C-13

Long Beach Unit

Thums Long Beach Company
(Agent for Field Contractor)

ANNUAL PLAN

July 1, 2006 through June 30, 2007

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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, 2006 through June 30, 2007 ("FY06/07"). It is being submitted as required by Section 5(a) of Chapter 138, Statutes of 1964, First Extraordinary Session, and as revised by passage of Assembly Bill 227 (Chapter 941) and the Optimized Waterflood Program Agreement approved by the State of California, the City of Long Beach, and Atlantic Richfield Company, whose interest has been assigned to Occidental Petroleum Corporation.

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

Plan Category	**Fiscal Year 2006 – 2007 ($ Million)**
Development Drilling	$ 73.1
Operating Expense	$114.8
Facilities, Maintenance, and Plant	$ 71.5
Unit Field Labor and Administrative	$ 43.5
Taxes, Permits, and Administrative Overhead	$ 23.1
Total	$326.0

A. Plan Basis

This Plan was developed based on the parameters outlined in the Program Plan for the period July 2005 through June 2010 and provides current estimates of volumes, drilling activity and expenditures for FY06/07. A change from the Program Plan is the inclusion of an additional part-time drilling rig. The additional drilling associated with this expanded plan is contingent on oil prices remaining near or above current levels and a sufficient number of economic projects being identified and approved in accordance with Unit documents.

Volumes

Oil and gas production volumes in the Program Plan were predicted to average 32.6 Mbopd and 8.5 MMcfd, respectively, in FY06/07. Oil and gas volumes and ranges have been revised from the Program Plan. Oil production is now expected to average 31.4 Mbopd within a revised range of 28.3 to 33.0 Mbopd, and gas production is expected to average 10.0 MMcfd within a revised range of 7.5 to 10.0 MMcfd. Water production and injection volumes have been revised upward from the Program Plan. Water production and injection volumes in the Program Plan were predicted to average 826 Mbwpd and 926 Mbwpd, respectively. Water production for the period is now expected to average 879 Mbwpd within a revised range of 791 to 923 Mbwpd. Water injection is expected to average 986 Mbwpd within a revised range of 887 to 1,035 Mbwpd.

The downward revision in oil production volumes is a result of:

- Slower drill completion pace due to more complex well projects, and slower drilling and processing time per well due to market pressures which have impacted the availability of labor and equipment from vendors.

The upward revision in gas production volumes is a result of:

- The expected implementation of the Shallow gas program and robust gas production from UPFord zone development wells.

Revenue and Expenses

A projected oil price of $40.00/bbl and gas price of $7.00/mcf will result in revenues of $484.1 million, which is $137.3 million higher than anticipated in the Program Plan. Budgeted expenses of $326.0 million for FY06/07 are $61.5 million higher than anticipated in the Program Plan. Projected net profit in FY06/07 is $158.1 million versus $82.3 million in the Program Plan.

The projected revenue increase in FY06/07 is the result of higher forecasted oil and gas prices ($28.00/bbl and $4.50/mcf in the Program Plan). The higher projected expenses stem primarily from running three full-time drilling rigs (contingent on oil prices remaining near or above current levels and a sufficient number of economic projects being identified and approved in accordance with

Unit documents), higher electricity costs (resulting from higher gross fluids rate, higher natural gas fuel cost and SCE grid rate increases), Increasing vendor costs (due to market pressures), funding of the Amine Plant and preliminary work around facility capacity limits. Other expenses consistent with strategies outlined in the Program Plan are also included but will be curtailed if revenues are not available to offset them. A comparison of revenue, expenditures, net income, and volumes is shown in Part II-C of this Plan.

Drilling

This Plan allows for drilling approximately 55 new and redrilled development and/or replacement wells. The three rig drilling plan is to start at Island Grissom and Island Chaffee and then move to White and Freeman during the year. A 3rd rig will be deployed on Pier J, and moved to an alternate site when that work is completed. A workover rig will provide drilling preparation and completion work. Locations of production and injection wells to be drilled or redrilled will vary from the Program Plan (given in Part II, Schedule 2B of this Plan) to reflect drilling from Pier J.

Maintenance

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

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

Abandonment

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

Safety, Environmental, and Regulatory Compliance

Projects relating to safety, environmental issues, or others 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.

