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DOE/BC/14935-9
(OSTI ID: 776910)

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

Final Report
January 15, 2001

Date Published: April 2001

Work Performed Under Contract No. DE-FC22-95BC14935

Pacific Operators Offshore, Inc.
Santa Barbara, California

National Energy Technology Laboratory
National Petroleum Technology Office
U.S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

DOE/BC/14935-9
Distribution Category UC-122

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

Gary Walker, Project Manager
National Petroleum Technology Office
P.O. Box 3628
Tulsa, OK 74101

Prepared by
Pacific Operators Offshore, Inc.
University of Southern California
205 E. Carrillo Street, Suite 200
Santa Barbara, CA 93101

Abstract

In 1994 Pacific Operators Offshore, Inc. sought and won a United States Department of Energy Class III cost sharing project to perform reservoir studies leading to the drilling of a tri-lateral redevelopment well in their Carpinteria Offshore Field in the Santa Barbara Channel of California. The intent of the project was to increase production and extend the economic life of this mature field through the application of advanced reservoir characterization and drilling technology, demonstrating the efficacy of these technologies to other small operators of aging fields. Two study periods were proposed; the first to include data assimilation and reservoir characterization and the second to drill the demonstration well. The initial study period showed that a single tri-lateral well would not be economically efficient in redevelopment of Carpinteria's multiple deep water turbidite sand reservoirs, and the study was amended to include the drilling of a series of horizontal redrills from existing surplus well bores on Pacific Operators' Platform Hogan. After some 42 months of study, during which all existing field data were digitized, wells were re-correlated, digital petrophysical studies were performed, fault blocks defined and reservoir geometries identified and mapped, and redevelopment targets identified and graded, four target zones in two fault blocks were selected for initial redevelopment. Two pilot wells were drilled in the selected fault blocks to verify adequate remaining oil saturation, resulting in the re-assessment of one of the target zones. For economic efficiency, these wells were completed as conventional infill producers. Immediately following, drilling was commenced on the four horizontal wells. Each was completed in its target zone using slotted liner. Producing intervals averaged around 500 feet in length. In total, the initial redevelopment project added 760 barrels per day, dramatically increasing the production from Platform Hogan and extending the economic life of the field.

Executive Summary

In 1994 Pacific Operators Offshore, Inc. was successful in winning a Class III cost share project from the Department of Energy. This project proposed to first perform a number of reservoir characterization tasks which would permit expansion of reservoir drainage and reduction of sand and water production through the drilling and completion of a tri-lateral horizontal well from one vertical wellbore. Ultimately, studies showed that the concept of a single tri-lateral well was not appropriate for initial redevelopment at Carpinteria, and the project was amended to consist of two vertical pilot wells and four near-horizontal redrills from existing well bores rather than a single tri-lateral.

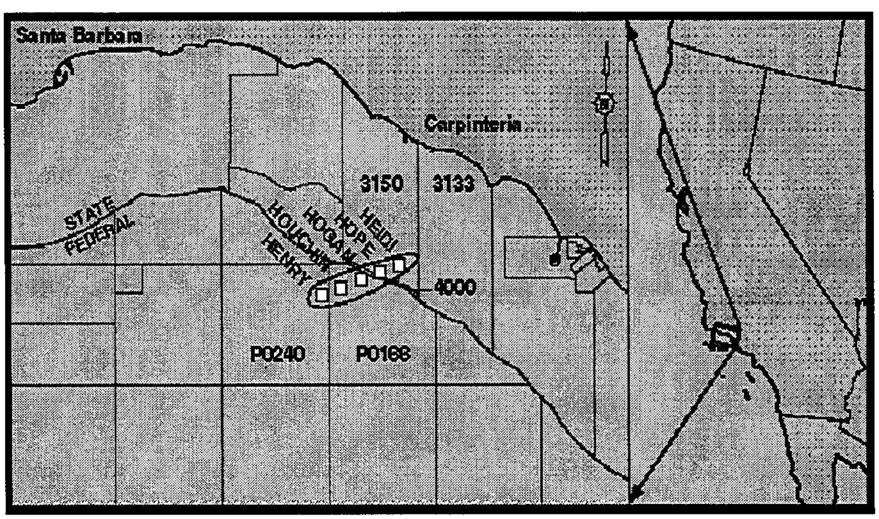

Figure 1: Location map showing Carpinteria Offshore field in relation to the eastern Santa Barbara Channel

Pacific Operators Offshore Inc. (POOI) formed a study team and entered into a cooperative agreement with the United States Department of Energy (DOE) for sharing cost and information on development of a novel approach for economic survival of the Carpinteria

Offshore Field. The Carpinteria Offshore Field is located about three miles off the shore of California in the Santa Barbara Channel as shown in Figure 1. The purpose of the project was to maximize recovery and reserves of the field with multi-lateral horizontal holes.

Our project included two budget periods. Budget period I was data assimilation and reservoir characterization. Budget period II consisted of actual field demonstration. As a result of the budget period I analysis, the project was modified to redrill existing vertical producers into a horizontal configuration. This proved to be far more economically beneficial than drilling a single tri-lateral well. The concept was that a horizontal completion can access a larger drainage area and several reservoir compartments unique to the fan lobe structures in turbidite sequences, while minimizing the commingling of water from wet sands and result in lower sand production.

At the time the project was proposed POOI's Federal lease, OCS P-0166 lease, faced a maximum of six year economic life. Both POOI and the Federal Government, as the royalty holder, would loose substantial revenues if the field is prematurely abandoned prior to development of its full potential.

The proposed concept of increasing production through horizontal drilling, if successfully demonstrated in the pilot project, would lead to a progressive re-development of the field. The result would generate a substantial data base which could be used for development of other similar slope and basin clastic reservoirs in California and elsewhere.

In anticipation of drilling under the Class III project, Pacific Operators performed numerous geologic and reservoir engineering studies, by itself and in concert with others. These studies resulted, in part, in a re-correlation of all zones throughout the field, digitization of all well log traces and calculation of basic reservoir parameters therefrom, display of all well logs on true stratigraphic thickness depth scales, construction of geologic structure maps for all zones, and a database of well bore fault intercepts derived from electric log correlation. The results were collected in electronic databases and displayed using computer graphics software and in a three-dimensional computer model. This work led to a refined definition of the fault structure of Lease P 0166, a quantification of the original hydrocarbon saturation of the various reservoir zone, and a grading of zones and fault blocks, which permitted the location of new wells to be drilled in the redevelopment project.

These geologic and engineering studies showed that the original concept of drilling a single tri-lateral well was not optimal and the project was revised to consist of four horizontal redrills and two near vertical pilot wells. The change to a concept of redrilling of existing surplus boreholes resulted in drilling economies through the reclamation of existing uphole casing while expanding the volume of the reservoir being investigated by increasing the number of zones and fault blocks to be penetrated. The pilot wells were critical to an understanding of remaining hydrocarbon saturation in a mature reservoir where historic production had been from comingled multiple zone completions. As a further economy, the pilot wells were themselves completed as producers, thus providing income as well as information.

The horizontal redrill trajectories were laid out in the selected target zones using 3-D modeling software which permitted optimization of planned well paths to penetrate the most attractive targets while avoiding interference with existing wellbores. Well paths were planned with a "U" shape in order to intersect all elements of the internally layered turbidite sand target zones. Final well planning was done by the directional drilling contractor that would be responsible for the actual drilling. Wells were drilled with 6 1/8 inch bits and 4 ¾ inch tools from windows milled in existing 7 inch casings. Measurement-While-Drilling (MWD) techniques were used to steer and log the wells, and completions utilized external casing packers (ECP) and slotted liner.

All four of the horizontal redrills were completed as producers. The pilot wells were also completed in any zones containing adequate saturation. In total, the redrill program added 760 barrels per day of initial production. Initial water cut in these wells was low, amounting to 24% compared to a lease average of 74%. Sand production in the redrills was also reduced compared to the existing producers. The redrill program dramatically increased the production from Platform Hogan and extended the economic life of the Lease.

Project Description and Scope

The project proposed a complete reservoir evaluation and characterization phase prior to the redrilling phase to probe the reservoir framework and to test the productivity of horizontal sections versus conventional directional wells. Two budget periods were proposed. During Budget Period I, the current ongoing reservoir studies at POOI were to be augmented by participation of researchers at the University of Southern California and Coombs & Associates for a collaborated mapping of reservoir architecture. From this phase, a suitable location for the drilling of the proposed test well was to be identified. Information generated during Budget Period I would be used for the planning and implementation of drilling and completion activities relative to the proposed well. The proposed trilateral hole was to be drilled during Budget Period II. From the testing and evaluation of the newly drilled well, POOI proposed to update the conceptual geologic model of the field and consider widespread re-development activity based on drilling of additional multilateral horizontal wells.

Project Objectives

The main objective of this project was to devise an effective re-development strategy to combat producibility problems related to the Repetto turbidite sequences of the Carpinteria Field. Specific goals to attain this objective were as follows:

- Develop an integrated data base of all existing data from work done by the former ownership group.
- Expand reservoir drainage and reduce sand production problems through horizontal drilling and completion.
- Update and validate reservoir's conceptual model by incorporating new data from the proposed horizontal drilling.

In accomplishing these objectives POOI, in conjunction with other project participants, would:

- Transfer methodologies employed in geologic modeling and drilling horizontal wells to other operators with similar reservoirs.
- Furnish the Department of Energy with progress reports regarding both the project activities and expenditures.

Description of the Field

The Carpinteria Offshore Field is located about three miles off the shore of Carpinteria, California in the Santa Barbara Channel. The two closest cities are Santa Barbara, ten miles northwest of the field and Ventura which is approximately fourteen miles to the southeast.

Discovered in 1964 by Chevron, the field lies within three State Parcels and two Federal leases as shown in Figure 2. The State leases 3133, 3150 (now 7911) and 4000, and the two Federal leases OCS P-0166 and OCS P-0240 segment the Carpinteria Offshore field into two portions. The primary site of interest in regard to this proposal and its underlying project objective is that portion of the field which lies within boundaries of the Federal lease OCS P-0166.
This lease is now fully owned by Signal Hill Service, Inc. of Santa Barbara, California, and is operated by Pacific Operators Offshore, Inc.

The State portion of the field has been developed with a total of 77 wells originating from platforms Hope and Heidi. These platforms were installed in 1965 and 1966 and operated by Chevron until August, 1992 when they were shutdown as uneconomic and later removed in 1996 The State lease gross production at the time operations were suspended averaged approximately 1,100 barrels of oil per day at 91 percent water cut.

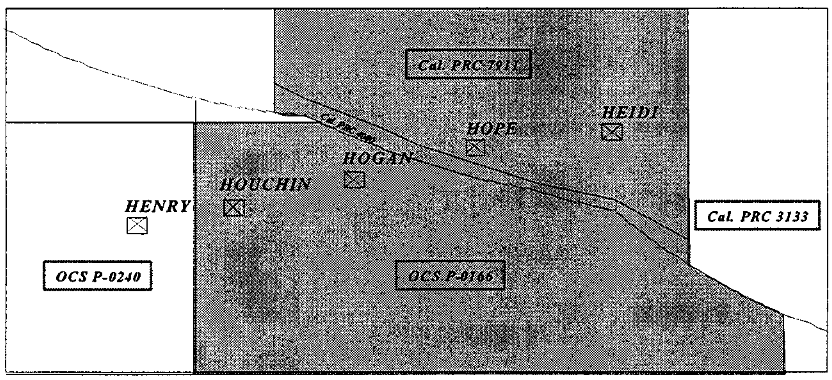

Figure 2: Location map showing Carpinteria field platforms and distribution of leases. Pacific Operators leases shaded.

The Federal segment of the field has been developed with a total of 110 wells from three platforms - Hogan, Houchin, and Henry. In 1968, (approximately two years after field pro duction had already begun on the State side), platforms Hogan and Houchin were installed on Federal lease OCS P-0166 (demonstration site) for the ownership group which then included Phillips Petroleum, Cities Services, and Continental Oil Company. The third Federal platform (Henry) was installed on Carpinteria lease OCS P-0240 in 1979 by Sun Oil Co. and is currently operated by Torch. The water depth in the vicinity of the five original platforms ranged between 150 and 180 feet.

The Carpinteria field (State and Federal) cumulative production and well count by lease are summarized in Table 1. Almost two-thirds of oil recovery is from Federal leases; specifically, cumulative production from the State leases by the time the two State platforms were shutdown in August 1992, totaled approximately 34 million barrels oil, 114 million water and 34 billion cubic feet gas. Production from the two Federal leases totaled 64 million barrels oil, 76 million barrels water and 53 billion cubic feet gas, for a fieldwide total recovery of 98 million barrels of oil and 87 billion cubic feet gas.

TABLE 1

CUMULATIVE GAS AND LIQUID RECOVERED

(As of January, 1999)

LEASE	OIL (MMBO)	GAS (BSCF)	EQUIV. BARRELS (MMBOEG)	WATER (MMBW)	TOTAL WELLS DRILLED
PRC 3150/4000	34	34	40	114	77
OCS P-0166	47	40	59	65	85
OCS P-0240	17	13	19	11	25
TOTALS	98	87	113	190	188

As of October, 1999, total Carpinteria field production was approximately 2,400 BOPD, 1,600 MCFPD and 6,700 BWPD from 50 producing wells. Carpinteria field production is summarized by lease in Table 2.

