CALENDAR ITEM
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CONSIDER APPROVAL OF THE LONG BEACH UNIT PROGRAM PLAN (JULY 1, 2009 THROUGH JUNE 30, 2014) AND THE ANNUAL PLAN (JULY 1, 2009 THROUGH JUNE 30, 2010), LONG BEACH UNIT, WILMINGTON OIL FIELD, LOS ANGELES COUNTY

APPLICANT:

City of Long Beach
Long Beach Gas and Oil Department
Attn.: Mr. Christopher J. Garner, Director
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 (OWPA), the Long Beach Unit Program Plan (July 1, 2009 through June 30, 2014) and the Long Beach Unit Annual Plan (July 1, 2009 - June 30, 2010) have been submitted by the City of Long Beach (City) to the California State Lands Commission (Commission).

At its meeting on March 10, 2009, the Long Beach City Council adopted the proposed Program Plan and Annual Plan (collectively Plans) and authorized their submission to the Commission for consideration and approval. The Plans were submitted to the Commission on March 18, 2009 for consideration. Pursuant to the provisions of the OWPA the Commission has 45 days following formal submission of the Plans to review them. If the Commission takes no action during this time, the Plans will be deemed to be accepted by the Commission as submitted.

Under AB 227 and the OWPA, the Commission's review of the Program Plan is limited to finding whether the Program Plan (a) is consistent with good oil field practice, (b) is consistent with the optimized waterflood program, (c) is consistent with the Long Beach Unit and Unit Operating Agreements, and (d) does not involve significant environmental or safety risks. As all oil and gas operations pose some risk to the environment, a finding that the Program Plan does not involve significant environmental or safety risks consists of insuring that the operations adhere to all applicable laws and regulations that address safety and environmental protection. The Commission's review of the Annual Plan, as prescribed by AB 227 and the OWPA, is limited to determining whether the Annual Plan is consistent with the current Program Plan. The scope of the Commission's discretion, therefore, is limited by statute and by the contract entered into pursuant to the statute. If the Plans meet these statutory and contractual criteria, the Commission may not reject the Plans. Commission staff has reviewed the Plans and has determined that these criteria have been met.

Program Plan

The Program Plan is a five year projection of Unit development activities, expenditures and revenues, which is prepared every two years and reflects changes in Unit performance and economic conditions.
The economic projections for the Program Plan, (July 1, 2009 through June 30, 2014), as presented by the City, are shown on the following table:

ALL FIGURES ARE IN MILLIONS OF DOLLARS			
PERIOD	**TOTAL REVENUE**	**EXPENDITURES**	**NET INCOME**
FY 09-10	399.2	350.2	49
FY 10-11	385.3	353.4	31.9
FY 11-12	370.9	343.3	27.6
FY 12-13	357	325.5	31.5
FY 13-14	340	313.5	26.5
TOTAL	**1,852.4**	**1,685.9**	**166.5**

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's Gas and Oil Department. The City has estimated that the Unit net income from July 1 through June 30, 2014 will be $166.5 million, after total expenditures of $1,685.9 million. This income scenario is based on a forecasted average oil price of $40.00 per barrel and average natural gas price of $6.00 per mcf, for the five-year period covered by the Program Plan. This income will be generated primarily from oil revenues based on production forecasts ranging from an average producing rate of 25,500 barrels per day (BOPD) in Fiscal Year 2009/2010 to 22,000 BOPD in Fiscal Year 2013/2014. These production rates are based on the assumption that development activity will include 50 wells to be drilled in each of Fiscal Years 2009/2010 and 2010/2011, 47 wells in Fiscal Year 2011/2012, 27 wells in Fiscal Year 2012/2013, and 18 wells in Fiscal Year 2013/2014. This will result in a total of 185 wells to be drilled or redrilled during the five-year Program Plan period. Expenditure levels and project mix may be adjusted as needed to respond to fluctuations in oil price and other economic conditions.

Annual Plan

The Long Beach Annual Plan is prepared and submitted to the Commission each year. The Annual Plan contains the proposed Unit activities for the upcoming year in sufficient detail to evaluate the adequacy of those activities to meet the economic and operational objectives projected within the five-year Program Plan. The proposed Long Beach Unit Annual Plan (July 1, 2009 through June 30, 2010) was developed based on parameters outlined in the Program Plan. The Annual Plan provides for drilling, production, water injection and other associated activities of the Long Beach Unit. The budget for these activities is grouped into five major categories.

Annual Plan Category	**$ Million**
Development Drilling	$74.0
Operating Expense	103.8
Facilities, Maintenance, and Plant	$77.6
Unit Field Labor and Administrative	$52.8
Taxes, Permits and Admin. Overhead	$42.0
Total	**$350.2**

The Commission's staff has reviewed the proposed Annual Plan, budget and associated activity levels and has determined that they have been prepared to

achieve the objective for efficient operations of the Long Beach Unit. The Annual Plan contains the proper amount of flexibility to allow adjustment in expenditure levels, as needed to respond to fluctuations in oil prices or other economic conditions that may occur during the fiscal year.

Commission staff's review of the Program Plan and Annual Plan has involved an analysis of the technical content of the Plans' activities, an evaluation of the Plans' flexibility to adjust to changing economic and operational conditions, an ascertainment of the ability of the proposed activities to meet economic projections, and a determination of whether the Plans conform to all environmental and safety laws and regulations. These Plans provide a framework to meet the objectives of the OWPA and are 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. Ongoing detailed project review and approval occur 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 submitting the Long Beach Unit Program Plan and Annual Plan to the California State Lands Commission.
B. Long Beach Unit Program Plan (July 1, 2009 through June 30, 2014)
C. Long Beach Unit Annual Plan (July 1, 2009 through June 30, 2010)

PERMIT STREAMLINING ACT DEADLINE:

N/A (not a "development project" subject to the Act)

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, 2009 THROUGH JUNE 30, 2014) AND THE LONG BEACH UNIT ANNUAL PLAN (JULY 1, 2009 THROUGH JUNE 30, 2010), LONG BEACH UNIT, WILMINGTON OIL FIELD, LOS ANGELES COUNTY.

W 17163

EXHIBIT A

CITY OF LONG BEACH
Gas & Oil
DEPARTMENT

CHRISTOPHER J. GARNER
DIRECTOR

2400 EAST SPRING STREET · LONG BEACH, CA 90806
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March 13, 2009

Mr. Gregory D. Scott, 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 PLAN (JULY 1, 2009-JUNE 30, 2010) AND PROGRAM PLAN (JULY 2009-JUNE 2014)**

Dear Mr. Scott:

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 two copies of the Long Beach Unit Annual Plan (July 1, 2009-June 30, 2010) and Program Plan (July 2009-June 2014).

The Plans were approved by the Long Beach City Council on March 10, 2009. If you have any questions, please contact Ms. Sue Schoij at (562) 570-3973.

Sincerely,

for Christopher J. Garner, Director
Long Beach Department of Gas and Oil

CJG:scs

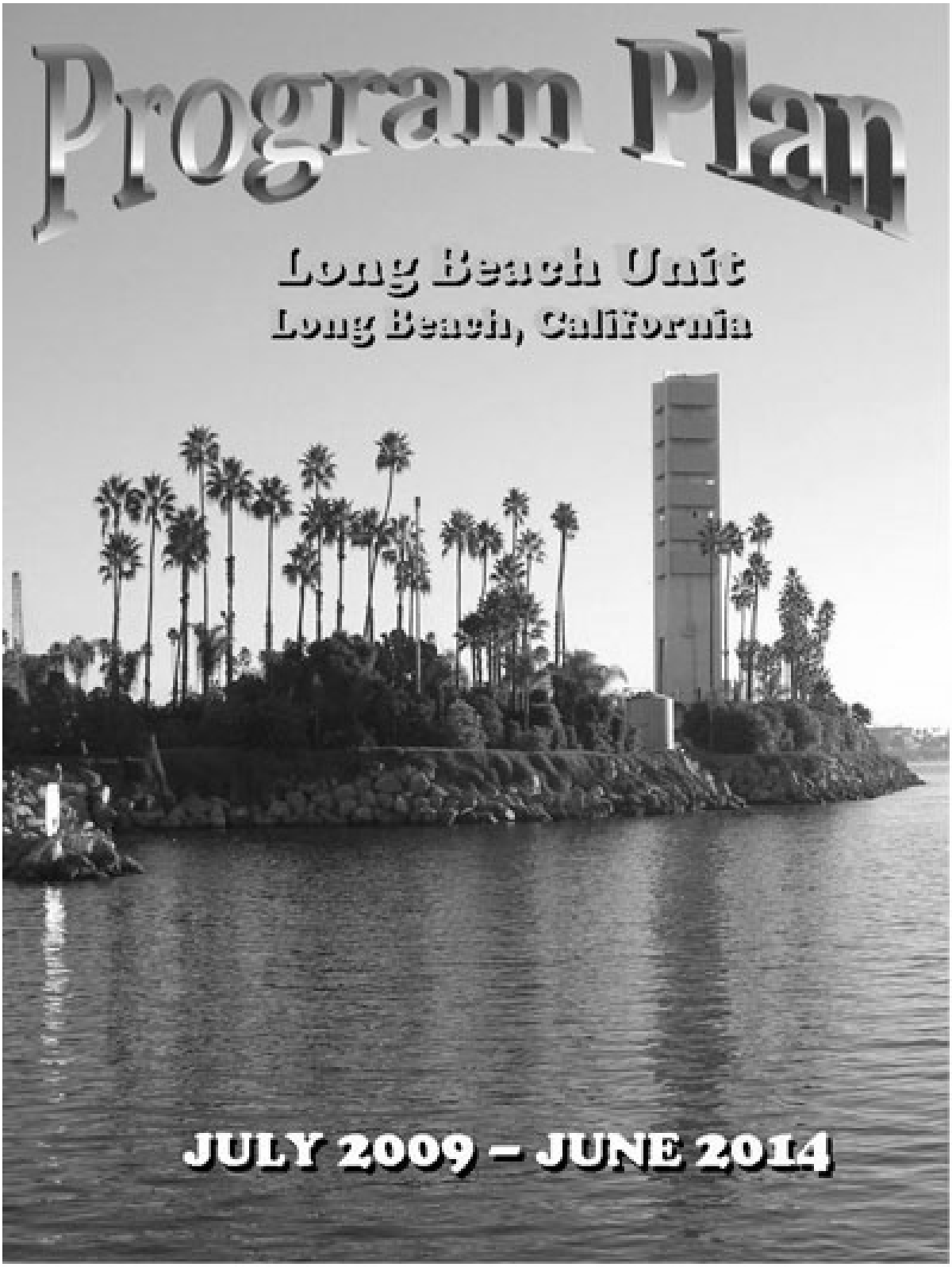
Enclosures

cc: Marina Voskanian
Paul D. Thayer
Alan V. Hager
Frank Komin
Rich Anthony
J. Charles Parkin

FIN 312.006

Exhibit B

W 17163



PROGRAM PLAN

Long Beach Unit

July 2009 through June 2014

Prepared Jointly by:

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

OXY Long Beach, Inc.
(Field Contractor)

THUMS Long Beach Company
(Agent for the Field Contractor)

February 2009

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Executive Summary

This Program Plan covers the period from July 1, 2009 through June 30, 2014. The purpose of the Plan is to describe key issues facing the Unit and to outline strategies for maximizing profitability while maintaining excellence in safety and environmental protection. This Plan is the culmination of a cooperative effort by the Long Beach Gas & Oil Department, City of Long Beach (Unit Operator), OXY Long Beach, Inc. (Field Contractor), and THUMS Long Beach Company (agent for the Field Contractor). The Program Plan meets requirements of Section 2.03 of the Optimized Waterflood Program Agreement ("OWPA").

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

The Plan includes expenses associated with drilling 185 development and replacement wells over the life of the Program Plan. This schedule will result in a steady decline in oil production rate through the end of FY13/14. Unit production and injection rates are expected to average 25.5 Mbopd, 954.8 Mbwpd and 1,039 Mbwipd in FY09/10 and 24.9 Mbopd, 976.7 Mbwpd and 1,062 Mbwipd in FY10/11, respectively.

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

Facility improvement projects envisioned during the Plan include projects to improve water quality and thus injector performance, electrical infrastructure improvements to enhance facility efficiency and reliability and to build out remaining capacity projects required to support the planned development program. These improvements are focused on right-sizing facility capacity limits to accommodate the forecast drilling program throughout all 5 years of the Program Plan period. These investments result in enhancement of revenue streams, lower maintenance and operational costs, and improved safety and environmental performance. The first year of the Program Plan also includes funds to encase a pipeline in the port area per requirements set by the Unit's agreement with the Port of Long Beach.

