MINUTE ITEM
This Calendar Item No. C37 was approved as Minute Item No. 37 by the California State Lands Commission by a vote of 3 to 0 at its 04-07-03 meeting.

CALENDAR ITEM
C37

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04/07/03
W 17157
M. LeClair

APPROVE THE LONG BEACH UNIT PROGRAM PLAN (JULY 1, 2003 THROUGH JUNE 30, 2008), AND THE LONG BEACH UNIT ANNUAL PLAN (JULY 1, 2003 THROUGH JUNE 30, 2004), LONG BEACH UNIT, WILMINGTON OIL FIELD, LOS ANGELES COUNTY

APPLICANT:

City of Long Beach
Attn.: Mr. Dennis M. Sullivan, Director
Department of Oil Properties
211 East Ocean Boulevard, Suite 500
Long Beach, CA 90802

BACKGROUND:

In accordance with Chapter 941 of the Statutes of 1991 (AB 227) and the Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, the Long Beach Unit Program Plan (July 1, 2003 through June 30, 2008) and the Long Beach Unit Annual Plan (July 1, 2003 - June 30, 2004) has been submitted by the City of Long Beach (City) to the California State Lands Commission (Commission).

At its meeting on February 18, 2003, the Long Beach City Council adopted the proposed Annual Plan and authorized its submittal to the Commission for consideration and approval. The Commission has 45 days following formal submission of the Annual Plan to take action. If no action is taken, the Program Plan and Annual Plan will be deemed approved as submitted. The economic projections for the period July 1, 2003 through June 30, 2008 (as presented by the City) are shown below:

ALL FIGURES ARE IN MILLIONS OF DOLLARS			
PERIOD	**TOTAL REVENUE**	**EXPENDITURES**	**NET INCOME**
FY 03-04	221.6	194.7	26.9
FY 04-05	219.0	188.7	30.3
FY 05-06	212.6	177.0	35.6
FY 06-07	204.1	175.8	28.3
FY 07-08	195.2	173.1	22.1
TOTAL	**1052.5**	**909.3**	**143.2**

As presented, the Long Beach Unit Program Plan includes anticipated rates of production, revenues, expenditures, and net profits for the Unit as projected by the City of Long Beach Department of Oil Properties. The City has estimated that the Unit net income from July 1, 2003 through June 30, 2008, will be $143.2 Million, after total Expenditures of $909.3 Million. This income is based on a forecasted oil price of $18.00 per barrel over the five-year plan period. This income will be generated primarily from oil revenues based on production forecasts ranging from 32,100 barrels of oil per day (BOPD) in Fiscal Year 2003/2004 to approximately 28,100 BOPD in FY 2007/2008. These production rates are based on the assumption that development drilling will include 24 wells per year for Fiscal Year 2003/2004 and Fiscal Year 2004/2005 with continued drilling of 19 wells in Fiscal Year 2005/2006, 14 wells in Fiscal Year 2006/2007 and 11 wells in Fiscal Year 2007/2008.

Included in the plan are facility improvement projects which include improved facility automation, completing strategic pipeline replacements, and other investments to increase the longevity of the Unit by improving safety and environmental performance. With completion of the 47MW power generation plant in Fiscal Year 2002/2003, the Unit now supplies approximately 75 percent (75%) of its electricity needs. The Program Plan provides funding to convert the power plant into a cogeneration facility, which will help capture more revenue through heat sales.

Commission staff has reviewed the Program Plan and Annual Plan as submitted by the City and believes that it provides an engineering framework to meet the objectives of the Optimized Waterflood Agreement and is based on all engineering, geologic, and economic information available at the time of preparation. Engineers representing the State, City, THUMS, and Oxy agree that objectives will be met in all areas of interest, including those of good oil field practice, proper reservoir management, safety to employees and the public, and environmental protection, through active participation by all parties at Unit forums, Engineering Committee meetings, Voting Party Committee meetings, and during events as they occur in the field.

OTHER PERTINENT INFORMATION

1. Pursuant to the Commission's delegation of authority and the State CEQA Guidelines [Title 14, California Code of Regulations, section 15060(c)(3)], the staff has determined that this activity is not subject to the provisions of the CEQA because it is not a "project" as defined by the CEQA and the State CEQA Guidelines.

   Authority: Public Resources Code section 21065 and Title 14, California Code of Regulations, sections 15060 (c)(3) and 15378.

EXHIBITS:

A. Letter from the City of Long Beach to the California State Lands Commission requesting approval of the Long Beach Unit Program Plan (July 1, 2003 through June 30, 2008) and the Annual Plan (July 1, 2003 through June 30, 2004)
B. Long Beach Unit Program Plan (July 1, 2003 through June 30, 2008)
C. Long Beach Unit Annual Plan (July 1, 2003 through June 30, 2004)

PERMIT STREAMLINING ACT DEADLINE:

N/A

RECOMMENDED ACTION:

IT IS RECOMMENDED THAT THE COMMISSION:

CEQA FINDING:

FIND THAT THE ACTIVITY IS NOT SUBJECT TO THE REQUIREMENTS OF THE CEQA PURSUANT TO TITLE 14, CALIFORNIA CODE OF REGULATIONS, SECTION 15060(c)(3) BECAUSE THE ACTIVITY IS NOT A PROJECT AS DEFINED BY PUBLIC RESOURCES CODE SECTION 21065 AND TITLE 14, CALIFORNIA CODE OF REGULATIONS, SECTION 15378.

AUTHORIZATION:

APPROVE THE LONG BEACH UNIT PROGRAM PLAN (JULY 1, 2003 - JUNE 30, 2008) AND ANNUAL PLAN (JULY 1, 2003 - JUNE 30, 2004), LONG BEACH UNIT, WILMINGTON OIL FIELD, LOS ANGELES COUNTY.

EXHIBIT A W 17157

CITY OF LONG BEACH

DEPARTMENT OF OIL PROPERTIES

211 EAST OCEAN BOULEVARD, SUITE 500 • LONG BEACH, CALIFORNIA 90802 • (562) 570-3900 • FAX 570-3922

March 10, 2003

Mr. Paul B. Mount II, P.E.
Chief, Mineral Resources Management Division
California State Lands Commission
200 Oceangate, 12th Floor
Long Beach, CA 90802-4331

SUBJECT: **SUBMISSION OF THE LONG BEACH UNIT ANNUAL AND PROGRAM PLANS (JULY 1, 2003 - JUNE 30, 2008)**

Dear Mr. Mount:

The City of Long Beach, as Unit Operator of the Long Beach Unit, and in accordance with Chapter 138, Section 5, Chapter 941, Section 3, and the Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, Article 2, submits ten copies each of the Long Beach Unit Annual and Program Plans (July 1, 2003 - June 30, 2008).

The Plans were approved by the Long Beach City Council on February 18, 2003. If you have any questions, please contact Ms. Sue Schoij at (562) 570-3973.

Sincerely,

Dennis M. Sullivan
Director

DMS:RJR

Enclosures

cc: P. D. Thayer
A. V. Hager
F. O. Ludlow
F. Komin
J. Charles Parkin

FIN 312.006

W 17157

Exhibit B

PROGRAM PLAN

Long Beach Unit

July 2003 through June 2008

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)

January 2003

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Executive Summary

This Program Plan covers the period from July 1, 2003 through June 30, 2008. 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 91 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 FY03/04 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 32.1 Mbopd, 749 Mbwpd and 833 Mbwipd in FY03/04 and 28.1 Mbopd, 788 Mbwpd and 869 Mbwipd in FY07/08, 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 can be accomplished on Pier J, and Islands Chaffee, Freeman, and Grissom with the use of Unit rigs T-9 and T-5 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. This Program Plan includes funding for aesthetic and noise abatement measures associated with drilling operations on Island White if such plans become economic in the future. It is possible that development results, new 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 recompletions and basic facility modifications associated with this project, as well as gas production and the associated revenue. Funds for a deep test are not included.

