DOE Contract No. DE-FC22-95BC14935

**Feasibility of Optimizing Recovery and Reserves
from a Mature and Geological Complex Multiple
Turbidite Offshore California Reservoir
Through the Drilling and Completion
of a Trilateral Horizontal Well**

Annual Report

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**Prepared for
U. S. Department of Energy
Assistant Secretary for Fossil Energy**

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Abstract

The main objective of this project is to devise an effective re-development strategy to combat producibility problems related to the Repetto turbidite sequences of the Carpinteria Field. The lack of adequate reservoir characterization, high-water cut production, and scaling problems have in the past contributed to the field's low productivity.

To improve productivity and enhance recoverable reserves, the following specific goals were proposed:

- Develop an integrated database of all existing data from work done by the former ownership group.
- Expand reservoir drainage and reduce sand problems through horizontal well drilling and completion.
- Operate and validate reservoir's conceptual model by incorporating new data from the proposed trilateral well.
- Transfer methodologies employed in geologic modeling and drilling multilateral wells to other operators with similar reservoirs.

Pacific Operators Offshore, Inc. with the cooperation of its team members; the University of Southern California; Schlumberger; Baker Oil Tools; Halliburton Energy Services and Coombs and Associates undertook a comprehensive study to re-examine the reservoir conditions leading to the current field conditions and to devise methodologies to mitigate the producibility problems.

A computer based data retrieval system was developed to convert hard copy documents containing production, well completion and well log data into easily accessible on-line format. To ascertain the geological framework of the reservoir, a thorough geological modeling and subsurface mapping of the Carpinteria field was developed. The model is now used to examine the continuity of the sands, characteristics of the sub-zones, nature of water influx and transition intervals in individual major sands.

The geological model was then supplemented with a reservoir engineering study of spatial distribution of voidage in individual layers using the production statistics and pressure surveys. Efforts are continuing in selection of optimal location for drilling and completion of probing wells to obtain new data about reservoir pressure, in-situ saturation and merits of drilling a series of horizontal wells.

The probing re-drills and horizontal wells are scheduled for Budget period II.

Information generated on the characteristics of the geology and reservoir setting have been presented at various SPE Meetings and Tech Transfer workshops of PTTC. Oil and gas professionals from State and Federal agencies have visited POOI offices and have received briefings on the Carpinteria re-development progress.

Executive Summary

Pacific Operators Offshore, a small independent operator, submitted a proposal under the Class III cost share program of U.S. Department of Energy and was granted support to pursue its study of the Carpinteria Field, Santa Barbara, California. The proposal called for improved and innovative drilling and completion strategies for the re-development of the field.

The reservoir in the Carpinteria field consists of thin to massive deep water sandstone's with intercalated siltstone and claystone. A total of 29 separate layers have been identified in the producing horizon. Major producibility problems in the field include high water cuts, sand production and poor wellbore mechanical conditions. The purpose of the proposal was to scrutinize all existing data about the field and develop a better description of the reservoir architecture, devise alternative drilling and completion strategies for redevelopment of the field and reduce the water cuts by pinpointing the source of the water.

A team consisting of the following entities assisting POOI in its field study submitted the proposal:

The University of Southern California, experts in reservoir characterization and reservoir engineering;
Coombs and Associates, experts in well log analysis;
Schlumberger, a service company;
Halliburton, a service company;
and Baker Oil Tool, also a service company.

The database effort resulted in the design and implementation of a readily accessible production data system using the Production Analyst software. Well log interpretation work resulted in identification of the micro-lamina, oil water contacts and information about displacement across fault planes and a consistent approach to calculation of reservoir attributes such as porosity and saturation.

Basic reservoir engineering work generated estimates of by-passed oil and allocation to individual horizons. Analyses of water production pinpointed the sources of water and the role of the aquifers in maintaining reservoir pressure.

A number of target spots for drilling of new development wells have been identified. Computation of recovery from pilot horizontal wells has established the economic merit of drilling and completing such wells for draining the trapped oil.

With active participation in the workshops given by the Petroleum Technology Transfer Council, SPE meetings, tours and meetings, results of the studies have been disseminated to other producers. Additionally various presentations to both State and Federal agencies have been made.

Acknowledgements

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The following individuals and companies provided valuable assistance to this project through

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1 Introduction

1.1 Report Overview

This report constitutes the first cumulative report on the project. Pacific Operators Offshore, Inc. received pre-award authorization for this project effective May 9, 1995 and final approvals were obtained effective September 1, 1995 and as such began work on the database tasks set forth in the proposal. To date a significant amount of progress has been made on development of a database and reservoir characterization, which includes production data (project task 1.1.1), well log data (project task 1.1.2), well completion data (task 1.1.3) well test and PVT data (task 1.1.4), stratigraphy and micro lamination (task 1.2.1), reservoir performance (task 1.2.2), analysis of water production (task 1.2.3), management and administration (task 1.3.1) and tech transfer (task 1.4.1).

In this chapter an overview of the project is presented. A general description of the Carpinteria field is included .