Based on production from 50 development and replacement well projects planned for FY09/10 of the Program Plan and an average oil price of $40.00/bbl, total revenue, expenditures, and net profits are projected to be $399.2 million, $350.2 million, and

$49.0 million, respectively. Over the five-year Program Plan period, cumulative total revenue, expenditures, and net profit are expected to reach $1,852.4 million, $1,685.9 million, and $166.5 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, 2009 through June 30, 2014. The purpose of this Plan is to describe key issues facing the Unit, and to outline strategies for maximizing profitability while maintaining excellence in safety and environmental protection.

This Plan is divided into four major sections:

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

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

- The *Economic Summary* section provides a forecast of Unit revenues, expenditures, and profits anticipated during the Plan period, assuming an oil price of $40.00/bbl during the Program Plan period and gas price of $6.00/mcf. This section also includes the schedules that will be incorporated into the FY09/10 and FY10/11 Annual Plans.

Introduction

History

The Long Beach Unit ("Unit") commenced operation April 1, 1965. Since its inception, a major requirement of Unit operations has been to minimize the impact on the environment and to comply with all applicable environmental laws and regulations. No oil-related subsidence has occurred since the inception of the Unit, although minor positive and negative elevation fluctuations have been observed. An active subsidence monitoring system is in place and remedial measures would start immediately if significant subsidence was detected.

Development drilling began in July 1965. Initial development activity peaked with 20 rigs operating in 1968. This high level of drilling activity continued into early 1970. Drilling activity decreased to four rigs in 1973 and dropped to one rig in mid-1976. Full zone production and injection locations were emphasized. The pace of development accelerated in 1977, reaching a peak of nine rigs in 1982, when sub-zone development was initiated to improve oil recovery by completion of wells in sands with high remaining oil saturation. This level of activity was held until early 1986 when drilling activity again began to decline due to low oil price. Activity dropped to one rig in the summer of 1986. No drilling rig activity occurred from mid-March 1987 until August 1987, at which time one rig was re-activated. A second rig was started in January 1988, and a third in January 1990. Rig activity dropped to one rig again in 1994, fluctuated between a one and two rig pace until 2003 where it remained at two rigs until 2005. In September 2005 a third rig was contracted to capitalize on the high oil price environment. However, after conducting rigorous technical and economic analysis to determine optimal drilling pace, Unit Stakeholders made the decision to move from a three to a two rig drilling program effective November, 2007. For the remainder of the FY07/08 fiscal year the drilling program was executed using two Unit rigs. In November 2008 a third rig was contracted to execute accelerated drilling pace due to 237 zone exploration wells and the activities from the Injection Balance and Optimization Team (IBOT) efforts. The Unit continued drilling operations with three rigs until January 2009 when the contract rig was demobilized. Drilling is expected to be at an approximately two-rig pace through the FY 09/10 and will gradually drop through the remaining years of this Program Plan.

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

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

Unit Reservoir Management Plan

Goal

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

Reservoir Management Strategy

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

1. Maximize economic production from existing assets by the use of sound waterflood practices. This effort is focused on waterflood surveillance activities including well monitoring, flood performance analysis, and voidage management for subsidence control. In third quarter of FY 07/08, an "Injection Balance and Optimization Team" (IBOT) was formed to execute such strategy through a structured and detailed process.
2. Assess and deliver additional development investment opportunities via the drilling and investment wellwork programs. Development activities are currently focused on capturing bypassed, unswept oil and increasing waterflood throughput in immature areas.
3. Implement new technologies to decrease costs, improve efficiencies, and develop unproven reserves. The Unit's Technology Plan identifies technology needs, impacts, and implementation issues. Enhanced oil recovery applications will be considered for implementation if economically and technically viable.

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

Production and Surveillance

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

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

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

- The Unit was formerly 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. Since July 2006, the LBGO Subsidence and Geology Division, along with the Thums RMT and Well Surveillance Leaders have been periodically modifying the voidage accounting rules to ensure stable ground elevations (subsidence and dilation), while providing prudent operational flexibility to improve waterflood management. We are collaborating on methodology for the voidage account, and identifying key wells to survey for bottomhole pressures to support semi-annual ground elevation measurements.

Development Opportunities

The Unit has a strategy to invest to build oil production rate. To support this strategy, development activities have focused on:

- Drilling injection wells targeting increased throughput in the less mature sand layers and improving zonal injection control. Drilling results to date have shown good success from injection wells drilled to establish new injection patterns in the relatively underdeveloped areas of the field such as northern cut-recovery block 1 in Ranger West. Injection wells have been somewhat less effective in the more mature areas or when used as isolated infill injectors, but have still successfully advanced this strategy.
- Adding production wells: (1) where required to complete new injection patterns, (2) in areas of unswept oil (3) in lower productivity sands that cannot produce well in combination with higher productivity zones in long completions, (4) in areas of high oil saturations banked along sealing faults, and (5) in areas where improved injection warrants additional production capacity.
- Investing in wellwork projects that will increase the ultimate recovery of the field or require special planning and attention. Investment wellwork includes well conversions, recompletions, permanent profile modifications and hydraulic fracture stimulations. The Wellwork group handles projects considered more routine, like recompletions and conversions. Fracture stimulations, which are more complex and require special planning and expertise, are coordinated by the Drilling Group. The investment wellwork program is still one of the Unit's most successful programs, adding reserves at comparatively low cost. The investment wellwork program will continue at a healthy pace throughout the upcoming Plan period.

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

Technology

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

Unit Forecasts

Drilling Schedule

The Program Plan projects development and replacement drilling to average 50 wells per year in both FY09/10 and FY10/11. This schedule can be met with approximately 2 Unit drilling rigs running continuously. Workover rigs will continue to be used for new well completions to capitalize on improved completion quality control and to provide better drilling rig efficiency.

Exhibit B shows the drilling plan by Unitized Formation for the Program Plan period, and the required Schedules 1B and 2B show the anticipated range of development and replacement wells to be drilled into each cut-recovery block during FY09/10 and FY10/11. This drilling plan reflects the current understanding of new development well economics. The drilling candidate list is updated annually by the reservoir development teams. Drilling projects are submitted to Voting Parties for approval at least 2-4 months ahead of the planned spud date. Individual well AFEs are submitted subsequently. The economics of each well are fully investigated at that time, and changes in key factors such as oil price, drilling cost, or candidate quantity and quality may result in changes to the overall plan.

Rate Forecasts

Exhibit C shows the Unit production forecasts for the Plan period, and the required Schedules 1A and 2A show the anticipated rates for FY09/10 and FY10/11. These forecasts were developed by combining a forecast of existing well performance with the expected results of the previously outlined development plan. The expected case injection forecast shown in Exhibit D was generated based on the gross fluid rates from the production forecast. Graphs comparing historical and predicted field rate performance data are presented in Exhibits E and F. The plots clearly show the variability of historical rate data, necessitating the use of rate ranges to account for uncertainty in the rate projections.

The oil and water production forecast for the existing wells is based on a process that uses extrapolations of well groups within each Unitized Formation summed together to yield a forecast of the existing wells' production for the entire Unit. Each of these pools is comprised of the wells within a reservoir volume that is believed by the reservoir development teams to be acting as an independent waterflood area. These are generally comprised of either one or more cut-recovery blocks or a fault block. For each pool, the expected future oil and water rates are extrapolated from historical trends of oil and gross fluid rates vs. time and the trend of water-oil ratio vs. cumulative oil production using conventional decline curve techniques. For pools that reach the economic water-oil ratio before the approximate end of the Unit’s expected economic life in 2030, production is ramped down over several years using Unit developed shut-in logic. While this evaluation is more sophisticated than a single Unit exponential decline evaluation, it more accurately models the Unit’s reservoirs. The resulting prediction shows a near term exponential decline of about 11% per year. Longer term, the forecast follows a hyberbolic decline.

The incremental production contribution for new development wells is calculated by adding together type wells. The type wells are determined by reservoir area and

completion type (conventional producer, frac producer, horizontal producer and injector). The engineers managing individual reservoir pools determine type wells for their areas based on historical performance. Depending on available data, type wells are built by reservoir, by pool, or by cut-recovery block. The producer type wells are based on recent average initial production rates and reserves. The injector type wells are based on average injection rates, peak offset oil and gross response measured in effected wells and reserves. The type well rates are combined with the development drilling schedule to generate the expected rate contribution for new development wells. The total Unit production forecast is the sum of the existing well and development well forecasts. The Unit water production forecast was derived as the difference between the gross fluid and oil production rates.

Major Issues and Projects

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

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

People

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

Health and Safety

The Unit is committed to conducting all aspects of its business in a manner that provides for the safety and health of employees, contractors, and the public, and safeguards the environment in which it operates. 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.

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

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.

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

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

The Unit continues to strive to improve 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. Current injection rules require net injection to exceed gross production by an average of 41.2 MBWPD in the eleven voidage pools with each pool having specific injection requirements. Since July 2006, the LBGO Subsidence and Geology Division, along with the Thums RMT and Well Surveillance Leaders, have been periodically modifying the voidage accounting rules to ensure stable ground elevations (subsidence and dilation), while providing prudent operational flexibility to improve waterflood management. We are collaborating on methodology for the voidage account, and identifying key wells to survey for bottomhole pressures to support semi-annual ground elevation measurements.

Well Abandonment Plan

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

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

Cost Management

The Unit continuously strives to be efficient in spending its operational funds. Emphasis is given to spending funds wisely, investing in opportunities with the best economic return, and continuing to look for ways to become more efficient in business operations. Employing effective cost management strategies will aid in achieving the Unit's goal of performing in the lowest cost per net barrel quartile for comparable operations. Cost management gains will be aggressively pursued during the term of this Plan. Some of the areas where the Unit plans to make substantial gains include the following:

Operations: The Facility Operations group is accountable for electricity usage, operation of oil, gas and water treating facilities, chemical usage, and make-up water. Amine Plant operations, used to reduce produced-gas CO2 levels, will be optimized in conjunction with Power Plant operations. Process optimization, best operating practices, and operating cost reductions will be focus areas. Improvements in electrical efficiency, optimization of make-up water sources, maintaining water quality, enhanced well surveillance, and improved coordination between operations, wellwork, and facility maintenance are expected outcomes over the Program Plan period.

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

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

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 and a leased rig. Activity on Grissom can be accomplished with Unit Rig T-5. Activity on Island White can be accomplished with Unit Rig T-3. Additional drilling methods will be considered for lowering drilling costs on all locations. These include contract drilling rigs, workover rigs, top drive and coiled tubing units.

Expansion of Facility Capacity

Expansion of current facility processing and production capacity will be needed to optimize the economics of the planned field development during the Program Plan

period. Activities to help achieve capacity expansion include piping enhancement projects, pumps, motors, electrical gear and subsea pipeline optimization. The planned expansions will optimize the common processing capability on each of the islands and lead to integrated management of Unit fluid processing. This Plan includes funding to complete the upgrades needed to meet the anticipated drilling activity.

Disposal Project

The quality of the re-injected water in the waterflood program has a significant impact on reservoir recovery and on the efficiency and effectiveness of individual injectors. The disposal project is intended to remove the "worst" flows from the water plant and injection system. Plans are underway to scope out a phased approach that includes an injection well and processing facilities for each individual producing location (islands and Pier J). Benefits will accrue from greater efficiency at the water plant and from improved injection and oil-sweep.

Shallow and Deep Gas Development

Currently the Shallow Gas accumulation under Grissom is being produced. To date four of the six wells have been completed in the A16 sand, and one in each of the A20 and A14 sands, respectively. Well A-268 watered out in June 2008 followed by watering out of Well A-260 in September 2008. Current daily production rate for Grissom Shallow Gas production is averaging 3,700 mcfd, with production from two active producers, Well A-301 (horizontal well completed in the A16 sand) and Well A-271 (A16 recompletion).

Electricity Generation

Electricity is the single largest cost element for the Unit. Currently the Unit consumes approximately 660 million kWh per year, and is one of the largest single-site users of electricity in Southern California Edison's territory. Any change in the electrical rates or availability of electricity supply significantly affects the profitability of Unit operations.