TABLE 2

CURRENT PRODUCTION RATES

(As of January, 1999)

LEASE	OIL (BOPD)	GAS (MCFPD)	EQUIV. BARRELS (BOEGPD)	WATER (BWPD)	TOTAL FLUID (BPD)	WATER CUT (%)	PROD. WELLS
PRC 3150/4000	--	--	--	--	--		--
OCS P-0166	1,520	1,110	1,705	4,250	5,770	74	28
OCS P-0240	890	500	970	2,480	3,370	74	22
TOTALS	2,410	1,610	2,675	6,730	9,140	74	50

Lease OCS P-0166

Platform Hogan is located in 155 feet of water approximately 3-1/2 miles offshore Carpinteria, California on Federal lease OCS P-0166. Platform Houchin is located slightly further west of Hogan in 180 feet water. Both platforms were designed, fabricated and installed in 1968 by McDermott, Inc. for the original lease ownership group led by Phillips Petroleum.

Both platforms have a similar design: consisting of a conventional pile-type, twelve-leg (8 for Houchin), multi-deck drilling and production platform each with a 66-well capacity. Both platforms are connected with a 10" subsea pipeline for liquids and a 12" line for gas.

Facilities on each platform consist of two test separators, two gross production separators, which separate gas from liquid, and electric-powered 5½" x 10" duplex pumps for pumping produced liquid to the La Conchita onshore treatment plant via a 10" flowline. The separated gas flows at an inlet pressure of about 80 psi into a separate subsea 12" line to the La Conchita treatment plant. Once in the plant, the separated gas is further dehydrated, compressed and sold.

Fluids arriving from offshore are separated and treated in a series of heater treaters and separators. The separated water is processed through a flotation cell and filters before being pumped back offshore to platform Hogan for disposal overboard under a EPA-NPDES permit. The treated oil (23.5 degrees average API gravity) is sold through a LACT unit and shipped via pipeline to Los Angeles area refineries. The onshore oil/water treatment facility has a design capacity of 30,000 barrels of oil per day.

Both platforms receive electrical power from shore via a submarine power cable.

Geologic History of the Santa Barbara Channel

The Carpinteria Field is contained within a geologically young anticlinal fold that lies in the Santa Barbara Channel, offshore south-central California. The productive structure is an east plunging asymmetric anticline which was modified by several generations of folding and faulting. In order to understand why commercial quantities of oil have been trapped here, and particularly to understand the nature of additional potential accumulations which we believe may be present on this trend, it is necessary to briefly review the geologic history that gave rise to the structure and to the hydrocarbons trapped within it.

The geologic history of this part of coastal California is recorded in rocks ranging in age from more than 80 million years to the present. During this period, several stages of crustal shortening and extension, seafloor subduction, crustal block rotation, and tectonic compression, tension and wrenching have left their marks on the structural and sedimentary patterns of this area. Of these many events, only those of the last eight to ten million years have had a direct effect on the configuration of the Carpinteria Field. The deepest field well, the P-0166 B32 well drilled from Platform Houchin, bottomed in rocks of about that age; the lower Monterey formation (middle Miocene, 18,401 feet). Older rocks are expected to be present at greater depth but no details are available except by projection of regional data. The Monterey formation in the B32 well consists of more than 5000 feet of sandstone, silicic siltstone, chert and limy shale. As much as half this apparent thickness may be due to fault repetition and/or steep dip. The Monterey was deposited in a stable, deep water basin which was one of many similar features along the Miocene California coastline. Low oxygen content of the waters trapped in these deep basins allowed preservation of organic material within the bottom sediments and imprinted a unique lithologic character upon these rocks. Geochemical studies have shown that all southern California coastal basin and offshore oils, with the exception of a few older samples of Eocene age, could have been sourced from Monterey rocks. It is therefore highly likely that Monterey formation rocks in the deep subsurface beneath and adjacent to Carpinteria Field are the source of the oils trapped in the younger formations. The Monterey formation can also be an excellent reservoir for petroleum where properly trapped and fractured.

Overlying the Monterey formation are more than 7000 feet of late Miocene (upper Mohnian and Delmontian Stage) shales and sandstones. Again, this thickness is probably exaggerated by faulting and dip. This sequence records a progressive filling in of the Monterey basins and a return to more oxygenated bottom waters. Generally, the late Miocene section represents a transition from the restricted basin depositional style of the Monterey to the deep water turbidite and slope channel style of the early Pliocene. In the eastern Santa Barbara Channel, these rocks are assigned to the Santa Margarita formation. Isolated sandstones with the Santa Margarita formation have been petroleum reservoirs in some fields. Productivity potential of these rocks at Carpinteria is under study.

The currently productive zones of the Carpinteria Field all lie within the Pliocene Pico formation. A single paleontologic report identifies at least the lowest two named zones as belonging to the early Pliocene lower Repettian foraminferal stage. Correlations by Chevron USA Inc. on PRC 3150 indicate that all of the overlying productive section is Repettian as well. The Repettian consists of an alternating sequence of sandstone and shale beds which have been subdivided by the prior operator into 30 zones, divided into 5 groups designated C, D, E, F and G. Each group is further divided by numbers and, in some cases, yet again using letters, e.g., G3B. These zones are an attempt to designate individual producing units which, on the electric logs, generally appear as single blocks of sand. The highest named zone is C1, the lowest G7. In order to calculate exact zone thicknesses, the Carpinteria Project has further refined the terminology by picking the base of each zone, designating it with the letter "X", e.g., G3BX.

Sedimentation Patterns at Carpinteria Field

The depositional environment of the Repettian sands is indicated by the shape of the electric log curve and by the vertical and areal distribution of various lithologically related properties which can be calculated from the petrophysical log suite. A variety of depositional styles appear to be present, including turbidites, channelized sands and overbank deposits, all probably modified by sea floor current activity. The presence of these depositional types is indicative of a deep water submarine fan environment[1] where the exact position relative to individual fan elements has varied through time. The lowest zones, G6 through G7, show a tendency for porosity and thickness isolines to trend approximately east-west, suggesting deposition in a paleoenvironment with a gradient at right angles to the modern structure, such as an outer mid fan area or outer fan margin. Higher in the section , depositional patterns show more variability along the axis of the structure, suggesting some sort of channelized flow environment, such as that found in the distributary channel section of suprafan lobe in the mid-fan position. Detailed study of Carpinteria Field stratigraphy continues, but it is already clear that faulting rather than stratigraphic variability is the most important factor in production distribution and that the main sand bodies that make up the producing zones are for the most part continuous across the field.

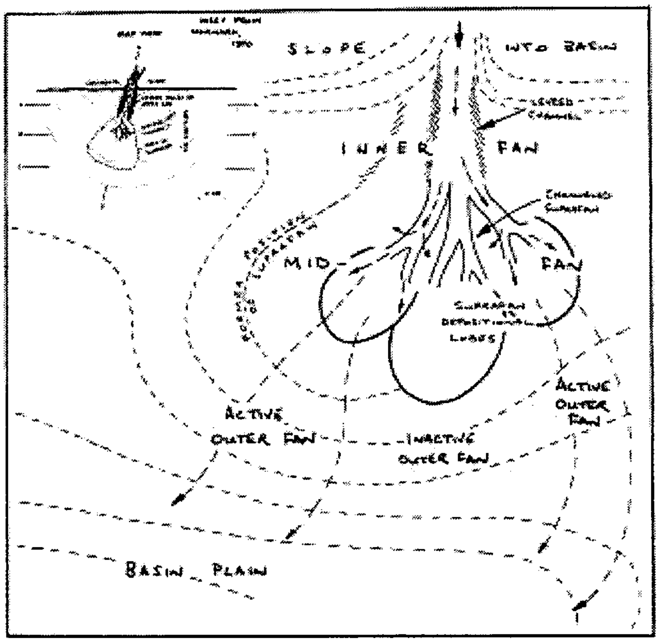

Figure 3: Diagram showing anatomy of a subsea fan.

Rincon Trend Tectonics

The anticline that contains the Carpinteria Field is part of the Rincon structural trend, which extends from Rincon Field on the east to the Dos Cuadras Field on the west. Further east, the Ventura Avenue trend, including the Ventura Avenue and San Miguelito fields, are closely related tectonically. To the west the Rincon trend continues beneath the waters of the Santa Barbara Drilling Sanctuary where geologic data is limited. Beyond Santa Barbara the Five Mile trend, containing the Gato Canyon Unit and the Santa Ynez Unit (Hondo and Sacate fields) is very similar in structural position and tectonic history. The Rincon trend is an east plunging, asymmetric south verging anticline developed in the hanging wall of the Pitas Point/Dos Cuadras fault system, a steeply north-dipping structural discontinuity which defines the south limit of the Rincon trend structural block. Limited seismic evidence shows the south limb of the anticline to

[1]Walker, Roger G. and Emiliano Mutti, 1973, Turbidite Facies and Facies Associations in Turbidites and Deep Water Sedimentation, Gerald V. Middleton and Arnold H. Bouma, *eds.*, SEPM Pacific Section Short Course, Anaheim, CA., p. 119-157.

dip at approximately 30 degrees while the north limb dips at a slightly shallower 22 to 25 degrees. Back thrusts off the main reverse faults traverse many of the trend's fields and are frequently flexed or even folded. Such back thrusts are found in the Ventura Avenue, San Miguelito, Rincon and Dos Cuadras fields, as well as the Carpinteria Field, where the back thrust is called the Hobson fault. A number of normal, reverse and wrench faults of lesser displacement are also present, and may limit production locally.

Structural Development of Carpinteria Field

Timing of structural events at Carpinteria Field is somewhat difficult to determine because of the paucity of paleontologic data; however, the fact that all of the structural trends mentioned in the previous section are tectonically related allows some inferences to be made. As noted earlier, the Repettian sands which make up the productive section are of deep water origin, related to a deep sea fan system which persisted through this time period. This is true all along the trend, attesting to a structurally quiet period through the Repettian. Only far to the west, at Gato Canyon and Santa Ynez Units west of Santa Barbara, is there evidence of the beginnings of tectonic disturbance late in this period. The presence of abundant sand in the Repettian section, however, attests to high rates of erosion nearby, no doubt in the central portions of the Santa Ynez Mountains which now stand at an elevation of more than 2000 feet. The sudden presence of the G7 sand in an otherwise relatively fine-grained section may attest to the first subaerial exposure of the upwarping Santa Ynez chain. The onset of compressional strain which began to fold the Carpinteria anticline cannot be directly dated because , as evidenced on the few available seismic lines, some denudation of critical section has taken place on the crest of the structure where all of the wells were drilled. Seismic lines do show, however, a section of young sediments unconformably lying on the south flank of the structure, within which are several small scale unconformities. We estimate the age of these sediments to be post-venturian and probably pre-hallian. This would place the initiation of Carpinteria Field structural uplift as no earlier than 1.9 mybp (million years before present) and no later than 0.5 mybp. If it were possible to drill an exploratory well into these flank sediments it would be possible, coupled with high resolution seismic data, to closely date these structural events, but the cost of such a project for essentially academic benefits would be high. In any event, it is clear that the Carpinteria structure is very young.

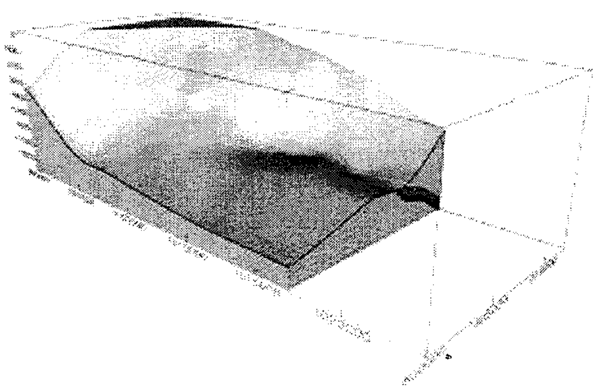

Figure 4: Perspective view of the Hobson fault plane looking northwest. Note antiformal fold in the fault plane surface.

Despite the lack of timing data, the following sequence of structural events can be inferred from geological data coupled with regional understanding. Somewhere around 2.4 mybp the Santa Ynez Mountain uplift breached sea level and began to shed coarse sediment into the deep basin to the south. As uplift continued, stress was transferred into the foreland area resulting in subsidiary folding at the mountain front. At some point around the end of Pico formation deposition (late Venturian-early Wheelerian; approx. 1.9 mybp) this process resulted in the initiation of a reverse or wrench/reverse fault system (the Pitas Point/Dos Cuadras system), in the hanging wall of which an anticline began to develop. Other workers have suggested that such leading edge reverse faults may sole out (become horizontal) at depth to become low angle thrusts along which lateral movements of major blocks are accommodated. In any event, as folding of the anticline progressed in the hanging wall block, a backthrust developed, separating the anticline into a supra-thrust block and a subthrust block. Along the backthrust the supra-thrust block began to move northward relative to the subthrust rocks. This backthrust is now designated the Hobson fault. The part of the Hobson fault plane lying beneath State waters began to fold along with the developing anticline, continuing until a reversal of dip was formed in this part of the fault plane itself. By contrast, in the Federal leases to the west, the fault plane was not folded and maintained a fairly even southerly dip. Structural uplift was greater in the western part of the field, resulting in an easterly plunge to the anticlinal crest which is strongest under P-0166. Local stresses within the developing anticline produced a number of small displacement relief faults of both normal and reverse offset in the supra-thrust block. There is some evidence that the latest tectonic movements may have introduced a left-lateral wrench component, causing a slight re-alignment of the structural trend and possibly introducing some left-lateral slip movement on some faults. Initiation of structural growth on the anticline can be dated as certainly post-Repettian, and probably post-Venturian, probably no earlier than 1.9 mybp (Dickenson, et. al., 1987)[2], possibly as late as 0.2mybp based on initiation of structural growth at Ventura Avenue field, 12 miles to the east (Lajoie, et.al.,1982)[3].