1.2 Project Overview

The main objective of this project is to devise an effective re-development strategy to combat producibility problems related to the Repetto turbidite sequences of the Carpinteria Field. The lack of adequate reservoir characterization, high-water cut production, and scaling problems have in the past contributed to the field's low productivity.

To improve productivity and enhance recoverable reserves, the following specific goals were proposed:

- Development of an integrated database of all existing data from work done by the former ownership group.
- Expansion of reservoir drainage and reduction of sand problems through horizontal well drilling and completion.
- Operating and validating reservoir's conceptual model by incorporating new data from the proposed horizontal wells.
- Transferring methodologies employed in geologic modeling and drilling horizontal wells to other operators with similar reservoirs.

The project was proposed to be conducted in two phases. In the first phase, Budget Period I, we proposed to develop the field database, conduct reservoir analysis and field characterization, institute a modern reservoir management and surveillance system and transfer technology to other operators.

Drilling and completion of a series of horizontal wells , monitoring of production and updating of the geological and reservoir model for further field development planning were the items proposed for Budget period II. A major objective for this project and the pilot drilling is a formulation of a fieldwide development strategy. This is to follow after a careful analysis of results obtained from Budget period II.

The project is expected to take approximately 4 years to complete. The first budget period began in September 1995 and is expected to be phased out by summer 1998. The second budget period is

planned to start in the last quarter of 1997.

Implementation of the budget period I portion of the project is monitored through a series of tasks proposed in the original proposal as listed below:

1. Task 1.1.1 - Database: Production Data
2. Task 1.1.2 - Database: Well Log Data
3. Task 1.1.3 - Database: Well Completion Data
4. Task 1.1.4 - Well Test / PVT
5. Task 1.2.1 - Stratigraphy and Micro Lamination
7. Task 1.2.2 - Reservoir Performance
8. Task 1.2.3 - Analysis of Water Production
9. Task 1.3.1 - Management and Administration
10. Task 1.4.1 - Tech Transfer

The team members of the project include:

Pacific Operators Offshore
University of Southern California
Coombs and Associates
Schlumberger Well Service
Halliburton Energy Service
Baker Oil Tools

1.3 The Carpinteria Field

1.3.1 Development and Production History

The Carpinteria Offshore Field was discovered by Chevron in 1964. It originally covered two State parcels and two Federal leases. State leases 3133, 3150 and 4000 were shut-in in 1992 and abandoned in 1996. The two Federal leases OCS P-0166 and OCS P-0240 are still producing. As of December 1996, total field production has been:

92 MMBO Oil, 174 MMBW Water and 84 BCF Gas

Pacific Operators operation is from OCS P-0166 and currently contributes 1400+ BOEPD (barrels oil and gas equivalent) to the total daily production of 2,800 BOEPD of the entire field. Cumulative oil production for lease OCS P-0166 as of December, 1996 is 45.69 MMbbls oil, 38.85 BCF gas and 60.54 MMbbls water.

Figure 1 shows water cut as a function of cumulative oil produced for lease OCS P-0166. High water production is evident from the early history of the field.

Figure 1 - Water Cut vs. Cumulative Production Plot

The State portion of the field was developed with a total of 77 wells originating from platforms HOPE and HEDI. These platforms were installed in 1965 and 1966 and were operated by Chevron until their abandonment in 1996. The Federal portion of the field has been developed with a total of 110 wells from three platforms, Hogan, Houchin and Henry. Fig. 2 Shows the chronological installation of the platforms for the Carpinteria field.

Figure 2 - Platform Timeline

1.3.2 Geologic Conditions

Carpinteria Field is located in the northern portion of the Ventura Basin. The producing formation is the multiple -zone Pliocene age Repetto. The trap is a faulted anticline with paytops ranging from 2500 to 5500 ft subsea. Formation dip range from 5 degrees to 15

degrees.

The Santa Barbara Channel, where the Carpinteria Offshore Field is located, is about eighty miles long and twenty-five miles wide. The Channel is a tectonic depression that extends east into Ventura Basin. These strata in the Channel have been subjected to major tectonic folding and complex faulting

creating multiple hydrocarbon traps.

Carpinteria is the fourth of the five fields located along the "Rincon Trend", a structure that is the northerly limit of the Ventura Basin. All the fields are divided by a major thrust fault into two major reservoirs, one above the thrust fault and one below. All fields have numerous fault blocks created by transverse faulting as well as stratigraphic changes resulting in compartmentalized reservoirs.

The Carpinteria field extends from approximately two miles offshore in State waters to 3.3 miles further on to Federal parcels P-0166 and P-0240. It is less than one mile wide at its widest point. The structure of the field and the current fault model is shown in Figure 3. Major producing horizons

Figure 3 - F-1 Structure Map with Current Fault Interpretation

Figure 4 - EarthVision block diagram looking west showing overthrusting of G-zones along Hobson Fault

within the field are the sands identified as E-1 through E-4, F-1 through F-5 and G-1 through G-7a above the Hobson fault and G-1 through G-7 below the fault. A 3-D block diagram showing the displacement of the Hobson thrust fault is shown in Figure 4.