Several facility improvement projects are planned throughout the initial two to three years of the Plan. These improvements are focused on facility automation and completing strategic pipeline replacements, and could include projects such as installation of casing gas compression, cogeneration, 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 24 development and replacement well projects planned for FY03/04 of the Program Plan and an average oil price of $18.00/bbl, total revenue, expenditures, and net profits are projected to be $221.6 million, $194.7 million, and $26.9 million, respectively. Over the five year Program Plan period, cumulative total revenue, expenditures, and net profit are expected to reach $1,052.5 million, $909.3 million, and $143.2 million, respectively. A schedule of projected revenue, expenditures, and net profits by year is given in Exhibit A. Expenditure levels and project mix will be adjusted as needed to respond to fluctuations in oil price and other economic conditions.

Overview

This Program Plan covers the period from July 1, 2003 through June 30, 2008. 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 our 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 $18.00/bbl. This section also includes the schedules that will be incorporated into the FY03/04 and FY04/05 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 subzone 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. Current development plans require one drilling rig.

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).

Recent Events

Electric commodity costs have increased substantially since 2000. A number of factors have contributed to these high levels, including the statewide electric supply shortage of 2000-01, erratic fuel gas costs, and deregulation design flaws. In 2002, the Long Beach Unit constructed a 47 MW power generation plant to help mitigate the higher expense and lost production resulting from the volatile energy environment. This plant will provide approximately 75% of the Unit's current electrical needs.

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, and hydrocarbon throughput analysis. Based on the analysis results, development opportunities will be identified and evaluated including recompletions, 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 is programmed 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 fracture stimulation program has been historically very successful, but as the program has extended into the less prolific, thin bedded lower Ranger and UP Ford zones, results have been mixed. Effort is already underway and will continue into the upcoming Plan period to improve the fracture stimulation results.

In January 2002, the Surveillance Engineering and Reservoir Engineering Groups were reorganized to place more emphasis on development. Reservoir Engineers were assigned to pools and now have surveillance and development responsibilities. This change should produce more comprehensive management of each pool. Streamline modeling and hydrocarbon pore volume throughput studies will be initiated in select pools.

The Subsurface Team, formed in mid-2000 and charged with identifying additional development investment opportunities in the Unit, successfully completed streamline modeling studies of the UP Ford and Ranger East reservoirs. The models have since been used to screen multiple drilling locations and evaluate pattern configuration modifications. The tools will continue to be updated to reflect recent performance data and changes to our understanding of reservoir description. Petrophysical studies are ongoing in the UP Ford to help define floodable pay and assist in our understanding of potential targets for moveable oil. The team members have now been moved into their respective reservoir teams to provide development and operations support.

As a part of the 2002 reorganization, a Waterflood Conformance Team was created to address concerns associated with increasing watercuts and associated water handling costs. The team's primary focus is to establish an evaluation process to identify opportunities for water shut-off and diversion into inadequately swept sands, incorporating applicable technologies to achieve these goals. A water conformance pilot program was undertaken by late 2002 targeting subblocks 402 and 403 of Ranger West. While data is collected and evaluated to determine the success of the pilot program, a forward plan will be developed on a second water conformance target area.

A 3D vertical seismic profile was collected in early 2002 to identify south flank / sub-thrust exploration prospects and optimize numerous development well locations. The new seismic survey was designed to obtain higher resolution data than had previously been acquired. This data is currently being processed and interpreted.

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 wells and horizontal well gravel packing, short radius wells, special design and extended reach wells, cased hole completions, hydraulic fracturing, 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 24 wells per year for FY03/04 and FY04/05. This schedule can be met with one Unit drilling rig 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. A reduced level of drilling will likely continue after FY04/05 to redrill failed wells and to 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 FY03/04 and FY04/05. This drilling plan reflects the current understanding of new development well economics. The drilling candidate list is updated annually by the reservoir development teams. Each drilling project is submitted to Voting Parties for approval 2-4 months ahead of the planned spud date. The economics of each well is 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 FY03/04 and FY04/05. 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 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 multiple waterflood "pools" 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 2018, 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, we believe this method more accurately models the Unit's reservoirs. The resulting prediction shows a stabilized overall exponential decline of about 11% per year.

The incremental production contribution for new development wells is based on expected rates for average Unit wells, referred to as "type wells." The producer type well is based on a statistical fit of the production rates and declines seen in all Unit producers drilled in 1999 through 2001. The injector type well is a wellcount-weighted average of the injector type wells from the reservoir development teams, with injection volumes in turn based on observed injection response by Unitized Formation. The expected 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 264 standard cubic feet per barrel of oil produced over the Plan period. In addition, contribution from recompleting wells in the Lower Pliocene shallow gas formations is also included in the forecast. These recompletions will occur as part of the shallow gas development proposal that is expected to be in place prior to the Program Plan start date.

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 we may face 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 we operate. 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 our industry that will take our 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 our business operations. By employing effective cost management strategies, we strive to perform in the lowest cost per net barrel quartile for comparable operations. We will aggressively endeavor to achieve cost management gains 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.

Chemical Treatment Program: A Corrosion Strategy Team was formed in mid-2000 to address downhole and surface corrosion issues and design a comprehensive Unit-wide strategy. After the successful implementation of a pilot program, this strategy was implemented Unit-wide during 2002. This Plan includes funds necessary to maintain this program that should result in significant future savings by reducing failures related to downhole corrosion and surface corrosion.

Waste Management: Present operations at the C-822I 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 our 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. Island White is the only Unit location that does not currently have a working Unit drilling rig assigned to it. The repairs necessary to bring the Island White drilling rig up to standard make drilling on that location uneconomic. This Plan includes funding for aesthetic and noise abatement measures in the event drilling operations on Island White become attractive. Additional drilling methods will be considered for lowering drilling costs on all locations. These include contract drilling rigs, workover rigs, and coiled tubing units.

Automation: A project to automate many surface and downhole facilities and processes began during 2002. This project targets cost structure reduction and production acceleration opportunities. The primary components are well and facility monitoring systems and improved user interfaces. The project will also facilitate compliance with regulations. This plan contains funding to continue this project through its estimated completion in FY04/05.

Fluid Handling: The Unit's fluid handling strategy is to maximize efficiency of current water handling facilities until consolidation of water plants is possible as total fluid production decreases. Water plant consolidation will eventually allow the elimination of substantial amounts of water plant surface equipment and the associated maintenance and operational costs. The newly completed Pier J Water Plant has eliminated inefficient water bottlenecks at the central processing facility by increasing its capacity to handle excess production shipped from the islands. While the timing of water plant consolidation is dependent on gross production rates and oil price, consolidation of these facilities is inevitable due to attendant cost reduction benefits. Several facility upgrade projects will be completed over the Program Plan period to prepare for facilities consolidation.

Facility Infrastructure Upgrades

Significant components of the Unit's infrastructure are 20 to 35 years old and have reached the end of their serviceable lives. Substantial cost savings and efficiencies can be realized by upgrading these systems to reduce future maintenance requirements. Several strategic projects to replace or upgrade pipelines and other systems have been underway since 2000. This Plan includes funding to complete these ongoing projects.

Shallow Gas Development

An agreement between the State of California, City of Long Beach, and OLBI regarding the development of shallow 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. Additional components of this agreement, including the potential for exploration drilling, will be addressed through the Determination / Voting Parties process.

Electricity Generation

Electricity is the single largest cost element for the Unit. Currently the Unit consumes approximately 500 million kWh per year, and any change in the electrical rates significantly affects the profitability of Unit operations.

The Unit has constructed a 47MW power generation plant in an effort to insulate the Unit from the risks of escalating wholesale electric costs. The plant commenced operations in FY02/03 and supplies approximately 75% of the Unit's electricity.

The Plan also includes funding to convert the power plant into a cogeneration facility. This project will capture more revenue from heat sales and provide the basis for favorable treatment regarding exit fees that may be charged for coming off the grid. If this project is determined to be economically viable, construction should occur during the first year of this plan.

Efforts will also focus on electrical production equipment efficiency. Efforts to improve injection pump efficiency will continue, including utilizing power monitoring devices on injection pumps 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.

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 1995 through 1999. Outstanding items include the impact on valuation of the Oxy change of ownership in 2000 and the exemption status of the Nonoperating Contractors' interest for 1995 through 2002. 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 $1,052.5 million, based on a $18.00/bbl oil price, $3.00/mcf gas price, and average daily oil and gas production as projected in Exhibit C. Projected revenue for FY03/04 is expected to be $221.6 million.

