0	0	
	36							0	0												0	0	
	7							0	0												0	0	
	8			0	0			0	0					0	0								
	9			0	1									0	0								
	10			0	0									0	0								
	11			0	1									0	0								
	12			0	0									0	0								
	13			0	0			0	0					0	0						0	1	
	37							0	0												0	0	
Ranger East	14			0	0								0	0									
	15			0	1			0	1				0	0							0	0	
	16			0	0			0	0				0	0	0	0					0	0	
	17					0	0							0	1								
	18					0	0							0	0								
	32					0	0							0	0								
	33					0	0							0	0								
	20					0	0							0	0								
	21					0	0	0	0					0	0						0	0	
	22					0	0	0	0					0	0						0	0	
Terminal	38	1	4										0	0							0	0	
	39	0	0	0	0			0	0	0	0	0	3		0	0				0	0	0	
	40			0	1			0	0					0	0					0	0		
	24			0	0			0	1					0	0					0	1		
	41													0	0								
	42					0	0								0	0							
43					1	2	1	2						0	0	1	2						
UP Ford	26			0	1			0	0					0	0					0	0		
	27			0	0			0	2					0	2					0	0		
	31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	44			0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	45			0	0	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	46			0	0	0	0	0	0	0	0	0	0	0	0	1	2	1	3				
237	30	0	0			0	1	0	0														
		TOTAL										TOTAL											
		12 - 47										8 - 28											

Part III

Itemized Budget of Expenditures

A. Development Drilling \$70,000,000

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 60 wells will be developed and/or replaced during the Plan year, using two and one half drilling rigs, and one part-time completion rig.

Drilling and completing new wells, as well as re-drilling and recompleting existing wells, account for 93 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 in regularly scheduled Unit forums.

B. Operating Expense \$96,300,000

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 32.2 Mbopd, estimated gas production of 8.4 MMcfpd, water injection requirement of 905 Mbwpd, and water production of 805 Mbwpd. Anticipated operating expenses were based on operating 4-1/2 workover rigs per month for servicing an active well count of 680 producers and 400 injectors, and up to 1/5 rig for abandonment activity. 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 29 percent of the funding provided in this category. Included are funds for acidizing, fracturing, routine well work, well conversions, in-zone plugs, conditional abandonments, and other charges incurred for well maintenance.

Electricity makes up 63 percent of the funds in this Category. Cost for electric power is based on estimated kilowatt usage of 555,903,000 kwh at an average rate of \$0.09/kwh. This cost includes all sources of Unit electrical power, including all costs associated with the power plant and electric utility purchases. Funds for a partial accelerated pay down of the power plant lease of \$10.4 million are also included in the budget.

C. Facilities, Maintenance, and Plant \$46,800,000

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 52 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 48 percent of the funding in this Category is for facilities repair and improvement projects. Improvement projects include spending for pipeline replacements, facility repair projects, and other infrastructure related investments that position the Unit for longevity. Also included are funds for the installation of a CO₂ plant (\$9 million) and investments to increase facility production capacity limits (\$3 million) to accommodate a full two rig drilling program throughout the full life of the Program Plan.

D. Unit Field Labor and Administrative \$37,900,000

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 74% 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; Unit Operator billable costs; OLBI billable costs; 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 \$21,000,000

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

Funding is provided for taxes levied on personal property, mining rights, and oil production; for the Petroleum and Gas Fund Assessment; annual well permits and renewals; Conservation Committee of California Oil and Gas Producers Assessment; California Oil Spill Response, Prevention, and Administration fee; land leases; and pipeline right-of-way costs. These costs represent approximately 58 percent of the Category total.

Funding is also provided in this Category for all Administrative Overhead 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 Department of Oil Properties, 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, 2006, the City of Long Beach shall present to the State Lands Commission a final report and closing statement of the FY05/06 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 expenditure 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 FY05/06 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

July 2005 through June 2010

Prepared Jointly by:

**Department of Oil Properties
City of Long Beach
(Unit Operator)**

**OXY Long Beach, Inc.
(Field Contractor)**

**THUMS Long Beach Company
(Agent for the Field Contractor)**

February 2005

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Executive Summary

This Program Plan covers the period from July 1, 2005 through June 30, 2010. 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 Department of Oil Properties, 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 192 development and replacement wells over the life of the Program Plan. This schedule will result in a reasonably stable production rate through the end of FY07/08 with an accelerated decline during the later stages of the Plan due to reduced development activities and continued field maturation. Unit production and injection rates are expected to average 32.2 Mbopd, 805 Mbwpd and 905 Mbwpd in FY05/06 and 30.5 Mbopd, 832 Mbwpd and 930 Mbwpd in FY09/10, 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, augmented with use of other Unit rig assets, contract drilling rigs, 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, 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.

The consummation of an agreement between stakeholders to develop shallow gas reserves is anticipated. This Plan includes funding for well drilling or recompletions and basic facility modifications associated with this project, as well as gas production and the associated revenue.

Several facility improvement projects are planned throughout the initial two to three years of the Plan. These improvements are focused on expanding current facility capacity limits to accommodate a full 2 and one half rig drilling program throughout all 5 years of the Program Plan period and could include projects such as installation of casing gas compression, and other investments that position the Unit for longevity. These investments result in enhancement of revenue streams, lower maintenance and operational costs, and improved safety and environmental performance.

Based on production from 60 development and replacement well projects planned for FY05/06 of the Program Plan and an average oil price of \$28.00/bbl, total revenue, expenditures, and net profits are projected to be \$345.8 million, \$272.0 million, and \$73.8 million, respectively. Over the five year Program Plan period, cumulative total revenue, expenditures, and net profit are expected to reach \$1,516.2 million, \$1,153.7 million, and \$362.5 million, respectively. Economic results reflect a staged decline in oil prices through the 5 year Program Plan period. 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, 2005 through June 30, 2010. 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 five reservoir areas: Ranger West/Tar, Ranger East, Terminal, UP Ford, and 237 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. This section also includes a brief discussion of the shallow gas development proposal and plans for managing electrical costs through operation of the newly constructed power generation plant.
- The *Economic Summary* section provides a forecast of Unit revenues, expenditures, and profits anticipated during the Plan period, assuming an oil price of \$28.00/bbl during the first 2 years of the Program Plan period and \$23.00 during the last 3 years of the Program Plan period. This section also includes the schedules that will be incorporated into the FY05/06 and FY06/07 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 decreased to four rigs in 1973 and dropped to one rig in mid-1976. Full zone production and injection locations were emphasized. The pace of development accelerated in 1977, reaching a peak of nine rigs 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. Activity dropped to one rig in the summer of 1986. No drilling rig activity occurred from mid-March 1987 until August 1987, at which time one rig was re-activated. A second rig was started in January 1988, and a third in January 1990. Rig activity dropped to one rig again in 1994 and has fluctuated between a one and two rig pace until 2003 where it has remained at two rigs. The drilling pace is expected to remain at a two rig pace through the first two years of this 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.
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.

Each of these strategies is discussed in more detail below. Specific strategies and goals for each reservoir are included 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. The Reservoir Engineering, Wellwork, and Operations Departments 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, waterflood sweep, hydrocarbon throughput analysis and streamline simulation. 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.

- The Unit is required to inject a total of 41.2 MBWPD in excess of gross production in designated voidage pools to ensure pressure maintenance and reduce the potential for subsidence. Reservoir engineers are responsible for insuring voidage targets are met for eleven separate voidage pools in the Tar, Ranger, and Terminal zones. This is accomplished by shutting-in producers, managing injection between pools, stimulating injectors, and/or performing well maintenance. The objective is to meet voidage targets, while minimizing expenses and the need to shut-in production.