The E-1 sands are generally highly porous, friable and with high permeabilities. The F-1 sand is 100-150 ft thick with medium to fine grained sand, moderate to well compacted with some

microlamination limiting the vertical permeability. The F-3 sand is up to 125 ft thick and is comprised of several sequences with intervening silt and shaly layers.

2 Database Development

2.1 Introduction

Information available on Carpinteria Field were primarily in hard copy format. Besides the monthly production data, important reservoir engineering data existed in a number of studies and reports by the previous working -interest owners. A significant effort was devoted to distill information for populating the database.

2.2 Production Data

For the purpose of computerizing the performance data, we employed production history management software called Production Analyst or “PA”. This software, developed by OGCI (Oil and Gas Consultants International), allows production history by individual wells to be easily combined and grouped to prepare diagnostic plots for analysis of reservoir behavior. The software was installed and all of the historical production history on a well by well basis were imported.

Because all the wells on the lease are drilled from one of two platforms (platform Hogan or Houchin), an X-Y coordinate system was used to show the reference datum well spots on the location map. This map interface accompanies the PA program. The datum used was the F1 sand.

The quality of the production history database was carefully compared with historical hard copy reports and production history database available from the regulatory agency, the Minerals Management Service. Each of these databases contains a huge number of monthly oil, gas and water production values. In order to compare the two databases a computer program was written to compare the data on a well by well, month by month basis. The differences then were checked with the hard copy and corrections were made where appropriate.

2.3 Well Log Data

A considerable amount of progress has been made on the well log database. Much of this work was initiated prior to the pre-award date. The well log processing system being used for this task is LOGCALC II, by Scientific Software, running on a DEC Micro-VAX II system.

Calculations of all petrophysical attributes is complete for all wells with useable data. All computed data were exported to the Stratigraphic Geocellular Model. Later, the SGM model was replaced with the EarthVision 3-D modeling package by Dynamic Graphics, Inc.

Using annotated computed logs and the marker data, oil water contact picks were re-evaluated with sections representing true vertical depth logs. Quality control consisted of use of the data in EarthVision, comparing the data with top and bottom picks and plotting a number of computer cross sections, which included the oil water contacts. The computer cross sections were also used to scrutinize the effect of production in the key areas. For these areas, studies have been started to assess the effect of production on logs for mapping swept and unswept oil, and to evaluate remaining reserves. Several potential remaining productive areas have been identified and additional evaluation is in progress.

Well log processing efforts have resulted in some calculated parameters that are currently undergoing quality control checks. A series of calculated log parameter maps has been created for each zone. These maps were developed by contouring each calculated parameter with a computer contouring package. Each map, for each layer or zone is compared to validate the calculated results.

Core data from four wells, A-9, B-15, B-35 and B-45, was used to develop a correlation for correcting lab permeability data for overburden pressure. This correlation was developed by using experimental compaction test data. Table 1 shows the core permeability and porosity data for all of the cored wells.

Table 1
Corrected Permeability and Porosity

Well	Formation	Corr k	Porosity
A-9	E-1	847.09	31.52
A-9	F-1	389.09	29.44
A-9	G-2	283.07	27.11
A-9	G-6BST	45.14	22.71
Avg.		391.10	27.70
B-15	F-1	229.96	27.73
B-15	F-2	427.95	29.43
B-15	G-1	199.26	28.56
B-15	G-1B	125.49	25.33
B-15	G-3	157.96	25.92
B-15	G-3B	153.40	25.60
Avg.		215.67	27.10
B-35	G-1	94.72	24.43
B-35	G-3	214.20	26.89
Avg.		154.46	25.66
B-45	E-1	396.79	35.21
B-45	E-1A	546.34	36.30
B-45	F-1	318.13	36.80
B-45	F-4	482.14	34.38
B-45	G-1	332.75	32.14
Avg.		415.20	34.97

Table 2
Comparison of Core Permeability and Porosity by Zone

Well	Formation	Corrected k	Porosity
A-9	E-1	847.09	31.52
B-45	E-1	396.79	35.21
B-45	E-1A	546.34	36.3
A-9	F-1	389.09	29.44
B-15	F-1	229.96	27.73
B-45	F-1	318.13	36.8
B-15	F-2	427.95	29.43
B-45	F-4	482.14	34.38
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B-35	G-1	94.72	24.43
B-45	G-1	332.75	32.14
B-15	G-1B	125.49	25.33
A-9	G-2	283.07	27.11
B-15	G-3	157.96	25.92
B-35	G-3	214.2	26.89
B-15	G-3B	153.4	25.6
A-9	G-6BST	45.14	22.71

Table 2 shows the same data but organized by producing zone. Although the data is somewhat sporadic there is a trend of decreasing permeability with depth as might be expected.

Special core analysis data including water-oil relative permeability, gas-oil relative permeability and air-water capillary pressure data have been digitized. Reservoir water-oil capillary pressure data has been derived from air-water capillary pressures. A complete set of reservoir data has been compiled for a reservoir simulation study.