The Unit constructed a 47MW power generation plant in an effort to increase the California in-state generation supply, as well as insulate the Unit from the risks of electricity supply disruptions and escalating wholesale electric costs. The plant commenced operations in FY02/03.

The power plant was converted into a cogeneration facility in FY04/05 to provide heat to a neighboring wallboard manufacturing facility, reducing their reliance on natural gas. As a result, and depending on demand from the wallboard facility, the Unit receives revenue from heat sales and favorable treatment regarding departing load charges that may be assessed for leaving Southern California Edison's electricity grid.

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

Taxes

The County of Los Angeles has significantly increased the assessed value of the Unit for assessment year 2008 caused in large part by the increase in oil price. Fluctuations in oil prices affect the Unit's property tax values and assessments.

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.

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

Economic Summary

Revenue Forecast

Unit Revenue will be generated from the sale of oil and gas from six producing formations: Lower Pliocene shallow gas sands, Tar, Ranger West, Ranger East, Terminal, and UP Ford/237. The projected revenue during the Program Plan period is $1,852.4 million, based on a $40.00/bbl oil price and $6.00/mcf gas price, and average daily oil and gas production as projected in Exhibit C. Projected revenue for FY09/10 is expected to be $399.2 million.

Cost Forecast

Total estimated expenditures for the first year of this Program Plan are consistent with the FY09/10 Annual Plan. Costs in subsequent years are projected by establishing a relationship between current costs and the variables believed to be principally responsible for driving future costs by Category. The most leveraging cost drivers overall are the levels of gross fluid production and injection, discretionary activity levels (e.g., drilling, abandonment, and major projects), and the number of wells and facilities that are active at a given time.

Based on the projected production rates, injection rates and activity levels, total expenditures during the Program Plan period are expected to be $1,685.9 million. The projected expenditures for FY09/10 are $350.2 million. Costs in future years will be refined upon completion of ongoing studies and projects and also be effected by changes and adjustments that may result from the economic conditions.

Profit Forecast

Based on the above revenue and cost forecasts, Unit profit during the Program Plan period is projected to be $166.5 million. Unit profit for FY09/10 is expected to be $49.0 million. A schedule of annual projected revenue, expenditures, and net profit is given in Exhibit A.

Budget commitments for FY10/11 will be established based on actual results and additional insights gained during FY09/10.

Table 1

SUMMARY OF PRODUCTION AND INJECTION
AS OF NOVEMBER 2008

JULY 2009 – JUNE 2014 PROGRAM PLAN, LONG BEACH UNIT

		Active Well Count:		Average Rates for November 2008				Average Well Rates	
Reservoir	CRB	Producers	Injectors	BOPD	BWPD	BIPD	Wtr Cut	BOPD/ Well	BIPD/ Well
SG	65	3	0	0	0	0	0.00%	0	0
Tar	35	6	1	104	923	2008	89.90%	17	2008
Ranger	1	49	28	1701	70717	70098	97.65%	35	2503
West	2	28	17	1053	39093	50347	97.38%	38	3051
	3	41	28	1676	78411	90117	97.91%	41	3218
	4	51	28	2017	89746	97612	97.80%	40	3486
	5	36	26	1622	70006	83137	97.73%	45	3260
	7	18	8	551	19301	19684	97.23%	31	2625
	8	13	7	290	12701	12515	97.77%	22	1788
	9	8	5	239	6355	7331	96.38%	30	1466
	10	23	20	921	27111	30867	96.71%	41	1543
	11	9	4	454	10274	6338	95.77%	53	1584
	12	6	4.5	149	6246	7166	97.67%	25	1593
	13	8	5	221	9831	9474	97.81%	28	1895
	36	26	17	804	40496	44203	98.05%	31	2600
	37	9	9	359	18232	23982	98.07%	40	2665
	Total	324	205	12055	498522	552870	97.64%	37	2697
Ranger	14	16	17	636	22909	30070	97.30%	40	1769
East	15	39	20	1253	48380	46803	97.48%	32	2340
	16	18	10	680	17117	17350	96.18%	38	1735
	17	21	11	699	14806	15016	95.49%	34	1365
	18	17	14	427	19597	31387	97.87%	25	2242
	20	11	6	314	10850	12675	97.19%	29	2304
	32	1.5	2	28	1398	4685	98.03%	19	2342
	33	30	18	1117	44797	37513	97.57%	37	2144
	21	30	22	1093	41434	45321	97.43%	36	2108
	22	18	7	576	15483	12279	96.41%	32	1889
	Total	201	125	6822	236772	253097	97.20%	34	2025
Terminal	24	30	18	965	16429	23621	94.45%	32	1312
	38	38	20	1079	43465	56800	97.58%	28	2840
	39	32	12	1074	27417	26480	96.23%	34	2207
	40	7	6	113	3239	4251	96.64%	16	709
	41	4	2	193	2514	3027	92.88%	48	1513
	42	9	6	287	10665	10728	97.38%	32	1788
	43	36	20	1248	27633	28759	95.68%	35	1438
	47	3	1	9	359	0	97.43%	3	0
	Total	159	85	4968	131722	153666	96.37%	31	1808
UP/Ford	26	0	2	0	0	1436	0.00%	0	718
	27	17	16	703	12235	15881	94.57%	41	993
	31	9	5	293	4501	4821	93.90%	33	964
	44	4	7	89	2627	8218	96.71%	22	1174
	45	24	14	738	15512	15106	95.46%	31	1119
	46	28	20	1189	20852	24333	94.61%	42	1248
	Total	82	63	3012	55726	69795	94.87%	37	1108
237	30	2	0	274	668	0	0.00%	0	0
	LBU Total	777	479	27235	924333	1031436	97.14%	35	2153

Exhibit A

ECONOMIC PROJECTIONS
July 1, 2009 through June 30, 2014 Program Plan
(Million Dollars)

	Fiscal 2009/10	Fiscal 2010/11	Fiscal 2011/12	Fiscal 2012/13	Fiscal 2013/14	Program Plan Period
Estimated Revenue						
Oil Revenue	$371.7	$363.8	$350.7	$338.4	$321.9	$1,746.5
Gas Revenue	$27.5	$21.5	$20.2	$18.6	$18.1	$105.9
Total Estimated Revenue	$399.2	$385.3	$370.9	$357.0	$340.0	$1,852.4
Estimated Expenditures	$350.2	$353.4	$343.3	$325.5	$313.5	$1,685.9
Net Income	$49.0	$31.9	$27.6	$31.5	$26.5	$166.5

Exhibit B

Anticipated Drilling Schedule

July 1, 2009 through June 30, 2014

FISCAL YEAR	RANGER WEST	RANGER EAST	TERMINAL	U.P. FORD/ 237	TOTAL WELLS
2009/10	12	22	5	11	50
2010/11	21	9	8	12	50
2011/12	26	4	3	7	40
2012/13	13	4	3	7	27
2013/14	8	4	2	4	18

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

Exhibit C

Range of Production Rates
July 2009-June 2014 Program Plan
Long Beach Unit

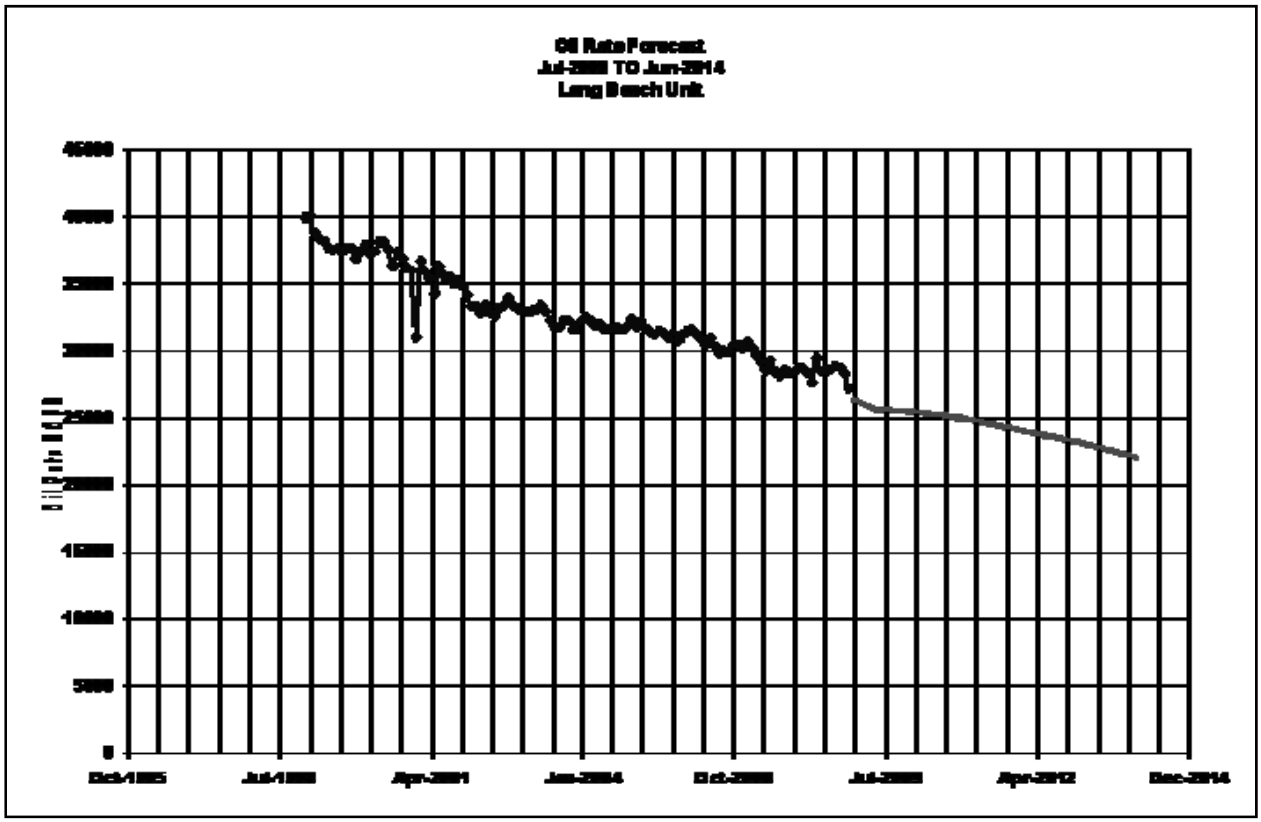
FISCAL YEAR	EXPECTED RANGE			EXPECTED RATE		
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	OIL MBOPD	WATER MBWPD	GAS MMCFPD
2009/10	24.6 - 26.0	928 - 974	10.8 - 13.6	25.5	955	12.6
2010/11	24.1 - 25.4	949 - 996	8.5 - 10.6	24.9	977	9.8
2011/12	23.2 - 24.5	950 - 997	7.9 - 10.0	24.0	978	9.2
2012/13	22.4 - 23.7	951 - 998	7.3 - 9.2	23.2	978	8.5
2013/14	21.3 - 22.5	921 - 967	7.1 - 9.0	22.0	948	8.3

Exhibit D

Range of Injection Rates
July 2009-June 2014 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
2009/10	1,010 - 1,060	1,039	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2010/11	1,032 - 1,083	1,062	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2011/12	1,032 - 1,083	1,062	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2012/13	1,032 - 1,083	1,062	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000
2013/14	999 - 1,049	1,028	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Exhibit E


