MINUTE ITEM
This Calendar Item No. C62 was approved as Minute Item No. 62 by the California State Lands Commission by a vote of 3 to Ø at its 4-9-02 meeting.

CALENDAR ITEM

C62

A 54 04/09/02
W17156
S 27 A. Reid

APPROVE THE LONG BEACH UNIT ANNUAL PLAN (JULY 1, 2002 through JUNE 30, 2003), LONG BEACH UNIT, WILMINGTON OIL FIELD, LOS ANGELES COUNTY

APPLICANT:

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

BACKGROUND:

In accordance with Chapter 941 of the Statutes of 1991 (AB 227) and the Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, the Long Beach Unit Annual Plan (July 1, 2002 - June 30, 2003) has been submitted by the City of Long Beach (City) to the California State Lands Commission (Commission) on March 13, 2002.

At its meeting on February 26, 2002, the Long Beach City Council adopted the proposed Annual Plan and authorized its submittal to the Commission for consideration and approval. The Commission has 45 days following formal submission of the Annual Plan to take action. If no action is taken, the plan is deemed to be approved as submitted. The economic projections for the period July 1, 2002 through June 30, 2003 (as presented by the City) are shown below:

Revenue	$205,600,000
Expenditures	$192,600,000
Net Income:	$ 13,000,000

As presented, the Long Beach Unit Annual Plan includes anticipated rates of production, revenues, expenditures, and net profits for the Unit as projected by the City of Long Beach Department of Oil Properties. The City has estimated that the Unit net income for the 2002-2003 Fiscal Year will be $13.0 Million, after total Expenditures of $192.6 Million. Although the proposed Annual Plan total expenditures are about the same as the current Five-Year Program Plan, the proposed Annual Plan's net income is about $64.2 million less than the Program Plan. The difference in net income can be attributed to: 1) The current Program Plan contained a $34.5 million credit during the 2002-2003 Fiscal Year for selling the Long Beach Unit Power Plant to a financing company. Financing plans have changed for the power plant project since the writing of the Program Plan. Occidental Energy Ventures Corporation will be financing the power plant construction without utilizing Unit funds. 2) The remaining difference of about $30 million in net income can be attributed to updated lower oil rate and oil price estimates. The proposed Annual Plan income scenario is based on a forecast oil production rate of 33,758 bbls/day, which is about 2,000 bbl/day less than the Five-Year Program Plan projection. The reduction in oil production volume is a result of the combination of several factors. Higher operational costs and lower oil prices resulted in the shut-in of additional uneconomic wells; higher than expected well failure rate due to I6 electrical power interruptions; lower than expected development program results; and the adoption of stricter voidage rules. Also, revenues for the proposed Annual Plan are based on an updated average oil price of $16.00/bbl as apposed to the Program Plan's estimate of $17.00/bbl. The proposed Annual Plan allows for drilling approximately 24 new and redrilled wells with one active drilling rig for Fiscal Year 2002-2003, and one completion rig for six months.

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

OTHER PERTINENT INFORMATION

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

the CEQA because it is not a "project" as defined by the CEQA and the State CEQA Guidelines.

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

EXHIBITS:

A. Letter from the City of Long Beach requesting approval of the Long Beach Unit Annual Plan (July 1, 2002 – June 30, 2003) from the California State Lands Commission.

B. Long Beach Unit Annual Plan (July 1, 2002 – June 30, 2003)

PERMIT STREAMLINING ACT DEADLINE:
N/A

RECOMMENDED ACTION:
IT IS RECOMMENDED THAT THE COMMISSION:

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

AUTHORIZATION:
APPROVE THE LONG BEACH UNIT ANNUAL PLAN (JULY 1, 2002 THROUGH JUNE 30, 2003), LONG BEACH UNIT, WILMINGTON OIL FIELD, LOS ANGELES COUNTY.

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

March 12, 2002

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

SUBJECT: **SUBMISSION OF THE LONG BEACH UNIT ANNUAL PLAN (JULY 1, 2002 - JUNE 30, 2003)**

Dear Mr. Mount:

The City of Long Beach, as Unit Operator of the Long Beach Unit, and in accordance with Chapter 138, Section 5, Chapter 941, Section 3, and the Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, Article 2, submits ten copies of the Long Beach Unit Annual Plan (July 1, 2002 - June 30, 2003).

The Annual Plan was approved by the Long Beach City Council on February 26, 2002. If you have any questions, please contact Mr. Bob Rawnsley at (562) 570-3961.