Development Opportunities

The Unit has a strategy to invest to build 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 establish new injection patterns in the relatively underdeveloped areas of the field such as northern cut-recovery block 1 in Ranger West. Injection wells have been somewhat less effective in the more mature areas or when used as isolated infill injectors, but have still successfully advanced this strategy.
- Adding production wells: (1) where required to complete new injection patterns, (2) in areas of unswept oil (3) in lower productivity sands that cannot produce well in combination with higher productivity zones in long completions, (4) in areas of high oil saturations banked along sealing faults, and (5) 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 hydraulic fracture stimulations. The Wellwork group handles projects considered more routine, like recompletions and conversions. Fracture stimulations, which are more complex and require special planning and expertise, are coordinated by the Drilling Group. 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. This work started in the UP Ford where it is nearly complete. In that work, a petrophysical model was developed, the Unit horizons were subdivided in sand packages and a new reservoir description was created. This new description was used to update the UP Ford streamline simulation model. History matching will be complete in the near future. The model is already being used to screen drilling targets.

With the assistance of DeGoyler and MacNaughton, Oxy's Worldwide Reservoir Characterization Group, other outside consultants and local staff, this effort is now focused on Ranger East and the Terminal. Work is under way to build petrophysical models and subzone both areas. The target is to build a reservoir description and a streamline simulation model in Terminal East and Terminal West, and to update the description and streamline simulation in Ranger East.

In Ranger West, a working streamline simulation model of Ranger 7 is being used to manage that pool. Work is under way to build a streamline simulation model of Ranger 6. This work will be completed during this Program Plan.

Reprocessing of the 1995 3D Seismic data began in 2004. The work involves repositioning the receivers and reprocessing the data. The repositioning work is complete and results are encouraging. Data clarity has been improved over almost the entire field. Reprocessing work will begin in very late 2004 or early 2005. This work should be complete by the beginning of the Program Plan, at which point interpretation and use in identifying waterflood improvement projects will begin.

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 including hydraulic fracturing and frac-n-pack 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 (artificial lift, stimulation, corrosion, and scale prevention), facilities (automation, corrosion control, water quality), reservoir (profile control, fracture, behind-pipe-oil detection, conformance evaluation software tools, reservoir modeling software tools, 3D reservoir characterization), and Health, Environmental and Safety training.

Unit Forecasts

Drilling Schedule

The Program Plan projects development and replacement drilling to average 60 wells per year for FY05/06 and FY06/07. This schedule can be met with two Unit and one half 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. As a result of facility constraints, the level of drilling will likely be reduced after FY06/07. At least a one rig drilling program is expected due to some facility limits but will continue with efforts to redrill failed wells and exploit growth opportunities that move probable and possible reserves into the proven reserve category.

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 FY05/06 and FY06/07. 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 FY05/06 and FY06/07. 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. A mandated excess water injection rate of 41.2 MBWPD over the gross fluid production rate is used in the Tar, Ranger and Terminal sands to preclude any possibility of subsidence. 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 extrapolations of well groups within each Unitized Formation summed together to yield a forecast of the existing wells' production for the entire Unit. Each of these pools is comprised of the wells within a reservoir volume that is believed by the reservoir development teams to be acting as an independent waterflood area. These are generally comprised of either one or more cut-recovery blocks or a fault block. For each pool, 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. For pools that reach the economic water-oil ratio before the approximate end of the Unit's expected economic life in 2020, production is ramped down over several years using Unit developed shut-in logic. While this evaluation is more sophisticated than a single Unit exponential decline

evaluation, it more accurately models the Unit's reservoirs. The resulting prediction shows a near term exponential decline of about 12% per year. Longer term, the forecast follows a hyperbolic decline.

The incremental production contribution for new development wells is based on average rates for Unit wells, referred to as "type wells." The type wells are determined by reservoir (Ranger, Terminal and UP Ford) and completion type (conventional producer, frac producer, horizontal producer and injector) The producer type wells are based on average initial production rates and reserves of all Unit producers drilled between 1999 and early 2004. 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.

The gas production forecast was calculated from the oil rate projections using a constant gas to oil ratio of 262 standard cubic feet per barrel of oil produced over the Plan period.

Major Issues and Projects

Several major issues must be considered when planning Unit strategies. These issues include consideration for people, safety, environmental protection, subsidence control, well abandonment, cost management, facility infrastructure adjustments, shallow gas development, electrical generation, make-up water, and property tax management. 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. Ensuring the safety of all personnel is crucial to the success of any enterprise and is a specific goal of the Unit. Operations are conducted in a manner to ensure compliance with applicable laws and regulations. The Health, Environment, and Safety (HES) Department is responsible for providing day to day health, environment, and safety support and service to the employees and contractors of the Unit.

The Safety and Environmental Steering Committee continues to be a key component in the ongoing health, environment, and safety improvement efforts for the Unit. The committee is made up of proven safety leaders within the organization and is designed to ensure participation by all employees. The committee will continue to be challenged to seek out new HES ideas and strategies from within and outside the industry that will take the Unit's safety performance to the next higher level.

Contractor Safety has been and will continue to be a primary focus at Thums. Contractors participate in many of the on-site safety meetings and also serve on many of the safety related teams and committees. Contractor performance is reviewed frequently to ensure that expectations are understood and are being met. Aggressive safety performance goals are set each year and are tracked to measure bottom line improvement.

Personnel awareness is essential for an effective safety program. Training will continue to be conducted routinely to meet regulatory requirements. Other safety awareness

training will be conducted as areas of need are identified in health, environment, and safety practices.

The Unit is proud of the safety record attained by its employees and contractors. To ensure continued compliance, safety assessments are conducted periodically by Unit personnel and outside organizations.

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. In the unlikely event such a situation does occur, trained personnel and emergency equipment are readily available for deployment. 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. These assessments and drills will continue, and 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.

The Unit is proud of the environmental record attained by its employees. 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 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. In general, the injection must exceed gross production by an average of 41.2 MBWPD in these eleven pools, with each pool having specific injection requirements. A subsidence monitoring program is in operation and consists of eight permanent monitoring stations, semi-annual GPS elevation surveys, and continual monitoring of pressures and injection volumes. This plan has proven to be effective in preventing subsidence and no subsidence impact is anticipated.

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 make-up water. 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.

Waste Management: Operations at the slurrification well continue to save waste disposal costs associated with drill cuttings and other waste and reduce potential future liabilities for waste disposal. This Plan includes funding to maintain this beneficial project.

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. Some of these include a well failure analysis team, a rig utilization team, a contracts/alliances team, and the Safety and Environmental Steering Committee.

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 White can be accomplished with Unit Rig T-3. Additional drilling methods will be considered for lowering drilling costs on all locations. These include contract drilling rigs, workover rigs, top drive and coiled tubing units.

Expansion of Facility Capacity

Significant expansion of current facility processing capacity will be needed if the Unit were to continue with a full 2 and one half rig drilling program during the full course of the Program Plan period. Activities to help achieve capacity expansion include piping enhancement projects, pumps, motors and subsea pipeline optimization. This Plan includes funding to complete the upgrades needed to meet the drilling activity involved.

CO₂ Processing Plant

Unit produced gas has exceeded the contractual limits on CO₂ content and an Amine plant will be constructed to remove the excess. Engineering design and regulatory permitting are progressing. Starting February 1st 2005 until the amine facility is operational the Unit Power Plant will be running as much as possible to prevent loss of value to the Unit. An Interim Dry Gas Agreement was approved by the SLC in December 2004 that will price the gas so the plant will not run at a loss to the Unit. The amine facility is expected to be operational in May of 2006. While the plant is being constructed the Unit power plant will be used to dispose of the high CO₂ content gas. The Amine Plant is expected to require approximately \$9 million in the first year of this Plan with approximately \$1 million occurring in the second year.

Shallow and Deep Gas Development

An agreement between the State of California, City of Long Beach, and OLBI regarding the development of shallow and deep gas reserves is expected to be finalized prior to this Program Plan start date. 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.

Electricity Generation

Electricity is the single largest cost element for the Unit. Currently the Unit consumes approximately 550 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 has 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 was converted into a cogeneration facility in FY04/05 to provide heat to a neighboring wallboard manufacturing facility, reducing their reliance on natural gas. As a result, the Unit receives revenue from heat sales and favorable treatment regarding departing load charges that may be assessed for leaving Southern California Edison's electricity grid.