Oil Rate Forecast
Jul-2008 TO Jun-2014
Long Beach Unit
Oil Rate BO/D
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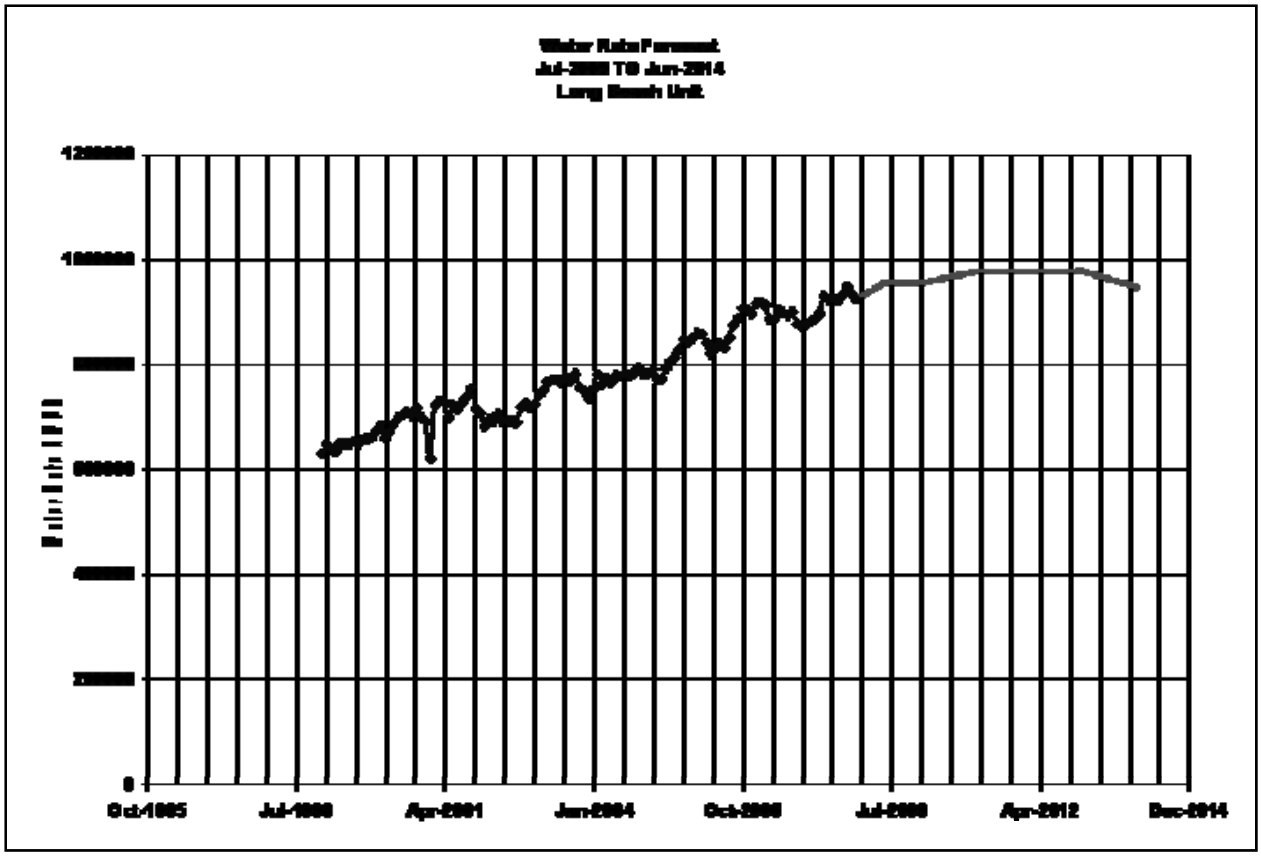
40000
35000
30000
25000
20000
15000
10000
5000
0
Oct-1995
Jul-1998
Apr-2001
Jan-2004
Oct-2006
Jul-2009
Apr-2012
Dec-2014


Water Rate Forecast
Jul-2009 TO Jun-2014
Long Beach Unit
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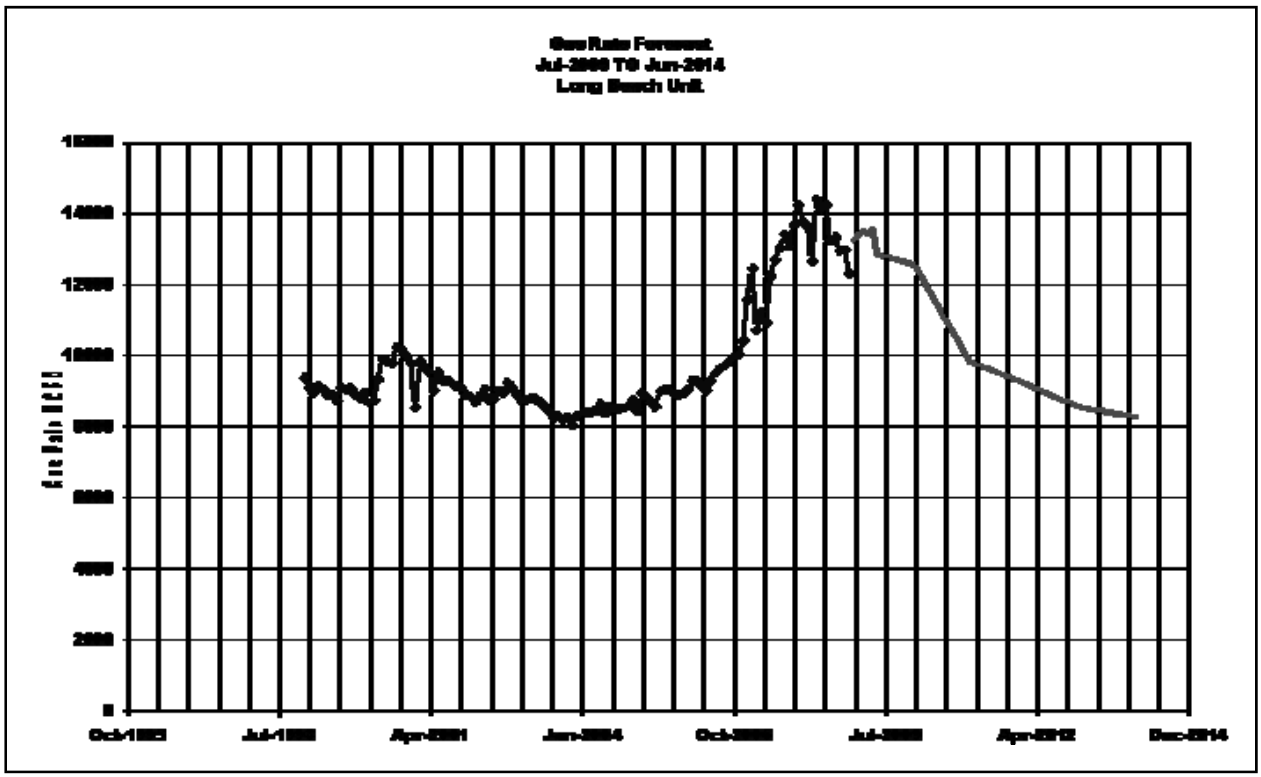
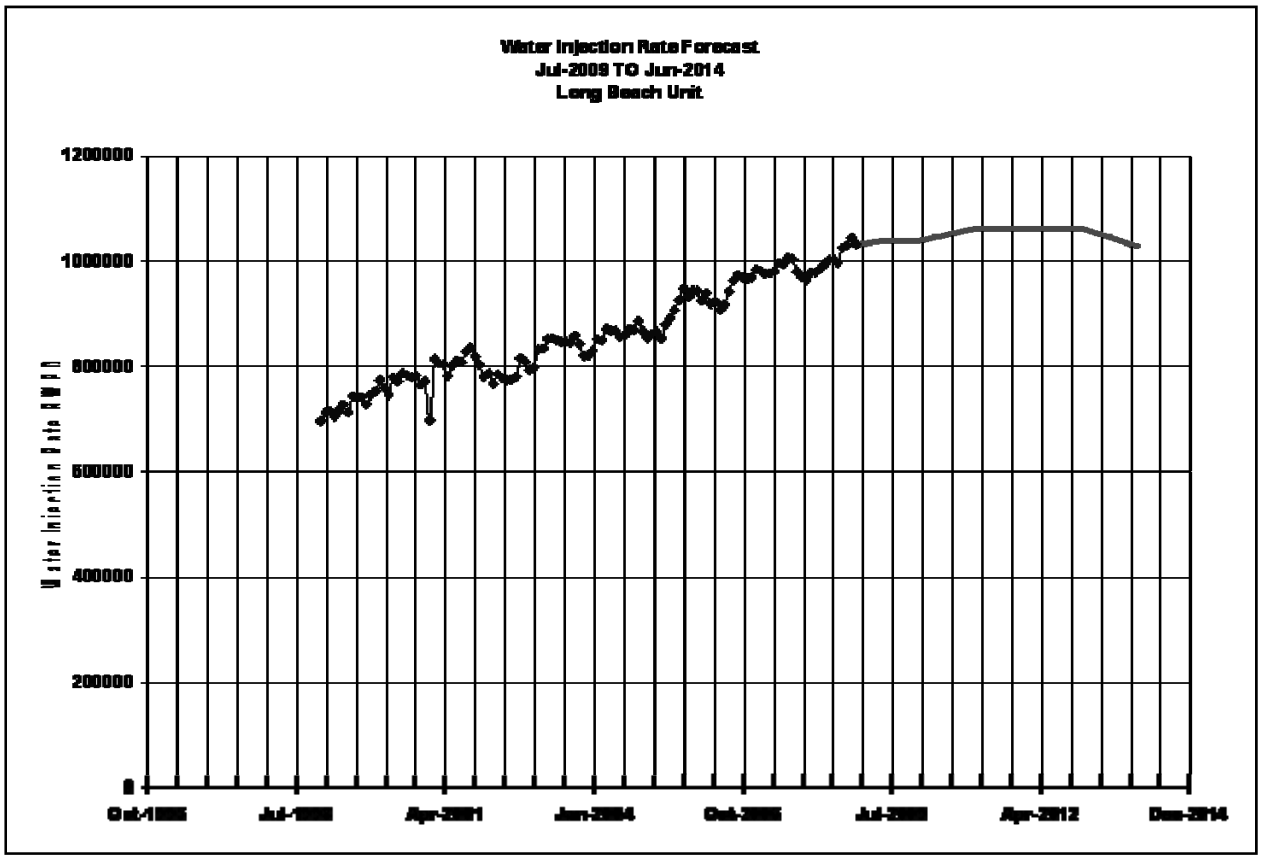
1000000
800000
600000
400000
200000
0
Oct-1995
Jul-1998
Apr-2001
Jan-2004
Oct-2006
Jul-2009
Apr-2012
Dec-2014

Exhibit F


Long Beach Unit


Water Injection Rate Forecast
Jul-2009 TO Jun-2014
Long Beach Unit
1200000
1000000
800000
600000
400000
200000
0
Apr-2012

Schedule 1 A

Range of Production and Injection

FY 2009/10

Long Beach Unit Program Plan, July 2009-June 2014

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2009-10	24.6 - 26.0	928 - 974	10.8 - 13.6	1,007 - 1,060

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2009-10	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Schedule 1 B

Anticipated Development and Replacement Locations

Fiscal Year 09/10

Long Beach Unit Program Plan, July 2009-June 2014

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		0	-	1	0	-	2							0	-	0	0	-	1										0	-	0
SG		0	-	1	0	-	1																								
Ranger West	1	0	-	1	0	-											0	-	1												
	2	0	-	1			1										1	-	2												
	3	0	-	1	0	-	1							0	-	1	0	-	1										0	-	0
	4	0	-	1	0	-	1				0	-	0	0	-	1	0	-	1	0	-	0				0	-	1	0	-	1
	5	0	-	1							0	-	0	0	-	1										0	-	1	0	-	1
	7										0	-	0	0	-	1										0	-	1	0	-	1
	8										0	-	0													0	-	1			
	9				0	-	1				0	-	0							0	-	1				0	-	1			
	10				0	-	1										0	-	2	0	-	1									
	11				0	-	1										0	-	2	0	-	1									
	12				0	-	1													0	-	0									
	13				0	-	1													0	-	0									
	36				0	-	0				0	-	0							0	-	0				0	-	1			
	37										0	-	0													0	-	0			
Ranger East	14				0	-	0													1	-	2									
	15				0	-	0				0	-	1							1	-	1				0	-	0			
	16				0	-	0	1	-	2	0	-	0							0	-	0	0	-	2	0	-	0			
	17							1	-	2													0	-	2						
	18							1	-	2													0	-	2						
	20							1	-	2													0	-	2						
	21							1	-	2													0	-	2						
	22							1	-	2													0	-	1						
	33							0	-	1													0	-	0	0	-	0			
Terminal	24	0	-	1	0	-	2							0	-	1	0	-	1										0	-	0
	38	0	-	0	0	-	0				0	-	0	0	-	0	1	-	2	0	-	0				0	-	0	0	-	0
	39				0	-	1				0	-	1							0	-	0				0	-	0			
	40				0	-	1				0	-	0							0	-	0				0	-	1			
	41																														
	42							0	-	1													2	-	3						
	43							0	-	2	0	-	0										0	-	0	1	-	2			
	47																														
UP Ford	26				0	-	1				0	-	1							0	-	0				0	-	0			
	27				0	-	0				0	-	1							0	-	0				0	-	0			
	30	0	-	2	0	-	0	0	-	1	0	-	1	0	-	0	0	-	2	0	-	0	0	-	1	0	-	0	0	-	1
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	45				0	-	0	1	-	2	0	-	1							0	-	0	1	-	2	0	-	1			
	46							1	-	2																					
237	30	0	-	1				0	-	2	0	-	1																		
		Total															Total														
								8	-	66													8	-	54						

