EXHIBIT B

W 17162

Long Beach Unit

Thums Long Beach Company

(Agent for Field Contractor)

ANNUAL PLAN

July 1, 2008 through June 30, 2009

ANNUAL PLAN

July 1, 2008 through June 30, 2009

Table of Contents

		Page
Part I - Introduction		2
A.	Plan Basis	3
B.	Economic Projections	5
C.	Major Planning Assumptions	6
Part II – Program Plan Schedules		7
A.	Range of Production and Injection	7
B.	Anticipated New & Redrilled Wells	8
C.	Comparison to Program Plan	10
Part III – Itemized Budget of Expenditures		12
A.	Development Drilling	12
B.	Operating Expense	12
C.	Facilities, Maintenance and Plant	13
D.	Unit Field Labor and Administrative	13
E.	Taxes, Permits and Administrative Overhead	14
Part IV – Definitions		15
A.	Modifications	15
B.	Supplements	15
C.	Final Report and Closing Statement	16

Part I

Introduction

This Annual Plan ("Plan") was developed to reflect anticipated activity levels during the fiscal period from July 1, 2008 through June 30, 2009 ("FY08/09"). 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 2008 – 2009 ($ Million)**
Development Drilling	$ 90.0
Operating Expense	$114.3
Facilities, Maintenance, and Plant	$ 87.8
Unit Field Labor and Administrative	$ 58.3
Taxes, Permits, and Administrative Overhead	$ 35.2
Total	$385.6

A. Plan Basis

This Plan was developed based on the parameters outlined in the Program Plan for the period July 2007 through June 2012 and provides current estimates of volumes, drilling activity and expenditures for FY08/09.

Volumes

Oil and gas production volumes in the Program Plan were predicted to average 30.5 Mbopd and 10.0 MMcfd, respectively, in FY08/09. Oil and gas volumes and ranges have been revised from the Program Plan. Oil production is now expected to average 27.3 Mbopd within a revised range of 25.3 to 29.3 Mbopd, and gas production is expected to average 14.7 MMcfd within a revised range of 13.2 to 16.3 MMcfd. Water production and injection volumes have been revised from the Program Plan. Water production and injection volumes in the Program Plan were predicted to average 998 Mbwpd and 1044 Mbwpd, respectively. Water production for the period is now expected to average 975 Mbwpd within a revised range of 900 to 1050 Mbwpd. Water injection is expected to average 1,059 Mbwpd within a revised range of 925 to 1,200 Mbwpd.

The downward revision in oil production volumes is primarily a result of a steeper decline in base production than historical trends would indicate. Action plans to mitigate the steepening of the base decline by redistributing injection to areas of lower water-oil ratios and other initiatives will be part of the FY08/09 Plan as a continuation of current efforts.

The upward revision in gas production volumes is a result of positive results from the shallow gas development program and robust gas production from UP Ford zone development wells.

Revenue and Expenses

A projected oil price of $55.00/bbl and gas price of $7.00/mcf will result in revenues of $585.6 million, which is $118.0 million higher than anticipated in the Program Plan. Budgeted expenses of $385.6 million for FY08/09 are $0.4 million higher than anticipated in the Program Plan. Projected net profit in FY08/09 is $200.0 million versus $82.4 million in the Program Plan.

The projected revenue increase in FY08/09 is the result of higher forecasted oil and gas prices ($40.00/bbl and $6.00/mcf in the Program Plan). Overall forecasted expenses are slightly higher but comparable to those predicted in the Program Plan with increased expenses for individual projects offset by decreases in forecast costs. Projected expenses to finalize construction of the Amine Plant will be higher than anticipated in the Program Plan due to delays in initiating the project, although there is no change to the total forecast costs for the plant. Likewise, the Plan includes higher expenses for facilities expansion projects because of project delays. Also included in the Plan is the Unit's first waste disposal project, designed to improve water quality and injector performance. Higher taxes are also forecast as compared to the Program Plan due to increased Unit valuation and higher production tax. Labor costs are anticipated to be higher than forecast due to increased incentives required to attract and retain petroleum technology professionals because of an increased industry demand for this skill set.