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.

Funding for the power plant was through a 10 year capital lease. If oil and gas prices continue to be strong, the Unit will accelerate the principal payments on this lease by approximately \$10 million in each of the first two years of this Plan. The accelerated payments will shorten the remaining life of the capital lease, reduce Unit interest expense, and improve the long term cost structure of the Unit.

Belmont Offshore – PRC 186

The offset lease PRC 186, Belmont Offshore will be drilling its initial phase of wells in during first year of the Plan. Belmont is not part of the Unit but the drilling affects the Unit through a facilities sharing agreement. Belmont will use Unit drilling and processing facilities in exchange for various financial considerations. The effect on the Unit will be to distribute fixed costs over a larger asset base and improve Unit profitability over the long term.

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 (TOPKO) produced water and Long Beach Water Department (LBWD) reclaimed water. Due to cost and environmental considerations, the Unit will use fresh potable water from LBWD only when necessary as a back-up supply.

The Unit evaluated the usage of reclaimed water because of quality issues related to the TOPKO 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.

The Unit continues to investigate options for improving the injection water quality by minimizing the negative impacts that occur when make-up water is mixed with Unit production water.

Property Tax Management

During FY02/03, a settlement regarding over-valuation of the Unit for property tax purposes was reached with Los Angeles County for tax years 1996 through 1999. In FY04/05 a settlement was reached on the exemption status of the Nonoperating Contractors' interest from 1995 through the economic limit of the field. Outstanding items include the impact on Prop 13 base year value resulting from the Oxy change of ownership in 2000 and the subsequent years' property valuation. Efforts will continue as needed to resolve these issues during the Plan period.

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 \$1,516.2 million, based on a \$28.00/bbl oil price and \$5.50/mcf gas price during FY05/06, \$28.00/bbl oil price and \$4.50/mcf gas price during FY06/07, \$23.00/bbl oil price and \$4.00/mcf gas price during the last 3 years of the Plan period, and average daily oil and gas production as projected in Exhibit C. Projected revenue for FY05/06 is expected to be \$345.8 million.

Cost Forecast

Total estimated expenditures for the first year of this Program Plan are consistent with the FY05/06 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 Plan period are expected to be \$1,153.7 million. The projected expenditures for FY05/06 are \$272.0 million. Costs in future years will be refined upon completion of ongoing studies and projects.

Profit Forecast

Based on the above revenue and cost forecasts, Unit profit during the Program Plan period is projected to be \$362.5 million. Unit profit for FY05/06 is expected to be \$73.8 million. A schedule of annual projected revenue, expenditures, and net profit is given in Exhibit A.

Budget commitments for FY06/07 will be established based on actual results and additional insights gained during FY05/06.

Exhibits

Table 1

**SUMMARY OF PRODUCTION AND INJECTION
AS OF OCTOBER 2004
JULY 2005 – JUNE 2010 PROGRAM PLAN, LONG BEACH UNIT**

Reservoir	CRB	Active Well Count:		Average Rates for October 2004				Average Well Rates	
		Producers	Injectors	BOPD	BWPD	BIPD	Wtr Cut	BOPD/Well	BIPD/Well
Tar	35	5	2	103	623	1,134	85.8%	21	567
Ranger West	1	46.5	30	2,365	67,963	70,015	96.6%	51	2,334
	2	23.5	16	1,162	31,090	43,975	96.4%	49	2,748
	3	38	22.5	2,040	59,000	59,081	96.7%	54	2,626
	4	50	20	1,992	65,504	79,502	97.0%	40	3,975
	5	31	18.5	1,656	64,597	56,872	97.5%	53	3,074
	7	19	18	757	38,299	44,918	98.1%	40	2,495
	8	15	6.5	534	14,256	15,659	96.4%	36	2,409
	9	10	7.5	481	13,878	16,144	96.7%	48	2,153
	10	6	4.5	190	5,851	7,718	96.9%	32	1,715
	11	20.5	20	996	27,265	36,628	96.5%	49	1,831
	12	6.5	4.5	333	9,389	6,834	96.6%	51	1,519
	13	4	4.5	134	5,449	8,358	97.6%	34	1,857
	36	7	3.5	292	11,331	7,370	97.5%	42	2,106
	37	10	8	454	19,852	22,477	97.8%	45	2,810
	Total	292	186	13,489	434,347	476,686	97.0%	46	2,563
Ranger East	14	17	13.5	610	21,195	29,677	97.2%	36	2,198
	15	40	22.5	1,857	44,577	47,305	96.0%	46	2,102
	16	19	7	995	14,275	9,967	93.5%	52	1,424
	17	19.5	11.5	840	10,983	14,520	92.9%	43	1,263
	18	20	14	607	19,738	27,107	97.0%	30	1,936
	20	11	3.5	391	8,968	8,271	95.8%	36	2,363
	32	1.5	2.5	51	1,159	4,439	95.7%	34	1,776
	33	28	16.5	1,091	32,879	31,556	96.8%	39	1,912
	21	33	22	1,359	36,611	39,540	96.4%	41	1,797
	22	17	6	576	11,647	11,249	95.3%	34	1,875
	Total	206	119	8,378	202,032	223,631	96.0%	41	1,879
Terminal	24	35	20	1,663	47,048	49,371	96.6%	48	2,469
	38	33	10	1,456	24,238	19,998	94.3%	44	2,000
	39	9	6	237	4,421	5,769	94.9%	26	962
	40	2	2	89	664	2,275	88.2%	44	1,138
	41	4	1	24	364	296	93.8%	6	296
	42	30	7	1,199	8,738	12,223	87.9%	40	1,746
	43	5	6	198	5,043	13,992	96.2%	40	2,332
	47	34	12	1,568	19,576	20,502	92.6%	46	1,709
	Total	152	64	6,435	110,091	124,426	94.5%	42	1,944
UP/Ford	26	2	1	37	458	1,467	92.4%	19	1,467
	27	3	1	95	1,088	197	92.0%	32	197
	31	18	9	987	8,097	10,897	89.1%	55	1,211
	44	6	5	208	2,309	3,204	91.7%	35	641
	45	21	10	835	12,207	9,399	93.6%	40	940
	46	24	10	1,140	13,209	19,362	92.1%	47	1,936
	Total	74	36	3,302	37,367	44,527	91.9%	45	1,237
237	30	0	0	0	0	0	0		
LBU Total		724	405	31,604	783,837	869,271	96.1%	44	2,146

Exhibit A

ECONOMIC PROJECTIONS July 1, 2005 through June 30, 2010 Program Plan (Million Dollars)

	Fiscal 2005/06	Fiscal 2006/07	Fiscal 2007/08	Fiscal 2008/09	Fiscal 2009/10	Program Plan Period
Estimated Revenue						
Oil Revenue	\$328.9	\$332.8	\$270.0	\$261.2	\$256.4	\$1,449.3
Gas Revenue	\$16.9	\$14.0	\$12.4	\$11.9	\$11.7	\$66.9
Total Estimated Revenue	\$345.8	\$346.8	\$282.4	\$273.1	\$268.1	\$1,516.2
Estimated Expenditures	\$272.0	\$264.5	\$205.7	\$205.8	\$205.7	\$1,153.7
Net Income	\$73.8	\$82.3	\$76.7	\$67.3	\$62.4	\$362.5

Exhibit B
Anticipated Drilling Schedule
July 1, 2005 through June 30, 2010

FISCAL YEAR	RANGER WEST	RANGER EAST	TERMINAL	U.P. FORD/ 237	TOTAL WELLS
2005/06	32	3	16	9	60
2006/07	11	10	8	31	60
2007/08	20	1	1	2	24
2008/09	10	4	6	4	24
2009/10	3	12	3	6	24

* 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 2005-June 2010 Program Plan
Long Beach Unit