Cost Forecast

Total estimated expenditures for the first year of this Program Plan are consistent with the FY03/04 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, abandonments, 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 $909.3 million. The projected expenditures for FY03/04 are $194.7 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 $143.2 million. Unit profit for FY03/04 is expected to be $26.9 million. A schedule of annual projected revenue, expenditures, and net profit is given in Exhibit A.

Budget commitments for FY04/05 will be established based on actual results and additional insights gained during FY03/04.

Exhibits

Table 1

SUMMARY OF PRODUCTION AND INJECTION
AS OF NOVEMBER 2002
JULY 2003 – JUNE 2008 PROGRAM PLAN, LONG BEACH UNIT

		Active Well Count:		Average Rates for November 2002				Average Well Rates	
Reservoir	CRB	Producers	Injectors	BOPD	BWPD	BIPD	Wtr Cut	BOPD/Well	BIPD/Well
Tar	35	5.0	2.0	101	668	1,616	86.9	20	808
Ranger West	1	43.0	29.5	2,663	66,101	67,816	96.1	62	2,299
	2	24.0	14.0	1,015	28,680	39,456	96.6	42	2,818
	3	36.0	21.5	1,931	49,248	51,581	96.2	54	2,399
	4	47.0	20.5	2,135	62,017	64,915	96.7	45	3,167
	5	25.0	18.5	1,362	47,824	49,508	97.2	54	2,676
	7	13.0	5.5	534	10,959	12,684	95.4	41	2,306
	8	11.0	8.0	476	14,051	18,114	96.7	43	2,264
	9	6.0	5.0	204	6,230	7,547	96.8	34	1,509
	10	21.5	20.0	1,238	25,916	33,432	95.4	58	1,672
	11	6.5	4.5	319	8,602	6,104	96.4	49	1,356
	12	7.0	4.5	236	7,454	9,512	96.9	34	2,114
	13	8.0	3.0	332	11,916	8,218	97.3	42	2,739
	36	20.0	18.0	813	35,250	41,058	97.7	41	2,281
	37	10.0	7.5	557	20,361	18,519	97.3	56	2,469
	Total	278.0	180.0	13,816	394,609	428,463	96.6	50	2,380
Ranger East	14	17.0	13.5	725	24,867	27,241	97.2	43	2,018
	15	36.0	20.5	1,801	34,707	36,865	95.1	50	1,798
	16	19.0	8.0	1,098	11,239	14,043	91.1	58	1,755
	17	19.5	12.5	1,054	11,236	17,762	91.4	54	1,421
	18	20.0	17.0	825	19,527	28,415	95.9	41	1,671
	20	10.0	5.0	538	9,536	12,300	94.7	54	2,460
	32	2.5	2.5	110	2,518	5,023	95.8	44	2,009
	33	28.0	14.0	1,112	31,074	30,004	96.5	40	2,143
	21	31.0	21.0	1,235	31,871	36,211	96.3	40	1,724
	22	15.0	6.0	728	10,990	9,596	93.8	49	1,599
	Total	198.0	120.0	9,226	187,566	217,460	95.3	47	1,812
Terminal	24	27.0	7.0	1,230	7,650	9,922	86.2	46	1,417
	38	36.0	19.0	1,933	47,149	50,896	96.1	54	2,679
	39	29.0	7.0	1,305	17,092	9,873	92.9	45	1,410
	40	10.0	6.0	298	3,632	5,190	92.4	30	865
	41	2.0	1.0	107	877	1,615	89.1	53	1,615
	42	7.0	8.0	329	5,751	8,821	94.6	47	1,103
	43	27.0	14.0	1,198	17,183	19,622	93.5	44	1,402
	47	4.0	0.0	52	386	0	88.2	13	0
	Total	142.0	62.0	6,451	99,719	105,938	93.9	45	1,709
UP/Ford	26	3.0	1.0	67	626	1,149	90.4	22	1,149
	27	15.0	7.0	712	6,524	8,305	90.2	47	1,186
	31	5.0	1.0	175	1,995	1,076	91.9	35	1,076
	44	7.0	4.0	255	2,770	3,943	91.6	36	986
	45	23.0	10.0	1,195	12,435	13,678	91.2	52	1,368
	46	23.0	9.0	1,191	10,809	12,338	90.1	52	1,371
	Total	76.0	32.0	3,595	35,160	40,490	90.7	47	1,265
237	30	0.0	0.0	0	0	0	0.0	0	0
LBU Total		699.0	396.0	33,190	717,721	793,968	95.6	47	2,005

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Exhibit A

ECONOMIC PROJECTIONS
July 1, 2003 through June 30, 2008 Program Plan
(Million Dollars)

	Fiscal 2003/04	Fiscal 2004/05	Fiscal 2005/06	Fiscal 2006/07	Fiscal 2007/08	Program Plan Period
Estimated Revenue						
Oil Revenue	$211.6	$208.5	$202.0	$193.8	$185.2	$1,001.1
Gas Revenue	$10.0	$10.5	$10.6	$10.3	$10.0	$51.4
Total Estimated Revenue	$221.6	$219.0	$212.6	$204.1	$195.2	$1,052.5
Estimated Expenditures	$194.7	$188.7	$177.0	$175.8	$173.1	$909.3
Net Income	$26.9	$30.3	$35.6	$28.3	$22.1	$143.2

Exhibit B

Anticipated Drilling Schedule

July 1, 2003 through June 30, 2008

FISCAL YEAR	RANGER EAST	RANGER WEST	TERMINAL	U.P./FORD	TOTAL WELLS
2003/04	8	2	4	10	24
2004/05	0	12	8	4	24
2005/06	4	6	1	8	19
2006/07	3	3	6	2	14
2007/08	0	8	1	2	11

* See text for a description of the process that will be used to identify and approve all new locations

Exhibit C

Range of Production Rates

July 2003-June 2008 Program Plan

Long Beach Unit

FISCAL YEAR	EXPECTED RANGE			EXPECTED RATE		
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	OIL MBOPD	WATER MBWPD	GAS MMCFPD
2003/04	28.9 - 33.7	674 - 786	8.2 - 9.5	32.1	749	9.1
2004/05	28.6 - 33.3	701 - 818	8.6 - 10.1	31.7	779	9.6
2005/06	27.7 - 32.3	708 - 826	8.7 - 10.1	30.8	787	9.6
2006/07	26.5 - 31.0	711 - 829	8.5 - 9.9	29.5	790	9.4
2007/08	25.3 - 29.5	709 - 827	8.2 - 9.6	28.1	788	9.1