Structural movement continues today on this trend, as evidenced by modern earthquake epicenter data which shows a concentration of small magnitude quakes along the Carpinteria anticline. Migration of oil into the structure probably began at the same time or shortly after the initiation of folding and almost certainly continues to this day. The likely source of the oils is the middle to late Miocene Monterey formation.

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[2]Dickenson, William R., et. al., 1987, Geohistory Analysis of Rates of Sediment Accumulation and Subsidence for Selected California Basins, *in* Raymond V. Ingersoll and W. G. Ernst, eds., Cenozoic Basin Development of Coastal California, Rubey Volume VI, Prentice-Hall, N.J., pp 1-23.

[3]Lajoie, K.R., A.M. Sarna-Wojcicki and R.F. Yerkes, 1982, Quaternary chronology and rates of crustal deformation in the Ventura area, California, Neotectonics in Southern California, Cordilleran Sect. Field Trip Guideb., pp. 43-51, Geol. Soc. Of Am., Anaheim, Calif.

Reservoir Sand

Net reservoir thickness ranges between 30 and 1,070 ft. with an average of 350 feet. The reservoir has reasonably good properties, especially in the overthrust sands (Table 3), with sample rock permeabilities averaging 450 md for the shallowest pay horizon (E-1) to about 80md for the deepest subthrust pay (G-7).

TABLE 3
CORE ANALYSIS AND ENGINEERING DATA

PROPERTY	RANGE	AVERAGE
Core Porosity (%)	15 - 39	28
Log Porosity (%)	10 - 30	20
Permeability (MD, air)	33 - 2200	550
Net Pay (ft)	30 - 1070	350
Well Spacing (acres)		5
Initial Water Saturation (%)	15 - 60	40
Reservoir Temperature (°F)	100 - 160	125
Initial Reservoir Pressure (PSI)		1500 @ 3300'
Current Reservoir Pressure (PSI)		550 @ 3300'
Formation Compressibility	64-110E-06	85E-06
FLUID PROPERTIES		
API Gravity	20 - 34	25
Oil Viscosity (CPS)	1.7-16.9	8 @ 1500 psi, 125 °F
Initial GOR (SCF/STB)	170 - 390	270
Initial FVF (RB/STB)	1.08-1.18	1.15
Bubble Point Pressure (PSI)	970 - 2150	1250

Pay Sand Designation

Operators of different leases comprising the Carpinteria offshore field assign different marker identifications to the various producing sands of the Repetto Formation.

For the Federal lease OCS P-0166 individual sands are identified and divided into four main groups or zones, namely E, F, G and ST or subthrust (Table 4). Each main group is further subdivided into subgroups such that a normal reservoir section reveals up to twenty-two sands in the overthrust block. If the maximum possible number of layers are repeated in the subthrust, the aggregate count of reservoir layers easily climbs to 30 in a single well. These subdivisions comprise separate reservoirs and may have individual oil-water contacts.

TABLE 4
STRATIGRAPHIC COLUMN DESIGNATIONS
Carpinteria Offshore Field

Main Pool	Lease OCS P-0166	State Leases
	E1...E4, F1...F4	F, G, UH
	G1, G1a, G1b, G2, G3, G3a	LH, J, K
	G4, G5, G5a, G5b, G6, G6a, G6b, G6c, G7, G7a	SJ, SK, SL-P
Subthrust	G3, G4, G5, G6, G7	J, K, L-P

Due to the sand-shale depositional sequence, it is often easy to trace the main sand members (F-1, G-1, G-3) across the field. The less-developed sands are not as easily identified and correlated. The shale breaks separating the various zones and subzones typically range from a few feet to 30 feet. The reservoir sands also manifest rapid gradational changes in thickness, quality and areal extent which may be ascribed to the depositional process. Isochore maps of OCS P-0166 show the F-4 sand generally thickening to the east, whereas the F-2 sand thickens to the west. The largest areal extent of reservoir sand is the F-1 layer with approximately 438 acres and the smallest (G - 5A) is about 10 acres.

Lack of Adequate Reservoir Characterization

The lack of adequate reservoir characterization prior to this project was reflected in the lack of consensus among the prior working interest owners about the reservoir conditions and the geometry of the Carpinteria Field. Primarily a question of structural interpretation, the areas of

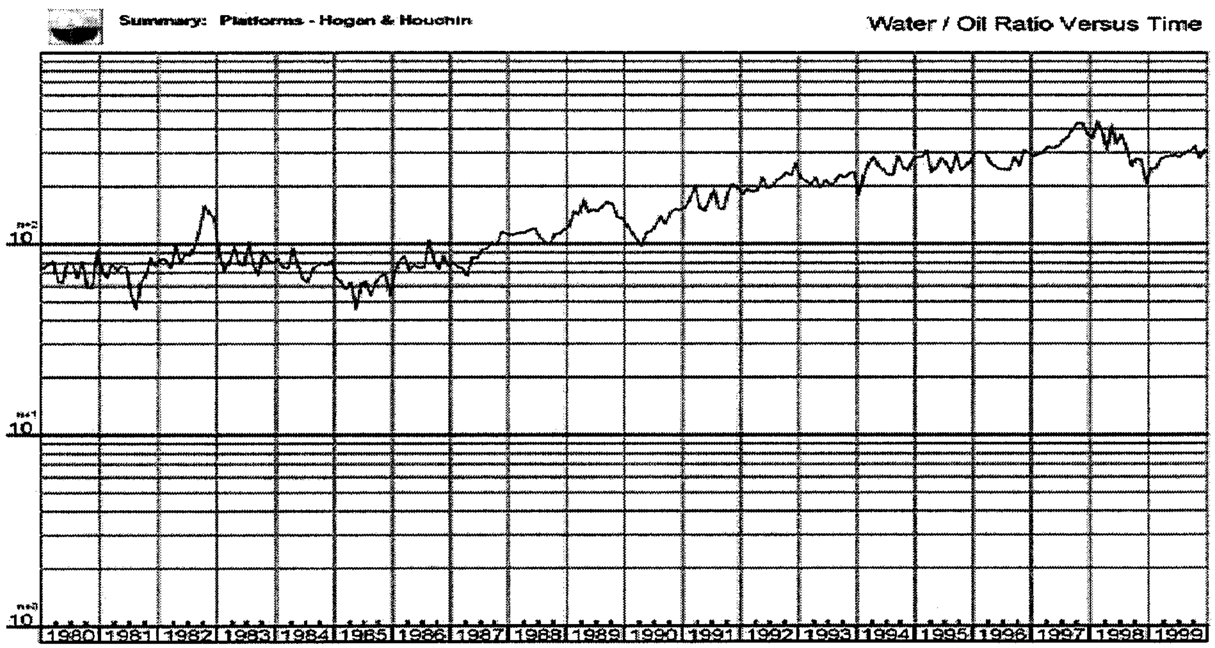

Figure 5: Plot of water/oil ratio (logarithmic) over time for Lease P 0166 (Hogan and Houchin)

disagreement included identification of the various zones and subzones markers, depth variation of numerous oil/water contacts, causes for their multiplicity and, in general, the overall complexity of the fault systems.

High water cut production, shown in the Water Cut vs Time Graph in Figure 5 continue to inhibit production in the field. In part these problems were attributed to the completion methods adopted, but more fundamentally, to the delineation of aquifers and the transition zones, as well as the number and sealing characteristics of the faults. The redrill project is designed to reduce overall water cut by placing horizontal well bores in individual zones which can be shown to have low water saturations.

Lack of Cost-effective Reservoir Management Strategy

The completion design used in the Carpinteria field was one of the few options available at the time the field was initially developed. Well course configurations described the "S" curve profile with the producing interval in a near vertical portion of the well. Multiple zone, gun perforated

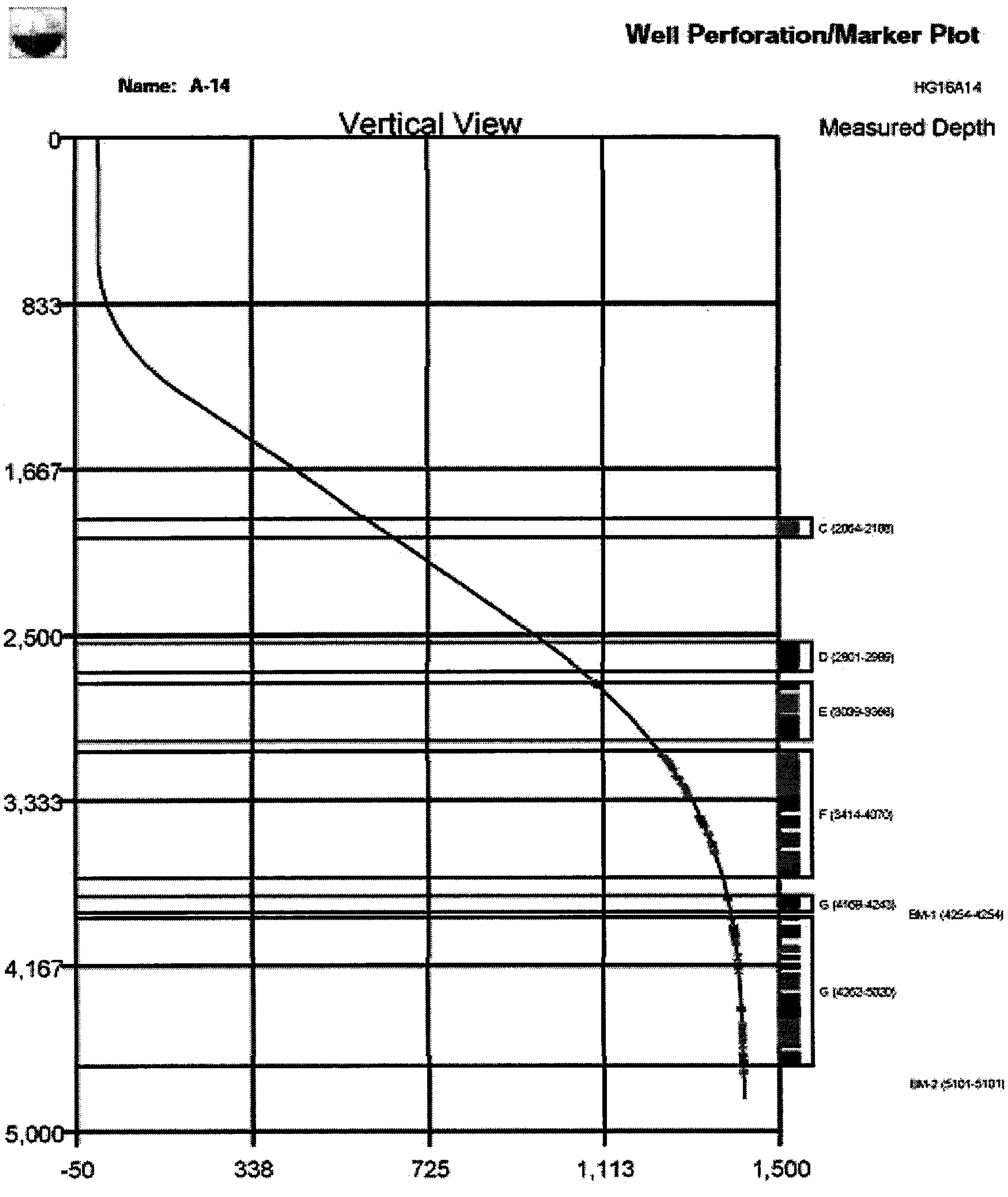

Figure 6: Example plot of an S-shaped well path characteristic of legacy wells at Carpinteria Field

completions, each with a separate oil water contact, in a single well bore created a problem in water and sand control. Figure 6 shows a typical wellbore configuration with perforated intervals. Reduction of the problem would have required multiple and costly workovers, cementing off wet zones and installing gravel packs to control water and sand production. But this was not done and sand migration and water production resulted in the shut-in of 39 wells and is still a major problem in the remaining 28 active producers.

Core data indicate that the Carpinteria turbidite series are loose to moderately consolidated. Laboratory analysis of some of these cores also indicate an unusually high formation compressibility - in the range of 65 to 110 x 10^{-6} vol/vol/psi. There is a substantial amount of fine sand or silt in most of the reservoir rock. A gravel-pack or liner screen would be the only mechanical means of controlling sand production.

Well response to acid treatment to eliminate scale and enhance production has generally been unsuccessful, with an increase of oil production typically lasting two to three months. The acid treatment aggravates the sand migration problem, and polymer treatment to reduce water production has also shown limited short-term benefits.

In view of these problems, while conventional workover techniques must be pursued to improve production from legacy wells, the best improvements of productivity and reduction of sand and water problems in the future is expected to come from novel development techniques such as horizontal drilling.

Proposed Class III Activities

The 1994 proposal included data assimilation and reservoir characterization tasks under budget period 1 and field demonstration based on the budget period 1 results under budget period 2. The following section summarizes the original proposal tasks and objectives.

Improved Reservoir Management Strategies

Modern reservoir analysis and characterization techniques, as well as drilling and completion technology were to be applied during the proposed project to achieve a significantly better understanding of the reservoir and to examine a potentially more effective reservoir management strategy for widespread re-development of the Carpinteria field.

Reservoir Characterization Methods

Reservoir characterization aspects of the project was primarily aimed at estimation of the remaining reserves for the entire Carpinteria field. The complex sequence stratigraphy of the field with a mix of thin and thick and wet and hydrocarbon-bearing sands at various stages of depletion, however, complicates the process. Thus the essential first step was to build a geologic model taking note of the three dimensional variations in sand quality and reservoir attributes such as shale content, porosity, and fluid saturations. Considerable amount of well log data existed to build a three dimensional representation of the geologic model of the field. This model was then to be refined by incorporating conventional and sidewall core data.