The increase in predicted expenses is offset by lower operating and drilling expenses due mainly to drilling rig efficiencies resulting in the elimination of roughly half a rig. 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 58 new and redrilled development and/or replacement wells. The plan is to use two and one-half drilling rigs (versus three in the Program Plan) to drill the same number of wells. The first rig will start at Island White and then move to Grissom; the second rig will stay at Island Chaffee throughout the year. A third rig may be deployed to complete the planned drilling program as required. A workover rig will perform drilling preparation and completion work.

Locations of production and injection wells to be drilled or redrilled are generally consistent with those given in the Program Plan (see attached Part II, Schedule 2B) with the exclusion of wells drilled from Pier J which have already been completed. Locations of anticipated drilling candidates have been better defined since the Program Plan was developed and are outlined in Revised Schedule 2B (attached). Significant variances include additional drilling of 0-2 production wells in the 237 zone from Islands Chaffee and possibly Freeman, and 0-3 shallow gas production wells from Islands Grissom or White.

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 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.

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 FY08/09	BUDGET SECOND QUARTER FY08/09	BUDGET THIRD QUARTER FY08/09	BUDGET FOURTH QUARTER FY08/09	BUDGET TOTAL FY08/09
ESTIMATED REVENUE					
Oil Revenue	$140.9	$138.6	$134.6	$133.9	$548.0
Gas Revenue	$9.5	$9.5	$9.3	$9.3	$37.6
TOTAL REVENUE	$150.4	$148.1	$143.9	$143.2	$585.6

ESTIMATED EXPENDITURES

Development Drilling	$22.5	$22.5	$22.5	$22.5	$90.0
Operating Expense	$27.7	$26.8	$28.6	$31.2	$114.3
Facilities & Maintenance	$24.1	$21.2	$21.3	$21.2	$87.8
Unit Field Labor & Administration	$12.9	$16.4	$15.9	$13.1	$58.3
Taxes, Permits & Overhead	$8.8	$8.8	$8.8	$8.8	$35.2
TOTAL EXPENDITURES	$96.0	$95.7	$97.1	$96.8	$385.6
NET PROFIT	$54.4	$52.4	$46.8	$46.4	$200.0

C. MAJOR PLANNING ASSUMPTIONS

	BUDGET FIRST QUARTER FY08/09	BUDGET SECOND QUARTER FY08/09	BUDGET THIRD QUARTER FY08/09	BUDGET FOURTH QUARTER FY08/09	BUDGET TOTAL FY08/09
OIL PRODUCTION					
PRODUCED (1000 BBL)	2,562	2,520	2,448	2,435	9,965
(AVERAGE B/D)	27,848	27,393	27,199	26,756	27,301
GAS PRODUCTION					
PRODUCED (1000 MCF)	1,352	1,352	1,323	1,338	5,365
(AVERAGE MCF/D)	14,700	14,700	14,700	14,700	14,699
WATER PRODUCTION					
PRODUCED (1000 BBL)	87,044	89,076	88,725	91,144	355,989
(AVERAGE B/D)	946,134	968,217	985,833	1,001,582	975,312
WATER INJECTION					
INJECTED (1000 BBL)	94,624	96,725	96,279	98,819	386,447
(AVERAGE B/D)	1,028,526	1,051,364	1,069,762	1,085,925	1,058,759
OIL PRICE ($/BBL)	$55.00	$55.00	$55.00	$55.00	$55.00
GAS PRICE ($/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 2008/09
Long Beach Unit Program Plan, July 2007-June 2012

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2008-09	30.4 - 30.8	975 - 1027	9.9 - 10.1	1021 - 1073

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P./FORD PSI
2008-09	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