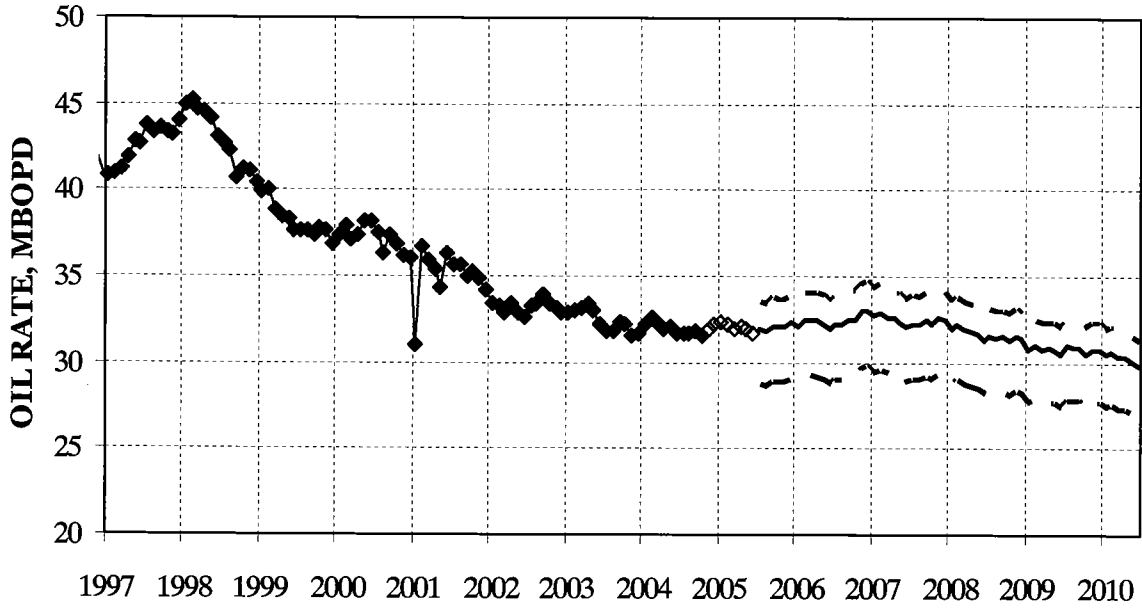
FISCAL YEAR	EXPECTED RANGE						EXPECTED RATE					
	OIL MBOPD		WATER MBWPD		GAS MMCFPD		OIL MBOPD	WATER MBWPD	GAS MMCFPD			
2005/06	29.0	-	33.8	724	-	845	7.6	-	8.9	32.2	805	8.4
2006/07	29.3	-	34.2	743	-	867	7.7	-	9.0	32.6	826	8.5
2007/08	28.9	-	33.7	745	-	870	7.6	-	8.8	32.1	828	8.4
2008/09	28.0	-	32.7	746	-	870	7.3	-	8.6	31.1	828	8.2
2009/10	27.5	-	32.1	749	-	873	7.2	-	8.4	30.5	832	8.0

Exhibit D
Range of Injection Rates
July 2005-June 2010 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		
2005/06	815	-	950	905	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2006/07	833	-	972	926	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2007/08	839	-	979	932	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2008/09	839	-	979	933	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2009/10	837	-	977	930	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Exhibit E

OIL RATE FORECAST JUL-05 TO JUN-10 PROGRAM PLAN LONG BEACH UNIT



WATER RATE FORECAST JUL-05 TO JUN-10 PROGRAM PLAN LONG BEACH UNIT

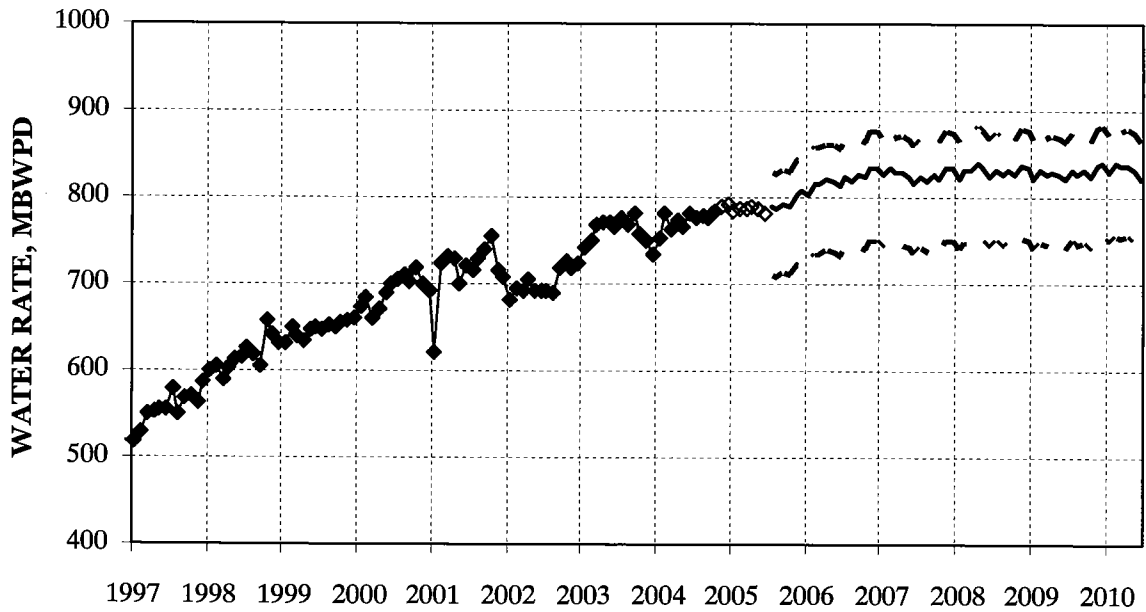
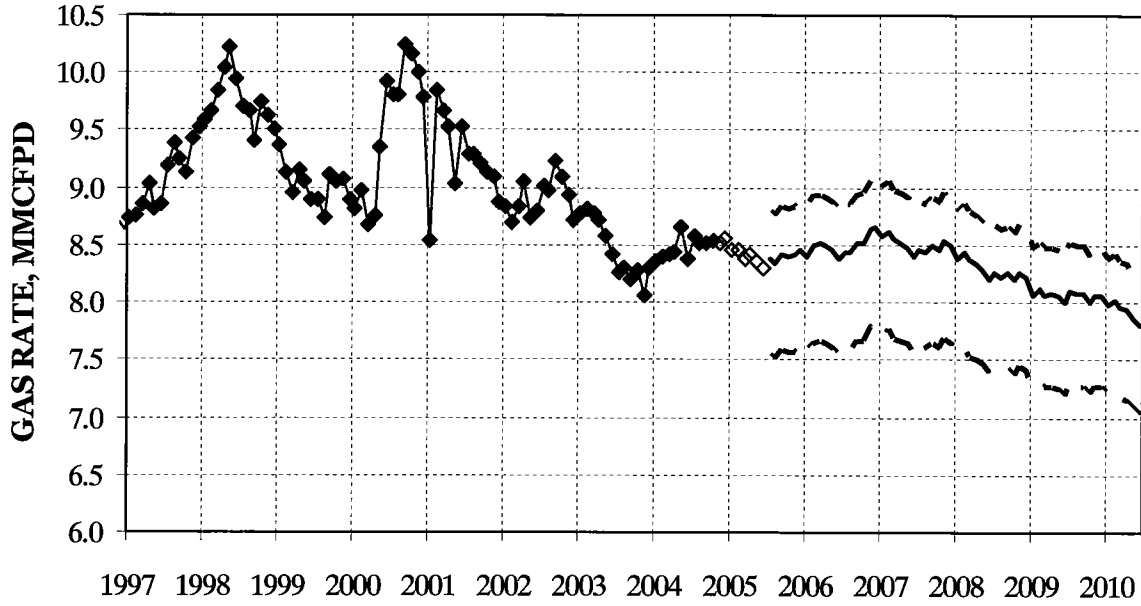
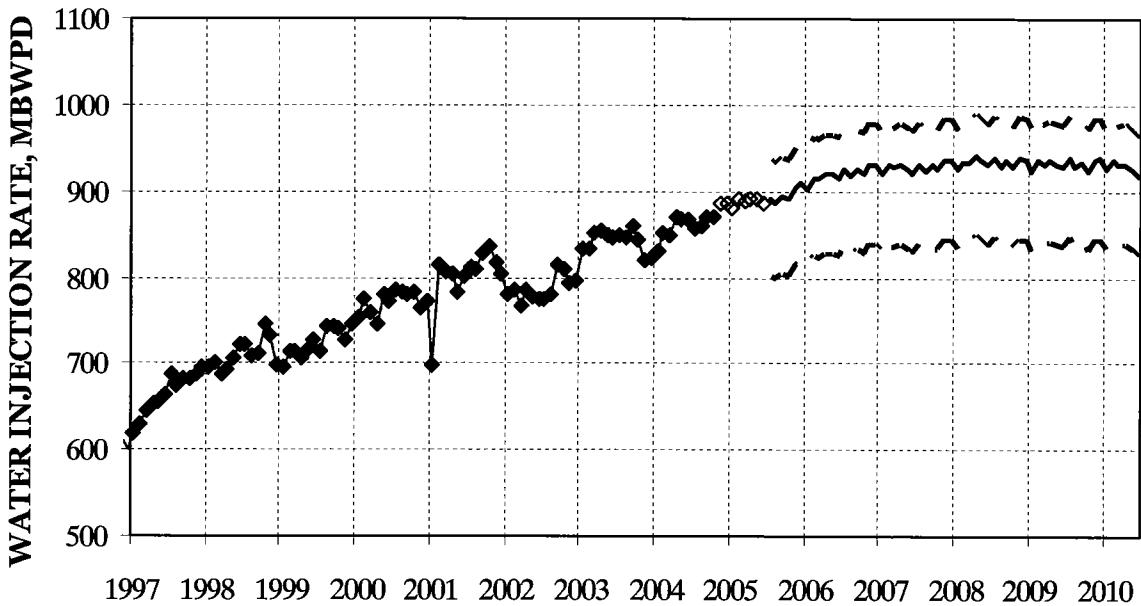