All available geological and engineering data in different hard copy files were to be systematically inventoried, collated and reviewed. At the time of the proposal all 47 development and redrill wells on the Hogan platform and 39 wells on platform Houchin had been inventoried with respect to available directional survey records, conventional and sidewall core and analysis data, reservoir fluid data, open hole and production log data, and current well status data. In analyzing these logs, particular emphasis was planned to resolve ambiguities about the structure, geometry and thickness of the various pays (and repeat pays from faulting), the precise tops of the multiple aquifers, and the extent of their associated transition zones.

We planned on developing a 3-D geologic model using StrataModel software to enhance reservoir understanding and to provide realistic explanations for the observed patterns of production and water cuts from the various zones, subzones and sectors of the field.

The data collection and collation contemplated in this objective resulted in extensive electronic database of Adobe Acrobat copies of existing reports maintained on an internal website available to all project participants. The geologic modeling effort resulted in a 3-D model in StrataModel software, maintained at Los Alamos National Laboratory, which included the structural configuration of all zones, the geometry of all existing well bores, and the distribution of porosity, permeability and saturation parameters for the entire field. During preparation for Budget Period II the model was ported to an EarthVision model maintained by Pacific Operators which incorporated the results of the fault delineation studies.

Production and Pressure Performance Analysis

An extensive database existed on individual well production histories. However, further reviews of these data were needed, especially in relation to the completion and workover status at critical junctures in the well production cycle. Attempts were to be made to utilize all existing shut-in pressure data (by zone and by well) when conducting the aquifer and voidage distribution analyses.

This objective resulted in electronic and hard-copy databases which helped to identify legacy wells with potential for conventional workovers, and provided a valuable cross-check for local zone and fault block pressure depletion or water-sweeping as we progressed toward the initiation of Budget Period II drilling.

Reservoir Properties

Adequate suites of logs were run in every well in the field. Conventional (rubber-sleeve) coring, however, was limited to approximately 400 ft in five wells. Sidewall cores were taken in nine wells. Most of the coring occurred primarily within the F and G zones, which together are believed to hold an estimated 90% of the original oil in place. Significant differences, sometimes as high as 29%, between log and core porosity data have been noted in some of the prior studies on the field, especially in the loosely consolidated shallow pay zones. Log calculations were to be redone using revised computation models. Core analysis, porosity and permeability were to be adjusted for overburden and compaction using some existing data and information from rocks of similar characteristics. The correlation between core permeability and porosity was to be carefully re-examined as part of the core-log modeling exercise.

Significant insight into spatial variation of reservoir properties was expected to be provided by the MWD logging of the proposed horizontal sections. The 5-acre spacing adopted by the prior owners for the development of the Carpinteria field lease OCS P-0166 is adequate from a normal field drainage standpoint, however, it was felt to not provide sufficient information for characterizing interwell distribution of reservoir properties.

This objective resulted in the digitization of all applicable electric logs in the field. An electronic database, generated by LogCalc software on a Vax system maintained by Pacific Operators, was prepared which contains basic log traces as well as reservoir parameter calculations including porosity and permeability computations, lithology indicators such as Vshale, and a variety of saturation indicators. This database has been ported into MSAccess and is available to the Pacific Operators internal network and to selected external parties via remote network access software. As part of this effort, the trace files were populated with coordinate data corrected for both well deviation and structural dip which allowed correlation (or any parameter) traces to be plotted on a true stratigraphic thickness depth scale. This proved critical to the analysis of faulting by well log correlation.

Reservoir Management

Adaptation of improved reservoir management strategies for the Carpinteria Field must take note of certain constraints. The primary goal in the Project was to increase production and to extend the life of the field. Reservoir management, from both technical and operational point of view must be based on a compromise between maximum ultimate recovery and current cash flow. This can be accomplished by lowering operating costs, and increasing daily production and total oil recovery from the reservoir.

It was anticipated that with the complete reservoir description from this project, there would be sufficient information to help design a system for expansion of primary production and to prepare for pressure maintenance or other improved recovery operations. Satisfaction of this objective resulted in the drilling of four horizontal redrill wells which have significantly increased field production (described in detail below) and has provided necessary information for a planned future waterflood.

Development

Considering the desired information base of the horizontal well, we proposed to probe three main completion intervals by conducting MWD surveys in each leg. The three sands where information was desired were the E-1 sand which is very porous, friable and permeable with good vertical to horizontal permeability ratio, the F-1 sand that holds major reserves and is more stratified than the E-1, and the F-3 sand which is similar to the F-1 but may have more water problems. The G sands, which grow progressively thinner down structure, were also to be considered.

An important consideration in well design is to maintain the course of the lateral(s) near the crest or high point of the structure, possibly along the axis of the plunge to remain as far away as possible from water and gas cap. In a faulted structure with the hole near perpendicular to faults, one lateral could possibly drain several blocks. Initial wells following these design criteria have been drilled and are described in detail below.

Well Testing and Monitoring

Each lateral section was to be individually tested by isolating the zone with a packer and retrievable bridge plug configuration. In this manner, the productivity and reservoir characteristics of each zone would be determined and monitored.

The tri-lateral concept was replaced with a multiple slimhole redrill concept that has been implement and reported below.

Completion Design

Each lateral section was to be completed with a slotted liner to provide wellbore stability and to reduce sand influx to a tolerable level. The horizontal course was expected to result in water-free production. But if a wet interval was encountered, it was to be isolated with a blank section of liner and external casing packers to prevent water migration behind pipe in the liner-open hole annulus.

The tri-lateral concept was replaced with a multiple slimhole redrill concept. In the initial four well program wet intervals were carefully avoided and each horizontal was successfully completed with slotted liner.

Field Demonstration

The purpose of the field demonstration was to prove that a strategically placed horizontal well near the high point structurally in a producing horizon would avoid water production, reduce scale and sand problem, and thus improve well oil production and lease economics. The demonstration well was to be further used to update and enhance the geological model and the total reservoir characterization.

Horizontal completions have become a common method to enhance productivity in reservoirs throughout the world by increasing reservoir drainage contact area. Multi-lateral well completions are a direct application of horizontal drilling technology utilized to simultaneously produce multi-layered reservoirs. This technology was deemed applicable to the turbidite sequences in the Carpinteria Field and was to be used to develop the multiple lobes of the Repetto Formation. At the time of the proposal, approximately ten extended reach horizontal and trilateral wells had been successfully drilled in the adjoining Dos Cuadras field, with horizontal legs typically about 4,800 feet. The well path of the laterals in our demonstration well was to be designed based on the results of the reservoir characterization.

The horizontal hole would have a larger amount of sand open from which to produce. This was expected to increase productivity in the very porous and permeable sands, but sands with low vertical permeability due to micro-lamination or layering might not sustain high productivity, hence the optimal well course was to be in the more massive sands.

Because the proposed geological modeling approach is predominantly a deterministic one, mapping of reservoir attributes from well logs and other reservoir data in a three dimensional setting requires an estimation procedure for unsampled spots. MWD record of a horizontal well bore in a well developed, massive sand was expected to allow estimation of typical lateral reservoir changes by providing the correlation of directional stratigraphical changes in a typical sand. It would further define some structural style and faulting patterns as previously mapped and allow the reservoir model or description to be updated.

The tri-lateral concept was replaced with a multiple slimhole redrill concept, reported below. Measurement While Drilling (MWD) techniques permitted assessment of reservoir quality during drilling and resulted in the definition of additional faulting in the eastern portion of Lease P 0166 which has improved our understanding of the distribution of reserves in this area.

Technology Transfer

POOI and the participating team members in this project are highly committed to technology transfer, especially for the benefit of other small operators. The concept proposed in this project has two potential benefits: First, from the standpoint of reservoir characterization, probing the turbidite series in various lateral directions can generate valuable information about the mode of sedimentation and genetic differences of various lobes. Second, the expected improved productivities from the proposed drilling method can result in a very effective and economically attractive re-development strategy for this field and other SBC reservoirs. Information about reservoir characterizations and reservoir testing in general was to be released to industry through various avenues, such as professional publications, professional society meetings and workshops. The goal of the technology transfer for this team was that each medium of communications be visited at least once during a one-year cycle. Presentations at local meetings of professional societies were to be conducted at least once on a quarterly basis.

Pacific Operators and other study team members have authored and presented multiple talks and papers, both in the trade press and in professional meetings and journals, detailing the redevelopment of the Carpinteria field throughout the history of the project. These papers are cited below.

Coombs, Steven F., 1999, The Feasibility of Optimizing Recovery and Reserves from a Mature and Geologically complex Multiple Turbidite Offshore California Reservoir Through the Drilling and

Completion of a Horizontal Well (DOE Class III), _presented orally_, West Coast PTTC Annual Forum, University of Southern California, Los Angeles, December 10, 1999.

Edwards, Edwin B., 2000, New Oil from and Old Oil Field: Results of Redevelopment from Platform Hogan, Carpinteria Offshore Field, California, _abst._, Program and Abstracts, Pacific Section Convention and Western Regional Meeting, Amer. Assoc. Petroleum Geologists and Society of Petroleum Engineers, Long Beach, California, June, 2000, p. A15.

Edwards, Edwin B., 1998, Redevelopment of the Carpinteria Field, Santa Barbara Channel, California _in_ Dale S. Kunitomi, Thomas E. Hopps and James M. Galloway, _eds._, Structure and Petroluem Geology, Santa Barbara Channel, California: Pacific Section AAPG and Coast Geological Society, Miscellaneous Publication 46, pp. 239-246.

Edwards, Edwin B., 1997, _interview in_ 3-D Structural Modeling Mitigates Risk _by_ Tim Beims, American Oil and Gas Reporter, November 1997, pp. 99-109.

Fleckenstein, W. W., S. F. Coombs and E. B. Edwards, 2000, Redevelopment Activities in the Carpinteria Field Offshore Santa Barbara County, California: Slimhole Horizontals Reap Big Benefits, _in_ Proceedings, SPE/AAPG Western Regional Meeting, 19-23 June 2000, Long Beach, California U.S.A., _compact disk_, SPE 62530.

Pawar, R. J., E. B. Edwards and S. F. Coombs, 2000, Comprehensive Reservoir Modeling of a Mature Geologically complex Reservoir, _in_ Proceedings, SPE/AAPG Western Regional Meeting, 19-23 June 2000, Long Beach, California U.S.A., _compact disk_, SPE 62533

Impact

The target audience for the proposed technology includes all operators of turbidite reservoirs. In particular, the small operators would learn guidelines on economic viability of using effective modern drainhole technologies to access several compartments in complex slope and basin reservoirs. The entire proposed process of developing a geologic reservoir framework model to pinpoint optimum courses for the infill multi-lateral horizontal wells has significant technology transfer value to the other small operators. The change from the tri-lateral concept to the multiple slimhole redrill concept has enhanced applicability for smaller operators with limited capital through the application of Measurement While Drilling and slimhole drilling and completion techniques to redrills from existing surplus wellbores.

Applicability of Technology

The horizontal drilling technology is a proven method for enhancing well productivities while minimizing water production from adjoining wet stringers. Horizontal holes have been drilled into California turbidite sands. The mode of the proposed trilateral hole to drain several sand lobes would open up new opportunities for economic re-development of reservoirs under the influence of wet stringers. The TORIS data base shows that 17% (or 60 billion barrels) of the total domestic oil resources base is in the turbidites. Successful implementations of the proposed project was expected to have wide impact on the re-birth and re-development of aging fields.

The tri-lateral concept was replaced with a multiple slimhole redrill concept as described below. The success of the multiple redrill redevelopment project in which horizontal wellbores are placed in structurally advantageous positions in Carpinteria's Pliocene turbidite sands has dramatically increased the life of the Carpinteria field. Similar technologies would be applicable to a number of aging turbidite fields, as well as to fields in other sedimentary settings that result in laterally continuous sand/shale sequences.

Budget Period I Results

Budget Period I Overview

The field study efforts completed to date have built and analyzed a significant database consisting of reservoir and geologic data from over 200 wells previously drilled in the field. A new geologic interpretation was developed using state of the art 3-D modeling software called EarthVision. This software allows the complex database of information to be viewed in a format that is most understandable by the various technical and management personnel of Pacific Operators, and by third party service contract representatives. Inputs to the 3-D modeling package included re-processed well logs that were reformatted employing a consistent methodology. In addition to porosity and saturation values, the log processing effort resulted in the generation of true stratigraphic thickness (TST) logs for nearly every well in the field. Largely due to the availability of TST logs, a team of geologists was able to make detailed correlations across the field identifying 14 separate faults. Many of these faults were not identified by prior investigators.

One of the complexities of the field has been that its historical production was commingled from several different producing zones. For the first time, the POOI study has made a serious attempt to identify the amount of oil produced from each of those zones. That was accomplished by developing a computer program that allocated the production on a zone by zone, well by well basis, over the entire producing history of the field. Other investigators have only been able to make rudimentary estimates of single zone production, so our efforts go a long way in helping determine remaining oil and gas in individual sands.

Oil and Gas reserves for Lease OCS P-0166 (P-0166) were determined using both the material balance technique and volumetrically. Additional estimates for the entire field were estimated using volumetrics alone.

Finally, an economic model was created based for the budget period II well drilling program. We recognized at the outset that the redevelopment program proposed here was subject to constant review and revision, both leading up to and after the drilling program was underway, so we could incorporate both our increased knowledge from our study and the results from all the wells drilled to that point.