Exhibit D

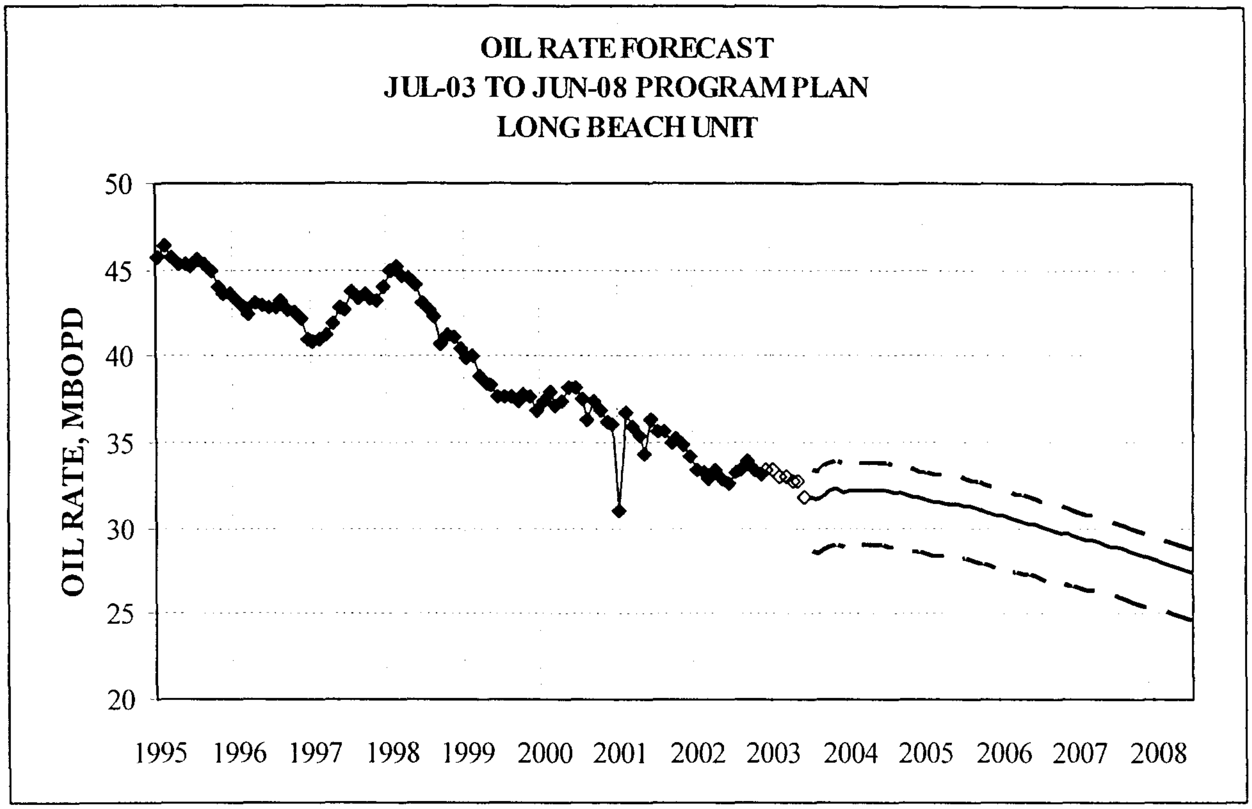
Range of Injection Rates

July 2003-June 2008 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
2003/04	749 - 874	833	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2004/05	768 - 896	854	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2005/06	779 - 909	866	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2006/07	785 - 916	872	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2007/08	782 - 912	869	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Exhibit E



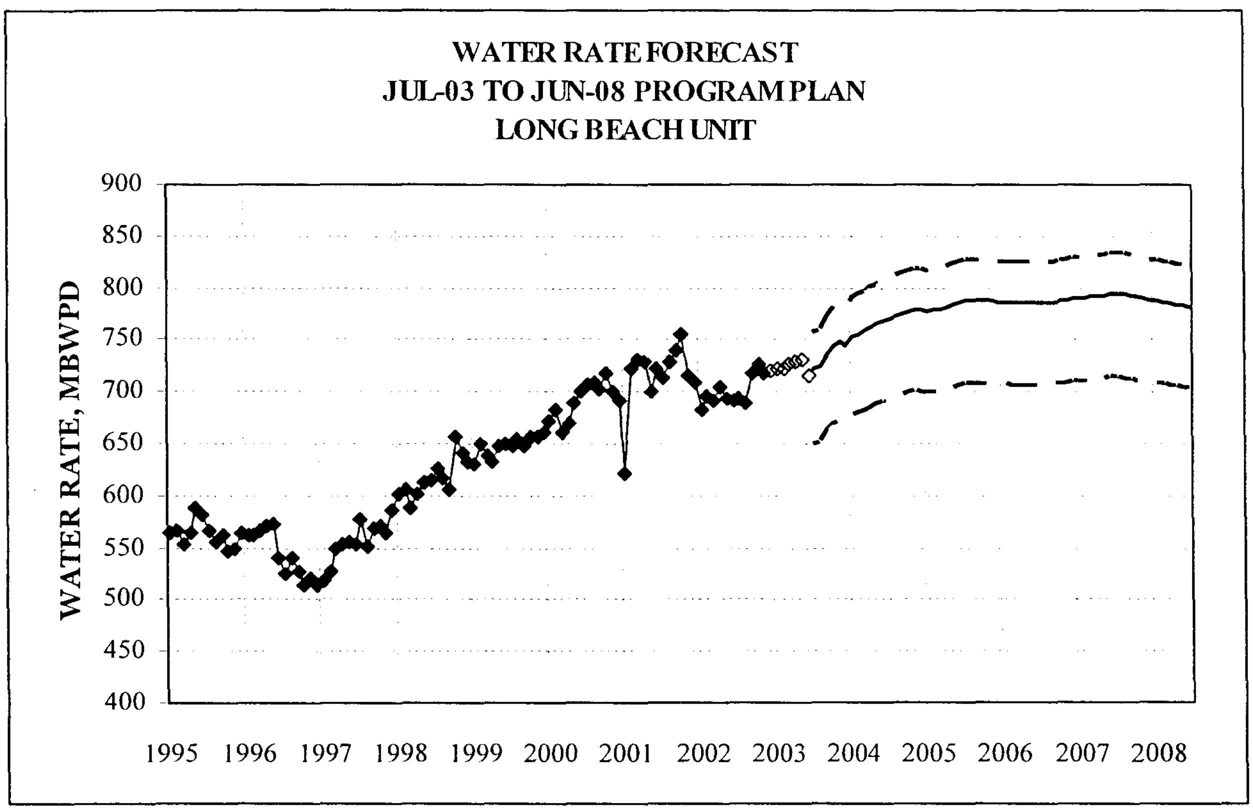


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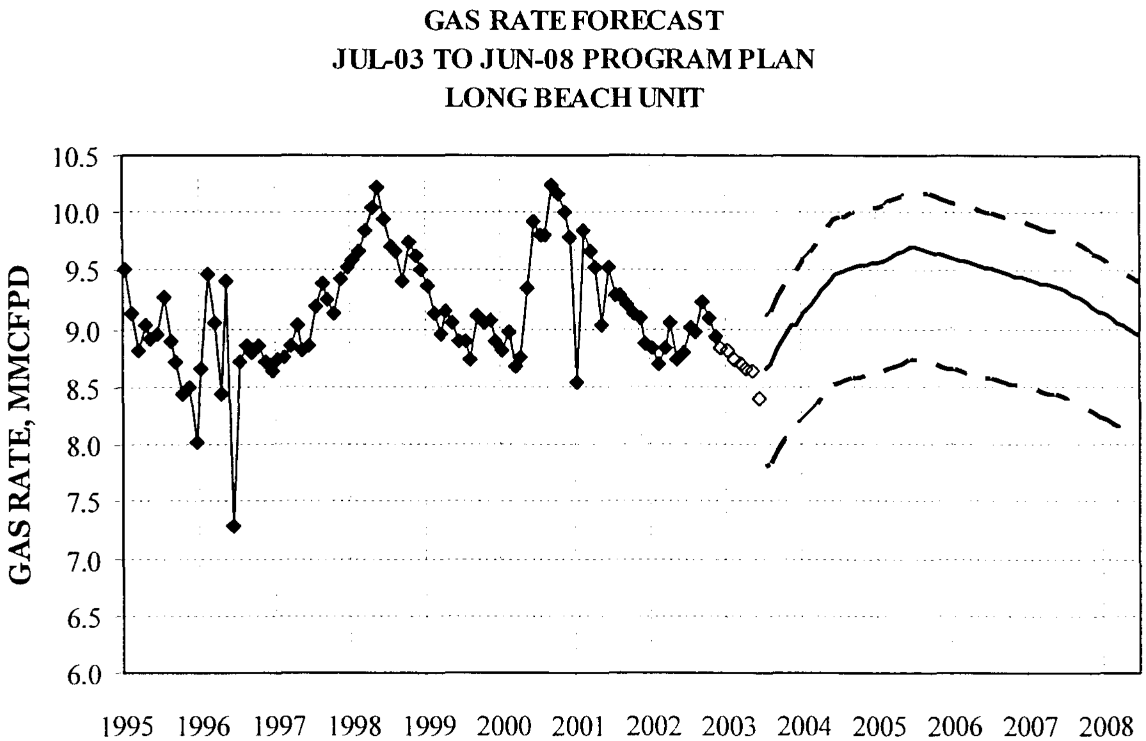
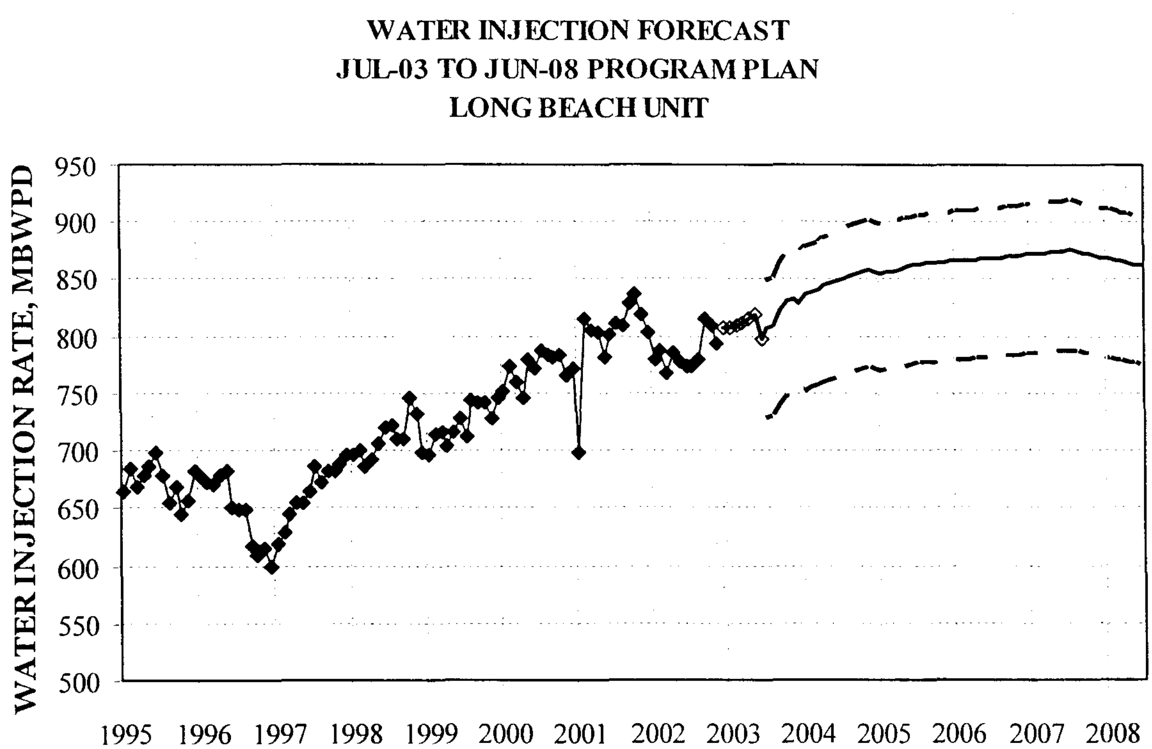
Exhibit F