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 FY06/07	BUDGET SECOND QUARTER FY06/07	BUDGET THIRD QUARTER FY06/07	BUDGET FOURTH QUARTER FY06/07	BUDGET TOTAL FY06/07
ESTIMATED REVENUE					
Oil Revenue	$114.5	$115.2	$113.5	$115.4	$458.6
Gas Revenue	$6.4	$6.4	$6.3	$6.4	$25.5
TOTAL REVENUE	$120.9	$121.6	$119.8	$121.8	$484.1
ESTIMATED EXPENDITURES					
Development Drilling	$18.2	$18.3	$18.3	$18.3	$73.1
Operating Expense	$26.9	$36.7	$25.5	$25.7	$114.8
Facilities & Maintenance	$17.9	$17.9	$17.9	$17.8	$71.5
Unit Field Labor & Administration	$10.6	$10.6	$11.7	$10.6	$43.5
Taxes, Permits & Overhead	$5.7	$6.0	$5.7	$5.7	$23.1
TOTAL EXPENDITURES	$79.3	$89.5	$79.1	$78.1	$326.0
NET PROFIT	$41.6	$32.1	$40.7	$43.7	$158.1

C. MAJOR PLANNING ASSUMPTIONS

	BUDGET FIRST QUARTER FY06/07	BUDGET SECOND QUARTER FY06/07	BUDGET THIRD QUARTER FY06/07	BUDGET FOURTH QUARTER FY06/07	BUDGET TOTAL FY06/07
OIL PRODUCTION					
PRODUCED (1000 BBL)	2,863	2,880	2,837	2,884	11,464
(AVERAGE B/D)	31,121	31,304	31,521	31,697	31,409
GAS PRODUCTION					
PRODUCED (1000 MCF)	920	920	900	910	3,650
(AVERAGE MCF/D)	10,000	10,000	10,000	10,000	10,000
WATER PRODUCTION					
PRODUCED (1000 BBL)	79,399	80,804	79,582	81,128	320,913
(AVERAGE B/D)	863,029	878,308	884,240	891,515	879,212
WATER INJECTION					
INJECTED (1000 BBL)	89,253	90,554	89,124	90,792	359,723
(AVERAGE B/D)	970,140	984,280	990,266	997,715	985,541
OIL PRICE ($/BBL)	$40.00	$40.00	$40.00	$40.00	$40.00
GAS PRICE ($/MCF)	$ 7.00	$ 7.00	$ 7.00	$ 7.00	$ 7.00

Part II

Program Plan Schedules

Schedule 2 A

Range of Production and Injection
FY 2006/07
Long Beach Unit Program Plan, July 2005-June 2010

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

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

SCHEDULE 2B

ANTICIPATED NEW AND REDRILLED WELLS
FISCAL YEAR 2006-07

LONG BEACH UNIT PROGRAM PLAN, JULY 2005 – JUNE 2010

Reservoir	CRB	PRODUCERS					INJECTORS				
		GRISSOM	WHITE	CHAFFEE	FREEMAN	PIER-J	GRISSOM	WHITE	CHAFFEE	FREEMAN	PIER-J
		MIN MAX	MIN MAX	MIN MAX	MIN MAX	MIN MAX	MIN MAX	MIN MAX	MIN MAX	MIN MAX	MIN MAX
Tar	Sc	0 - 0				0 - 0	0 - 0				0 - 0
Ranger West	1	3 - 9	0 - 0				1 - 2				
	2	3 - 9					0 - 0				
	3	1 - 4	0 - 0			0 - 0	0 - 0				0 - 0
	4	0 - 0	0 - 0		0 - 0	0 - 0	0 - 0	0 - 1		0 - 0	0 - 0
	5	0 - 0			0 - 0	0 - 0				0 - 0	0 - 0
	36				0 - 0	0 - 0				0 - 0	0 - 0
	7				0 - 0					0 - 0	
	8		0 - 0		0 - 0			0 - 0		0 - 0	
	9		0 - 0					0 - 1			
	10		1 - 2					0 - 0			
	11		0 - 0					0 - 0			
	12		0 - 0					0 - 0			
	13		0 - 0		0 - 0			0 - 0		0 - 0	
	37				0 - 0					0 - 0	
Ranger East	14		0 - 0					0 - 0			
	15		0 - 0		0 - 0			0 - 0		0 - 0	
	16		0 - 0	0 - 0	0 - 0			0 - 0	0 - 0	0 - 0	
	17			0 - 1					0 - 1		
	18			0 - 0					0 - 0		
	32			0 - 0					0 - 0		
	33			0 - 0					0 - 0		
	20			0 - 0					0 - 0		
	21			0 - 0	0 - 0				0 - 0	0 - 0	
	22			0 - 0	0 - 0				0 - 0	0 - 0	
Terminal	38	0 - 1				0 - 0	0 - 0				0 - 0
	39	1 - 2	0 - 0		0 - 0	0 - 0	0 - 0	0 - 0		0 - 0	0 - 0
	40		0 - 0		0 - 0			0 - 0		0 - 0	
	24		0 - 0		0 - 1			0 - 0		0 - 0	
	41										
	42			0 - 0					0 - 0		
	43			0 - 0	1 - 3				0 - 0	0 - 0	
UP Ford	26		0 - 0		0 - 0			0 - 0		0 - 0	
	27		2 - 8		0 - 0			0 - 0		0 - 0	
	31	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	44		0 - 0	1 - 2	0 - 0			0 - 0	0 - 1	0 - 0	
	45		0 - 0	3 - 9	0 - 0			0 - 0	2 - 7	0 - 0	
	46		0 - 0	3 - 8	0 - 0			0 - 0	1 - 2	0 - 0	
237	30	0 - 0		0 - 1	0 - 0						
		TOTAL					TOTAL				
		19 - 60					4 - 15				