Our current strategy began with the Class III, DOE cost sharing well . Thereafter, we planned to evaluate the possibility of drilling multi-lateral wells, but only after drilling several single zone horizontal wells and observing their performance. We planned to re-drill several existing wells from Platform Hogan. Those re-drills would only require cutting a window in the existing 7" casing and drilling short slim-hole laterals into specific sands. Those redrills were important because they would allow: (1) Productive utilization of the drilling rig while evaluating the results of the first horizontal well, and; (2) Important reservoir and productivity information on selected, single zones for much less expense than drilling a completely new well.

In December, 1996 we initiated a study of the existing wells (both producing and shut-in) and started a workover program in the field on both Hogan and Houchin. These early workovers consisted of acid stimulation, gravel packing wells that produce excessive sand and installation of new progressive cavity pump (PCP) equipment. The results from those workovers were very helpful and important in proving the current potential of some of the sands we were targeting for horizontal drilling.

Petrophysics

Log Data

The petrophysical log data was gathered for over 200 wells in the Carpinteria field and, along with a few scattered seismic lines, constitutes all of the subsurface information that exists. Formation dip data, recorded on most wells, is a key portion of the information package, as is the directional or well course survey that was collected during the drilling of all of the wells. This petrophysical data was corrected for any environmental effects or deficiencies in recording. This was accomplished for all wells and a set of log databases containing both original and corrected data was prepared.

Geological interpretation relies heavily on the log trace data in that detailed layer recognition and correlation are required before structural surface configuration and fault distribution can be accurately determined. These functions can be much better performed from well logs that have been modified to remove the distorting effects of borehole deviation and in-hole apparent dip. Such corrections have been made to the Carpinteria field logs and true vertical depth (TVD) and true stratigraphic thickness (TST) logs have been prepared. These logs were made using borehole directional and dipmeter data, with guidance from preliminary structure maps made previously on the main zone tops.

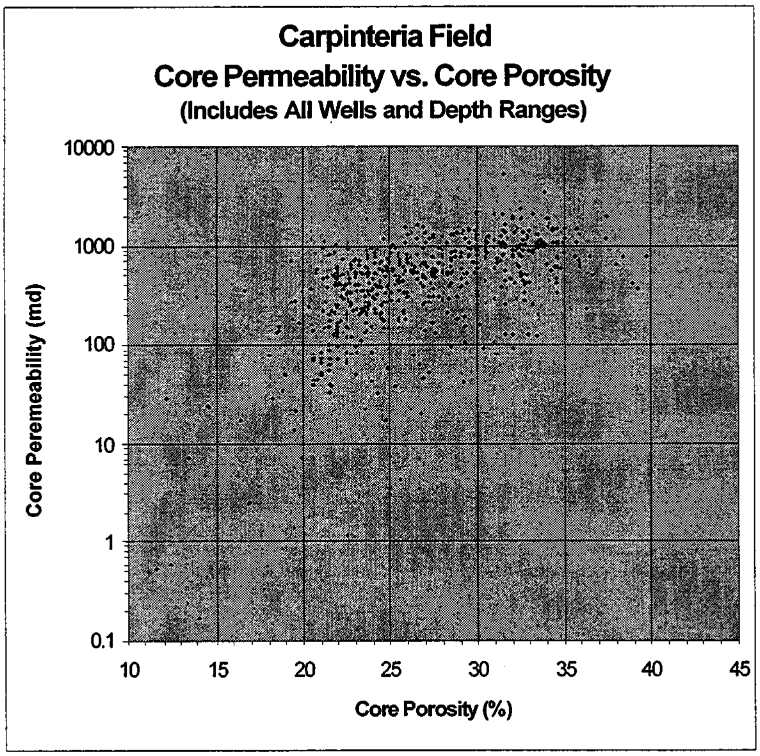

Figure 7: Graph of core permeability versus core porosity for carpinteria field

In addition to removal of directional and structural distortion, the new logs had consistent scaling and visual appearance which facilitated comparison. Using these improved log data sets, correlation markers and faulting were interpreted and collected in the geological data base. The structural interpretation based on the layer tops and bottoms defined by the correlation markers is the key information guiding the geological and petrophysical modeling which is used to describe the reservoir. Accurate marker information is also used to control further log analysis, and serves as the basic framework for reservoir engineering study.

Core Data

Core data is a key part of the petrophysics in that the porosity, permeability and fluid content from cores is used for the calibration of logs. Core data, while considered to be "ground truth", is only accurate with careful handling. Consider that the core is taken from a well at depth and under pressure. It is brought to surface and subsequently analyzed. The handling between the cutting of the core and the analysis is critical to accuracy. Many of the conditions of core handling and analysis are unknown, and hence the analytic results must be considered to be less than absolute.

Figure 7, Core permeability vs Core Porosity shows the range and trend of the data. It is apparent that over a portion of the range that there is a log/linear trend to the data. As is typical there is a great deal of scatter in the data. Of particular note is the fact that the permeability drops sharply below about 15% porosity. It is from this observation that a cutoff for porosity data is estimated for use in determining the productive reservoir volume from log analysis.

Cores are expensive, and core analysis can cost easily as much as the core itself. The coring tool, therefore, is not used any more than absolutely necessary. Core analysis, whether from "whole core" or "plug samples" evaluates only an inch or so of the formation. This coupled with the limited distribution of the data forces the major interpretation of reservoir characteristics from well logs. There is at least one order of magnitude between the distribution of core data and the logs and as much as two orders in portions of this reservoir, meaning that we are comparing a core sample of 1 inch with logs that have a minimum resolution of 2 feet and have a density of core samples as infrequently as every 5 feet down to one per foot. Typically there are fewer than 200 to 300 core samples in a single well.

From this core data, which is generally equivalent to the total porosity, log data can be adjusted to follow the same trends. Typically there is little adjustment to be made once the log and cores are set to the same overburden pressure loading. Figure 8 shows a comparison of Core and Log porosity data for the entire OCS portion of the Carpinteria field. There is considerable scatter which in part can be considered a matter of scale and some depth mismatching.

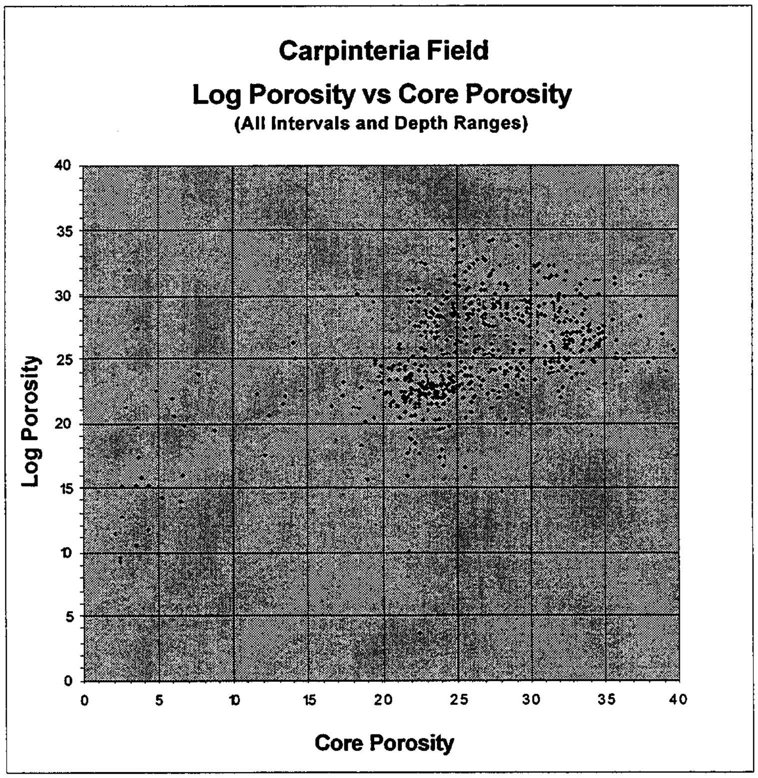

Figure 8: Graph of log porosity versus core porosity for Carpinteria field.

From the log derived porosity, an attempt is made to determine a permeability value from porosity and clay content of the rock. Considering the poor correlation of log and core porosity and a poor correlation of core porosity and core permeability, the resultant core permeability vs log permeability is not a strong correlation. Figure 9 is a scatter plot of log derived permeability vs core permeability. It appears in part to be bimodal. It does, however provide a continuous permeability trace for all wells and allows distribution of this attribute over the reservoir.

Point by point examination of logs through intervals where cores were taken shows porosity from the core can be both higher and lower than the log porosity. Log permeability approaches the value of core permeability in the low to mid ranges, but does not reflect the very high permeability seen in some cores. One additional correlation is that of the comparison of core water saturation with flushed zone saturation from the logs. This correlation is frequently good suggesting that the overall log saturation calculation method is correct.

Petrophysical log analysis allows determination of the types and amounts of fluid, the porosity and the permeability encountered by the wells.

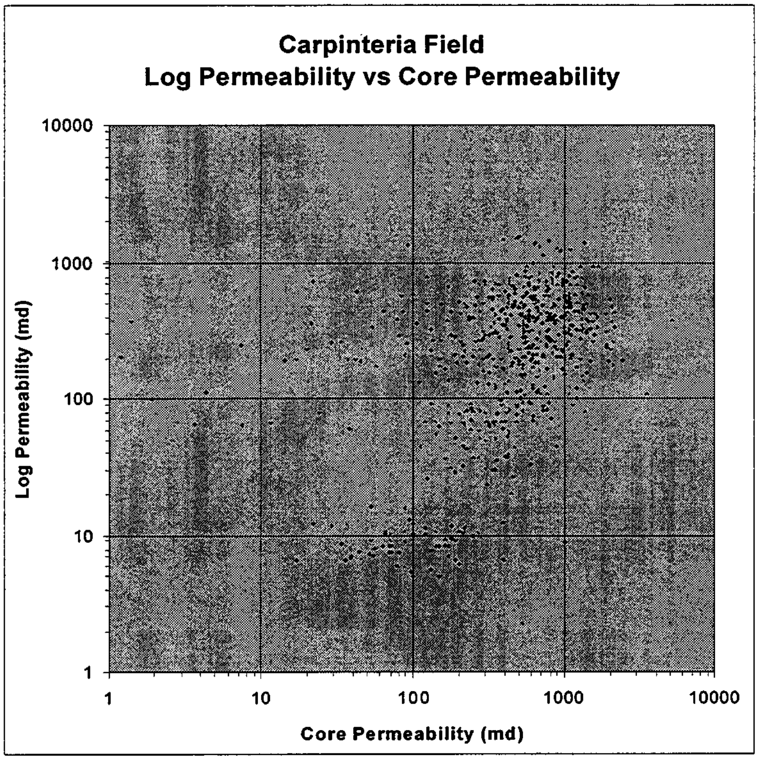

Figure 9: Graph of log permeability versus core permeability for Carpinteria field

Engineering Data

Engineering data such as pressure, fluid characteristics, and permeability derived from pressure and flow tests in wells assist in log analysis as well. This data is used to provide limits and controls for log calculations. However, the log calculations themselves can provide the knowledge of the types and amounts of fluid, the porosity, the permeability, and the distribution of these attributes throughout the reservoir. Again there is the matter of scale. Reservoir engineering data can consider the reservoir as a whole or at least a fairly large volume of rock near the well. Logs provide data all within a few feet of the well bore, or a fairly small volume of rock.

Analysis of Results

The analysis of log results is generally given in graphic formats as well as in tables of numbers and totals. The typical formats are: (1) A computed log output, or graph of results vs depth for each well. This allows understanding of the rock and fluid characteristics on a foot by foot basis for every penetration of the reservoir; (2) Computed log cross sections showing portions of the log for several wells. These show conveniently how characteristics, such as accumulations of oil, change from well to well and; (3) Contoured maps of numerical values of results showing changes on a large scale basis

All of the petrophysical analysis was done in two dimensions but was later ported into Dynamic Graphics' EarthVision 3-D modeling program. This computer graphics display can show one or more characteristics, such as oil saturation or oil filled pore volume, as color changes while the structural characteristics are shown in three dimensions. In addition to the three dimensional nature of the reservoir, the program also allows two dimensional slices through the reservoir showing areas or pods or oil saturation or porosity. Further, the program, with adequate input, allow the computation of oil in place and output to flow simulators running on a similar grid system.

Porosity and Saturation

Log derived porosity values were used for the project's reservoir parameters analysis. Log derived porosity values are created from a number of measurements, primarily the density, neutron, and sonic log, with help from all the other logs recorded. Log porosity is defined as total porosity or as effective porosity. We were particularly interested in effective porosity since it is considered to be that portion of the pore volume from which fluid can be extracted or moved, and it defines the total reservoir volume for material balance and other analysis. Fluids which are locked into the structure of the rock, or very finely divided solids which are not part of the rock structure, are in the ineffective portion of the pore space. The effective pore space contains fluids, gas, oil, or water which can be moved. Most log determinations are based on the water portion of the fluids. Each log measurement treats rock matrix and fluid characteristics differently. These differences allow determination of porosity, rock type, fluid type and distribution within the pore volume. None of the measurements directly measure the information that is needed for the complete reservoir description. Where possible these log derived values were calibrated against core data to maintain and integrated analysis approach.

Permeability

No log measurements available in this data set are a direct measurement of permeability. We derived permeability through a process of multiple regression with several log inputs and outputs, then created an algorithm which has a reasonable correlation to core permeability.