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Schedule 1 A

Range of Production and Injection

FY 2003/04

Long Beach Unit Program Plan, July 2003-June 2008

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2003-04	28.9 - 33.7	674 - 786	8.2 - 9.5	749 - 874

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2003-04	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Schedule 1 B

Anticipated Development and Replacement Wells

Fiscal Year 03/04

Long Beach Unit Program Plan, July 2003-June 2008

RESERVOIR	CRB	PRODUCERS GRISSOM MIN MAX	PRODUCERS WHITE MIN MAX	PRODUCERS CHAFFEE MIN MAX	PRODUCERS FREEMAN MIN MAX	PRODUCERS PIER-J MIN MAX	INJECTORS GRISSOM MIN MAX	INJECTORS WHITE MIN MAX	INJECTORS CHAFFEE MIN MAX	INJECTORS FREEMAN MIN MAX	INJECTORS PIER-J MIN MAX
TAR	Sc	0 - 0				0 - 0	0 - 0				0 - 0
RANGER WEST	1	0 - 0	0 - 0				0 - 0				
	2	0 - 0					0 - 0				
	3	0 - 0	0 - 0			0 - 0	1 - 2				0 - 0
	4	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0			0 - 0	0 - 0
	5	0 - 0			0 - 2	0 - 0				0 - 0	0 - 0
	36				0 - 0	0 - 0				0 - 0	0 - 0
	7				0 - 0					0 - 0	
	8		0 - 1		0 - 0			0 - 0		0 - 0	
	9		0 - 0					0 - 0			
	10		0 - 0					0 - 1			
	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 - 2	
	16		0 - 0	1 - 2	0 - 0			0 - 0	0 - 0	0 - 0	
	17			2 - 3					1 - 2		
	18			0 - 0					0 - 0		
	32			0 - 0					0 - 0		
	33			0 - 0					1 - 2		
	20			0 - 0					0 - 0		
	21			0 - 0	0 - 0				1 - 2	0 - 0	
	22			0 - 0	0 - 0				0 - 0	0 - 0	
TERMINAL	38	0 - 0				0 - 0	0 - 0				0 - 0
	39	0 - 0	0 - 0		0 - 0	0 - 0	1 - 2	0 - 0		0 - 0	0 - 0
	40		0 - 0		0 - 0			0 - 0		0 - 0	
	24		0 - 0		0 - 2			0 - 0		0 - 0	
	42			0 - 0					0 - 0		
	43			0 - 0	0 - 3				0 - 0	0 - 0	
UP FORD	26		0 - 0		0 - 0			0 - 0		0 - 0	
	27		0 - 0		0 - 2			0 - 0		0 - 0	
	31	0 - 1	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 - 0	0 - 0	
	45		0 - 0	1 - 3	0 - 0			0 - 0	0 - 0	0 - 0	
	46		0 - 0	0 - 2	1 - 2			0 - 0	1 - 2	0 - 0	
237		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		TOTAL					TOTAL				
		6 - 25					6 - 15				

Schedule 2 A

Range of Production and Injection

FY 2004/05

Long Beach Unit Program Plan, July 2003-June 2008

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2004-05	28.6 - 33.3	701 - 818	8.6 - 10.1	768 - 896

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2004-05	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

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Schedule 2 B

Anticipated Development and Replacement Wells

Fiscal Year 04/05

Long Beach Unit Program Plan, July 2003-June 2008

RESERVOIR	CRB	PRODUCERS GRISSOM MIN MAX	PRODUCERS WHITE MIN MAX	PRODUCERS CHAFFEE MIN MAX	PRODUCERS FREEMAN MIN MAX	PRODUCERS PIER-J MIN MAX	INJECTORS GRISSOM MIN MAX	INJECTORS WHITE MIN MAX	INJECTORS CHAFFEE MIN MAX	INJECTORS FREEMAN MIN MAX	INJECTORS PIER-J MIN MAX
TAR	Sc	0 - 0				0 - 0	0 - 0				0 - 0
RANGER WEST	1	2 - 5	0 - 0				0 - 0				
	2	1 - 2					1 - 2				
	3	1 - 3	0 - 0			0 - 0	1 - 2				0 - 0
	4	1 - 3	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	
	8		0 - 1		0 - 0			0 - 0		0 - 0	
	9		0 - 0					0 - 0			
	10		0 - 0					0 - 1			
	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 - 0					0 - 0		
	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 - 3				0 - 0	0 - 0				0 - 0
	39	1 - 3	0 - 0		0 - 0	0 - 0	1 - 3	0 - 0		0 - 0	0 - 0
	40		0 - 0		0 - 0			0 - 0		0 - 0	
	24		0 - 0		1 - 3			0 - 0		0 - 0	
	42			0 - 0					0 - 0		
	43			0 - 0	0 - 0				0 - 0	0 - 0	
UP FORD	26		0 - 0		0 - 0			0 - 0		0 - 0	
	27		0 - 0		0 - 0			0 - 0		0 - 0	
	31	0 - 1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	44		0 - 0	0 - 0	0 - 0			0 - 0	0 - 0	0 - 0	
	45		0 - 0	0 - 0	0 - 0			0 - 0	0 - 0	0 - 0	
	46		0 - 0	0 - 0	0 - 2			0 - 0	0 - 0	1 - 2	
				0							
237		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
				TOTAL					TOTAL		
				8 - 26					4 - 10		

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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 1.3 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 30 and throughput meeting or exceeding targets of 2.0 hydrocarbon pore volumes injected (HPVI). In the less mature northern blocks, oil recoveries range from 22-28%, WOR's range from 20-24, and throughputs are on the order of 2.0 HPVI.