Schedule 2 A

Range of Production and Injection

FY 2010/11

Long Beach Unit Program Plan, July 2009-June 2014

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2010-11	24.1 - 25.4	949 - 996	8.5 - 10.6	1,032 - 1,083

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2010-11	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Schedule 2 B

Anticipated Development and Replacement Locations

Fiscal Year 10/11

Long Beach Unit Program Plan, July 2009-June 2014

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		0	-	3	0	-	0							0	-	0	0	-	2										0	-	0
SG		0	-	2	0	-	2																								
Ranger West	1	0	-	1	0	-											0	-	1												
	2	0	-	3			1										1	-	2												
	3	0	-	3	0	-	1							0	-	1	0	-	1										0	-	0
	4	0	-	5	0	-	1				0	-	0	0	-	1	0	-	1	0	-	0				0	-	0	1	-	3
	5	0	-	2							0	-	0	0	-	1										0	-	0	2	-	4
	7										0	-	0	0	-	1										0	-	0	1	-	2
	8										0	-	0													0	-	0			
	9				0	-	1				0	-	0							0	-	1				0	-	0			
	10				0	-	1										0	-	2	0	-	1									
	11				0	-	1										0	-	2	0	-	1									
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	13				0	-	1													0	-	1									
	36				0	-	0				0	-	0	1	-	2				0	-	0				0	-	1	0	-	2
	37										0	-	0													0	-	0			
Ranger East	14				0	-	1													0	-	0									
	15				0	-	1				0	-	1							0	-	0				0	-	0			
	16				0	-	1	0	-	1	0	-	0							0	-	0	0	-	1	0	-	0			
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	40				0	-	0				0	-	0							0	-	0				0	-	0			
	41	1	-	2																									0	-	2
	42							0	-	1													0	-	2						
	43							0	-	1	0	-	0										0	-	0	0	-	0			
	47																														
UP Ford	26				0	-	0				0	-	0							0	-	1				0	-	0			
	27				0	-	0				0	-	0							0	-	1				0	-	0			
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	45				0	-	0	1	-	1	0	-	0							0	-	0	0	-	1	0	-	0			
	46							1	-	2																					
237	30	0	-	0				0	-	3	0	-	0																		
		Total															Total														
								11	-	72													8	-	55						

Appendix 1

Ranger West / Tar
Reservoir Management Plan

History

The Ranger West reservoirs are comprised of the Ranger 6 and Ranger 7 fault blocks. Ranger West is the largest pool in the Unit with 1.4 billion barrels of original oil in place (OOIP). The first pool developed at field startup in late 1965, Ranger West contains a contrasting mix of mature and under-developed blocks. The crestal and southern blocks are generally more mature than the northern blocks in the Ranger West area. In the more mature crestal and southern blocks, waterflood recovery is generally high (30-40% OOIP) with water-oil ratios (WOR's) approaching 40. In the less mature northern blocks, oil recoveries range from 26-30% and WOR's range from 27-31.

The Ranger West waterflood was originally implemented using a 3-1 staggered line drive (SLD) pattern containing three rows of producers for each row of injectors. There are twelve cut-recovery blocks (CRB's) still using this pattern framework. The only exceptions are CRB-8, which lies between 2 faults on the crest, and CRB's 1 and 10, which were re-configured through development drilling as injector-centered patterns (1992-1994). In 1986, 70 offset row producers were shut-in because of 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 F0, the F-X, and X-HX1 (Lower Ranger). Over the majority of the Ranger West pool, the F0 is the thickest and most dominant sand package. Original wells used full-zone, open-hole gravel packs across all three intervals. The more permeable F0 sand received the majority of the injected water through point exits resulting in bypassed oil within the F0 and throughout the lower zones. The Subzone Redevelopment Program, from 1980-1984, was successful in diverting injection and production to the F-X and Lower Ranger intervals by selectively completing only those subzones. Ranger West production increased 4,000 BOPD during 1980-1984 from this effort. Pockets of bypassed oil throughout the Ranger West area continue to be the target of horizontal wells, injection realignment/conversions, and selective, 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 2008 were 12.1 MBOPD and 498.5 MBWPD (97.6% water cut) from 324 producers. November 2008 injection averaged 552.9 MBWPD from 205 injectors. Average active well rates were 37 BOPD and 1538 BWPD for producers and 2697 BWPD for injectors.

Ranger West currently has 62 inactive wells that have not been plugged in zone. 40 of these wells are being evaluated for repair and/or conversion. Additionally there are 43 wells that have previously been plugged in zone and are currently inactive.

Recovery through November 2008 was 486.0 MMBO (35.5% OOIP). Ranger West is expected to produce an additional 43.79 MMBO by 2030 bringing ultimate recovery from existing development to 530.2 MMBO (38.7% OOIP). Additional development through drilling and investment wellwork is expected to add 23.7 MMBO by 2030.

While the base production in Ranger West reservoir has been declining at around 13% per year, the active development program in 2007-2008 resulted in a 7% decline in total rate for the January to December 2008 period. Additional information concerning the development drilling and wellwork activities can be found in the Calendar Year 2007-2008 Activities and Results section.

Calendar Years 2007 and 2008 Activities and Results

Since publication of the last Program Plan, 37 producers (11 horizontal, 13 conventional, and 13 cased-hole completions) and 12 injectors (1 horizontal open hole injector, 10 single string vertical cased injectors and 1 dual string vertical cased injector) have been drilled and completed in the Ranger West pool.

The average initial stabilized rate for the producers drilled in the Ranger West Pool is 103 BOPD with initial rates ranging from 7 BOPD to 408 BOPD. This rate is close to the anticipated average rate of 102 BOPD. The average initial production rate is 237 BOPD for the horizontal completions and 60 BOPD for the cased-hole completions. The injection wells drilled during the 2007-2008 period were selectively perforated in specific intervals with historically low waterflood throughput and relatively high remaining oil saturation. All the injection wells met injectivity expectations with an average injection rate of 1186 BWPD.

During the 2007-2008 Plan period, a total of 21 development (investment) wellwork jobs were also completed (2 producers and 19 injectors). Both producer development projects were selective recompletions/add pay projects targeting bypassed oil sands. Overall, the producer development wellwork has been successful, averaging about 29 BOPD/job at a cost of $369M per job. Injector development wellwork projects included 6 convert to injectors, 6 profile modifications and add pay projects and 7 recomplete and add pay projects. The injection work targeted increasing water throughput in selective sands and pattern areas. Injection development wellwork projects contributed an average of 1230 bpd of injection per well at an average cost of about $159M per job.

Maintenance wellwork continues to play a major role in maximizing Ranger West base production. During 2007-2008, approximately 192 producer maintenance wellwork projects at a cost of about $65,495/job were performed on 153 producers. Over the two

year period, the 153 wells produced close to 1,268 MBO. 446 injector maintenance projects were also completed on 193 injectors at an average cost of about $13,068/job.

Reservoir Management Objectives

The primary reservoir management objective is to maximize the profitability of the Ranger West pool. Maximum profitability will be achieved by increasing recovery in underdeveloped blocks through identifying optimal locations for development drilling/investment wellwork combined with the right placement of injection water. Throughput objectives are to reach an HPVI target of at least 6.0 for each sand in all CRB's. As of November 2008, HPVIs range from less than 0.5 to more than 4.0 on an individual sand basis. As a result, oil recoveries range from values as low as 26% in some CRB's up to 40% in other CRB's. By ensuring that each sand reaches an HPVI target of at least 6.0, oil recoveries for individual sands should reach a minimum of 30-33% for an overall recovery in excess of 37% for the Ranger West sand. In the more mature blocks, maximum profitability will be achieved through minimizing the volume of low value water cycling, directing water to the remaining economic reservoir targets and targeting by-passed oil pockets with development drilling and investment wellwork projects. In the absence of economic options, idle wells will be abandoned to reduce future abandonment liabilities and reservoir crossflow. Risk of subsidence will be minimized in all reservoir management actions.

Strategies

The Ranger West development plan includes drilling an additional 12 development wells and performing 7 investment wellwork projects in FY09/10. The development plan will be implemented under the guidance of the reservoir management objectives discussed above. The best new drilling and investment wellwork locations will be evaluated and selected for inclusion in the drilling and wellwork programs based on a combination of economic and strategic criteria. Projects will be reviewed carefully to ensure that only projects that will be profitable even in low price environments are executed. Pool reviews/reservoir studies, conducted on an ongoing basis, will be used as the foundation for identifying the best drilling and wellwork opportunities and to monitor progress towards achieving reservoir management goals.

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

Critical Issues

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

- Continue throughput optimization in under-injected sands in the F0, 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 F0 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 history matched streamline simulation model with new Petrel model.
- Update the geologic and reservoir description in Tar V and develop a depletion plan.
- Construct streamline reservoir models to evaluate depletion optimization in Ranger VI.
- Continued testing and evaluation of cased-hole resistivity logs to identify zones of unswept oil and recomplete wellwork candidates.
- Systematic development of throughput analysis and monitoring tools for eighteen vertical flow units in the Ranger sands to identify opportunities for vertical conformance improvements and waterflood optimization.
- Development of vertically detailed streamtube models for waterflood performance prediction applications.

Ranger East

Reservoir Management Plan

History

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

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

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

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

Status

As of November 2008, Ranger East production is 6.8 MBOPD and 236.8 MBWPD from 201 active producers. Total water injection was 253.1 MBWPD into 125 active injectors.

Since the last reporting period in December 2006, oil production has declined at 7.1% per year from 7.6 MBOPD to 7.1 MBOPD. The WOR increased from 32.1 to 34.6. Cumulative oil production as of November 2008 is 239.4 MMBO (30.4% OOIP).

Production from Ranger East is typically tracked in the three 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/8B consists of CRB's 14, 15, and 16, and as of November 2008 is producing 2.6 MBOPD and 88.4 MBWPD, with a water injection rate of 94.2 MBWPD. Since the last reporting period in December 2006, oil production declined at an average rate of 10% per year and the WOR increased from 33.9 to 34.6. Five producers and five injectors were drilled in Ranger 8A/8B during this reporting period. One producer was drilled that was completed in Ranger 8A and Ranger 90N.

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 2.7 MBOPD and 93.3 MBWPD, with 111 MBWPD of water injection. Oil production declined at an average rate of 15% per year since the last reporting period. The WOR increased from 32.1 to 35.2 since the last reporting period. During this reporting period, three producers and one injector were drilled in Ranger 90N. One was drilled and completed in Ranger 8A and Ranger 90N.

Ranger 90S consists of CRBs 21 and 22, which are producing 1.7 MBOPD and 57.4 MBWPD, with 58.9 MBWPD of injection. Since the last reporting period, the oil production rate has declined at an average rate of 0% per year (holding flat). This fault block has a current WOR of 33.6, up from 29.0 from the last reporting period. One producer was drilled in Ranger 90S during this period.

Recovery through November 2008 is 239.4 MMBO (30.4% OOIP). Ranger East is expected to produce an additional 41.1 MMBO by 2030 bringing ultimate recovery from existing development to 282.1 MMBO (37%OOIP). Additional development through drilling and investment wellwork is expected to increase reserves by 4.9 MMBO to 287 MMBO (37.0% OOIP) by 2030.

Ranger East has 18 open idle wells.

Calendar Years 2007 and 2008 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.

Twelve wells were drilled in the Ranger East area in the period from January 2007 to November 2008. These wells brought in 2.1 MMBO in reserves at $6.72/BO. Seven of the twelve wells were producers. They consisted of two horizontal wells with an open-hole gravel packed completion and five conventional wells with open-hole gravel packed completions. The horizontal completions had an average initial oil production rate of 64 BOPD. The conventional open-hole gravel packed wells averaged an initial oil rate of 78 BOPD. The injectors are cased-hole, selectively perforated completion targeting intervals with low waterflood throughput and high remaining oil saturations. The injector cased-hole, perforated completion injection rate averaged 3145 BWPD.

Four development (investment) wellwork projects were completed during this reporting period and all four were injection well projects. Two projects were conversions from producer to injector while the other two injector projects were add-pays to the existing completions. The objective of these jobs was to displace unswept oil reserves previously not open in the existing completion or facilitate the progression of the waterflood front. These investment projects had planned average incremental oil production of 24 BOPD.