Data Summaries

To permit mapping of results, log calculations for porosity, water saturation, probable permeability, and hydrocarbon saturation values were averaged by well and by zone. Initially, the results were mapped in two dimensions. One of the more important mappable values is the Hydrocarbon Pore Volume, or "HPV". HPV is calculated from effective porosity, hydrocarbon saturation and true vertical thickness, for each identifiable layer that contains oil. Volumes of oil in place can then be calculated for fault blocks, zones, or the entire field, by determining the area of the accumulation. Hydrocarbon pore volume maps were useful in determining which zones and fault blocks had the best initial saturation volumes and, assuming proportional depletions, could be expected to be the best targets for further development.

More sophisticated mapping and calculation can be done within the three dimensional EarthVision computer model. Sorting, detailing, visualizing and working with the data allow the determination of the areas that have, or had, the best oil accumulation, and the areas which have the best potential for additional development. We successfully ported the log calculated reservoir properties data into EarthVision but were unsuccessful in obtaining reliable reservoir volumes because inability to accurately model the inclination of the oil/water contacts caused the model to project unreasonable hydrocarbon volumes down flank beyond well control. We anticipate that we will overcome this problem with a second generation model which is planned before resumption of redevelopment drilling.

Interpretation

The basic interpretation of the log analysis methods consisted of determining the attributes for each well for each interval on which there is an adequate well log data set. These attributes included identification of the clay or shales for every point in the well. This output allowed us to consider: (1) The volume of shale (known as Vshale) within a unit volume of the formation. From this value we were able to develop an understanding of the rock deposition and the potential of the rock to contain fluids; (2) The pore space within the rock (both effective and total porosity); (3) The nature and amount of fluids in the pore space (including oil, water, and gas); (4) The permeability of the pore space, derived from correlations with core and engineering data, and; (5) The potential for production of gas, oil, and water.

Summaries of the attributes within each well, shown as an areal distribution, provided for a determination of the volume of the reservoir, and consequently the oil in place. Data taken at the discovery of the field can be taken as a measure of the original oil in place, or OOIP. Data taken at later times has in some cases provided a measure of depletion.

Petrophysical Conclusions

Results of the log analysis and other evaluation data, such as well testing, engineering analysis, and production, agree on a well by well basis, verifying that log calculated reservoir parameters are reliable.

Mapping of attributes such as hydrocarbon pore volume, porosity, and oil saturation on a layer by layer basis support the geological mapping and production results, and indicate areas where additional development is possible. The results of drilling under Budget Period II verified the efficacy of this approach. Determination of oil/water contacts, or limits of production from logs suggests that there is no level oil water surface for each sand, layer, or group of sands or layers. There appears to be a tilted oil water contact. This is a critical observation that proved key to successful fault interpretation and is an important component in the layout of redrill well bores.

Additional analysis and sorting to provide data for a second generation of the three dimensional Earth Vision reservoir model is needed.

Geologic Interpretation and Modeling

Structural Description of Carpinteria Field

Fold Geometry

The Carpinteria anticline is an east plunging slightly asymmetric fold trending N74°E on leases P-0240 and P-0166, changing to N86°E on Lease PRC 3150. Plunge is greatest on Lease 0166 where it averages 5 ½ degrees. To the east on the PRC 3150 lease the plunge is much less, averaging only about 3 degrees east, while at P-0240 the easterly plunge is only 1 ½ degrees. The south flank of the field is slightly steeper than the north flank, averaging about 30 degrees versus 22 to 25 degrees. Flank dips are poorly controlled since the vast majority of the wells were drilled on the crest where dips are 10 degrees or less. A very few flank wells and coreholes, coupled with a handful of seismic lines of varying quality define the reported values.

Hobson Fault

The anticline is cut by a major reverse fault; the Hobson fault. In well data the Hobson is recognized as a repeat of Pliocene sandstones below a section of Miocene siltstones, and as a sudden and dramatic increase in dip on the dipmeter. Movement on the Hobson fault has displaced the rocks above the fault plane (the hanging wall) northward relative to those below (the foot wall). The amount of this displacement varies from place to place, but is frequently on the order of about 1000 to 1200 feet. The rocks in the hanging wall of the fault have been termed the supra-thrust block; those in the foot wall the subthrust block.

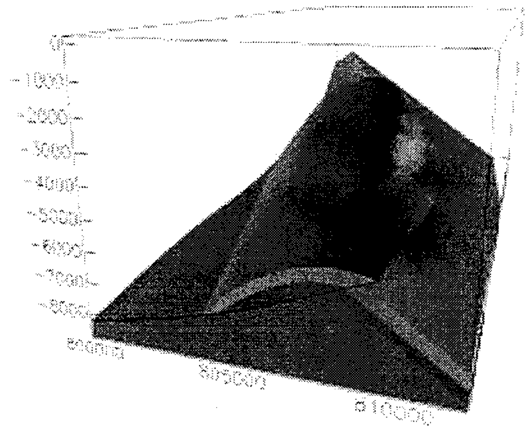

Figure 10: View looking southwest at 3-D model showing offset on Hobson thrust fault.

An unusual condition is found in the State portion of the field (leases PRC 3150 and PRC 3133) in which the Hobson fault plane is folded into an antiform with a structural relief of 200 to 300 feet This folding of the fault plane has important implications for the structural history of the Carpinteria Field. The presence of a fold in the fault plane in the area of the State leases coupled with a smooth fault plane under the Federal leases suggests that movement on the fault may have ceased in the eastern area while the fault was still active to the west. Termination of movement in the folded area seems to be required by the geometric difficulty of moving relatively competent rock over a complexly curved surface. Later structural movement to the west is consistent with the observed difference in structural elevation between the two areas as evidenced by the easterly plunge of the anticline. Such a change of movement would seem to require a stress partitioning fault plane between the two areas. The East Boundary fault (described below) would be a candidate. Ongoing detailed geologic studies of the subthrust wells should provide further control on the order of faulting.

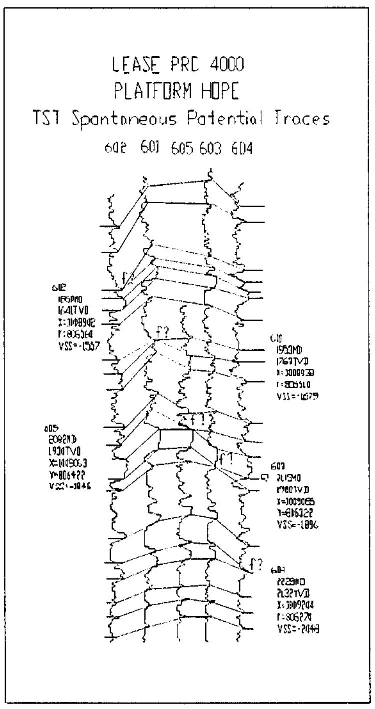

Figure 11: Example of detailed correlation of well log traces showing the effect of faulting.

Although the fold in the Hobson fault plane seems to terminate at about the Federal/State boundary, two other possibilities exist. The fault plane fold could change trend in a southerly direction, continuing along the south flank of the anticline but beyond the reach of the current P-0166 wells. Alternatively, what seems to be a uniformly south dipping Hobson fault plane on P-0166 could actually be a splay of the main fault, with the actual Hobson fault continuing its antiformal configuration onto P-0166 deeper in the subsurface. These possibilities are currently under investigation. Importantly, both configurations could provide opportunities for unexplored hydrocarbon potential on P-0166; the first by enhancing entrapment opportunities for south-dipping Repettian sands in the subthrust south of current production, and the second by creating a deeper trap in north flank rocks. These possibilities are discussed in greater detail below.

Supra-thrust Faulting

The distribution of faulting in the rocks of the Hobson fault hanging block (the supra-thrust block) was carefully studied because of the potentially important effect of such faulting on the distribution of hydrocarbon saturation in the productive section. Previous interpretations of the Carpinteria anticline have shown it as being divided into numerous individual fault blocks by a series of approximately north-trending cross faults. These faults were interpreted largely because of a need to account for an extremely complicated distribution of oil/water contacts observed in the wells. Not only are separate oil/water contacts present in individual producing sands, but contacts are found at different elevations within the same sand at different locations in the field. Faults were frequently invoked to explain saturation anomalies even in the absence of supporting evidence.

POOI has carefully re-examined all of the available well data in an attempt to clarify the fault interpretation. With the application of computer technology to the problem, it was possible to prepare true stratigraphic thickness (TST) logs for each well, correcting for the effects of both well deviation and in-hole dip. It is much easier to perform detailed log correlations using TST logs and thus much more accurate interpretations of duplication or deletion of stratigraphic section can be made. Such stratigraphic anomalies are direct evidence of faulting within a well bore. To further enhance the interpretation, masses of well data were examined simultaneously by using TST log correlation panels on which traces (spontaneous potential or gamma ray) for as many as 20 wells can be displayed at one time. On the computer screen, sections of log from one well can be laid along side any other well and can be "slipped" up or down to permit very detailed comparison. By examining many wells at one time it is much easier to determine if correlation anomalies are due to faulting or are due to gradual changes in stratigraphic sequence due to depositional effects.

A total of 81 fault intercepts were identified by log correlation during the study. All but 20 were assigned to one of 14 fault planes. Fault planes were identified by contouring fault intercepts in a local area. Intercepts with similar magnitudes of stratigraphic offset which also appeared to define a geologically meaningful surface were assigned a name based on their geographic location and were considered to represent a fault plane. Stratigraphic offset magnitudes are not the same as fault throws. Consider, for example, a fault with purely lateral (horizontal) movement in flat lying beds. Such a fault could have essentially unlimited throw without showing any stratigraphic offset because each bed would be moved only parallel to its own surfaces. While stratigraphic offsets may be less than actual fault throw, they will never be more. At Carpinteria, the structural geometry is such that the magnitudes of stratigraphic offset seen in the wells probably at least approximates actual fault throw, but some variations are to be expected among the fault intercepts that define individual fault planes because some lateral movement along these faults is likely.

Faults may or may not impede the flow of hydrocarbons through the subsurface. Evidence for reservoir segregation by faulting at Carpinteria comes form mapping of saturation characteristics in individual zones and from contour mapping of oil/water contact surfaces. If zone penetrations up structure from a fault show as wet or as containing an oil/water contact while those down structure are saturated from top to bottom, it is reasonable to infer that the fault has impeded migration up structure and is therefore evidence that it is sealing. Similarly, if contoured oil/water contact surfaces appear to be offset by a fault, then the same inference may be drawn.

Fault planes identified in the supra-thrust block at Carpinteria field have been designated as follows:

West Henry Fault: sense of movement – normal; stratigraphic offset – about 80 to 90 feet, fault intercepts identified – 4; location – south flank area of P-0240, south to southeast dipping, trending northeasterly, curving more northerly to pass between the east well spread from Platform Henry and the west well spread from Platform Houchin. The West Henry Fault appears to have a major effect on saturation distribution between P-240 and P-0166.

North Flank Fault: sense of movement – reverse; stratigraphic offset – about 30 to 40 feet; fault intercepts identified – 15; bcation – north flank area of P-0166, south dipping, steepening with depth and trending approximately east-west. The North Flank Fault shows evidence of having some effect on hydrocarbon distribution but more detailed studies using 3-D geological modeling of saturation data will be required to confirm.

South Flank Fault: sense of movement – reverse; stratigraphic offset – about 30 to 40 feet; fault intercepts identified – 4; location – south flank area of P-0166 in the vicinity of Platform Houchin, north dipping, trending approx. east-west. The South Flank Fault has not been associated with production anomalies.

West Hogan Fault: sense of movement- normal; stratigraphic offset – about 30 to 40 feet, fault intercepts identified – 3; location – westerly well spread from Platform Hogan, trending north-northwest. The West Hogan Fault appears to account for some saturation variations in the F zones and is located near some oil/water contact anomalies.

West Boundary Fault: sense of movement – normal; stratigraphic offset – about 20 feet; fault intercepts identified – 3; location- east well spread from Platform Hogan, dipping easterly, trending north-northwest. The West Boundary Fault seems to be a shallow feature related to the East Boundary Fault described below.

East Boundary Fault: sense of movement – normal; stratigraphic offset – about 25 feet; fault intercepts identified – 6; location – throughout the 600 series wells drilled into PRC 4000 between PRC 3150 and P-0166, dipping steeply westerly and trending north-northwest nearly parallel to the P-0166 east lease boundary. The East Boundary Fault seems to clearly affect saturation in all zones and to control several oil/water contacts.

North Hope Normal Fault: sense of movement – normal; stratigraphic offset - 75 to 100 feet; fault intercepts identified - 3; location - northeast well spread from Platform Hope, south dipping, trending approximately east-west. This fault, found only in the shallow portions of three Hope wells, has the greatest stratigraphic offsets yet recognized. Despite its large apparent offset, the North Hope Normal Fault has not been recognized below -2050 feetand its effect on production has not been determined.

North Hope Reverse Fault: sense of movement - reverse; stratigraphic offset - 30 to 60 feet; fault intercepts identified - 3; location - north flank of the anticline in the extreme northern wells from Platform Hope. This fault trends northwesterly. Its lateral extent cannot be traced further because of lack of well data. Effect on production has not been determined.

South Hope Faults One, Two and Three: sense of movement - normal; stratigraphic offset - 10 to 60 feet; fault intercepts identified - 12; location - south and west well spread from

Platform Hope. This group of faults represents an attempt to catagorize a cluster of fault intercepts found in this area. Fault traces are approximately east-west. Effects on production have not been determined.

West Heidi NorNormal Faults One and Two: sense of movement - normal; stratigraphic offset - 15 to 35 feet; fault intercepts identified - 9; location - west well spread from Platform Heidi. These two relatively small displacement faults cannot be traced deeper than about -2800 feet Their effect on production has not been determined.