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 November, 2002 were 13.8 Mbopd and 395 Mbwpd (96.6% water cut) from 278 producers. November 2002 injection averaged 428 Mbwpd from 180 injectors. Average active well rates were 50 bopd and 1419 bwpd for producers and 2380 bwpd for injectors. The current status of each Ranger West/Tar CRB is shown in Table 1.

Ranger West has 115 idle producers and 35 idle injectors. All idle wells are evaluated periodically for reactivation, repair, or abandonment.

Recovery through November 2002 was 459.9 MMbo (33.0% OOIP). Ranger West is expected to produce an additional 45.0 MMbo by 2018 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 4.6 MMbo to 509.5 MMbo (36.6% OOIP) by 2018.

An active development program in the Ranger West reservoir has reduced the base decline rate of 13% per year to approximately 9% per year. Additional information concerning the development drilling and wellwork activities can be found in the Calendar Year 2001-2002 Activities and Results section.

Calendar Years 2001 and 2002 Activities and Results

Since publication of the last Program Plan, thirteen producers (nine horizontal, one conventional, and three cased hole completions) and ten injectors have been drilled and completed in the Ranger West pool. This 2001-2002 activity level compares to fourteen producers and five injectors drilled during the 1999-2000 period reported in the last Program Plan.

The average initial stabilized rate for the thirteen producers drilled in the Ranger West Pool is 219 BOPD with initial rates ranging from 400 BOPD to 60 BOPD. This rate is slightly higher than the anticipated average rate of 205 bopd. The average initial production rate is 275 BOPD for the horizontal completions, 80 BOPD for the cased hole completions and 185 BOPD for the conventional open-hole gravel pack completion. Two of the horizontal wells drilled in the upper Ranger interval were extremely successful with rates averaging 400 BOPD.

All ten of the injection wells drilled during the 2001-2002 time period were cased hole, selectively perforated completions targeting intervals with historically low waterflood throughput and relatively high remaining oil saturation. All ten wells met injectivity expectations with an average injection rate of 1800 bwpd.

Maintenance wellwork continues to play a major role in maximizing Ranger West base production. During 2001-2002, approximately 215 producer maintenance wellwork projects were completed yielding an average of 45 bopd at an average cost of about $55,000. Roughly 355 injector maintenance projects were also completed yielding an average of 25 bopd/job at an average cost of about $15,000.

During the FY 01/02 Plan period, a total of 18 development (investment) wellwork jobs were also completed (11 producers and 7 injectors). Nine of the producer development projects were selective uphole recompletions/add pay projects targeting bypassed oil sands. Overall, the producer development wellwork has been successful, averaging about 76 bopd/job at a cost of $220,000/job. The 7 injector development wellwork jobs included uphole recompletions, producer to injector conversions, and profile modifications. The injection work targeted increasing water throughput in selective sands and pattern areas. Injection development wellwork projects contributed an average of 2175 bpd of injection per well and an associated 55 bopd at an average cost of about $115,000.

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 25% 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 36% 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 14 development wells and performing 11 investment wellwork projects in the calendar years 2003 through 2004. 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 the northern part of Ranger VI and VII where less mature waterflood development is seen.

- 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 18 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 have subsequently been 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 November 2002, Ranger East production was 9.2 Mbopd and 188 Mbwpd from 198 active producers. Total water injection was 217 Mbwpd into 120 active injectors.

Since the last reporting period in November 2000, oil production has declined at 8.5% per year from 10.9 Mbopd to 9.2 Mbopd. The WOR increased from 19.1 to 20.3, and the water injection rate has declined by 15 Mbwpd. Cumulative oil production as of November, 2002 was 222 MMbo (25.6% 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 November 2002 is producing 2.5 Mbopd and 59.6 Mbwpd, with a water injection rate of 64.1 Mbwpd. Since the last reporting period in November 2000, oil production declined at an average rate of 4% per year, the WOR increased from 20.3 to 23.6, and water injection rate decreased by 1.0 Mbwpd. One producer and one injector, both cased hole completions, were drilled in Ranger 8A during this reporting period.

Ranger 8B, or CRB-16, is a small fault block producing 1.1 Mbopd and 11.2 Mbwpd, and injecting 14.0 Mbwpd. Oil production declined at an average rate of 8% per year since the last reporting period. The WOR increased from 8.5 to 10.2 which is in line with the historical trend, while the water injection rate increased by 2.4 Mbwpd since the last reporting period. One producer, a conventional open hole completion, and one pattern injector were drilled during this reporting period. The pattern injector was drilled in order to improve injection throughput in the upstructure portion of the fault block.

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 3.6 Mbopd and 73.9 Mbwpd, with 93.5 Mbwpd of water injection. Oil production declined at an average rate of 4% per year since the last reporting period. Two producers, a conventional and a horizontal completion, were drilled in R90N during this reporting period. Four injection wells were also drilled in order to provide injection support in Ranger 90N. The WOR increased from 19.8 to 20.5 and the water injection rate increased by 11.4 Mbwpd since the last reporting period.

Ranger 90S consists of CRB's 21 and 22, which are producing 2.0 Mbopd and 42.8 Mbwpd, with 45.8 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 21.4, up from 17.8 from the last reporting period. One injection well, a cased hole completion, was drilled in Ranger 90S during this period. The water injection rate is up by 5.6 Mbwpd.

Calendar Years 2001 and 2002 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.

Eleven wells were drilled in the Ranger East area in calendar years 2001 and 2002, comprised of four producers and seven injectors. The four producers consisted of one cased-hole completion, one horizontal well with an open-hole gravel packed completion, and two conventional wells with open-hole gravel packed completions. The cased-hole and horizontal completions had initial oil production rates of 28 and 25 bopd, respectively. The conventional open-hole gravel packed wells averaged an initial oil rate of 68 bopd. The injectors were all cased hole, selectively perforated completions targeting intervals with low waterflood throughput and high remaining oil saturations. The average injection rate from the seven injectors was 1700 bwpd.

A total of twenty development (investment) wellwork projects were completed during this reporting period consisting of ten producer projects and ten injection well projects. Development wellwork consists of producer recompletes, injector recompletes/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 recompletes were performed during the reporting period. The primary recompletion target is the most prolific Fo-sand plus any other sands not swept by water. These targets are identified primarily with nearby pass-through logs of recently drilled wells. Initial results of these recompletions have met expectations with average incremental oil production benefit of about 100 bopd. The two additional projects were part of an unsuccessful hot water stimulation pilot project conducted on Island Freeman.

A total of five 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. Five 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 2001-2002, approximately 160 producer maintenance wellwork projects were completed yielding an average of 45 bopd/job at an average cost of about $50,000. Roughly 185 injector maintenance wellwork projects were also completed yielding an average of 25 bopd/job at an average cost of $20,000.

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 10.2 in Ranger 8B to 23.6 in Ranger 8A, indicating strong remaining reserves potential before reaching a nominal economic limiting WOR of 30. The injection target volume is 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. Numerous diverted acid stimulation jobs and injector cleanouts have been performed to improve the profiles. Another challenge is the optimal placement of injectors in the highly faulted Ranger East pool. Producer to injector conversions and injector recompletions have been done to improve sweep efficiency.

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

Strategies

The Ranger East development plan includes drilling an additional 8 development wells and performing 10 investment wellwork projects in calendar years 2003 through 2004. The majority of both drilling and investment wellwork projects will be injectors. The emphasis on injector projects is needed to improve water injection throughputs into all four major fault blocks and accelerate their waterflood development.

Development of a streamline reservoir model encompassing the entire Ranger East area and history matched through 2001 was completed in early 2002. This study was undertaken due to the high degree of faulting in Ranger East requiring a thorough reservoir study before a comprehensive injection enhancement project could be implemented. The reservoir was described by 15 vertical layers and 120 by 164 areal layers. Prediction runs with this model have been used to evaluate individual development project feasibility, as well as to assess ultimate oil recovery under different development options. The high remaining reserves potential as reflected by the low WOR's and the high degree of faulting makes this model an ideal tool to identify specific sand intervals requiring additional injection throughput and production withdrawal, and the necessary projects required (drilling or investment wellwork) to optimally deplete the reservoirs. Many of the projects included in the upcoming development plan have been identified using this model.