Exhibit F

GAS RATE FORECAST JUL-05 TO JUN-10 PROGRAM PLAN LONG BEACH UNIT



WATER INJECTION FORECAST JUL-05 TO JUN-10 PROGRAM PLAN LONG BEACH UNIT



Schedule 1 A
Range of Production and Injection
FY 2005/06
Long Beach Unit Program Plan, July 2005-June 2010

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES											
	OIL MBOPD			WATER MBWPD			GAS MMCFPD			INJECTION MBWPD		
2005-06	29.0	-	33.8	724	-	845	7.6	-	8.9	815	-	950

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES										
	TAR PSI			RANGER PSI			TERMINAL PSI			U. P./FORD PSI	
2005-06	UP TO 1500			UP TO 2500			UP TO 2500			UP TO 3000	

Schedule 1 B

Anticipated Development and Replacement Wells

Fiscal Year 05/06

Long Beach Unit Program Plan, July 2005-June 2010

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	Sc	0	0									0	0									0	0
Ranger West	1	0	0	0	0							2	7										
	2	2	7									1	2										
	3	3	9	0	0							1	2									0	0
	4	0	0	0	1			0	0	1	3			0	1			0	0			0	0
	5	0	0					0	0	1	3							0	0			0	1
	36							0	0	0	1							0	0			0	0
	7							0	0									0	0			0	0
	8			0	0			0	0					0	0			0	0				
	9			0	1									0	0			0	0				
	10			0	0									0	0			0	0				
	11			0	1									0	0			0	0				
	12			0	0									0	0			0	0				
	13			0	0			0	0					0	0			0	1				
	37							0	0									0	0				
Ranger East	14			0	0									0	0								
	15			0	1			0	1					0	0			0	0				
	16			0	0	0	0	0	0					0	0			0	0				
	17					0	0							0	1								
	18					0	0							0	0								
	32					0	0							0	0								
	33					0	0							0	0								
	20					0	0							0	0								
	21					0	0	0	0					0	0			0	0				
	22					0	0	0	0					0	0			0	0				
Terminal	38	1	4							1	2			0	0							0	0
	39	0	0	0	0			0	0	0	0			1	3	0	0			0	0	0	0
	40			0	1			0	0					0	0			0	0				
	24			0	0			0	1					0	0			0	1				
	41																						
	42					0	0							0	0								
	43					1	2	1	2					0	0			1	2				
UP Ford	26			0	1			0	0					0	0			0	0				
	27			0	0			0	2					0	2			0	0				
	31	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0
	44			0	0	0	1	0	0					0	0	0	0	0	0	0	0		
	45			0	0	1	2	0	0					0	0	0	0	0	0	0	0		
	46			0	0	0	0	0	0					0	0	1	2	1	3				
	237	30	0	0			0	1	0	0													
		TOTAL										TOTAL											
		12 - 47										8 - 28											

Schedule 2 A

Range of Production and Injection

FY 2006/07

Long Beach Unit Program Plan, July 2005-June 2010

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2006-07	29.3 - 34.2	743 - 867	7.7 - 9.0	833 - 972

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2006-07	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Schedule 2 B
Anticipated Development and Replacement Wells
Fiscal Year 06/07
Long Beach Unit Program Plan, July 2005-June 2010

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	Sc	0	0									0	0								0	0
Ranger West	1	3	9	0	0							1	2									
	2	3	9									0	0									
	3	1	4	0	0							0	0								0	0
	4	0	0	0	0				0	0		0	0					0	0		0	0
	5	0	0						0	0		0	0					0	0		0	0
	36								0	0		0	0					0	0		0	0
	7								0	0								0	0		0	0
	8			0	0				0	0				0	0			0	0			
	9			0	0									0	1							
	10			1	2									0	0							
	11			0	0									0	0							
	12			0	0									0	0							
	13			0	0				0	0				0	0						0	0
	37								0	0											0	0
Ranger East	14			0	0									0	0							
	15			0	0			0	0					0	0						0	0
	16			0	0	0	0	0	0					0	0	0	0				0	0
	17					0	1									0	1					
	18					0	0									0	0					
	32					0	0									0	0					
	33					0	0									0	0					
	20					0	0									0	0					
	21					0	0	0	0							0	0	0	0			
	22					0	0	0	0							0	0	0	0			
Terminal	38	0	1							0	0	0	0								0	0
	39	1	2	0	0			0	0	0	0	0	0								0	0
	40			0	0			0	0					0	0						0	0
	24			0	0			0	1					0	0						0	0
	41																					
	42					0	0									0	0					
43					0	0	1	3						0	0					0	0	
UP Ford	26			0	0			0	0					0	0						0	0
	27			2	8			0	0					0	0						0	0
	31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	44			0	0	1	2	0	0					0	0	0	1	0	0		0	0
	45			0	0	3	9	0	0					0	0	2	7	0	0		0	0
	46			0	0	3	8	0	0					0	0	1	2	0	0		0	0
237	30	0	0				0	1	0	0												
		TOTAL										TOTAL										
		19 - 60										4 - 15										

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 1.4 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 (30-40% OOIP) with water-oil ratios (WOR's) approaching 40. In the less mature northern blocks, oil recoveries range from 26-30% and WOR's range from 27-31

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 two 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 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 SLD pattern makes pattern balancing difficult with less than optimal areal sweep due to reservoir heterogeneity.

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 Fo, the F-X, and X-HX1 (Lower Ranger). Over the majority of the Ranger West pool, the Fo is the thickest and most dominant sand package. Original wells used full-zone, open-hole gravel packs across all three intervals. The more permeable Fo sand received the majority of the injected water through point exits resulting in bypassed oil within the Fo 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, cased hole 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 average Ranger West/Tar production rates in October 2004 were 13.5 Mbopd and 434 Mbwpd (97% water cut) from 292 producers. October 2004 injection averaged 477 Mbwpd from 186 injectors. Average active well rates were 46 bopd and 1487 bwpd for producers and 2563 bwpd for injectors. The current status of each Ranger West/Tar CRB is shown in Table 1.