2.4 Well Completion Database

Well completion design in Carpinteria lease OCS P-0166 allows artificially assisted production from individual zones to commingle. A well completion database containing the completion history of all of the wells was created. This information is maintained in a MS-Access database.

2.5 Well Test /PVT Data

A total of 39 pressure buildup tests were analyzed which include 17 drill stem tests. Results of analysis from DST No. 3, 4 and 5, which had surface flow rates, are believed to produce the most reliable permeability values for the sub-thrust G-7 and the supra thrust G-1 and F-1 layers respectively in the drainage areas encountered during the tests.

2.5.1 PVT Data

A total of five oil samples were taken from lease OCS P-0166 for PVT analysis. The first oil sample was prepared from recombining a sample of separator liquid with a synthesized separator gas in order to obtain a fluid having a bubble point equal to the original reservoir pressure of 1545 psig at 110 °F. This sample was taken on November 28, 1967 prior to start of lease production. Although the synthesized gas was not exact in its physical properties, it was felt to be within the practical limits for the recombination. The saturation pressure of the recombined sample was measured to be 1546 psig at a reservoir temperature of 110 °F. During differential pressure depletion at 110 °F the fluid evolved 223 SCF/STB. The viscosity of the liquid varied from a minimum of 14.4 centipoise at saturation pressure to a maximum of 46.5 centipoise at atmospheric pressure. The gravity of the residual oil was 22.0 °API at 60 °F.

The second recombined sample was taken early in the producing life of the lease on July 12, 1968 from well A-4. The well was opened to the E, F and G zones. The separator gas oil ratio (GOR) was 436 SCF/STB. PVT analysis of this sample resulted in 460 SCF/STB of gas in solution at a saturation pressure of 2528 psig and reservoir temperature of 122 °F. It is worth noting that this pressure is approximately 400 psi higher than the hydrostatic pressure at the deepest oil bearing point in the well (4630 ft. subsea). The gravity of the residual oil was 26.2 °API at 60 °F.

The third sample is a subsurface sample taken from Well A-7 on Sept. 28, 1968 from the F zone. This sample established a saturation pressure of 2155 psig at a reservoir temperature of 122 °F and a solution GOR of 336 SCF/STB. The gravity of the residual oil was 25.2 °API at 60 °F.

Subsurface samples 4 and 5 were taken April 24, 1969 during Drill Stem Test No. 1 (DST No. 1) on Well B-2A. The producing interval during the test was 5090-5115 ft. MD which corresponds to the G-5A sub-thrust sand. DST No.2 on the same well sampled the G-3A sand from a producing interval 3785-3805 ft. MD. These samples exhibited saturation pressures of 974 psig at 145 °F and 1271 psig at 126 °F with solution GORs of 273 and 212 SCF/STB respectively. The gravity of the residual oil samples were 32.4 and 25.8 °API at 60 °F respectively.

All available gas analysis data have been digitized. Also the historical API gravity measurements have been digitized. Chronological drop of API gravity's are attributed to the loss of the light components during the solution gas drive process and variable contribution from individual layers.

All available gas analysis data have been digitized. Table 3 shows a typical gas analysis data set. Also the historical API gravity measurements have been digitized.

TABLE 3
TYPICAL GAS ANALYSIS

Well No.: A-6 , Sample # 1, Date : 7-25-68	
Component	Mole per cent
He	< .01
CO ₂	3.28
N	0.06
CH ₄	84.34
C ₂ H ₆	2.67
Propane	4.1
I-Butane	0.84
N-Butane	1.81
I-Pentane	0.82
N-Pentane	0.74
Hexane	0.52
Heptanes and Heavier	0.82
Specific Gravity	0.7487
Heating Value	
Dry	1237
Wet	1215

2.6 Conclusions

Conversion of hard copy format report on production, pressure, PVT and production test into a computer based data retrieval system has been completed. The system allows real time access of the data for reservoir analysis.

3 Reservoir Characterization

3.1 Introduction

Implementation of a successful re-development program requires an understanding of the reservoir setting with respect to the following areas:

- Characterization of the structural nature of the reservoir
- Delineation of the stratigraphic nature of the reservoir
- Location and exact orientation of transverse faults
- Mapping of facies changes
- Relative contribution of individual sands to the commingled production
- Nature of the drive mechanisms of the wet sands
- Petrophysical properties of reservoir rock
- Quality of available reservoir pressure data
- The interplay of existing well completion with the stratigraphy of the field.

We have made progress in understanding some of these issues by implementing an integrated reservoir characterization method.

3.2 Stratigraphy and Microlamination

Based on the well log correlation's a total of 29 sub-layers have been identified. These sub-layers were identified using an onscreen correlation approach. A typical correlation panel of SP log traces is shown in Figure 5. These correlation panels were created by using the calculated True Stratigraphic Thickness (TST) logs and then displaying the traces in Autocad for correlation.