Looking ahead, the model results will be calibrated by extending the history match with emphasis placed on the history-match quality of the recently completed development projects in Ranger East. This will enhance the model's reliability for performing future prediction studies. Longer term plans include a subzoning study of the major Ranger East sands, a Petrel reservoir model development, and incorporation of the new description into the streamline model.

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 inexpensively drilling and completing 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 waterflood optimization studies of each major fault block and develop a depletion plan by year end 2003.
- 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 through existing slotted liner completions
- 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 140 MMbo. The Terminal zone is about 1300 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 November 2002 is 6.5 Mbopd and 99.7 Mbwpd resulting in an average WOR of 15.3. There are currently 142 active producers resulting in an average per well rate of 45 bopd and 702 bwpd. Terminal zone injection for November 2002 is 105.9 Mbwpd from 62 wells yielding an average injection rate of 1,709 bwpd per active injection well. Current rates and active well counts by cut-recovery block (CRB) are shown in Table 1.

Seventeen Terminal wells are currently mechanically idle and capable of being reactivated with further investment. We are evaluating conversion and/or repair options for these wells. Six additional wells are idle and have previously been plugged in zone.

Cumulative production through November of 2002 totaled 129 MMbo (31.1% OOIP) and ultimate production for continued operations is expected to reach 148 MMbo (36% OOIP) by 2018 resulting in 19 MMbo remaining reserves. Additional development through infill drilling is expected to yield additional reserves of 3.6 MMbo for an ultimate recovery of approximately 152 MMbo (36.5% OOIP).

Successful infill drilling and well work activities have partially offset the underlying Terminal zone oil production decline rate of 14%/year. Production is down 0.8 Mbopd, or only 6% per year from the November, 2000 rate of 7.3 Mbopd.

Calendar Years 2001 and 2002 Activities and Results

In calendar years 2001 and 2002, eleven producers were drilled compared to four producers and one injector in 1999 and 2000 calendar years referenced in the previous Program Plan.

Actual stabilized production from the eleven producers averaged 86 bopd compared to an average expected rate of 104 bopd.

The cost to drill and complete new wells was slightly less that in the previous reporting period. For the producers drilled, the average cost was $667,000, compared to an average cost of $676,000 for the previous reporting period.

Development (investment) wellwork projects on producers accounted for production totaling 662 bopd from January 2001 through November 2002. Nine producer projects were performed resulting in an average incremental rate of approximately 74 bopd per well. These projects had an average cost of $190,000. Four injector projects were completed over the same period at an average cost of $150,000. Average stabilized injection rates for the wells was 3,400 bwpd/well.

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.

Terminal reservoir targets remain at 30% OOIP ultimate recovery with 1.9 HPVI. Additional reservoir description work will be performed to better define Terminal zone OOIP and sand connectivity. This work will help fine-tune our assessment of current and projected throughput and will be utilized to attain our 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

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. In Terminal East, we hope to expand the successful UP-Ford fracture stimulation program to the lower subzone AC-AD intervals since they are similar in character to UP-Ford sands. Terminal 8A development will include additional injection projects to achieve throughput targets. Finally, injection in Fault Block 90 will continue to be tailored to our 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. Stream tube 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. We will also evaluate application of fracture stimulation technology in the Terminal zone 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 our reservoir objectives.

Critical Issues

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

- 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.
- Expand the successful fracture stimulation program to Lower Terminal AC-AD subzones. Also evaluate fracture stimulation of other Terminal subzones for sand control and improved reservoir deliverability.
- Increase reservoir throughput in Terminal 8A through injection well drilling and conversions.

- Develop stream tube models and create optimized sub zone depletion strategy for Terminal 8 producers .
- 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 93.8 MMbo to date and current active well counts are 73 and 29 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 relatively expensive because of the greater depth. 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, prompting a reduction in the pace of development of the UP-Ford to allow time to evaluate performance drivers. Upside economic benefit may be realized through improved understanding of the operational and reservoir risk associated with drilling and wellwork activities in the UP-Ford.

Status

The UP Ford Zone consists of three fault blocks: UPF8, UFP90, and UPF98. Cumulative production from each of these is 22.4 MMbo, 67.6 MMbo, and 3.9 MMbo, respectively. November 2002 production from the UP Ford was 3.6 Mbopd and 35.2 Mbwpd, with a WOR of 9.8. Overall UP Ford zone injection for November 2002 averaged 40.5 Mbwpd yielding an overall injection-voidage ratio of 1.04. Average well rates are 47 bopd and 463 bwpd for producers and 1265 bwpd for injectors. Current rates and active well counts by cut-recovery block are shown in Table 1.

Thirteen UP Ford wells are currently idle and capable of being reactivated with further investment. We are evaluating conversion and repair options for these wells.

Cumulative production through November of 2002 totaled 94 MMbo (15.4% OOIP) and ultimate recovery is expected to reach 108 MMbo (17% OOIP) in 2018. Infill drilling is expected to account for 4 MMbo (0.7% OOIP) of the 14 Mmbo remaining reserves.

Successful infill drilling and well work activities have helped to offset the UP Ford zone oil production decline. Production is down 0.7 Mbopd representing an 9% decline from the November 2000 rate of 4.3 Mbopd.

Calendar Years 2001 and 2002 Activities and Results

From January 2001 through November 2002, six producers were drilled. An average new producer made 60 bopd compared to an average expected rate of 150 bopd. The average well cost was $0.974 million compared to an average cost of $1.015 million for the previous reporting period.

Producer investment wellwork accounted for production totaling 358 bopd for 2001-2002. Nine producer well work projects were completed resulting in an average project incremental rate of 36 bopd. These projects had an average cost of $235,000. Six injector investment wellwork projects were performed over the same period resulting in an average injection rate of 1400 bwpd at a cost of $175,000 per job.

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

The various Unit programs currently in place will be utilized to help achieve our 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.

We will expand the inzone injection program 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. And finally, the Unit will actively seek out and advocate reduction of artificial lift, drilling, completion and workover costs while meeting our management reservoir objectives.

Critical Issues

To fully understand the UP Ford reservoir and refine our development plans, we will focus on five key issues in 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 at a stabilized rate of 25 bopd. Since that time the well has continued to decline in rate and has since failed.

Calendar Years 2001 and 2002 Activities, Results, and Status

No activity was performed in the 237 zone during the reporting period. Information collected from Well D-571 was analyzed and increased the knowledge about this zone's potential for further development. At this time, no further economic potential is seen for the existing 237 pools. As additional processing is conducted on the recently acquired 3D VSP seismic survey data, the 237 zone will again be evaluated for possible upside development potential.

W 17157

Exhibit C

Long Beach Unit

Thums Long Beach Company
(Agent for Field Contractor)

ANNUAL PLAN

July 1, 2003 through June 30, 2004

THUMS
LONG BEACH
COMPANY

ANNUAL PLAN

July 1, 2003 through June 30, 2004

Table of Contents

Part I

Introduction

This Annual Plan ("Plan") was developed to reflect anticipated activity levels during the fiscal period from July 1, 2003 through June 30, 2004 ("FY03/04"). 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 2003 – 2004 ($ Million)
Development Drilling	$ 21.3
Operating Expense	$ 78.7
Facilities, Maintenance, and Plant	$ 42.4
Unit Field Labor and Administrative	$ 35.7
Taxes, Permits, and Administrative Overhead	$ 16.6
Total	$194.7

A. Plan Basis

This Plan was developed based on the parameters outlined in the Program Plan for the period July 2003 through June 2008 and provides current estimates of volumes, drilling activity and expenditures for FY03/04.