Ranger West has 44 open idle wells. Forty wells are being evaluated for repair and/or conversion. Four wells have been identified for plug in zone. Seventy-three wells are idle and have previously been plugged in zone.

Recovery through October 2004 was 469 MMbo (34% OOIP). Ranger West is expected to produce an additional 35.8 MMbo by 2020 bringing ultimate recovery from existing development to 504.9 MMbo (36.2% OOIP). Additional development through drilling and investment wellwork is expected to increase reserves by 9.8 MMbo to 514.7 MMbo (36.9% OOIP) by 2020.

An active development program in the Ranger West reservoir has reduced the base decline rate of 13% per year to approximately 2% per year. Additional information concerning the development drilling and wellwork activities can be found in the Calendar Year 2003-2004 Activities and Results section.

Calendar Years 2003 and 2004 Activities and Results

Since publication of the last Program Plan, eighteen producers (seven horizontal, six conventional, and five cased hole completions) and seven injectors have been drilled and completed in the Ranger West pool. These wells added 5.8 Mmbo in reserves at a cost of \$3.38/bo

The average initial stabilized rate for the eighteen producers drilled in the Ranger West Pool is 214 BOPD with initial rates ranging from 716 BOPD to 26 BOPD. This rate is slightly higher than the anticipated average rate of 137 bopd. The average initial production rate is 485 BOPD for the horizontal completions, 114 BOPD for the cased hole completions and 96 BOPD for the conventional open-hole gravel pack completion. The horizontal wells and frac completions have performed above expectations in 2004.

All seven injection wells drilled during the 2003-2004 time period were cased hole, selectively perforated completions targeting intervals with historically low waterflood throughput and relatively high remaining oil saturation. All seven wells met injectivity expectations with an average injection rate of 1800 bwpd.

During the 2003-2004 Plan period, a total of seventeen development (investment) wellwork jobs were also completed (nine producers and eight injectors). All nine producer development projects were selective uphole recompletions/add pay projects targeting bypassed oil sands. Overall, the producer development wellwork has been successful, averaging about 38 bopd/job at a cost of \$189,000/job. The eight injector development wellwork jobs included uphole recompletions and profile modifications. The injection work targeted increasing water throughput in selective sands and pattern areas. Injection development wellwork projects contributed an average of 1400 bpd of injection per well and an associated 45 bopd at an average cost of about \$91,000.

Maintenance wellwork continues to play a major role in maximizing Ranger West base production. During 2003-2004, approximately 162 producer maintenance wellwork

projects were completed yielding an average of 37 bopd at an average cost of about \$58,000. Roughly 335 injector maintenance projects were also completed yielding an average of 1100 bwipd/job at an average cost of about \$11,000.

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 2.0 for each sand in all CRB's. As of November 2002, HPVIs range from less than 0.5 to more than 4.0 on an individual sand basis. As a result, oil recoveries range from values as low as 26% in some CRB's up to 40% in other CRB's. By ensuring that each sand reaches an HPVI target of at least 2.0, oil recoveries for individual sands should reach a minimum of 30-33% for an overall recovery in excess of 37% 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 32 development wells and performing four investment wellwork projects in FY05/06. 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. 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 in the Fo, lower F, and H zones in CRB-1.

- Continue to exploit opportunities to increase well deliverabilities and pattern throughput in the Lower Ranger sands in CRB's 2, 3, and 4 (including horizontal wells, fracturing technology, etc.).
- Continue application of horizontal well technology with emphasis on thinner Fo oil targets, oil trapped along faults, and under-developed Lower Ranger reservoir targets.
- Optimize and exploit successes using hydraulic fracturing to improve producibility and recovery from lower permeability, thin bedded sands in the lower F, H, X-G6 sands. Explore fracturing through existing slotted liner completions.
- Develop low cost replacement drilling options for failed wells.
- Realign/optimize crestal and south flank injection patterns emphasizing injection into low throughput sands and balancing offtake.
- Complete the Ranger West subzoning and Petrel model development.
- Update the geologic and reservoir description in Tar V and develop a depletion plan.
- Construct streamline reservoir models to evaluate depletion optimization in Ranger VI.
- Continued testing and evaluation of cased-hole resistivity logs to identify zones of unswept oil and recomplete wellwork candidates.
- Systematic development of throughput analysis and monitoring tools for eighteen vertical flow units in the Ranger sands to identify opportunities for vertical conformance improvements and waterflood optimization.
- Development of vertically detailed streamtube models for waterflood performance prediction applications.

Ranger East

Reservoir Management Plan

History

The Ranger East area is comprised of the four major fault blocks east of the Long Beach Unit fault: Ranger 8A, Ranger 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.

Status

As of October 2004, Ranger East production was 8.4 Mbopd and 202 Mbwpd from 206 active producers. Total water injection was 224 Mbwpd into 119 active injectors.

Since the last reporting period in November 2002, oil production has declined at 5% per year from 9.3 Mbopd to 8.4 Mbopd. The WOR increased from 20.3 to 24.1. Cumulative oil production as of October 2004 was 228 MMbo (26.4% OOIP).

Production from Ranger East is typically tracked in the four major fault blocks or in their component CRB's. The current well counts and producing statistics are summarized in Table 1 by CRB's. Ranger 8A consists of CRB's 14 and 15, and as of October 2004 is producing 2.5 Mbopd and 65.8 Mbwpd, with a water injection rate of 77.0 Mbwpd.

Since the last reporting period in November 2002, oil production declined at an average rate of 6% per year and the WOR increased from 23.4 to 26.6. Two producers and one injector were drilled in Ranger 8A during this reporting period.

Ranger 8B, or CRB-16, is a small fault block producing 1.0 Mbopd and 14.3 Mbwpd, and injecting 10.0 Mbwpd. Oil production declined at an average rate of 5% per year since the last reporting period. The WOR increased from 10.2 to 14.4 which is in line with the historical trend. One producer, a conventional open hole completion, was drilled during this reporting period.

Ranger 90N is the largest fault block in Ranger East and includes CRB's 17, 18, 20, 32, and 33. The total production rates are 3.0 Mbopd and 73.7 Mbwpd, with 85.9 Mbwpd of water injection. Oil production declined at an average rate of 10% per year since the last reporting period. During this reporting period, no new wells were drilled in Ranger 90N. The WOR increased from 21 to 24.7 since the last reporting period.

Ranger 90S consists of CRB's 21 and 22, which are producing 1.9 Mbopd and 48.3 Mbwpd, with 50.8 Mbwpd of injection. Since the last reporting period, the oil production rate has declined at an average rate of 3% per year. This fault block has a current WOR of 24.9, up from 21.4 from the last reporting period. One open hole producer was drilled in Ranger 90S during this period.

Recovery through October 2004 was 228.1 MMbo (26.4% OOIP). Ranger East is expected to produce an additional 29.9 MMbo by 2020 bringing ultimate recovery from existing development to 258.0 MMbo (29.8% OOIP). Additional development through drilling and investment wellwork is expected to increase reserves by 1.7 MMbo to 259.7 MMbo (30.0% OOIP) by 2020.

Ranger East has 35 open idle wells. Thirty four wells are being evaluated for repair and/or conversion. One well has been identified for plug in zone. Twenty nine wells are idle and have previously been plugged in zone.

Calendar Years 2003 and 2004 Activities and Results

This section of the report will highlight the key results of development drilling evaluation and implementation, development wellwork evaluation and implementation, and reservoir studies, while the next section will discuss reservoir management.