All available conventional core analysis from whole core and sidewall plugs from 6 core holes and 5 development wells were digitized. In addition, screen or sieve analysis, where available, were also used in the micro lamination study. Core analysis data was used to map silt

Figure 5 - Typical TST correlation panel created in AutoCAD showing section thickness anomalies indicative of faulting

stones and shales in wells. A correlation for correcting laboratory permeability data for overburden

pressure was developed by using experimental compaction test data. For material balance studies, a database was developed to relate cumulative production of oil and water to various sub-categories of producing horizons.

This data will be used for the microlamination study. In addition, screen or sieve analysis, where available, will also be studied in detail. A general trend of east to west permeability decrease was observed from core data and analysis of initial oil production.

Lithology of cored sections has been investigated. A detailed study of thin shales and silt stones in cored wells is in progress. This study will include comparisons of resistivity logs, continuity of thin shales and silts tones and their effect on past production. The 3-D visualization model, EarthVision

Figure 6 - East-west cross-section through EarthVision model showing producing zones and faults.

(Dynamic Graphics Software) is now being used for visualization, comparison and posting data. A east-west cross section created in EarthVision is shown in Figure 6.

A general trend of east to west permeability decrease was observed from core data and analysis of initial oil production.

Special core analysis data including water-oil relative permeability, gas-oil relative permeability and air-water capillary pressure data have been digitized. Reservoir water-oil capillary pressure data has been derived from air-water capillary pressures. A complete set of reservoir data for preliminary reservoir simulation study has been prepared.

3.3 Basic Reservoir Engineering

The reservoir engineering efforts completed so far have focused on three primary issues: (1) Estimating original oil in place (OOIP), using both volumetric and material balance techniques; (2) Estimating oil produced by well and by zone; and (3) Estimating the productivity of horizontal wells that will be drilled in the field.

This effort incorporated the results of recent geological and petrophysical interpretations. The study was hampered by limited pressure and core data, commingled production, heterogeneous reservoir fluids and incomplete geological and petrophysical evaluations of the subthrust reservoirs.

3.3.1 Original Oil in Place

Original oil in place (OOIP) for P-0166 is estimated to be 157 MMSTB by volumetric method and 166 MMSTB by material balance (MB) calculations. A second phase 3-D EarthVision model will result in more refined volumetric estimates of OOIP. Following is a discussion for the basis of our current OOIP calculations:

3.3.1.2 Volumetric method: P-0166

Our current 3-D EarthVision model only includes detailed reservoir attributes for the supra-thrust sands, series C through G5. Therefore, our 3-D model is only helpful in determining volumetrics for these zones. The determination of the productive areas in sands G6, G7 and the subthrust for the P-0166, as well as for the rest of the field, is still in progress. In this report, for the sake of completeness, previously determined reservoir data was used to complete the estimation of OOIP for G6, G7 and the subthrust. These estimates will be revised when new well attributes and net pay volumes become available. Net average thickness and thickness weighted average porosity and water saturation of each sand are used in the estimation of OOIP. The limits and cut-offs of reservoir parameters are shown in Table 4. An average oil formation volume factor of 1.15 bbl/STB is used in the volumetric calculations.

The original oil in place for P-0166 is presented by layer in Table 5. That table shows the E1, F1, G1 and G3 sands to have the largest oil accumulations in the lease. Statistical analysis of OOIP was performed by utilizing a Monte Carlo simulation using triangular distributions for area and net sand thickness. The mean value of reserves depicted there is 157 MMSTB with a 75% certainty of reserves between 144 MMSTB and 174 MMSTB.

TABLE 4
CUT OFFS OF RESERVOIR PARAMETERS

Shale cut off	35 %
Net pay total porosity cut off	15 %
Net pay total water saturation cut off	70 %
Effective porosity cut off	12 %
Effective water saturation cut off	60 %

TABLE 5
OOIP FOR P-0166 BY VOLUMETRIC METHOD

Sand	Productive area acres	Net thickness Feet	Ave. ϕ_e	Ave. Sw	OOIP, MSTB
C1	0.0	3.6	0.2920	0.5003	0
D1A	47.8	8.8	0.2403	0.4965	345
E1	281.3	37.9	0.2642	0.3754	11,857
E1A	207.9	31.2	0.2585	0.4462	6,255
E2	13.3	7.1	0.2293	0.5189	71
E3	3.7	2.6	0.2583	0.5206	8
E4	63.0	13.1	0.2715	0.4942	763
F1	475.2	116.5	0.2263	0.3681	53,387
F2	220.1	33.6	0.2348	0.4514	6,431
F2A	108.4	18.8	0.2110	0.4979	1,454
F3	255.3	30.3	0.2093	0.4465	6,049
F4	268.6	33.0	0.2157	0.4115	7,589
F5	111.2	18.1	0.2198	0.4662	1,589
F6	69.3	13.3	0.2098	0.5053	647
G1	253.6	44.5	0.2190	0.3445	10,938
G1B	176.6	23.4	0.2109	0.3320	3,921
G2	281.3	13.0	0.2055	0.3900	3,103
G3	238.0	68.8	0.2155	0.3361	15,794
G3A	119.4	10.9	0.2067	0.4581	987
G3B	88.9	23.6	0.2251	0.3501	2,069
G4	98.6	7.8	0.2010	0.4502	572
G5	75.6	6.5	0.1818	0.5111	294
G5A	67.7	9.5	0.2084	0.4668	484
G5B	31.6	5.2	0.2053	0.5325	106
G5C	22.5	3.2	0.1957	0.5369	45
G6	23.7	12.0	0.2077	0.4767	208
G6A	29.2	4.6	0.2080	0.4955	95
G6B	44.9	16.5	0.1989	0.4563	541
G6C	35.5	4.6	0.1819	0.4697	107
G7	87.5	20.4	0.1907	0.4211	1,332
ST	558.0	43.0	0.2100	0.4200	19,715
Total OOIP					156,754