Maintenance wellwork also plays a major role in maximizing Ranger East base production. From January 2007 to November 2008, approximately 94 producer maintenance wellwork projects were completed yielding an average of 31 BOPD/job at an average cost of about $76,000. Roughly 347 injector maintenance wellwork projects were also completed yielding an expected average of 770 BWIPD/job at an average cost of $16,000.

A study of the Ranger 8 fault block was undertaken and completed in 2008 to develop a depletion plan for the block. The improved streamline reservoir model was incorporated into the study. The focus was to identify and prioritize new development and maintenance opportunities in order to maximize the profitability of Ranger 8.

Reservoir Management Objectives

The primary goal of the reservoir management plan is to maximize the profitability and economic oil recovery from the Ranger East pool. This can be accomplished by developing proper waterflood pattern closure, providing adequate injection throughput into all the individual sand intervals in each pattern, reducing water cycling in swept zones where possible, and maximizing well productivity. Current WOR's in the three major fault blocks range from 33 to 35 with WOR’s as low as 22 in CRB 17 of Ranger 8A/8B, indicating strong remaining reserves potential before reaching a nominal economic limiting WOR of 120. The injection target volume is greater than 6.0 hydrocarbon pore volumes into each sand before reaching a producing WOR of 70. Injection throughput has been challenged by the difficulty of maintaining good vertical profile control. Another challenge is the optimal placement of injectors in the highly faulted Ranger East pool. Producer to injector conversions and injector recompletions have been done to improve sweep efficiency.

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

Strategies

The Ranger East development plan includes drilling an additional twenty-two development wells and performing several investment wellwork projects in FY09/10. These projects will target insufficiently swept pay.

An update of the Ranger East geologic description and streamline reservoir model has been completed. Fine-tuning of the streamline reservoir model is continuing. The geologic study was undertaken to improve the reservoir characterization of Ranger East, to improve the estimate of net pay and OOIP and to provide the framework for the simulation model. The goals of the simulation model are to understand flux into or out of the Unit, identify hydrocarbon hot spots, manage waterflooding, optimize the Ranger East depletion plan and assist with well planning. The low ultimate recovery indicates a greater amount of study is needed to maximize recovery in Ranger East.

The profitability of the development plan will be maximized by reducing costs where possible and prudent. The focus will be on using existing wellbores, correcting injection profiles with workovers or remedial wellwork where possible, returning idle producers to production, shutting in high WOR producers 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 to reduce drilling and completion costs for these wells.

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

Critical Issues

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

- Continue to refine and update the existing Ranger East streamline model.
- Complete depletion studies by CRB for Ranger 90N/90S.
- 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 throughput rates and improve vertical conformance.
- Select the optimal injector drilling locations by utilizing the results of the improved streamline simulation model.
- Continue fracturing mid and lower Ranger zones to improve productivity and ultimately reserves.
- Evaluate the feasibility of high-angle slant wells in the M1 in the eastern part of the pool similar to the Belmont Upper completions.

Terminal Zone

Reservoir Management Plan

History

Reservoir sands in the Terminal interval are expected to ultimately yield over 162 MMBO. The Terminal zone is about 1000 feet thick and its productive limits cover an area about four miles long and two miles wide within the Unit. The LBU fault divides the Terminal into the Upper and Lower Terminal zones on the west side of the field from the Terminal East zone on the east side.

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

Wells on the west side of the field have generally been completed in Upper Terminal sands, in either the HX1-Y4 or Y4-AA intervals; however, a few wells include the less prolific Lower Terminal AA-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 full-zone completions due to competition from the upper, more prolific intervals.

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

Status

Total production from the Terminal zone for November 2008 is 5.0 MBOPD and 131.7 MBWPD resulting in an average WOR of 26.3. There are currently 159 active producers resulting in an average per well rate of 31.0 BOPD and 828.4 BWPD. Terminal zone injection for November 2008 is 153.7 MBWPD from 85 wells yielding an average injection rate of 1,808 BWPD per active injection well.

Four Terminal wells are currently mechanically idle and capable of being reactivated with further investment. Evaluation of repair and/or conversion options is underway for these wells. There are currently no idle wells slated to be plugged in zone.

Cumulative production through November 2008 totaled 142.1 MMBP (32.3% OOIP) and ultimate production for continued operations is expected to reach 159.0 MMBO (36.2% OOIP) by 2030 resulting in 16.7 MMBO remaining reserves. Additional development through infill drilling (P1) is expected to yield additional reserves of 2.8 MMBO for an ultimate recovery of approximately 162.8 MMbo (37.1% OOIP).

Successful infill drilling and well work activities have partially offset the underlying Terminal zone oil production decline rate of 9%/year. Production is down 440 BOPD from the November 2007 rate of 5.7 Mbopd.

Calendar Years 2007 and 2008 Activities and Results

In calendar years 2007 and 2008, ten producers and twelve injectors were drilled bringing in 3.4 MMbo in reserves at $7.71/bo. Initial stabilized production from the producers averaged 42 bopd and the average initial injection rate for the injectors was 1200 BWIPD. For the producers drilled, the average cost was $1,459,000. For the injectors, the average cost was $1,070,000.

Over the same time period, seven development (investment) wellwork projects were completed. These added 0.5 Mmbo in reserves at a cost of $4.96/bo. Three were producer projects. The average rate was approximately 15 bopd per well. These projects had an average cost of $425,000. Four injector projects were completed over the same period at an average cost of $271,000. Average stabilized incremental injection rate per well was 250 bwpd.

Maintenance wellwork also plays a major role in maximizing Terminal base production. During 2007-2008, approximately 86 producer maintenance wellwork projects were completed yielding an average of 40 bopd/job at an average cost of about $80,000. Roughly 39 injector maintenance wellwork projects were also completed yielding an average of 150 bwipd/job at an average cost of $48,000.

Reservoir Management Objectives

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

In 2004 and 2005, a reservoir study was conducted to improve the geological and reservoir description of the Terminal Zones and better define the estimation of OOIP. This project resulted in the creation of a streamline reservoir simulation model for the Terminal East area and a second model for Terminal West. These models are and will continue to be used as a directional tool to identify opportunities to maximize recovery from the reservoir.

Production and injection infill well locations will be identified and drilled to recover oil banked near faults, to improve areal sweep efficiency and to increase reservoir throughput. Profile modification will be attempted to reduce thief intervals and improve vertical conformance. Recovery from existing wells will be optimized to ensure

maximum economic value. Completion techniques will be modified to increase injectivity, minimize reservoir damage, and reduce high decline rates.

Strategies

The Terminal Zone development plan for FY 09/10 assumes five drilling projects and six investment workover projects. These objectives will be met by utilizing the various Unit programs currently in-place. The best new production and injection infill well candidates will be evaluated and selected for inclusion in the drilling schedule based on economic and strategic development criteria. Pool reviews will be conducted regularly to identify well work, conversion, and infill opportunities. The semi-annual management reviews will be used to communicate production targets and Unitized Formation goals. Reservoir studies are being performed to develop long term depletion plans and to reliably forecast future reservoir performance.

Key reservoir management strategies have been formulated for each Terminal reservoir pool. The focus strategy for UT6 CRB-38 is to improve vertical conformance due to the block's waterflood maturity and highly layered system. In addition, a highly selective drilling program will be conducted to target bypassed oil. The reservoir management goal for UT6 CRB-39 is to increase the overall level of development through infill drilling in this less mature block. Increased throughput and optimization of vertical and areal conformance will also be focus areas for the block. The development strategy for UT7 includes crestal injection to augment the current peripheral injection configuration due to the area's highly faulted nature. Terminal 8A development will include additional injection projects to achieve throughput targets. Finally, injection in Fault Block 90 will continue to be tailored to the improved understanding of fault compartmentalization.

Reservoir studies incorporating updated volumetric analyses, based on additional geologic interpretation, will help fine tune future drilling requirements. Throughput analyses will be performed in those areas with the greatest development potential to quantify injection requirements. The streamline models will be used to optimize the waterflood and generate development projects for depletion planning. Detailed review of existing well histories and performance during pool reviews will help identify candidates for well work to improve management of the reservoir. 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 larger perforating guns, gravel pack and frac and pack technology. Fracture stimulation technology in the Terminal zone will continue to be applied on a case by case basis to provide sand control and improve well deliverabilities in sensitive, low permeability formations. The team will actively seek out and advocate cost reduction strategies while meeting reservoir objectives.

Critical Issues

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

- Update the Terminal East and West streamline models with the latest production, completion and log data. In addition, update the Terminal East fault model.
- 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 high angle producers to exploit in Terminal Blocks 38 and 39.
- Strategically develop thinly bedded Lower Terminal East sands independently of more permeable zones characterized by higher water saturations.
- Accelerate reservoir development through a measured infill drilling program and aggressive redrilling of failed peripheral injectors for UT6 CRB-39.
- Optimize crestal injection in UT7 to augment the current peripheral injection configuration.
- Increase reservoir throughput in Terminal 8A through injection well drilling and conversions.
- Optimize waterflood pattern development in Terminal 90N by incorporating detailed reservoir fault analysis stream tube model development.

UP-Ford

Reservoir Management Plan

History

The UP-Ford Zone has produced 101.7 MMSTB oil to date and current active well counts are 82 producers and 63 injectors. Much of the historical production is attributable to natural water drive from the AX sand, which watered-out over almost the entire field by the early 1980's. Sands above the AX have been historically less prolific owing to several factors, including: lower formation permeability, thin-bedded discontinuous shaly sands which are prone to formation damage owing to a high clay content, a lack of adequate injection support and damaging completion and workover techniques.

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

From the late 1990's, success in pattern waterflood development in the Tract II area was achieved through adoption of non-damaging drilling and completion techniques, and the fracture stimulation program. As a result, UP-Ford oil production rate reached a 20-year high (6978 STB/D oil) during early 1998. During the early 2000's, attempts to further exploit these strategies in the upper UP-Ford sands were not successful because of the lack of adequate injection support. During a two year development break, the reservoir description was completely redone and completion techniques were reviewed. New Petrel geological model and Frontsim reservoir simulation model were built and history-matched in 2005. The drilling and workover program is continuing with many benefits being realized from hydraulic fracturing completion techniques.

Status

The UP-Ford Zone consists of three fault blocks: UPF8, UFP90, and UPF98. November 2008 production from the UP-Ford was 3.0 MSTB/D oil and 55.7 MSTB/D water, with a WOR of 18.6. Overall UP-Ford zone injection for November 2008 averaged 69.8 MSTB/D water yielding an overall injection-voidage ratio of 1.19. Average well rates are 37 STB/D oil and 851.2 STB/D water for producers and 1108 STB/D water for injectors. As of November 2008 UP-Ford has 82 producers and 63 injectors. Six UP-Ford wells are open idle and are being evaluated for conversion, redrill and repair options.

Cumulative production through November 2008 totaled 101.8 MMSTB (27% OOIP) and ultimate recovery is expected to reach 123.3 MMSTB (33% OOIP) in 2030. Proven

reserves are 18.3 MMSTB oil with PDP at 14.7 MMSTB and PUD at 3.5 MMSTB. Approximately 88 MMSTB oil in UP-Ford 98 is booked as contingent resources because of very high risk involved in finding and producing oil from that block under current economic conditions.

The production rate climbed from 3000 STB/D oil in Oct-03 to 4000 STB/D oil in May-06 and then it has declined since then to 3300 STB/D in Oct-08. Primary reasons for the decline are two: injection water short-circuiting to producers and producer failures and downtime. There has been a renewed focus on drilling more injectors in UP-Ford since year 2001 and the number of injectors has more than doubled between 2001 and 2008. Water production and WOR have increased as a result, but because of ESP limitation or island capacity limitations it has been difficult to drawdown the offset producers experiencing the injection response. The solution currently being implemented is to improve injection efficiency in injectors and conformance in producers though workovers and change in completion designs.

The second reason for a drop in oil production is well failures. UP-Ford is known to have ESP operational problems (gas locking, sanding, high temperature etc.) at a higher frequency than Ranger or Terminal. Average ESP life in UP-Ford is less than 2 years. Sanding, either owing to depletion or high injection pressure or owing to hydraulic fracturing, has resulted in some permanent well failures.