East Heidi Normal Fault: sense of movement - normal; stratigraphic offset - 25 feet; fault intercepts identified - 3; location - east Heidi wells, trend approximately east-west, north dip. Effect on production not determined.

The 20 fault intercepts which were recognized on the well logs but could not be assigned to fault planes are continually being reviewed to see if new data, such as saturation distribution, may shed light on their significance. Frequently a fault encountered in a given well may be oriented such that no other well penetrates the fault plane within a logged interval. Such a fault can only be mapped if it has some effect on an independently mappable property. Also, some of these unassociated "intercepts" may actually prove to be local stratigraphic variations rather than fault features. Interpretation of faulting at Carpinteria Field is an ongoing process that will evolve as existing data is re-examined and as new data is acquired.

Subthrust Structure

The structure of the subthrust block (the rocks of the Hobson fault footwall) is currently being investigated using the same correlation methods as described above for the supra-thrust block. Preliminary mapping of key subthrust horizons on P-0166 show a north-dipping flank inclined at about 30 to 45 degrees, trending slightly north of east as does the structure in the overlying supra-thrust block. On the preliminary maps there is a southerly deviation of the structural contours between wells A-36 and A-38 (California Lambert Zone 6 X-coordinate between 1,004,712 and 1,005,668), probably due to a fault with a down-dropped block on the east containing the A-38 well. Additional such faults are probably also present in the State portion of the subthrust, but correlations have not progressed far enough to delineate such features. The south flank of the subthrust structure was penetrated only in the A-42 well from Platform Hogan, studies of which have not been completed. Subthrust opportunities are of great interest for future field development, but are not germaine to the initial redevelopment effort in the supra-thrust block which is the subject of this report.

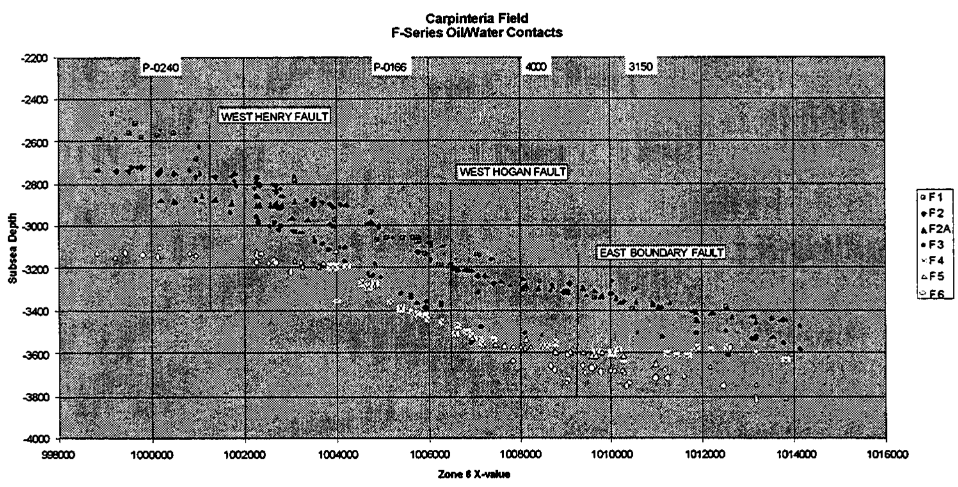

Figure 12: Graph of depth versus Zone VI east coordinate for oil/water contacts determined from well logs for Carpinteria field. The graph approximates a longitudinal secton along the fold axis. Strong east dip of oil/water contacts is

Oil/Water Contacts

It has long been known that the distribution of oil/water contacts within the Carpinteria Field is not simple, and as noted above, this has led some investigators to postulate faults that cannot be supported by independent geologic data. POOI has addressed this issue by the fault study just described and by a careful review of all the petrophysical saturation indicators. A database of observed oil/water contacts was prepared and some important observations have resulted. It is clear that few if any named reservoir zones share a common water contact. This implies that the shales which separate the zones are barriers to migration throughout the field. Zones F-1, F-2 and F-2A may constitute an exception in the central portion of the P-0166 lease, but even these show evidence of independence down plunge to the east.

The most important result of the study of oil/water contacts, however, is that they apparently are not horizontal. There is now strong evidence that most if not all of the individual zone's water contacts are inclined down plunge to the east, particularly on P-0166. The amount of this inclination approaches 5 degrees, slightly less than the amount of plunge of the structure. Weaker evidence suggests that there may be some southerly tilt to some contacts as well. To the east on State Lease PRC 3150, down plunge tilt still seems to be present, but is reduced to 2 or 3 degrees at most. On Lease P-0240 oil/water contacts appear to be essentially horizontal. Recognition of the unusual but basic fact of tilted water contacts relieves the need for superfluous faulting to account for perceived misties. The principal faults which have been found in the well data and which seem to be supported by the new understanding of oil/water contact distribution are the West Henry Fault, the West Hogan Fault, and the East Boundary Fault. Studies by Chevron on their Lease PRC 3150 suggest the likely presence of a fault somewhere between the Hope and Heidi wells. This could be related to the North Heidi Normal Fault described above. Integration of the recently acquired Chevron well data should help to settle this question.

Several possibilities exist to explain the presence of tilted oil/water contacts at Carpinteria Field, not all of which are equally likely. Most tilted contacts addressed in the literature have been explained as a feature of moving oil field fluids, notably water. The moving water is thought to exert a drag on the oil/water contact causing it to be displaced down dip in the direction of movement. This scenario is most likely in fields which border artesian basins where abundant water flow from the highlands to wells or seeps at elevations below the fields' oil/water contacts creates hydrodynamic flow through the fields. It is difficult to imagine such a condition existing in a marine setting such as at Carpinteria. Alternatively, it has been suggested that ongoing active migration of hydrocarbons could cause offset of contacts if inflow of oil to the reservoir was greater than could be accommodated by displacement of water from the opposite fold limb. At Carpinteria it is clear that the conditions necessary for this situation are present since the field is very young geologically and hydrocarbon generation and migration are active at the present time, but it is difficult to see how oil migrating up one or the other of the folds limbs could cause a tilt to occur in the direction of the folds plunge. Another possibility is that hydrocarbon production from PRC 3150 or even from the Rincon Field further east has caused a pressure sink which has caused oil to migrate east within the P-0166 reservoir, and therefore down plunge. There is, however, scant evidence for pressure variations of this magnitude in our data and the time scale of historic production along the trend seems short in view of the great volumes of fluid that would have to move through a porous medium to achieve OWC offsets as great as 1000 feet as is observed in the data. Also, associates at the University of Houston have performed some preliminary simulation experiments based on the hypothetical drawdown of 1000 feet in a single well within a uniform porous medium which required times on the order of 10^4 years to reach equilibrium, suggesting that mass fluid movement within a reservoir is a slow process.

A final possibility, and one that we currently favor, is that the folding of the Carpinteria structure was so recent (in fact it is no doubt still continuing) that oil/water contacts have not been able to achieve equilibrium in this dynamic structural setting. Although detailed paleontologic data is not available, we estimate from regional considerations and from a general understanding of the shallow stratigraphy of the field that uplift could not have begun before about 1.9 mybp possibly even more recently. Seismic evidence obtained from Chevron shows several small unconformities in the youngest beds on the flanks of the structure which probably record the effects of pulses of uplift along the anticline, showing that structural growth was episodic and at repeated intervals, leaving little time for water contacts to reach equilibrium prior to receiving another pulse of distortion. Uplift was most rapid on the west end of the structure as evidenced by the 1000 feet of structural relief between P-0240 and PRC 3150 so the contacts are tilted eastward down the plunge. Given multiple pulses of uplift and an onset of folding of less than 2 million years, the average time between structural disturbances would be on the order of 10^5 years, about an order of magnitude greater than the time in which equilibrium would seem to be achieved based on the Houston experiments, but it must be remembered that the simulation postulated a single well drawdown, not movement of an entire reservoir, and the input parameters included air permeabilities, not permeabilities to oil which are at least an order of magnitude less, so that the 10^4 time frame is probably a significant underestimate given real field conditions. More rigorous simulations are planned for the future. The significance of tilted OWCs to Carpinteria Field redevelopment is not the details of their origin, but rather the fact that they exist and that they must be considered and accounted for in future well planning.

Geologic Preparation for Budget Period II

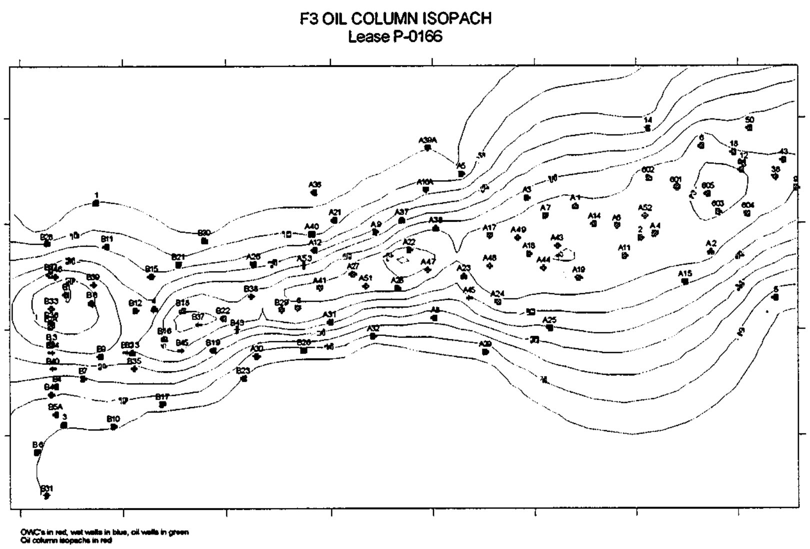

Figure 13: Saturation condition map of Zone F3 on Lease P 0166 showing isopach contours of oil column thickness in red. Area east of well A-23 shows greater original saturation as evidenced by broad

The final task in Budget Period One was the preparation for drilling which was to occur in Budget Period Two. This preparation consisted of applying the geologic and reservoir knowledge gained in Budget Period One to the selection of specific drilling targets and the layout of preliminary redrill wellbore trajectories. The geologic challenges during this phase were to integrate the knowledge gained in Budget Period One to a) refine the location and orientation of those faults which provide a seal against the migration of hydrocarbons, thereby defining the target fault blocks, and b) determining which zones within these fault blocks were most likely to contain hydrocarbon saturations adequate for redevelopment. From this analysis redrill targets could be selected.

The fault review process was somewhat simplified by the determination that, of the two platforms, Hogan and Houchin, Hogan was mechanically more ready to accept an adequately sized drilling rig than was Houchin. Therefore, only the Hogan wells were reviewed. In reviewing the well log correlations used to make the original fault identifications it was apparent that there were some areas, such as directly below the platform, where the geometry of the well bores precluded their crossing of vertical fault planes, so that such faults would not be found by correlation. Also, the fact that a fault is present does not mean that it will necessarily trap

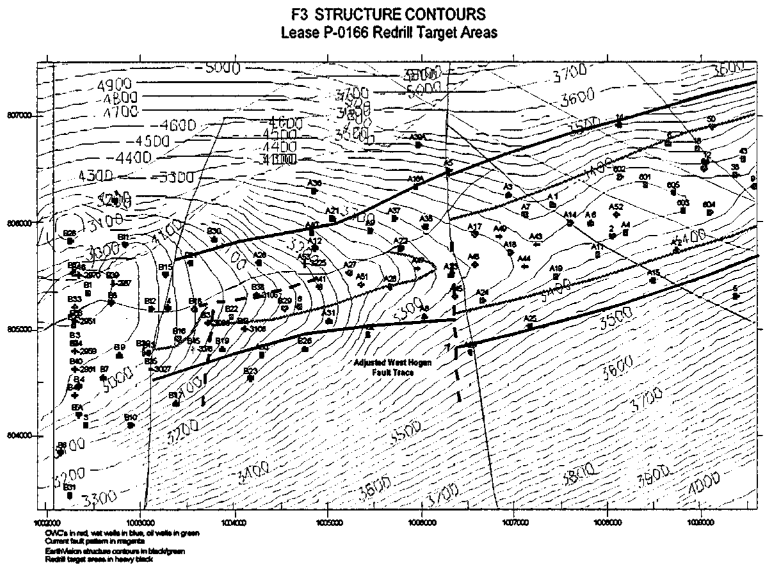

Figure 14: Saturation condition map of F3 zone with structure contour overlay. Fully saturated intervals shown in green, wet intervals in blue. Oil/water contacts shown in red. Heavy blue lines show estimated oil limit. Heavy green line shows limit of completely saturated section. Purple lines indicate fault traces estimated from analysis of electric log correlations. Heavy dashed black lines show adjustment to fault geometry required by saturation pattern analysis.

hydrocarbons. To gain more control over these issues, we prepared detailed maps of hydrocarbon saturation parameters for each zone. These maps, prepared in the commercially available software mapping package "Surfer", used color coded dots to indicate whether well penetrations into a given zone was wet or oil-filled based on the logs, or whether an oil/water contact was present. Further, these maps were plotted with structure contours and with contours of the oil/water contacts. An example of such a map for zone F3 is shown in figure 14. The West Hogan fault adjustment is an example of the use of saturation mapping to modify fault orientations previously determined from electric log correlation. The offset oil/water contact (blue) and full zone saturation (green) lines require that the West Hogan fault pass between wells A-23 and A-45 at this structural level, rather than to the east of A-45 as shown by the magenta line which represents the fault trace as estimated from electric log correlations. Similar maps were prepared for all zones, which, taken together, revealed a good picture of the geometry of sealing faults near Platform Hogan.