Schedule 2 B

Anticipated Development and Replacement Locations
Fiscal Year 08/09

Long Beach Unit Program Plan, July 2007-June 2012

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 - 1				0 - 0
Ranger West	1	0 - 0	0 - 0				0 - 1				
	2	2 - 5					0 - 1				
	3	3 - 7	0 - 0			0 - 0	0 - 1				0 - 0
	4	0 - 0	0 - 0		0 - 0	1 - 2	0 - 1	0 - 0		0 - 1	1 - 2
	5	0 - 0			0 - 1	1 - 2				0 - 1	0 - 1
	36				0 - 1	0 - 1				0 - 1	0 - 1
	7				0 - 0					0 - 1	
	8		0 - 0		0 - 2			0 - 0		0 - 1	
	9		0 - 0					0 - 0			
	10		0 - 0					0 - 0			
	11		0 - 0					0 - 0			
	12		0 - 0					0 - 0			
	13		0 - 0		0 - 0			0 - 0		0 - 1	
	37				0 - 0					0 - 0	
Ranger East	14		0 - 0					0 - 0			
	15		0 - 0		0 - 1			0 - 0		0 - 0	
	16		0 - 0	0 - 0	0 - 1			0 - 0	0 - 0	0 - 0	
	17			0 - 1					0 - 1		
	18			0 - 1					0 - 1		
	32			0 - 1					0 - 1		
	33			0 - 1					0 - 1		
	20			0 - 1					0 - 1		
	21			0 - 1					0 - 0	0 - 0	
	22			0 - 0					0 - 0	0 - 0	
Terminal	38	0 - 2				1 - 2	0 - 1				0 - 2
	39	0 - 0	0 - 0		0 - 0	0 - 0	0 - 1	0 - 0		0 - 0	0 - 0
	40		0 - 2		0 - 1			0 - 0		0 - 0	
	24		0 - 0		0 - 0			0 - 0		0 - 1	
	41										
	42			0 - 0					0 - 1		
	43			0 - 0	0 - 0				0 - 0	1 - 2	
UP Ford	26		0 - 0		0 - 1			0 - 0		0 - 0	
	27		0 - 0		0 - 1			0 - 0		0 - 0	
	31	0 - 2	0 - 0	0 - 0	0 - 1	0 - 1	0 - 2	0 - 0	0 - 1	0 - 0	0 - 1
	44		0 - 0	0 - 1	0 - 1			0 - 0	0 - 0	0 - 0	
	45		0 - 0	0 - 2	0 - 1			0 - 0	0 - 0	0 - 0	
	46		0 - 0	0 - 0	0 - 1			0 - 0	0 - 1	0 - 1	
237	30	0 - 0		0 - 0	0 - 0						
		Total					Total				
		8 - 48					2 - 34				

Schedule 2 B - Revised

Anticipated Development and Replacement Locations
Fiscal Year 08/09
Long Beach Unit Program Plan, July 2007-June 2012

		Producers						Injectors				
		Grissom	White	Chaffee	Freeman	Pier J		Grissom	White	Chaffee	Freeman	Pier J
Reservoir	CRB	Min - Max	Min - Max	Min - Max	Min - Max	Min - Max		Min - Max	Min - Max	Min - Max	Min - Max	Min - Max
Shallow Gas	6	0 1	0 2									
Tar	35	1 - 3						0 - 2				
Ranger West	1	1 - 3						1 - 4				
	2	1 - 4						1 - 3				
	3	0 1										
	4	1 3										
	5											
	36											
	7											
	8		0 1									
	9		0 2						0 2			
	10											
	11		0 - 2						0 - 2			
	12		0 - 2						0 - 2			
	13		0 - 2						0 - 2			
	37											
Ranger East	14		0 - 1						0 - 1			
	15		0 - 1						0 - 1			
	16		0 - 1						0 - 1			
	17			0 - 2						0 - 1		
	18									0 - 1		
	19											
	20									0 - 1		
	21			1 - 3						0 - 1		
	32											
	33			0 - 2						0 - 1		
Terminal	15										0 - 1	
	24										0 - 1	
	38	0 - 1						0 - 1				
	39	0 - 1						0 - 2	0 - 1			
	40											
	41											
	42			0 - 1						0 - 1		
	43			0 - 1								
UP Ford	26											
	27		0 - 1						0 - 1			
	31	0 - 1	0 - 1									
	44											
	45			1 - 3						0 - 2		
	46				0 - 1						0 - 1	
237	30			0 - 1	0 - 1							
		Total						Total				
		6 - 49						2 - 36				