Calendar Years 2007 and 2008 Activities and Results

From January 2007 through November 2008, twelve producers and eleven injectors have been drilled. This added 3.7 MMSTB oil at a cost of $11.12/STB oil. An average new producer made 83 STB/D oil compared to an average expected rate of 115 STB/D oil. The average producer cost was $2,152,000. The average injector added 850 STB/D to injection water at an average cost of $1,391,000.

Two producer investment wellwork projects added 0.18 MMSTB oil at a cost of $5.9/STB oil. Average project incremental rate was 20 STB/D oil. These projects had an average cost of $354,000. Five injector investment wellwork projects were performed over the same period resulting in an average injection rate of 610 STB/D water at an average cost of $213,600 per job.

Maintenance wellwork also plays a major role in maximizing UP-Ford base production. During 2007-2008, approximately 92 producer maintenance wellwork projects were completed yielding an average of 43 STB/D oil per job at an average cost of about $112,000. A total of 99 injector maintenance wellwork projects (mainly acidizing the completion interval to dissolve precipitates) were also completed during this period yielding an average of 300 STB/D incremental injection water per job at an average cost of $26,000 per job.

Reservoir Management Objectives

The goal of the UP-Ford Reservoir Management Plan is to maximize the profitability of the reservoir. As the recovery mechanism is waterflood, we have to increase the

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

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

Strategies

The development plan for UP-Ford in FY09/10 includes continued activity in this reservoir. The various Unit programs currently in place will be utilized to help achieve the development objectives stated above. Potential new production and injection infill well candidates will be evaluated and the best 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 models combining the best reservoir description and well performance data will help identify regions of high remaining oil saturation as well as regions with sub-optimal waterflood.

UP-Ford 8 and 90 fault blocks already have a calibrated reservoir flow model that is actively used and updated as part of this development strategy. In FY09/10 the model will be further upgraded based on most recent understanding of the geological framework and properties. The UP-Ford 98 block is being studied at present utilizing seismic, well log, core and production performance data to quantify future development opportunities as its recovery factor is low. Reservoir description studies will be performed to locate and map the most likely areas of sand development.

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

Critical Issues

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

- Increase pressure support in the upper reservoir sands utilizing in-zone injectors and conformance improvement projects for existing injection wells through stimulation and mechanical methods.
- Further exploit alternatives for increasing infill well deliverability primarily through hydraulic fracturing and stimulation.
- Continue to refine non-damaging procedures to complete and work over wells and determine injection water quality requirements.
- Establish pattern waterflood in the developed part of UP-Ford 98. Evaluate the potential of “central” UP-Ford 98.
- 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 Zone underlies the UP Ford Zone and comprises two distinct sub-zones, an upper clastic interval and a lower 237 Zone shale interval. The lower 237 Zone shale is further subdivided into the Hot Shale and Basal Shale members. About 2.65 MMBO has been produced from these fractured shales from 4 commercial wells within the LBU. Acoustic basement underlies the 237 Zone shales. These rocks include the Miocene San Onofre Breccia and Jurassic Catalina Schist basement. They have contributed an additional 1.35 MMBO from one LBU well.

The Hot Shale member of the Lower 237 Zone Is a world-class oil source rock. It contains a foraminte facies, but this has not been specifically targeted to date. The Basal Shale is also a good, but lesser quality source rock. It has numerous thin dolomitic interbeds and thin quartz cemented sandstones. This facies tends to have higher fracture density than the Hot Shale and has been somewhat more productive.

The first 237 Zone well was completed in 1968 at an initial rate of 1050 BOPD. Seventeen more wells were completed in the LBU with the last one in 2008. All reported oil and gas shows while drilling through the lower 237 Zone. Five of the wells were economic, one was marginally economic, nine were uneconomic and two are still being evaluated. One well was a mechanical failure and did not properly evaluate the lower 237 Zone. The uneconomic wells may have been damaged during drilling or lacked sufficient fracture systems to be productive. Through November 2008 cumulative production from the 237 Zone/acoustic basement is 4.0 MMBO with two active wells in the pool.

In 2006 a 237 team was formed to re-evaluate the fractured shale play. Using seismic coherency mapping and fracture trend measurements taken at local outcrops, Well C-250 was proposed. This was the first 237 zone well drilled in the LBU in over 11 years. C-250 targeted the Hot Shale and Basal Shale with acoustic basement as a secondary target. It was completed in December 2007 and flowed for seven months at rates between 750 and 300 BOPD with only a 2 percent water cut. A pump was installed in July 2008 and the well made 1240 BOPD. Water cut has been rising and at the end of November the rates were 274 BOPD and 668 BWPD. Oil production through the end of November from Well C-250 is 171,586 STB.

In FY08/09, two additional 237 zone wells were drilled from Island Freeman. These were ranked 3rd and 4th out of five proposed wells to build on the commercial C-250 discovery. They were drilled early in the program owing to cost savings related to rig moves. They targeted a previously drilled structure high thought to have remaining

potential. Well D-720A made 1,440 BWPD and 15 BOPD. It is being recompleted in an attempt to shut off the water zone(s). D-562A is still being completed.

Two to three additional wells are planned from Island Chaffee in FY09/10 as step-outs to the commercial C-250 well. Each of these wells will include new play elements such as a previously untested stratigraphic interval or a new position on structure.

Critical Issues

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

- Evaluation of open hole log and mud-log data acquired during drilling to better refine our completion design.
- Continued integration of reservoir performance, stress-field analysis, and geological understanding to high-grade future drilling targets.

Shallow Gas

Reservoir Management Plan

History

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

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

A separate production train was installed that collects, measures, and processes gas for sale to Long Beach Energy.

Status

The Shallow Gas reservoirs consist of 5 primary sand bodies: A10, A14, A16, A18 and A20. The Grissom Gas is currently the only Shallow Gas accumulation being produced, with the majority of the production coming from the A16 sand. To date four of the six wells have been completed in the A16, and one in each of the A20 and A14 respectively. With four wells producing out of the A16 sand a stabilized production rate was maintained at 5,000 mcfd. This rate was maintained until June 2008 when Well A-268 watered out. Well A-260 followed and watered out as forecasted in September 2008. Current daily production rate for Grissom Shallow Gas production is averaging 3,700 mcfd, with production from two active producers, Well A-301 (horizontal in A16 sand) and Well A-271 (A16 recompletion). Well A-313 (A14 sand completion) recently was returned to production after an inner liner was installed. Near term wellwork projects are to recomplete the watered out wells up-hole into the A14 sand. Daily rate by sand and cumulative production can be seen in Figure 1.

Seven idle wellbores are currently being held exclusively for Grissom Shallow Gas development and one is held for White Gas.

White Gas development is in the planning and engineering stages with a third quarter 2009 goal to place the first well on production. A two well development plan has been rolled out to target the White Shallow Gas reservoir. One well will produce from the A20 sand and it will be recompleted up hole as the sands water out. A second well will be completed in the A10 sand. Produced gas will be shipped to Grissom for dehydration and processing where it will commingle with Grissom Shallow Gas.

Cumulative production through November 2008 totals 2.810 BCFG (38.2% OGIP) and ultimate recovery is expected to reach 4.33 BCFG (61.0% OGIP) in 2011 for the Grissom Gas reservoir. Including White Gas production the ultimate recovery is expected to reach 6.344 BCFG (61.0% OGIP including both Grissom and White accumulations) by 2015. Underlying aquifer support within the reservoir will affect total gas recovered.

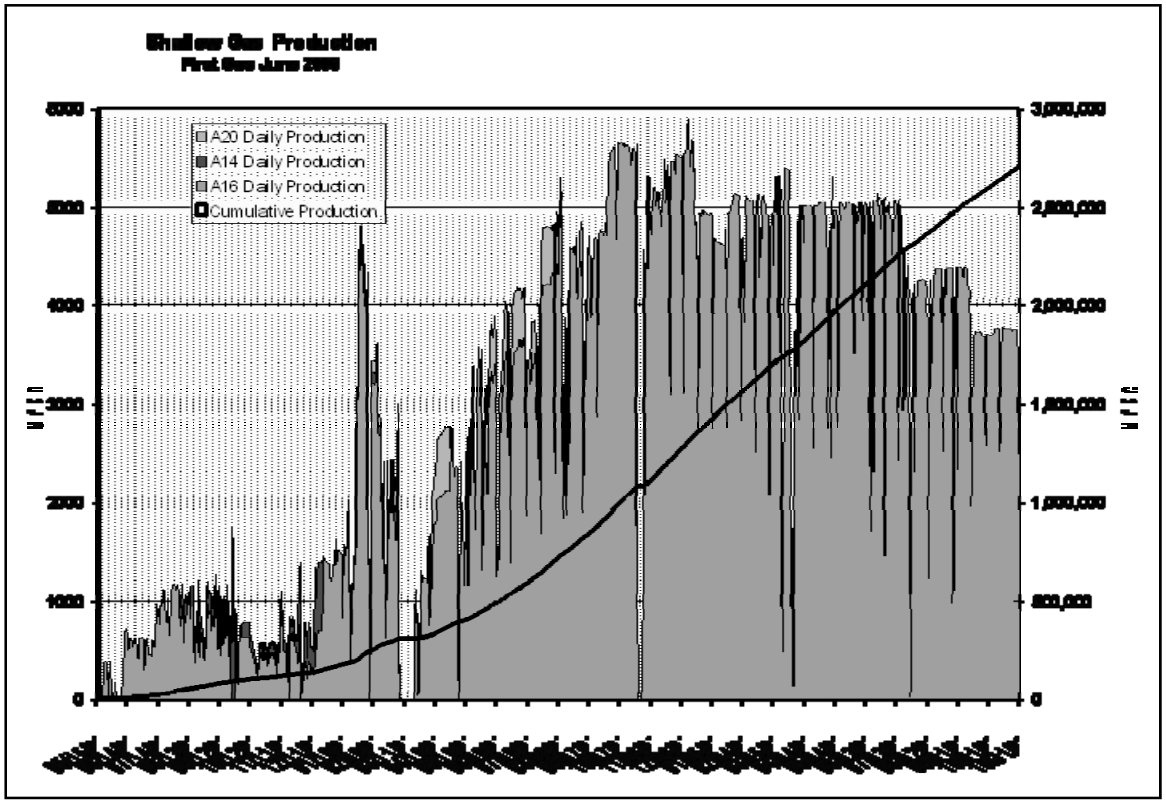

Figure 1: Grissom Shallow Gas production by sand

Reservoir Management Objectives

The overriding goal of the Shallow Gas Reservoir Management Plan is to maximize the profitability of the reservoir. Three objectives must be attained to achieve this goal. The first is to understand long-term reservoir energy support through monitoring of aquifer influx and pressure measurement. Understanding the rate of withdrawal to pressure change in the reservoir is fundamental to quantifying recoverable reserves. Through P/Z vs. Cum production analysis and a Fetkovich water influx simulation, production rate at or exceeding 3500 mcfd is required to best outpace the aquifer in the A16 sand. Secondly, all small gas “stringers” should be tested for viable productivity, which will add to development opportunities and increase the reserves volume if they are commercially

productive. Lastly, we must focus on utilizing the most ideally situated idle wellbores for Shallow Gas development to maintain a low cost development and maximize recovery through existing assets.

It has been found that sand control is needed in order to maintain the require production rates. Sand control has been installed on previously sanded wells. With the success of Well A-301 horizontal drill well, additional opportunities must be evaluated to optimize the economic success of Shallow Gas expansion through recompletions vs. drill project.

Strategies

The development plan has for the completion of three Grissom gas wells in FY 09/10. One new recompletion in the A16 sand, the remaining two will be utilizing Shallow Gas wellbores which have watered out to complete up hole reserves. Additionally, the two well White gas development strategy should be implemented in FY 2010. Reservoir studies will be done on the Pier J and Chaffee gas to better understand the connectivity of the shows and extent of the gas in place. These studies will utilize seismic, well log, and cased hole reservoir sampling data to quantify extensional development opportunities. Furthermore, a permanent down hole pressure gauge is to be installed in a gas well for constant flowing downhole pressure monitoring as well as improved build up pressure testing.

The key strategy for realizing optimal development of the Shallow Gas reservoir is understanding the lateral continuity of the smaller sand sequences. Geologic studies addressing structural uncertainty, continuity and distribution, as well as reservoir faulting and stratigraphy, are critical to this effort. Reservoir studies combining the best reservoir description and well performance data will help identify regions of high remaining hydrocarbon saturation. Geologic model and reservoir simulation tool are under construction to aid in optimizing ultimate recovery through optimal well recompletions, draw down rates and water influx.