3.3.1.2 Material Balance Methods

Based on the reservoir pressure database, the initial reservoir pressure on lease OCS P-0166 was calculated to be 1500 psig at a datum of 3300 ft subsea. In the basic material balance study of field, the combined effects of reservoir compressibility, depletion and water influx was examined. Indications are that the reservoir pressure from its initial value of 1500 psig dropped to 870 psig in a matter of 3 years. Following this initial drop in pressure, a period of pressure stabilization indicates

potential water influx. Cumulative production from various segments of the lease indicate considerable production of water. From diagnostic plots of water cut versus cumulative production, indications are that high water production is from commingled production from oil and wet sands and aquifer influx.

Two different approaches of the material balance equation (MBE) were considered for the estimation of original oil in place for lease P-0166. First the general material balance equation was examined using a water influx model as described by Ershaghi and Abdassah (JPT, Oct. 1984) in the form of X-plot. We also applied then a simplified form of the material balance equation. The general material balance equation for a reservoir incorporating the combined effects of aquifer support, formation compaction and the solution gas drive mechanism may be written as follows:

$$Z = a \bullet E + b \bullet I$$

Figure 7 - Xplot of Carpinteria production showing water influx.

where Z is the total reservoir withdrawal, A is the unknown OOIP, E is the unit of expansion, B is the unknown water influx constant and I is the influx function which will be calculated by the assumed water influx model. The MB equation was solved by the least square method. The OOIP was estimated 159 MM STB

The X-plot method has been found useful in obtaining an estimate of water influx in Carpinteria field lease P-0166. An example X-plot is shown in Figure 7. The water encroachment which is a mixture of bottom and edge water influx may be calculated using the following equation:

$$W_e = \frac{B_{oi}}{m f_w (1.0 - f_w)}$$

where W_e is water influx in barrels, m is the slope of the X-plot in 1/bbls (1.0372×10^{-7}), B_{oi} is the initial oil formation volume factor.

A Monte Carlo Simulation approach was devised to estimate OOIP in lease OCS P-0166. The material balance equation was rearranged in the following form:

$$N_i = a \times N_{pi} + b$$

where N_i is an apparent estimate of initial oil in place at different time steps, i , assuming no water influx, N_{pi} is cumulative oil production at different time steps and a and b are constants. For a reservoir with water influx, N_i tends to show mono-tonically increasing linear correlation with N_{pi} . The true value of original oil in place may be obtained by plotting N_i versus N_{pi} and extrapolating the straight line to $N_{pi} = 0$. Early time, data during which the reservoir was not fully developed, were excluded. Monte Carlo Simulation results in a mean of 168 MM STB, median of 162 MMSTB with a standard deviation of 42 MM STB.

3.3.2 Production Allocation

The majority of the wells in lease P-0166 were completed in multiple sands. As a first step in determining the remaining oil in each sand, a computer based back allocation algorithm was developed. The log derived net productive intervals with pertinent average effective porosity and water saturation, well completion data, core analysis and production data were used. The original oil in place (OOIP) in the supra-thrust reservoirs for each sand was calculated. The production allocation procedure was used to calculate cumulative oil production from each well and from each sand. The remaining oil in each sand was found by subtracting the amount of oil produced by each well from each individual sand from the original oil in place.

Due to the heterogeneous nature of reservoir fluids in lease P-0166 and large contrasts in individual layer pressures caused by differential depletion, an effort was began to develop new methods for production allocation to individual layers utilizing commingled well production. The allocated production data will be used to calculate initial oil in place in the three main sands as well as the sub-thrust reservoirs.