Sincerely,

Dennis M. Sullivan
Director

DMS:RJR

Enclosures

cc: P. D. Thayer
A. V. Hager
F. O. Ludlow
F. Komin
R. A. Alesso

FIN 312.006

EXHIBIT B W 17156

Long Beach Unit

Thums Long Beach Company

(Agent for Field Contractor)

ANNUAL PLAN

July 1, 2002 through June 30, 2003

LONG BEACH
COMPANY

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ANNUAL PLAN

July 1, 2002 through June 30, 2003

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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, 2002 through June 30, 2003 ("FY02/03"). 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 2002 – 2003 ($ Million)
Development Drilling	$ 20.7
Operating Expense	$ 78.3
Facilities, Maintenance, and Plant	$ 40.9
Unit Field Labor and Administrative	$ 34.8
Taxes, Permits, and Administrative Overhead	$ 17.9
Total	$192.6

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A. Plan Basis

This Plan was developed based on the parameters outlined in the Program Plan for the period July 2001 through June 2006 ("Program Plan") and revised to reflect current estimates of volumes, drilling activity, and expenditures for FY02/03.

Volumes

Oil and gas production volumes in the Program Plan were predicted to average 35.8 Mbopd and 8.2 MMcfd, respectively, in FY02/03. Both oil and gas volumes and ranges have been revised downward from the Program Plan. Oil production is now expected to average 33.8 Mbopd within a revised range of 30.4 to 35.4 Mbopd, and gas production is expected to average 7.9 MMcfd within a revised range of 7.1 to 8.3 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 715 Mbwpd and 770 Mbwpd, respectively. Water production for the period is now expected to average 737 Mbwpd within a revised range of 663 to 773 Mbwpd. Water injection is expected to average 817 Mbwpd within a revised range of 736 to 858 Mbwpd.

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

- Combination of higher operational costs and lower oil prices resulting in additional uneconomic wells
- Higher than expected wellbore failure rate resulting from I6 electrical interruptions
- Lower than expected Development Program results
- Adoption of stricter voidage rules

Revenue and Expenses

A projected oil price of $16.00/bbl and gas price of $2.95/mcf will result in revenues of $205.6 million, which is $65.7 million lower than anticipated in the Program Plan. Budgeted expenses of $192.6 million for FY02/03 are $1.5 million lower than anticipated in the Program Plan. Projected net profit in FY02/03 is $13.0 million.

The projected revenue decline in FY02/03 is the result of lower forecasted oil and gas prices ($17.00/bbl and $5.00/mcf in the Program Plan) and a lower production forecast. In addition, a $34.5 million credit associated with selling a Unit-constructed power plant back to a financing company was eliminated. The power plant is now planned to become operational in August 2002. The Plan includes all costs associated with operating this power plant, including lease payments, fuel, and other operational costs. The slightly lower projected expenses assume that lower drilling and wellwork costs will compensate for electricity costs that are higher than forecast in the Program Plan, despite the power plant coming on line. 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.

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Drilling

This Plan allows for drilling approximately 24 new and redrilled development and/or replacement wells. It is expected that this will be accomplished by primary crews moving the newly refurbished Unit T-9 drilling rig between islands Chaffee and Freeman, and by utilizing a workover rig for completion work. This Plan also includes funding for drilling rig repairs and/or other rig modifications that could become necessary for drilling on Island White. Island White drilling operations are contingent on program economics. Locations of production and injection wells to be drilled or redrilled are presented in Part II, Schedule 2B 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 subsea lines, facilities piping, tanks, and vessels. These projects are consistent with past activities to keep the Unit facilities in safe operating condition.

Abandonments

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

Safety, Environmental, and Regulatory Compliance

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

Economic Review

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

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

B. Economic Projections
(Data in Millions of Dollars)

	BUDGET FIRST QUARTER FY02/03	BUDGET SECOND QUARTER FY02/03	BUDGET THIRD QUARTER FY02/03	BUDGET FOURTH QUARTER FY02/03	BUDGET TOTAL FY02/03
ESTIMATED REVENUE					
Oil Revenue	$49.8	$50.1	$48.6	$48.6	$197.1
Gas Revenue	$2.2	$2.1	$2.1	$2.1	$8.5
TOTAL REVENUE	$52.0	$52.2	$50.7	$50.7	$205.6
ESTIMATED EXPENDITURES					
Development Drilling	$4.9	$5.2	$5.7	$4.9	$20.7
Operating Expense	$23.2	$18.8	$18.1	$18.2	$78.3
Facilities & Maintenance	$9.4	$9.0	$11.4	$11.1	$40.9
Unit Field Labor & Administration	$9.7	$8.5	$8.3	$8.3	$34.8
Taxes, Permits & Overhead	$4.8	$4.1	$4.6	$4.4	$17.9
TOTAL EXPENDITURES	$52.0	$45.6	$48.1	$46.9	$192.6
NET PROFIT	$0.0	$6.6	$2.6	$3.8	$13.0