Volumes

Oil production for FY03/04 is expected to average 32.1 Mbopd within a range of 28.9 to 33.7 Mbopd. Gas production is expected to average 9.1 MMcfd within a range of 8.2 to 9.5 MMcfd. Water production for the period is expected to average 749 Mbwpd within a range of 674 to 786 Mbwpd. Water injection is expected to average 833 Mbwpd within a range of 749 to 874 Mbwpd.

Revenue and Expenses

A projected oil price of $18.00/bbl and gas price of $3.00/mcf will result in revenues of $221.6 million. Based on a budgeted expense level of $194.7 million, this will result in a net profit of $26.9 million.

Drilling

This Plan allows for drilling approximately 24 new and redrilled development and/or replacement wells. It is expected that this will be accomplished by using the T-9 drilling rig starting at Island Chaffee and moving to Island Freeman mid year. 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.

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 FY03/04	BUDGET SECOND QUARTER FY03/04	BUDGET THIRD QUARTER FY03/04	BUDGET FOURTH QUARTER FY03/04	BUDGET TOTAL FY03/04
ESTIMATED REVENUE					
Oil Revenue	$52.8	$53.3	$52.8	$52.7	$211.6
Gas Revenue	$2.4	$2.5	$2.5	$2.6	$10.0
TOTAL REVENUE	$55.2	$55.8	$55.3	$55.3	$221.6
ESTIMATED EXPENDITURES					
Development Drilling	$5.2	$5.4	$5.3	$5.4	$21.3
Operating Expense	$21.2	$20.4	$18.5	$18.6	$78.7
Facilities & Maintenance	$11.8	$11.0	$10.3	$9.3	$42.4
Unit Field Labor & Administration	$8.7	$9.2	$9.6	$8.2	$35.7
Taxes, Permits & Overhead	$4.5	$4.0	$4.3	$3.8	$16.6
TOTAL EXPENDITURES	$51.4	$50.0	$48.0	$45.3	$194.7
NET PROFIT	$3.8	$5.8	$7.3	$10.0	$26.9

C. MAJOR PLANNING ASSUMPTIONS

	BUDGET FIRST QUARTER FY03/04	BUDGET SECOND QUARTER FY03/04	BUDGET THIRD QUARTER FY03/04	BUDGET FOURTH QUARTER FY03/04	BUDGET TOTAL FY03/04
OIL PRODUCTION					
PRODUCED (1000 BBL)	2,932	2,961	2,931	2,934	11,757
(AVERAGE B/D)	31,865	32,184	32,208	32,242	32,124
GAS PRODUCTION					
PRODUCED (1000 MCF)	803	828	837	855	3,323
(AVERAGE MCF/D)	8,725	9,001	9,198	9,398	9,080
WATER PRODUCTION					
PRODUCED (1000 BBL)	66,873	68,653	68,813	69,656	273,995
(AVERAGE B/D)	726,877	746,233	756,187	765,449	748,620
WATER INJECTION					
INJECTED (1000 BBL)	74,857	76,510	76,341	77,042	304,750
(AVERAGE B/D)	813,668	831,627	838,909	846,613	832,649
OIL PRICE ($/BBL)	$18.00	$18.00	$18.00	$18.00	$18.00
GAS PRICE ($/MCF)	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00

Part II

Program Plan Schedules

Schedule 1 A

Range of Production and Injection
FY 2003/04
Long Beach Unit Program Plan, July 2003-June 2008

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2003-04	28.9 - 33.7	674 - 786	8.2 - 9.5	749 - 874

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2003-04	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

SCHEDULE 1B

ANTICIPATED NEW AND REDRILLED WELLS
FISCAL YEAR 2003-04

LONG BEACH UNIT PROGRAM PLAN, JULY 2003 – JUNE 2008

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				0 - 0
RANGER WEST	1	0 - 0	0 - 0				0 - 0				
	2	0 - 0					0 - 0				
	3	0 - 0	0 - 0			0 - 0	1 - 2				0 - 0
	4	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0			0 - 0	0 - 0
	5	0 - 0			0 - 2	0 - 0				0 - 0	0 - 0
	36				0 - 0	0 - 0				0 - 0	0 - 0
	7				0 - 0					0 - 0	
	8		0 - 1		0 - 0			0 - 0		0 - 0	
	9		0 - 0					0 - 0			
	10		0 - 0					0 - 1			
	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 - 2	
	16		0 - 0	1 - 2	0 - 0			0 - 0	0 - 0	0 - 0	
	17			2 - 3					1 - 2		
	18			0 - 0					0 - 0		
	32			0 - 0					0 - 0		
	33			0 - 0					1 - 2		
	20			0 - 0					0 - 0		
	21			0 - 0	0 - 0				1 - 2	0 - 0	
	22			0 - 0	0 - 0				0 - 0	0 - 0	
TERMINAL	38	0 - 0				0 - 0	0 - 0				0 - 0
	39	0 - 0	0 - 0		0 - 0	0 - 0	1 - 2	0 - 0		0 - 0	0 - 0
	40		0 - 0		0 - 0			0 - 0		0 - 0	
	24		0 - 0		0 - 2			0 - 0		0 - 0	
	42			0 - 0					0 - 0		
	43			0 - 0	0 - 3				0 - 0	0 - 0	
UP FORD	26		0 - 0		0 - 0			0 - 0		0 - 0	
	27		0 - 0		0 - 2			0 - 0		0 - 0	
	31	0 - 1	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 - 0	0 - 0	
	45		0 - 0	1 - 3	0 - 0			0 - 0	0 - 0	0 - 0	
	46		0 - 0	0 - 2	1 - 2			0 - 0	1 - 2	0 - 0	
237		0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
		TOTAL					TOTAL				
		6 - 25					6 - 15				

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Part III

Itemized Budget of Expenditures

A. Development Drilling $21,300,000

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

Drilling and completing new wells, as well as redrilling and recompleting existing wells, account for 95 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). Also included in this category are recompletions associated with the shallow gas development proposal that is likely to be in place prior to the start of this Annual Plan.

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 $78,700,000

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 32.1 Mbopd, estimated gas production of 9.1 MMcfpd, water injection requirement of 833 Mbwpd, and water production of 749 Mbwpd. Anticipated operating expenses were based on operating 3-1/2 workover rigs per month for servicing an active well count of 670 producers and 390 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 41 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 59 percent of the funds in this Category. Cost for electric power is based on estimated kilowatt usage of 543,111,098 kwh at an average rate of $0.0863/kwh. This cost includes all sources of Unit electrical power, including all costs associated with the newly constructed power plant and electric utility purchases.

C. Facilities, Maintenance, and Plant $42,400,000

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 58 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 42 percent of the funding in this Category is for facilities repair and improvement projects. Improvement projects include spending for the ongoing facility automation project, pipeline replacements, the potential conversion of the power plant to cogeneration, and other infrastructure related investments that position the Unit for longevity.

D. Unit Field Labor and Administrative $35,700,000

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 76% 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 $16,600,000

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, 2004 the City of Long Beach shall present to the State Lands Commission a final report and closing statement of the FY03/04 Annual Plan, in accordance with the provision in Section 10 of Chapter 138.

A. Modifications

The City of Long Beach, acting with the consent of OLBI, has the authority to cause the expenditures of funds for Unit Operations in excess of the amount set forth in the budget included in the Annual Plan, provided, however, that no such expenditure shall be incurred that would result in any category of expenditures set forth in the budget to exceed 120 percent of the budgeted amount for that category. A budget modification would be required for any expenditures which would cause a budget category to exceed its budgeted amount by 120 percent.

Any transfer of funds between budget categories or an augmentation or decrease of the entire budget may be accomplished by a budget modification in accordance with section 5(g) of Chapter 138 and Article 2.06 of the Optimized Waterflood Program Agreement.

Investment, facilities, and management expense projects commenced in prior budget periods, which are to be continued during the current budget period, may be added to this budget by a modification in accordance with Article 2.06 of the Optimized Waterflood Program Agreement.

B. Supplements

This Annual Plan contains all the investment and expense projects reasonably anticipated at the time the Plan was drafted and for which adequate detailed studies existed. Any significant and uncommon expenses not originally contemplated may be added to this budget or transferred by a supplement in accordance with Article 2.06 of the Optimized Waterflood Program Agreement.

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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 FY03/04 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.