TABLE 1C
COMPARISON OF PROGRAM PLAN TO FISCAL YEAR 2006/07

	PROGRAM PLAN FY06/07	ANNUAL PLAN FY06/07	VARIANCE Over / (Under)	%
Drilling - Total Wells	60	55	(5)	-8%
Net Oil Production - bbls	11,884,400	11,464,286	(420,114)	-4%
Net Oil Production - bopd	32,560	31,409	(1,151)	-4%
Water Production - bbls	301,541,100	320,912,544	19,371,444	6%
Water Production - bwpd	826,140	879,212	53,072	6%
Water Injection - bbls	337,880,500	359,722,600	21,842,100	6%
Water Injection - bwpd	925,700	985,541	59,841	6%
Total Revenue	$346,774,000	$484,121,000	$137,347,000	40%
Total Expenditures	$264,516,000	$325,973,000	$61,457,000	23%
Net Income	$82,258,000	$158,148,000	$75,890,000	92%
Oil Price - $/bbl	$28.00	$40.00	$12.00	43%
Gas Price - $/mcf	$4.50	$7.00	$2.50	56%

C. Comparison to Program Plan

Drilling Variance: Drilling activity is forecast to be at a slower pace compared to the Program Plan, with 5 less wells anticipated to be completed in FY06/07. Drilling pace is slower than originally expected due to more complex well candidates and market pressures, which have led to delays in vendor labor and equipment availability.

Revenue Variance: The revenue variance from the Program Plan is due to higher oil and gas price forecasts.

Expenditure Variance: The overall expenditure variance is attributable to utilization of a third drilling rig, higher electricity costs, (resulting from higher fluid rates, SCE rate increases and higher gas price assumption), increases in vendor costs, funding for the Amine plant and preliminary work on the facilities capacity limits. The Unit will be aggressively trying to control costs during the Annual plan year. Investments in strategic projects aimed at reducing future costs will continue to be made as outlined in the Program Plan but will be curtailed if revenues are not available to offset them.

Part III

Itemized Budget of Expenditures

A. Development Drilling $73,100,000

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 55 wells will be developed and/or replaced during the Plan year, using three drilling rigs and one completion rig.

Drilling and completing new wells, as well as redrilling and recompleting existing wells, account for 93 percent of the funding provided in this Category. Included in these activities is funding for rig move-in, drilling and casing, completion activities, drilling rig in-zone plugs and conditional abandonments, and unscheduled activity (fishing operations, cement squeezing, special logging, contract drilling services). Also included in this category are rig repairs.

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 $114,800,000

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 31.4 Mbopd, estimated gas production of 10.0 MMcfpd, water injection requirement of 986 Mbwpd, and water production of 879 Mbwpd. Anticipated operating expenses were based on operating three and a half workover rigs per month for servicing an average active well count of 836 producers and 441 injectors, and up to 1/4 rig for abandonment activity. Abandonment well count will be determined as a function of drilling activity and the number of idle wells with no future use identified.

The day-to-day costs for production and injection well subsurface operations represent approximately 35 percent of the funding provided in this category. Included are funds for acidizing, fracturing, routine well work, well conversions, in-zone plugs, conditional abandonments, and other charges incurred for well maintenance.

Electricity makes up 63 percent of the funds in this Category. Cost for electric power is based on estimated kilowatt usage of 610,376,643 kwh at an average rate of $0.1192/kwh. This cost includes all sources of Unit electrical power, including all costs associated with the power plant and electric utility purchases. Also included is funding for the pay-down of the Power Plant lease.

C. Facilities, Maintenance, and Plant $71,500,000

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 40 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 60 percent of the funding in this Category is for facilities repair and improvement projects. Improvement projects include spending for the construction of the Amine plant, facility capacity limits expansion, pipeline replacements, and other infrastructure related investments that position the Unit for longevity.

D. Unit Field Labor and Administrative $43,500,000

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 67% 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 $23,100,000

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 48 percent of the Category total.

Funding is also provided in this Category for all Administrative Overhead as called for in Exhibit F of the Unit Operating Agreement.

PART IV

Definitions

This Annual Plan may be Modified or Supplemented after review by the State Lands Commission for consistency with the current Program Plan. All Modifications and Supplements to this plan will be presented by the Department of Oil Properties, City of Long Beach, acting with the consent of OLBI, to the State Lands Commission in accordance with Article 2.06 of the Optimized Waterflood Program Agreement.

In addition, on or before October 1, 2007 the City of Long Beach shall present to the State Lands Commission a final report and closing statement of the FY06/07 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 FY06/07 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.