C. MAJOR PLANNING ASSUMPTIONS

	BUDGET FIRST QUARTER FY02/03	BUDGET SECOND QUARTER FY02/03	BUDGET THIRD QUARTER FY02/03	BUDGET FOURTH QUARTER FY02/03	BUDGET TOTAL FY02/03
OIL PRODUCTION					
PRODUCED (1000 BBL)	3,115	3,129	3,040	3,037	12,322
(AVERAGE B/D)	33,860	34,010	33,778	33,379	33,758
GAS PRODUCTION					
PRODUCED (1000 MCF)	729	732	711	711	2,883
(AVERAGE MCF/D)	7,923	7,958	7,904	7,811	7,899
WATER PRODUCTION					
PRODUCED (1000 BBL)	67,033	67,856	66,764	67,224	268,877
(AVERAGE B/D)	728,619	737,560	741,822	738,729	736,649
WATER INJECTION					
INJECTED (1000 BBL)	74,166	75,203	74,236	74,706	298,312
(AVERAGE B/D)	806,157	817,424	824,847	820,947	817,293
OIL PRICE ($/BBL)	$16.00	$16.00	$16.00	$16.00	$16.00
GAS PRICE ($/MCF)	$ 2.95	$ 2.95	$ 2.95	$ 2.95	$ 2.95

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Part II

Program Plan Schedules

Schedule 2 A
Range of Production and Injection
FY 2002/03
Long Beach Unit Program Plan, July 2001-June 2006

FISCAL YEAR	RANGE OF PRODUCTION AND INJECTION RATES			
	OIL MBOPD	WATER MBWPD	GAS MMCFPD	INJECTION MBWPD
2002-03	32.2 - 37.5	608.0 - 751.0	7.4 - 9.0	693 - 809

FISCAL YEAR	RANGE OF INJECTION PRESSURES			
	TAR PSI	RANGER PSI	TERMINAL PSI	U. P. / FORD PSI
2002-03	UP TO 1500	UP TO 2500	UP TO 2500	UP TO 3000

SCHEDULE 2B

ANTICIPATED NEW AND REDRILLED WELLS
FISCAL YEAR 2002-03

LONG BEACH UNIT PROGRAM PLAN, JULY 2001 – JUNE 2006

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	35	0	0							0	0	0	0							0	0
RANGER WEST	1	0	0	0	0							0	0								
	2	1	1									0	0								
	3	1	1	0	0					0	0	0	0							0	0
	4	0	0	1	1			0	0	1	1	0	0					1	1	0	0
	5	0	0					0	0	1	1							0	0	1	1
	36							0	0	0	0							0	0	0	0
	7							0	0									0	0		
	8			1	3			0	0					1	1			0	0		
	9			0	0									0	0						
	10			0	0									1	1						
	11			0	0									0	0						
	12			0	0									0	0						
	13			0	0			0	0					0	0			0	0		
	37							1	3									0	0		
RANGER EAST	14			0	0									0	0						
	15			1	1			0	0					0	0			0	0		
	16			0	0	0	0	0	0					0	0	0	0	0	0		
	17					0	0									1	3				
	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	0							0	0	0	0							1	1
	39	0	0	1	1			0	0	1	1	0	0	0	0			0	0	0	0
	40			0	0			0	0					0	0			0	0		
	24			1	1			0	0					0	0			0	0		
	42					0	0									0	0				
	43					0	0	0	0							0	0	0	0		
UP FORD	26			0	0			0	0					0	0			0	0		
	27			0	0			0	0					0	0			1	3		
	31	0	0	1	1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0
	44			0	0	1	1	0	0					0	0	0	0	0	0		
	45			0	0	0	0	0	0					0	0	0	0	0	0		
	46			0	0	1	3	0	0					0	0	0	0	1	3		
237		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		TOTAL										TOTAL									
						15	21									8	14				