Five wells were drilled in the Ranger East area in period from 2003 to November 2004. These wells brought in 0.9 Mmbo in reserves at \$4.06/bo. Four of the five wells were producers. They consisted of two horizontal wells with an open-hole gravel packed completion and two conventional wells with open-hole gravel packed completions. The horizontal completions had an average initial oil production rate of 144 bopd. The conventional open-hole gravel packed wells averaged an initial oil rate of 96 bopd. The injector was a cased hole, selectively perforated completion targeting intervals with low waterflood throughput and high remaining oil saturations. The injection rate was 2000 bwpd. In addition, four more producers are projected to be completed by the end of 2004.

A total of 15 development (investment) wellwork projects were completed during this reporting period consisting of eight producer projects and seven injection well projects. Development wellwork consists of producer recompletions, injector recompletions/profile modifications, and producer to injector conversions. In all cases, the objective of these jobs was to either produce or displace unswept oil reserves previously not open in the existing completion. Eight producer recompletions were

performed during the reporting period. The primary recompletion target is any sands not sufficiently swept by water. These targets are identified primarily with nearby pass-through logs of recently drilled wells. These recompletions had an average incremental oil production of 52 bopd.

Three injector recompletions were performed in both pattern flood and line drive injector locations where evidence of unswept oil was identified. When warranted, mechanical profile control was also included to improve the injection profile. Four producers were converted to injectors. The producers, which are generally idle, are situated in areas that the flood front had already bypassed. Conversions of producers were done to facilitate the progression of the waterflood front.

Maintenance wellwork also plays a major role in maximizing Ranger East base production. During 2003-2004, approximately 118 producer maintenance wellwork projects were completed yielding an average of 37 bopd/job at an average cost of about \$52,000. Roughly 276 injector maintenance wellwork projects were also completed yielding an average of 1200 bwipd/job at an average cost of \$10,000.

Reservoir Management Objectives

The primary goal of the reservoir management plan is to maximize the profitability of 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's in the four fault blocks range from 14.4 in Ranger 8B to 34.7 in CRB 14 of Ranger 8A, indicating strong remaining reserves potential before reaching a nominal economic limiting WOR of 50. The injection target volume is greater than 2.0 hydrocarbon pore volumes into each sand before reaching a producing WOR of 30. 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 draw down 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 three development wells and performing four investment wellwork projects in FY05/06. These projects will target insufficiently swept pay.

An update of the Ranger East geologic description and streamline reservoir model is planned and will fall into the FY05/06 Plan. This study was undertaken to subdivide the vertical layers into flow units and improve the estimate of net pay. The low ultimate recovery indicates a greater amount of study is needed to maximize recovery in Ranger East.

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, and potentially adding or stimulating non-productive intervals. Existing wells will continue to be redrilled when warranted. Redrill candidates unit-wide are currently being compiled in order to assess ways of reduce drilling and completion costs for these wells.

A successful wellwork program will continue to be critical to Ranger East success. Strong communications between individuals in operations and engineering will be maintained through joint involvement in block reviews and joint review of wellwork opportunities and priorities.

Critical Issues

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

- Complete the Ranger East subzoning and Petrel model development.
- Incorporate the refined geologic and reservoir description and update the existing Ranger East streamline model.
- Develop proper waterflood pattern closure and improve the injection throughput into under-injected sands by prudent application of acid stimulation, wellwork, and drilling.
- Develop additional waterflood patterns to accelerate through put rates and improve vertical conformance.
- Select the optimal injector drilling locations by utilizing the results of the waterflood optimization studies.
- Evaluate fracturing mid and lower Ranger zones to improve productivity and ultimately reserves
- Test the use of cased-hole resistivity logs to identify zones of unswept oil and recomplete wellwork candidates.

Terminal Zone

Reservoir Management Plan

History

Reservoir sands in the Terminal interval are expected to ultimately yield over 169 MMbo. 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 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-AD sands.

Terminal East wells are completed in either the upper Y-AA or AA-AE 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-AD zone reserves were not fully recovered in the original fullzone 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 underbalanced perforating and wire-wrapped screens.

Status

Total production from the Terminal zone for October 2004 is 6.4 Mbopd and 100.1 Mbwpd resulting in an average WOR of 17.2. There are currently 152 active producers resulting in an average per well rate of 42 bopd and 724 bwpd. Terminal zone injection for October 2004 is 124.4 Mbwpd from 64 wells yielding an average injection rate of 1,944 bwpd per active injection well. Current rates and active well counts by cut-recovery block (CRB) are shown in Table 1.

Fourteen Terminal wells are currently mechanically idle and capable of being reactivated with further investment. Evaluation of repair and/or conversion options is underway for these wells. Two idle wells are slated to be plugged in zone. Five wells are idle and have previously been plugged in zone.

Cumulative production through October 2004 totaled 133.4 MMbo (31.9% OOIP) and ultimate production for continued operations is expected to reach 163.4 MMbo (39.1% OOIP) by 2020 resulting in 30.2 MMbo remaining reserves. Additional development

through infill drilling is expected to yield additional reserves of 5.4 MMbo for an ultimate recovery of approximately 169.0 MMbo (40.4% OOIP).

Successful infill drilling and well work activities have partially offset the underlying Terminal zone oil production decline rate of 15%/year. Production is down 0.1 Mbopd, or only 1% per year from the November 2002 rate of 6.5 Mbopd.

Calendar Years 2003 and 2004 Activities and Results

In calendar years 2003 and 2004, ten producers and eight injectors were drilled bringing in 3.7 MMbo in reserves at \$3.69/bo. Initial stabilized production from the producers averaged 170 bopd and the average initial injection rate for the injectors was 1500 bwpd. For the producers drilled, the average cost was \$867,000. For the injectors, the average cost was \$609,000.

Over the same time period, nineteen development (investment) wellwork projects were completed. These added 1.1 Mmbo in reserves at a cost of \$3.45/bo. Fifteen were producer projects. The average rate was approximately 59 bopd per well. These projects had an average cost of \$228,000. Four injector projects were completed over the same period at an average cost of \$197,000. Average stabilized incremental injection rate per well was 500 bwpd.

Maintenance wellwork also plays a major role in maximizing Terminal base production. During 2003-2004, approximately 112 producer maintenance wellwork projects were completed yielding an average of 39 bopd/job at an average cost of about \$53,000. Roughly 102 injector maintenance wellwork projects were also completed yielding an average of 1000 bwipd/job at an average cost of \$16,000.

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.

The current Terminal recovery of 31% OOIP ultimate recovery with WOR of 17.2 appears unrealistic. Additional reservoir description work will be performed to better define Terminal zone OOIP and sand connectivity. This work will help fine-tune the assessment of current and projected throughput and will be utilized to attain the overall reservoir management objectives.

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 modified to increase injectivity, minimize reservoir damage, and reduce high decline rates.

Strategies

The FY05/06 has sixteen drilling projects and nine 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. The semi-annual management reviews will be used to communicate production targets and Unitized Formation goals. Reservoir studies will be 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, application of horizontal production well technology will be exploited to capture bypassed reserves. The reservoir management goal for UT6 CRB-39 is to increase the overall level of development through infill drilling in this less mature block. Increased throughput and optimization of vertical and areal conformance will also be focus areas for the block. The development strategy for UT7 includes crestal injection to augment the current peripheral injection configuration due to the area's highly faulted nature. Terminal 8A development will include additional injection projects to achieve throughput targets. Finally, injection 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. Streamline models will be developed for use in waterflood optimization studies and 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. Cased hole logs which may help identify remaining oil behind pipe will also be evaluated and used if proven effective.

In order to optimize well performance, completion techniques will continue to include under-balanced perforating, larger perforating guns and charges, and smaller gravel-pack gravel placed at high rates. Application of fracture stimulation technology in the Terminal zone will also be evaluated as an alternative means of sand control and to improve well deliverabilities 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:

- Update geologic description across Terminal Zone and develop streamline models to evaluate waterflood enhancement projects.
- Improve vertical conformance in UT6 CRB-38 through selective drilling of a limited number of new cased hole producers, profile modification workovers of existing wells, and drilling of a limited number of injectors.
- Identify areas of bypassed oil and drill horizontal producers to exploit in Terminal Blocks 38 and 39.
- Accelerate reservoir development through a measured infill drilling program and aggressive redrilling of failed peripheral injectors for UT6 CRB-39.