TABLE 1C

COMPARISON OF PROGRAM PLAN TO FISCAL YEAR 2008/09

	PROGRAM PLAN FY08/09	ANNUAL PLAN FY08/09	VARIANCE Over / (Under)	%
Drilling - Total Wells	58	58	0	0%
Net Oil Production - bbls	11,142,700	9,965,000	(1,177,700)	-11%
Net Oil Production - bopd	30,528	27,301	(3,227)	-11%
Water Production - bbls	364,385,705	355,989,000	(8,396,705)	-2%
Water Production - bwpd	998,317	975,312	(23,005)	-2%
Water Injection - bbls	381,407,845	386,447,000	5,039,155	1%
Water Injection - bwpd	1,044,953	1,058,759	13,806	1%
Total Revenue	$467,600,000	$585,600,000	$118,000,000	25%
Total Expenditures	$385,200,000	$385,600,000	$400,000	0%
Net Income	$82,400,000	$200,000,000	$117,600,000	143%
Oil Price - $/bbl	$40.00	$55.00	$15.00	38%
Gas Price - $/mcf	$6.00	$7.00	$1.00	17%

C. Comparison to Program Plan

Drilling Variance: Drilling activity is forecast to generate the same well count as forecast in the Program Plan. Drilling spending is expected to be lower, however, as wells will be drilled more efficiently resulting in the elimination of roughly half a rig (two and a half rigs vs. three rigs in the Program Plan). The well mix will also focus on lower cost injection wells.

Oil Production Variance: Net oil production is forecast to be eleven percent lower than predicted in the Program Plan due primarily to steeper than forecasted base decline rates.

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

Expenditure Variance: Overall expenditures are expected to be comparable to those in the Program Plan. Drilling and operating expenses are projected to be lower due to cost benefits from reduced rig utilization, and electricity costs will benefit from tariff rates that are lower than forecast in the Program Plan. These reduced expenditures are offset by increased expenses for individual projects. Projected expenses to finalize construction of the Amine Plant will be higher than anticipated in the Program Plan due to delays in initiating the project, although there is no change to the total forecast costs for the plant. Likewise, the Plan includes higher expenses for facilities expansion projects because of project delays. Also included in the Plan is the Unit's first waste disposal project, designed to improve water quality and injector performance. Higher taxes are also forecast due to increased Unit valuation and higher production tax. Labor costs are anticipated to be higher than forecast due to increased incentives required to attract and retain petroleum technology professionals because of an increased industry demand for this skill set. 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 $90,000,000

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 58 wells will be developed and/or replaced during the Plan year, using approximately two and a half drilling rigs and a workover rig.

Drilling and completing new wells, as well as redrilling and recompleting existing wells, account for 87 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 $114,300,000

The Operating Expense category of expenditures encompasses the ongoing costs of day-to-day well production and injection operations necessary for producing, processing, and delivering crude oil and gas, and for all electric power charges. Expenses for this category are based on estimated oil production of 27.3 Mbopd, estimated gas production of 14.7 MMcfpd, water injection requirement of 1,059 Mbwpd, and water production of 975 Mbwpd. Anticipated operating expenses were based on operating three and a half workover rigs per month for servicing an average active well count of 863 producers and 461 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 61 percent of the funds in this Category. Cost for electric power is based on estimated kilowatt usage of 655,707,000 kwh at an average rate of $0.102/kwh. This cost includes all sources of Unit electrical power, including all costs associated with the power plant and electric utility purchases.

C. Facilities, Maintenance, and Plant $87,800,000

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

Approximately 45 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 55 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, waste disposal, pipeline replacements, and other infrastructure related investments that position the Unit for longevity.

D. Unit Field Labor and Administrative $58,300,000

The Unit Field Labor and Administrative category of expenditures encompasses costs for Unit personnel and other Unit support activities.

Funding for Unit personnel includes costs of salaries, wages, benefits, training, and expenses of all Thums employees. These costs represent approximately 74 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 $35,200,000

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 60 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, 2009 the City of Long Beach shall present to the State Lands Commission a final report and closing statement of the FY08/09 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 FY08/09 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.