C. COMPARISON TO PROGRAM PLAN

	PROGRAM PLAN FY02/03	ANNUAL PLAN FY02/03	VARIANCE Over / (Under)	%
Drilling - Total Wells	29	24	(5)	(17%)
Net Oil Production - bbls	13,067,000	12,321,670	(745,330)	(6%)
Net Oil Production - bopd	35,800	33,758	(2,042)	(6%)
Water Production - bbls	260,975,000	268,876,885	7,901,885	3%
Water Production - bwpd	715,000	736,649	21,649	3%
Water Injection - bbls	281,050,000	298,311,945	17,261,945	6%
Water Injection - bwpd	770,000	817,293	47,293	6%
Total Revenue	$271,300,000	$205,650,000	($65,650,000)	(24%)
Total Expenditures	$194,100,000	$192,655,000	($1,445,000)	(1%)
Net Income	$77,200,000	$12,995,000	($64,205,000)	(83%)
Oil Price - $/bbl	$17.00	$16.00	($1.00)	(6%)
Gas Price - $/mcf	$5.00	$2.95	($2.05)	(41%)

Drilling Variance: The drilling variance is due primarily to the deferral of side track drilling candidates for FY02/03 and the drilling of deeper and more complicated wells that take longer to drill. Both of these changes will result in fewer wells being drilled in FY02/03.

Revenue Variance: The revenue variance from the Program Plan is due to lower forecasted oil and gas prices and a lower production forecast. In addition, the Program Plan forecasted a $34.5 million credit in FY02/03 for selling the Long Beach Unit Power Plant back to a financing company. Financing plans have changed since the writing of the Program Plan. Occidental Energy Ventures Corporation will be financing the power plant construction without utilizing Unit funds.

Expenditure Variance: The overall expenditure variance is nearly flat; however, certain components have changed. Electricity costs are forecasted to be higher than originally forecast despite the power plant coming on line, but drilling and wellwork costs are forecasted to be low enough to compensate for the additional electricity costs. The Mining Rights Taxes valuation continues to be contested. The Unit will be aggressively trying to control costs during periods of lower oil prices. 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 $20,700,000

The Development Drilling category of expenditures encompasses all new well and replacement well activity, as well as maintenance and replacement of drilling equipment within the Unit. Funds for development drilling are based on the assumption that 24 wells will be developed and/or replaced during the Plan year, using one drilling rig and one part-time completion rig.

Drilling and completing new wells, as well as redrilling and recompleting existing wells, account for 95 percent of the funding provided in this Category. Included in these activities is funding for rig move-in, drilling and casing, completion activities, drilling rig in-zone plugs and conditional abandonments, and unscheduled activity (fishing operations, cement squeezing, special logging, contract drilling services). Funding for Island White drilling rig repairs and/or modifications is also included but expenditure is contingent on program economics.

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

B. Operating Expense $78,300,000

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 33.8 Mbopd, estimated gas production of 7.9 MMcfpd, water injection requirement of 817 Mbwpd, and water production of 737 Mbwpd. Anticipated operating expenses were based on operating up to 3-1/2 workover rigs per month for servicing active well counts of 650 producers and 370 injectors, and up to 1/3 rig for abandonment activity. Abandonment well count will be determined as a function of drilling activity and the number of idle wells.

The day-to-day costs for well production and injection operations represent approximately 38 percent of the funding provided in this category. Included are funds for acidizing, fracturing, routine well work, well conversions, in-zone plugs, conditional abandonments, and other charges incurred for well maintenance.

Electricity makes up 59 percent of the funds in this Category. Cost for electric power is based on estimated kilowatt usage of 533,000,000 kwh at an average rate of $0.0863/kwh.

C. Facilities, Maintenance, and Plant $40,900,000

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 67 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 33 percent of the funding in this Category is for facilities repair and improvement projects. Improvement projects include spending for facility automation and other investments that position the Unit for longevity.

D. Unit Field Labor and Administrative $34,800,000

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 72% 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 $17,900,000

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 61 percent of the Category total.

This category includes costs for a tax assessment by the Los Angeles County Tax Assessor for Mining Rights and Improvements and Personal Property Taxes, a portion of which we believe is incorrect and is being appealed.

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, 2003 the City of Long Beach shall present to the State Lands Commission a final report and closing statement of the FY02/03 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 FY02/03 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.

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