Critical Issues

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

- Continue to monitor rate of aquifer influx in the A16 flow unit.
- Identify and test small gas stringers present between the over and underlying gas sands.
- Investigate dual completions to maximize wellbore utility.
- Work cross functionally to optimize White Gas development and project implementation.
- Quantify unknown gas reserves under Islands Chaffee and Pier J.

Exhibit C

W 17163

Long Beach Unit

THUMS Long Beach Company
(Agent for Field Contractor)

ANNUAL PLAN

July 1, 2009 through June 30, 2010

ANNUAL PLAN

July 1, 2009 through June 30, 2010

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Part I - Introduction

This Annual Plan ("Plan") was developed to reflect anticipated activity levels during the fiscal period from July 1, 2009 through June 30, 2010 ("FY09/10"). It is being submitted as required by Section 5(a) of Chapter 138, Statutes of 1964, First Extraordinary Session, and as revised by passage of Assembly Bill 227 (Chapter 941, Statutes of 1991) and the Optimized Waterflood Program Agreement approved by the State of California, the City of Long Beach, and Atlantic Richfield Company, whose interest has been assigned to Occidental Petroleum Corporation.

This Plan provides for drilling, producing, water injection, and other associated activities from offshore and onshore locations. The budget for these activities is grouped into the following five major categories:

Plan Category	**Fiscal Year 2009 – 2010 ($ Million)**
Development Drilling	$ 74.0
Operating Expense	$ 103.8
Facilities, Maintenance, and Plant	$ 77.6
Unit Field Labor and Administrative	$ 52.8
Taxes, Permits, and Administrative Overhead	$ 42.0
Total	$ 350.2

A. Plan Basis

This Plan was developed based on the parameters outlined in the Program Plan for the period July 2009 through June 2014 and provides current estimates of volumes, drilling activity and expenditures for FY09/10. Expenditure levels and project mix will be adjusted as needed to respond to fluctuations in oil price and other economic conditions.

Volumes

Oil and gas production volumes are predicted to average 25.5 Mbopd and 12.6 MMcfpd, respectively, in FY09/10. Water production for the period is expected to average 955 Mbwpd and water injection is expected to average 1,039 Mbwpd.

Revenue and Expenses

A projected oil price of $40.00/bbl Wilmington and gas price of $6.00/mcf will result in revenues of $399.2 million. Budgeted expenses for FY09/10 total $350.2 million. Projected net profit in FY09/10 is $49.0 million.

Drilling

This Plan allows for drilling approximately 50 new and redrilled development and/or replacement wells. The plan is to use two drilling rigs for the FY09/10. Two workover rigs will perform drilling preparation and completion work. Locations of production and injection wells to be drilled or redrilled are given 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, but are not limited to, facilities piping, tanks, and vessels. These projects are consistent with past activities to keep the Unit facilities in safe operating condition.

Abandonment

Wells and facilities with no further economic use will be abandoned to reduce current and future Unit liability. This Plan provides funds for plugging wells to surface, in-zone, and conditional abandonments with approximately $0.42 million in spending for the Plan period.

Safety, Environmental, and Regulatory Compliance

The Unit is committed to conducting all aspects of its business in a manner that provides for the safety and health of employees, contractors and the public, and safeguards the environment in which it operates. Projects relating to safety, environmental issues, or other situations necessary for meeting compliance with code, permit, or regulatory requirements will continue to be implemented under this Plan in accordance with all Unit agreements. In addition, Thums will be placing additional emphasis on risk and system reviews and operational safeguards to assure reliable and compliant environmental performance.

Economic Review

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

All existing wells are frequently reviewed in light of changing crude prices to determine if they are economic to operate. Well servicing work is justified on economics and other conditions consistent with good engineering, business, and operating practices.

B. Economic Projections

(Data in Millions of Dollars)

	BUDGET FIRST QUARTER FY09/10	BUDGET SECOND QUARTER FY09/10	BUDGET THIRD QUARTER FY09/10	BUDGET FOURTH QUARTER FY09/10	BUDGET TOTAL FY09/10
ESTIMATED REVENUE					
Oil Revenue	$95.5	$94.5	$90.2	$91.5	$371.7
Gas Revenue	$7.4	$7.3	$6.2	$6.6	$27.5
TOTAL REVENUE	$102.9	$101.8	$96.4	$98.1	$399.2
ESTIMATED EXPENDITURES					
Development Drilling	$18.5	$18.5	$18.5	$18.5	$74.0
Operating Expense	$24.6	$24.8	$26.9	$27.5	$103.8
Facilities & Maintenance	$19.5	$19.5	$19.3	$19.3	$77.6
Unit Field Labor & Administration	$13.2	$13.2	$13.2	$13.2	$52.8
Taxes, Permits & Overhead	$10.5	$10.5	$10.5	$10.5	$42.0
TOTAL EXPENDITURES	$86.3	$86.5	$88.4	$89.0	$350.2
NET PROFIT	$16.6	$15.3	$8.0	$9.1	$49.0

C. Major Planning Assumptions

	BUDGET FIRST QUARTER FY09/10	BUDGET SECOND QUARTER FY09/10	BUDGET THIRD QUARTER FY09/10	BUDGET FOURTH QUARTER FY09/10	BUDGET TOTAL FY09/10
OIL PRODUCTION					
PRODUCED (1000 BBL)	2,388	2,362	2,256	2,288	9,294
(AVERAGE B/D)	25,956	25,671	25,067	25,138	25,461
GAS PRODUCTION *					
PRODUCED (1000 MCF)	1,232	1,213	1,036	1,105	4,586
(AVERAGE MCF/D)	13,388	13,184	11,514	12,138	12,563
WATER PRODUCTION					
PRODUCED (1000 BBL)	89,548	88,564	84,601	85,782	348,495
(AVERAGE B/D)	973,343	962,649	940,013	942,664	954,780
WATER INJECTION					
INJECTED (1000 BBL)	97,452	96,381	92,069	93,354	379,256
(AVERAGE B/D)	1,059,256	1,047,619	1,022,985	1,025,870	1,039,056
OIL PRICE ($/BBL)	$40.0	$40.0	$40.0	$40.0	$40.0
GAS PRICE ($/MCF)	$ 6.0	$ 6.0	$ 6.0	$ 6.0	$ 6.0

* Includes Shallow Gas

Part II – Program Plan Schedules

Schedule 1 A
Range of Production and Injection
FY 2009/10

Long Beach Unit Program Plan, July 2009-June 2014

A. Range of Production and Injection Rates

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2009-10	24.6 - 26.0	928 - 974	10.8 - 13.6	1,007 - 1,060

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2009-10	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Schedule 1 B
Anticipated Development and Replacement Locations
Fiscal Year 09/10

Long Beach Unit Program Plan, July 2009-June 2014

B. Anticipated Development and Replacement Locations

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		0	-	1	0	-	2							0	-	0	0	-	1										0	-	0
SG		0	-	1	0	-	1																								
Ranger West	1	0	-	1	0	-											0	-	1												
	2	0	-	1			1										1	-	2												
	3	0	-	1	0	-	1							0	-	1	0	-	1										0	-	0
	4	0	-	1	0	-	1				0	-	0	0	-	1	0	-	1	0	-	0				0	-	1	0	-	1
	5	0	-	1							0	-	0	0	-	1										0	-	1	0	-	1
	7										0	-	0	0	-	1										0	-	1	0	-	1
	8										0	-	0													0	-	1			
	9				0	-	1				0	-	0							0	-	1				0	-	1			
	10				0	-	1										0	-	2	0	-	1									
	11				0	-	1										0	-	2	0	-	1									
	12				0	-	1													0	-	0									
	13				0	-	1													0	-	0									
	36				0	-	0				0	-	0							0	-	0				0	-	1			
	37										0	-	0													0	-	0			
Ranger East	14				0	-	0													1	-	2									
	15				0	-	0				0	-	1							1	-	1				0	-	0			
	16				0	-	0	1	-	2	0	-	0							0	-	0	0	-	2	0	-	0			
	17							1	-	2													0	-	2						
	18							1	-	2													0	-	2						
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	22							1	-	2													0	-	1						
	33							0	-	1													0	-	0	0	-	0			
Terminal	24	0	-	1	0	-	2							0	-	1	0	-	1										0	-	0
	38	0	-	0	0	-	0				0	-	0	0	-	0	1	-	2	0	-	0				0	-	0	0	-	0
	39				0	-	1				0	-	1							0	-	0				0	-	0			
	40				0	-	1				0	-	0							0	-	0				0	-	1			
	41																														
	42							0	-	1													2	-	3						
	43							0	-	2	0	-	0										0	-	0	1	-	2			
	47																														
UP Ford	26				0	-	1				0	-	1							0	-	0				0	-	0			
	27				0	-	0				0	-	1							0	-	0				0	-	0			
	30	0	-	2	0	-	0	0	-	1	0	-	1	0	-	0	0	-	2	0	-	0	0	-	1	0	-	0	0	-	1
	31				0	-	0	0	-	1	0	-	1							0	-	0	0	-	1	0	-	0			
	44				0	-	0	0	-	1	0	-	1							0	-	0	0	-	1	0	-	0			
	45				0	-	0	1	-	2	0	-	1							0	-	0	1	-	2	0	-	1			
	46							1	-	2																					
237	30	0	-	1				0	-	2	0	-	1																		
		Total															Total														
								8	-	66													8	-	54						

Part III – Itemized Budget Expenditures

A. Development Drilling $74,000,000

The Development Drilling Category of expenditures encompasses all new well and replacement well drilling activity, as well as maintenance and replacement of drilling equipment within the Unit. Funds for development drilling are based on the assumption that 50 wells will be developed and/or replaced during the Plan year, using approximately two drilling rigs.

Drilling and completing new wells, as well as redrilling and recompleting existing wells, account for 94 percent of the funding provided in this Category. Included in these activities is funding for rig move-in, drilling and casing, completion activities, drilling rig in-zone plugs and conditional abandonments, and unscheduled activity (fishing operations, cement squeezing, special logging, contract drilling services).

Exact specifications regarding the distribution of wells, bottom hole locations, and completion intervals will be determined by OXY Long Beach, Inc. (OLBI). These decisions will be influenced by contributions from reservoir engineering personnel, results from ongoing engineering studies, and new well performance. This information will be reviewed and approved in accordance with Unit Agreements during regularly scheduled Unit forums.

B. Operating Expense $103,800,000

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 25.5 Mbopd, estimated gas production of 12.6 MMcfpd, water injection requirement of 1,039 Mbwpd, and water production of 955 Mbwpd. Anticipated operating expenses were based on operating three maintenance workover rigs per month for servicing an average active well count of 871 producers and 484 injectors. Abandonment well count will be determined as a function of drilling activity and the number of idle wells with no future use.

The day-to-day costs for production and injection well subsurface operations represent approximately 36 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 60 percent of the funds in this Category. Cost for electric power is based on estimated kilowatt usage of 669,559,000 kwh at an average rate of $0.092/kwh. This cost includes all sources of Unit electrical power, including all costs associated with the power plant and electric utility purchases.

C. Facilities, Maintenance, and Plant $77,600,000

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 50 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 50 percent of the funding in this Category is for facilities repair and improvement projects. Improvement projects may include spending for the facility capacity limits expansion, waste disposal, pipeline replacements, and other infrastructure related investments that position the Unit for longevity.

D. Unit Field Labor and Administrative $52,800,000

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 80 percent of the Category total.

Funding for Unit support activities includes, but is not limited to, costs for professional and temporary services necessary for the completion of support activities; charges for data processing; computer hardware and software; communications; office rent; general office equipment and materials; 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 $42,000,000

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

Funding is provided for taxes levied on personal property, mining rights, and oil production; for the Petroleum and Gas Fund Assessment; annual well permits and renewals; Conservation Committee of California Oil and Gas Producers Assessment; California Oil Spill Response, Prevention, and Administration fee; land leases; and pipeline right-of-way costs. These costs represent approximately 66 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 Long Beach Gas and Oil Department, City of Long Beach, acting with the consent of OLBI, to the State Lands Commission in accordance with Article 2.06 of the Optimized Waterflood Program Agreement.

In addition, on or before October 1, 2010 the City of Long Beach shall present to the State Lands Commission a final report and closing statement of the FY09/10 Annual Plan, in accordance with the provision in Section 10 of Chapter 138.

A. Modifications

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

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

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

B. Supplements

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

C. Final Report and Closing Statement

The final report and closing statement for FY09/10 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.