- Optimize crestal injection in UT7 to augment the current peripheral injection configuration.
- Increase reservoir throughput in Terminal 8A through injection well drilling and conversions.
- Optimize waterflood pattern development in Terminal 90N by incorporating detailed reservoir fault analysis stream tube model development.
- Reduce wellwork and drilling costs through effective use of technology to allow additional Terminal investment.

UP Ford

Reservoir Management Plan

History

The UP Ford Zone has produced 96.0 MMbo to date and current active well counts are 74 and 36 production and injection wells, respectively. Much of the historical production is attributable to natural water drive from the AX sand, which watered-out over the entire field by the early 1980's. Sands above the AX have been historically less prolific due to several factors, including: lower formation permeability, thin-bedded discontinuous pay sands which are prone to formation damage due to a high clay content, a lack of adequate injection support and damaging completion and workover techniques.

The UP Ford reservoir is complex from both reservoir and operational perspectives. Since it underlies the Ranger and Terminal zones, new wells are more expensive because the depth is greater. 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 due to the sensitive nature of the formation, and fracture stimulation is often required to yield economically successful wells.

During 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 10-year high during early 1998. During the early 2000's, attempts to further exploit these strategies in the upper UP-Ford sands were not successful. During a two year development break, the reservoir description was completely redone and completion techniques were reviewed. The drilling and workover program has been restarted with several successes this year.

Status

The UP Ford Zone consists of three fault blocks: UPF8, UFP90, and UPF98. October 2004 production from the UP Ford was 3.3 Mbopd and 37.4 Mbwpd, with a WOR of 11.3. Overall UP Ford zone injection for October 2004 averaged 44.5 Mbwpd yielding an overall injection-voidage ratio of 1.09. Average well rates are 45 bopd and 505 bwpd for producers and 1237 bwpd for injectors. Current rates and active well counts by cut-recovery block are shown in Table 1.

Thirteen UP Ford wells are open idle. All wells are being evaluated for conversion and repair options.

Cumulative production through October 2004 totaled 96.0 MMbo (18.6% OOIP) and ultimate recovery is expected to reach 103.6 MMbo (20% OOIP) in 2020. Proved development is expected to add 8.9 MMbo and bring the ultimate recovery in 2020 up to 112.5 MMbo (21.8% OOIP).

The production rate is down only 0.2 Mbopd representing a 3% decline from October 2002. Recent development success has brought the production rate back up from a low of 2.9 Mbopd in November 2003.

Calendar Years 2003 and 2004 Activities and Results

From January 2003 through November 2004, seven producers and two injectors were drilled. This added 2.8 Mmbo at a cost of \$4.10/bo. An average new producer made 138 bopd compared to an average expected rate of 122 bopd. The average well cost was \$1,317,000. The average injector added 1600 bwipd and cost \$1,053,000. This cost was exaggerated by the collision with D831 while drilling D7261.

Producer investment wellwork added 1.1 Mmbo at a cost of \$3.54/bo. Nine producer well work projects were completed resulting in an average project incremental rate of 42 bopd. These projects had an average cost of \$363,000. Five injector investment wellwork projects were performed over the same period resulting in an average injection rate of 900 bwipd at a cost of \$150,000 per job.

Maintenance wellwork also plays a major role in maximizing UP Ford base production. During 2003-2004, approximately 89 producer maintenance wellwork projects were completed yielding an average of 26 bopd/job at an average cost of about \$83,000. Roughly 102 injector maintenance wellwork projects were also completed yielding an average of 700 bwipd/job at an average cost of \$34,000.

Reservoir Management Objectives

The overriding goal of the UP Ford Reservoir Management Plan is to maximize the profitability of the reservoir. Three objectives must be attained to achieve this goal. The first is to maintain the current production and injection rates in existing wells. Secondly, sands above the AU must be effectively stimulated and waterflooded. 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 and their pressures can be increased through waterflooding. The last objective is to continue to minimize formation damage during drilling and workover operations.

Production and injection infill well locations will be identified and drilled to recover oil banked near faults, improve areal sweep efficiency and increase reservoir throughput. Profile modifications 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 modified to increase injectivity, minimize reservoir damage, and reduce high decline rates.

Strategies

In FY05/06, the development plan has eight drilling projects and five investment workovers. The various Unit programs currently in place will be utilized to help achieve the development objectives. Potential new production and injection infill well candidates will be evaluated and the best selected for inclusion in the drilling schedule based on economic and strategic development criteria. Reservoir studies will be performed 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 studies combining the best reservoir description and well performance data will help identify regions of high remaining oil saturation.

The UP-Ford 98 area will be studied utilizing seismic, well log, core and production performance data to quantify extensional development opportunities. Reservoir description studies will be performed to locate and map the most likely areas of sand development.

The inzone injection program will expand to the crest of the UP Ford structure to improve flood performance in the upper, less mature, reservoir sands. Fracture stimulation methods will continue to be refined in an attempt to reduce treatment cost while maintaining or improving effectiveness.

Critical Issues

To fully understand the UP Ford reservoir and refine the development plans, focus will be on five key issues during the Program Plan period:

- 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.
- Further exploit alternatives for increasing infill well deliverabilities primarily through hydraulic fracturing and stimulation.
- Continue to refine nondamaging procedures to complete and work over wells and determine injection water quality requirements.
- Evaluate the potential of UP Ford 98 along the western lease line.
- Continue to delineate the Northern down dip extent of UP Ford CRB-44 and CRB-45.
- Evaluate the development potential of the Horst block along the LBU Fault in CRBs 27 and 46.

237 Shale Zone

Reservoir Management Plan

History

The 237 Shale underlies the UP Ford Zone and is composed of two distinct members, the BA-BN and BN-BS intervals. The BA-BN interval consists of interbedded sands and shales that have produced little oil. The BN-BS interval is predominantly a black shale that produces oil from fractures near the BO marker and in the BR-BS sub-zone.

The first 237 Zone well was completed in 1968 at an initial rate of 1050 bopd. Fourteen more wells were completed with the last in 1998. All had oil and gas shows reported while drilling through the black shale. Four of the wells were economic, one was marginally economic, and nine were uneconomic. The uneconomic wells may have been damaged during drilling, lacked sufficient fracture systems to be productive, or were separated from productive reservoir by sealing faults. Through the end of 2002, cumulative production for the 237 Zone is 3.9 Mmbo with no active wells in the pool.

The first 237 zone well in over 12 years (D-571) was drilled in 1997. Seismic survey data was used to pick the well location, and the well was drilled to its target depth successfully. However, lift issues have plagued the performance of the well. In June 2000, the well was equipped with a jet pump and returned to production but declined steeply. Since that time, the well became uneconomic to operate and was plugged.

In 2004, a unit team re-evaluated the list of prospects in the 237 zone. The team recommended doing further evaluation of three prospects near Chaffee.

Status

The 237 has no active producers. Cumulative production is 3.9 Mmbo. Recent evaluations indicated the Chaffee area had the greatest productivity potential with the least depletion risk.

Strategies

In FY05/06, one 237 zone well is being considered in the Chaffee area. Three factors may be critical in making a 237 well economically attractive to all parties. First is the completion of a commercial agreement on the development of shallow and deep gas reserves. The second is better location identification through the reprocessed 1995 seismic survey. The third is identifying a good fall back location in the UP Ford to minimize the dry hole risk costs. An additional 237 Zone well is listed for FY06/07 to cover the possibility that the initial prospect drilling is delayed and for a potential follow up prospect if the initial well is successful.

Critical Issues

To fully understand the 237 reservoir and refine the development plans, focus will be on two key reservoir issues during the Program Plan period:

- Evaluate location using the reprocessed 1995 seismic survey to find the best location
- Coordinate with the UP Ford development program to identify a good fall back UP Ford location