In order to allocate oil production to each producing sand, the total perforation interval and the effective time duration for each perforation were determined for each well. Cumulative oil production for each time interval was calculated using the actual well production data. The oil transmissibility of individual perforation intervals are calculated utilizing formation average water saturation and the pertinent sands oil and rock properties. The total effective transmissibility for each well at each time interval is obtained by adding the active perforation transmissibilities during that time interval. The oil produced from the sand during each time interval for each well is obtained by multiplying the oil produced from the time interval by the effective formation transmissibility and dividing the product by the total effective well transmissibility. Finally oil production from each sand is calculated by adding the oil produced during each time interval. The allocation program was modified to take into account reservoir pressure history and changes in fluid saturations. Reservoir pressure history was used to estimate the pressure at the end of each producing month. The water saturation at the end of each time interval was updated by replacing produced oil by water. The drainage volumes for individual wells in each sand were also updated at the end of a given time step. It was assumed that the drainage volumes of the wells in each sand are directly proportional to the well's cumulative oil production and inversely proportional to the initial hydrocarbon column. Figure 8 is a bar graph depicting the original oil in place and the remaining oil on a sand by sand basis.

Figure 8 - Bar chart showing distribution of OOIP and cumulative oil produced by zone

3.3.3. Productivity of Horizontal Wells

A preliminary study of the expected productivity of horizontal wells producing from E-1, F-1 and F-3 sands in the Carpinteria offshore field, using pseudo steady state method presented by Babu and Odeh (SPERE Nov. 1989, p.417-421), has been completed. Reservoir and fluid parameters utilized in

this study are given in Table 6. Figure 9 shows the effect of well length on the productivity index, PI, for the three sands. Other effects, such as oil viscosity, horizontal permeability and permeability ratio were also analyzed. In general, for the range of applicable reservoir data, the proposed horizontal drilling can substantially increase the productivity of new wells in the Carpinteria sands.

Figure 9 – Productivity of horizontal well versus length

TABLE 6
Reservoir and Fluid Properties

Parameter	E-1 sand	F-1 sand	F-3 sand
Well length, feet	1500	1500	1500
Sand Width, a, feet	2000	2000	2000
Sand Length, b, feet	3000	3000	3000
Sand thickness, h, feet	45.60	107	42
Wellbore radius, r_w , feet	0.25	0.25	0.25
Oil viscosity, cp	20.0	8.5	8.5
Oil formation volume factor, bbl/STB	1.065	1.07	1.07
Permeability in x direction, md	425	223	223
Permeability in y direction, md	425	223	223
Permeability in z direction, md	340	178.4	178.4
x_0 , feet	1000	1000	1000
z_0 , feet	41.04	96.3	37.8
y_1 , feet	500	500	500
y_2 , feet	2000	2000	2000
Skin factor	0	0	0

3.4 Analysis of Reservoir Performance

Well Test Data – All pressure data for Lease OCS P-0166 has been analyzed. A total of 39 pressure buildup test were analyzed which include 17 DST test. The results of these DST tests are show in Table 7. Results of analysis from DST No. 3, 4 and 5, which had surface flow rates, are believed to produce the most reliable permeability values for the sub-thrust G-7 and the supra thrust G-1 and F-1 layers respectively in the drainage areas encountered during the tests.

TABLE 7
Analysis of Drill Stem Tests

Well No.	Fluid	Date	Type	Zones	Ref. Depth	P*, psig	k, md
CH#6	38 BOPD 12 BWPD	4/26/67	DST#3	G-7ST	-4944	2243.5	ko 1.43 kw 0.11
CH#6	348 BOPD	4/29/67	DST#4	G-1	-3436	1594	45.9
CH#6	555 BOPD	4/30/67	DST#5	F-1	-2854	1277	386.5
A-1	60% OIL 40% W	5/24/68	DST#1	G-6	-4254	1880	2.3 2FP 3.8
A-1	WATER	5/25/68	DST#2	F-4	-3467	1548.5	81.2
A-1	90% OIL	5/27/68	DST#3	F-4	-3467	1556	56.6
A-1	WATER	5/28/68	DST#4	E-1	-2641	1200.9	42.3
A-1	OIL	6/2/68	DST#5	E-1	-2641	1193.5	110.8
A-2	WATER	5/19/68	DST#1	F-4	-3496	1534	307
A-2	OIL	5/20/68	DST#2	F-1	-3170	1373	104.7
A-2	OIL	5/21/68	DST#3	E-2	-2785	1230	132.6
A-7	OIL	9/26/68	DST#1	F-1	-3077	1206	124.5
A-12	OIL	7/30/68	DST#1	G-7ST	-5120	2351	13.8
A-12	OIL	8/1/68	DST#2	G-6ST	-4829	2156	36
A-12	GAS	8/2/68	DST#3	G-5ST	-4741	-	0.3
B-2A	Oil	4/24/69	DST#1	G-5AST	-4818	2173	9.6
B-2A	Oil	4/25/69	DST#2	G-3B	-3485	1557	234

PVT Data - Further analysis of PVT data results in the data shown in Table 8 which presents a comparison between the properties of the reservoir fluids. Figure 10 shows a linear relationship of methane content with saturation pressure of the reservoir fluids.

TABLE 8
Comparison between Reservoir Fluids

No.	Type of Sample	Formation	Temp. °F	P _b , psig	R _s , SCF/STB @ P _b and Res. Temperature
1	Rec. Well CH-6	-	110	1546	223
2	Rec. Well # 40	E-1 zone	124	1218	173
3	BH sample A-7	F zone	122	2155	336
4	BH sample B-2A	G-3A zone	126	1271	212
5	BH sample B-2A	G-5A ST	145	974	273

Figure 10 - Saturation pressure vs. methane content

Reservoir Pressure - In addition to the static pressure data, a flowing bottom hole pressure database has been developed from fluid level measurements from the last 5 years of operations. Figure 11 presents flowing bottom hole pressure versus time from the fluid level data.

In the basic material balance study of the field, the combined effects of reservoir compressibility, depletion and water influx need to be examined. From the review of the database, indications are that the reservoir pressure from its initial value of 1500

psig dropped to 870 psig in a matter of 3 years. Following this initial drop in pressure, a period of pressure stabilization indicates potential water influx. Cumulative production from various segments of the lease indicate considerable production of water. From diagnostic plots of water cut versus cumulative production, indications are that high water production may be caused from commingled production from oil and wet sands and aquifer influx. In order to better understand field producibility problems a transmissivity map representing the heterogeneity of the field will be created. A qualitative distribution of remaining oil in the four most important layers, namely E-1, F-1, and F-3 using the above procedure was determined.

Figure 11 - Reservoir pressure interpreted from Fluid level information

3.5 Analysis of Water Production

Efforts are under way to construct the x-plots of individual wells for prediction of anticipated production under water influx. Water chemistry data are being compiled for finger-printing of the source of water and variation of water composition across the field and in individual sands. All available water chemistry data have been digitized. Table 9 shows a typical water analysis. Efforts are under way for fingerprinting of the source of water and variation of water composition across the

field and in individual sands. Water oil ratio versus cumulative oil production of individual wells were used to study the source of water production.

TABLE 9
Typical Water Analysis Data

WELL NO. : A-11		DATE: 5-23-69		
	Milligrams per liter	Milliequivalent per liter	Parts per million	Percent
Sodium	7905	343.85	7781	35.9
Calcium	20	1	20	0.09
Magnesium	41	3.37	40	0.19
Barium	0	0	0	0
Iron, Dissolved				
Iron, Total	0.4		0.4	0
Hydroxide	0	0	0	0
Carbonate	84	2.8	83	0.38
Bicarbonate	4111	67.42	4047	18.67
Chloride	9858	278	9704	44.77
Sulfate	0	0	0	0
Total Dissolved Solids (Sum.)	22019		21675	100
pH When Sampled				
pH in Lab	8.2			
Resistivity, Ohm-meters at 77 °F	0.326			
Specific Gravity 60 / 60 °F	1.0159			

3.6 Conclusions

During budget period I we have accomplished a large portion of our reservoir characterization objectives spelled out in the statement of work, which are summarized as follows:

Verified the original oil in place by two material balance methods and by volumetric analysis

Developed a system to allocate production by well and by layers and hence remaining reserves in each zone

Looked at the feasibility of horizontal wells which included a series of horizontal wells vs. one trilateral well.

4. Management and Administration

Monthly meetings of the steering committee continue to be held in POOI's Ventura office or at USC to monitor the progress of the individual tasks.

5. Technology Transfer

5.1 Publications and Reports

During this period we completed the following activities:

Bi weekly meeting at USC on the geology and production issues related to slope and basin reservoirs.

2. March 1, 1996: Pacific Operators hosted a tour of their offshore Platforms including a presentation on the field recovery potential to representatives from the DOE and the local congresswoman, Rep. Andrea Seastrand.
3. March 13, 1996: Made a presentation on the Carpinteria Redevelopment project at the API Energy Day
4. July 8, 1996: Presentation to regulatory agencies (Minerals Management Service and California State Lands Commission) on recovery potential of the Carpinteria field using convention reservoir engineering techniques.
5. August 21, 1996: Review of geology, drilling problems and reservoir issues presented New York investment community visiting in Santa Barbara.
6. June - September, 1996: Provided internship to three college students who received supervised instructing relating to the project.
7. August - Present: Developed a Pacific Operators maintained web site for online reporting on the progress of the Class III project. The address for this web site is: <http://www.pacops.com>
8. Attended Tech Transfer planning meeting with other Class III project in Valencia, CA.
9. Participated in brain-storming sessions related to the initial formation of the west coast PTTC.
10. Conducted sessions with the CSLC to demonstrate that the State portion of field has significant remaining reserves and that it should be included in the Class III study for potential drilling.
11. Pacific Operators was invited to contribute its reservoir database as an example of slope and basin reservoir as a part of the on-line database under development between USC and LLNL.

6. Budget Period II

6.1 Introduction

Our current plans are to proceed to budget period II during the third quarter of 1997. Our plans are to drill horizontal wellbores as called for in our SOW, however due to the remaining uncertainties in our understanding of the reservoir we will most likely drill the three wellbores by redrilling two existing wells and drilling one longer reach horizontal well. Figure 12 is an vertical section view of

a updip horizontal well that would be drilled from Platform Hogan.

Figure 12 – Vertical section view of a planned updip horizontal well