The saturation condition maps were useful in a second important way. The wells of Lease P 0166 had been drilled in two time periods, the first in the late sixties and early seventies. Being drilled in a short time frame immediately after the setting of Platforms Hogan and Houchin, these wells provided a picture of reservoir conditions before much drainage had occurred, therefore approximating virgin reservoir conditons. Subsequently, a second group of wells was drilled in the early eighties. These later wells, although fewer in number, offered an opportunity to see the effect of some ten years of production on the saturation pattern in certain zones and fault blocks. By preparing isochore maps of oil column thicknesses using the fully saturated wells and oil/water contact wells from the first drilling period, we could make maps showing which zones in which fault blocks had originally contained the greatest oil volumes. We then compared these maps against the results for the second set of wells to see which zones showed signs of depletion. From this we were able to rank each of the zone/fault block combinations as

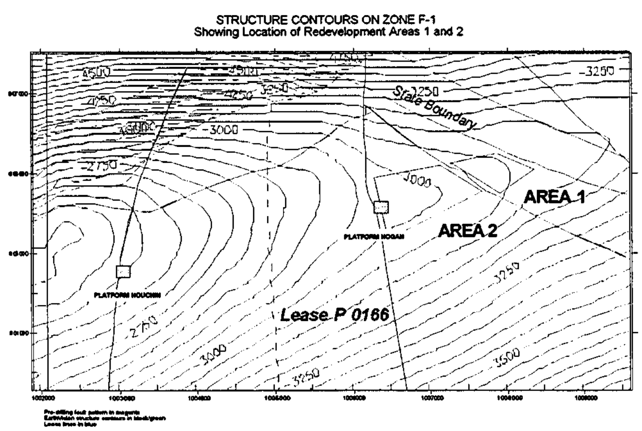

Figure 15: Location map showing redevelopment areas 1 and 2 in relation to Platforms Hogan and Houchin, and structural configuration at zone F-1

to their likelihood of holding sufficient remaining reserves for development by horizontal redrills.

The most attractive zones, because of their thickness and high original saturation, appeared to be the upper F-series sands, particularly the F1, as well as the G1 and the G3. Mechanical and operational efficiencies dictated that redevelopment drilling commence from Platform Hogan, and that area was studied even more closely. Small scale structure and reservoir saturation maps were generated. From these maps 4 fault blocks were identified with redevelopment potential in zones F1, F2, F3, F4, G1, G1b, G2, G3, G3b, G4 and G5.

As studies progressed, redrill options for he first drilling phase were narrowed two fault blocks east of Platform Hogan, designated Area 1 and Area 2 (see figure 15). Zones F1, F2, and F4 were selected as the most promising first targets. Because production from multiple zones in individual wells had been commingled by the prior operator there was insufficient data to be certain of the existing state of saturation of any of the target zones. There was evidence from production experience that oil/water contacts in some areas had moved locally over time. This was a complex phenomenon that could not be accurately predicted from existing information. In view of this, it was decided that the first redrill in each fault block would be a near-vertical pilot well to locate any depleted or swept zones. These wells would then be completed as conventional infill wells for any saturated zones that might be found.

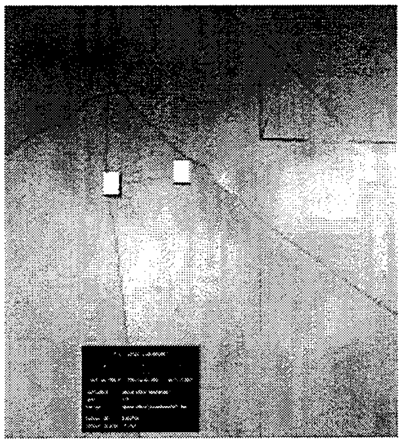

Figure 16: Example of the use of the 3-D model to plot well trajectories. Two critical points (yellow blocks) have been accurately placed on the 3-D surface using the 3-D cursor (at right). X, Y and Z positions of the cursor can be read in the black information box.

The pilots were planned in structurally high locations to maximize their potential as infill producers. In order that the drilling rig not have idle periods, both pilot wells and the four horizontal redrills that comprised the initial program were laid out and completely pre-planned, recognizing that some plans might have to be altered after results from the pilots were known. The plan called for pilot wells on or near the structural axis in up-plunge positions in areas 1 and 2. Four horizontal redrill trajectories were laid out; one in the F1 zone of Area 2 and one each in the F1, F2 and F4 zones of Area 1.

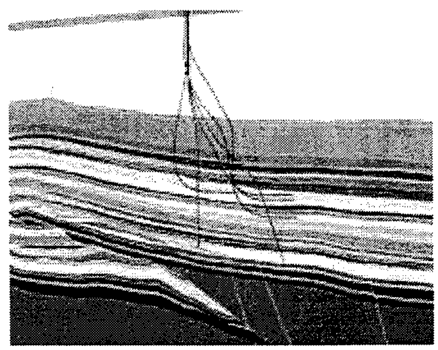

Figure 17: Longitudinal section through 3-D model showing planned pilot wells and redrill trajectories in relation to producing zones.

Figure 18: 3-D perspective view of redrill wellbores (yellow). 3-D view permits assessment of collision potential (upper center).

The redills were laid out using the 3-D model to locate their paths relative to the configuration of the target zone. The XY coordinates for the zone entry points and the total depths were obtained from the detailed 2-D structure and saturation maps. These were then entered into the well layout module of the 3-D modeling program where the Z-values of these critical points could be accurately determined. Figure 16 shows an example of this procedure. Figure 17 shows the configuration of the pilot well and redrill boreholes against a backdrop of a longitudinal section of the Carpinteria structure from the 3-D model.

The model was also useful in allowing us to see the interrelationships between the planned well paths and the paths of pre-existing boreholes. When planning wells in two dmensions it is easy to place the redrill path so as to avoid existing wells at the level of the mapped horizon; however, the situation is much more complicated in three dimensions. In the model, wellbores can be represented by tubes of different diameters, so that if it is desired to keep all wellbores separated by 40 feet, the tubes for each well can be set to a radius of 20 feet. An example is shown in figure 18. Early recognition of interference problems permits adjustments to be made, creating safe clearances between wellbores throughout their length.

As the relationship of the planned well bores to the details of local stratigraphy was more closely studied, it became apparent that a strictly horizontal redrill or a redrill paralleling the structural surface of the target zone could accidently come to be located in a local layer of relatively poor reservoir quality. This occurs because of the internal variablity of the turbidite sand zones. Figure 19 shows a detailed view of the electric log from the A-48 well in the F-3 zone. The zone is clearly seen to be a composite of thinner individual sand layers with intervening shale beds. Obviously, locating the well bore in one of the shales, or even in an anomalously tight sand layer, would seriously jeopardize the productivity of the well. We decided the best way to avoid this was to plan for the well to take a curved path through the producing zone so that all or at least most of the sub-layers would be intersected, guaranteeing that at least some of the slotted line would be across the most productive rock (figure 20). The well path waypoints determined with the 3-D model were modified to account for this problem, and the resulting modified waypoints were submitted to the directional drilling contractor for final well path planning. Once these plans were received and reviewed, geologic preparations in advance of Budget Period II well drilling were complete.

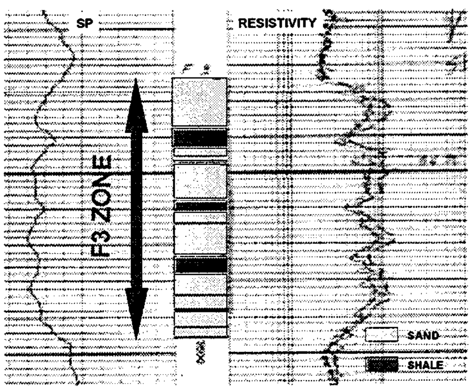

Figure 19: Dual induction log of F-3 zone interval in well A-48. Sedimentary sub-units which make up the zone shown as sand and shale.

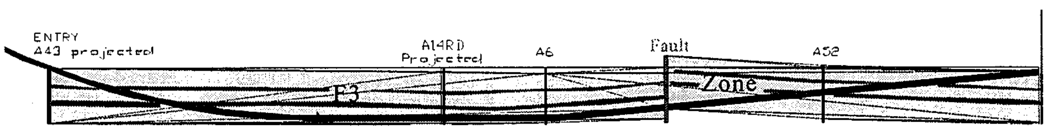

Figure 20: Cross section through final planned trajectory of redrill A43WB01 showing use of curved well path to intersect all subunits of zone F-3.

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.

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. Volumetrically determined, the OOIP for the total field is estimated to be 521 MMSTB. The MB calculation of OOIP for the total field will be determined when the pressure history for the field is finalized. Also, the phase II 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:

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 5. 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 6. 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 most likely data for that analysis is shown in Table 6. The mean value of reserves depicted there is 157 MMSTB with a 75% certainty of reserves between 144 MMSTB and 174 MMSTB.

TABLE 5
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 6
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

Volumetric Method: Total Field

Due to incompletion of results from the 3-D model, the volumetric calculation of OOIP for the entire field is based on the assumption of an average five acre drainage area for each well. Total field OOIP for the supra-thrust sands are shown in Table 7. Figure 21 provides a graphical representation of OOIP, along with the cumulative production from each zone.

TABLE 7
CARPINTERIA FIELD VOLUMETRIC OOIP BY SAND

Sand	OOIP, MM STB
C	6.2
D	4.0
E	71.2
F	186.2
G	165.0
Total for Supra thrust sands	432.6
*Sub thrust sands in lease 3150	69.2
**Sub thrust sands in P-0166	18.9
Total oil in place	520.9

* Data from Chevron Field Study 1987.
** Data from Phillips Petroleum Co. 1983 Engineering Report

Two different approaches of the material balance equation are presented for the estimation of OOIP for 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. A simplified form of equation is presented.

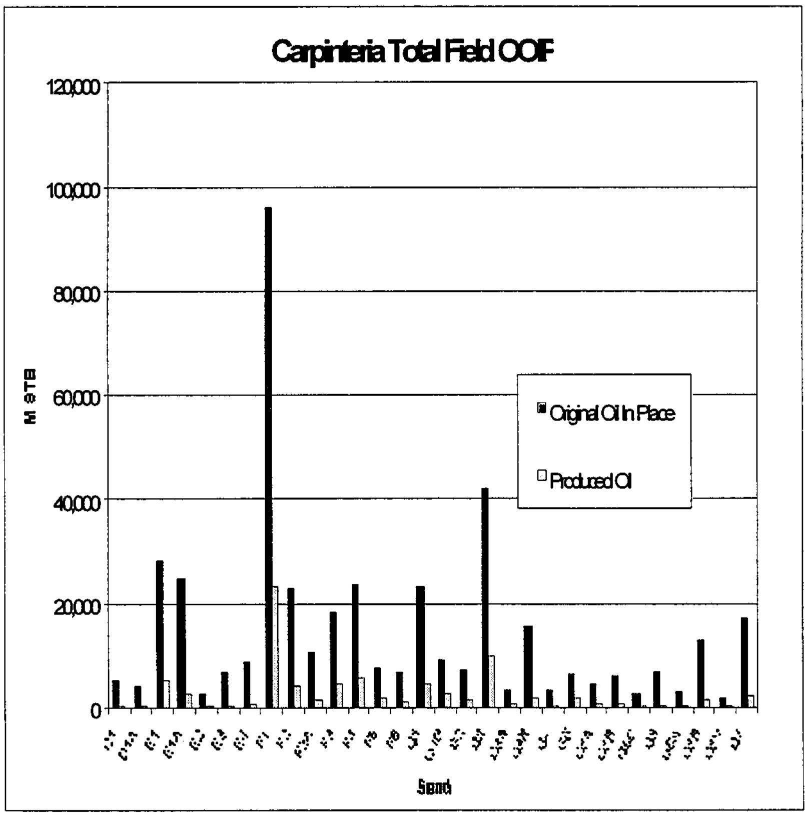

Figure 21: Comparison by zone of estimated original oil in place versus produced oil for Carpinteria field

The general material balance equation for a reservoir that incorporates the combined effects of aquifer support, formation compaction and solution gas drive mechanism, is written:

$$Z = A \times X + B \times Y$$

where Z is the total reservoir withdrawal, A is the unknown OOIP, X is the unit of expansion, B is the unknown water influx constant and Y is the influx function which is calculated by the assumed water influx model.

Water influx model - application of the X-plot method

The X-plot method was useful in estimating water influx into the Carpinteria reservoirs. The water encroachment, which is a mixture of bottom and edge water influx, is calculated by using the following equation:

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

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

Material Balance Calculations

The material balance equation is solved by the least squares method. In order to match the water influx constant (which is the reciprocal of the X-plot straight line slope) obtained from the lease X-plot, the fluid saturation pressure of well A-4 was shifted by -360 psi and the first five production data points were neglected. The pressure data used in this material balance calculation was corrected to a datum of -3300 feet sub-sea. Other assumptions and data introduced in the material balance calculations follow:

Initial Reservoir Pressure	= 1500 psig	Saturation pressure	= 1500 psig
Reservoir Temperature	= 110 °F	Initial water saturation	= 0.40
Initial solution GOR	= 349 SCF/STB	Rock compressibility	= $86\text{x}10^{-6}$ psi^{-1}
Water Influx constant	= 9.5 MM bbls	Water compressibility	= $3\text{x}10^{-6}$ psi^{-1}
Slope of X-plot from Lease water production data	=$1.037\text{x}10^{-7}$ bbl^{-1}		

The results of the material balance calculations for P-0166 follow:

Original Oil in Place = 159MM STB
Slope of X-plot from MB (reciprocal of water influx constant) = $1.053\text{x}10^{-7}$ bbl^{-1}
Water influx as of December 1995 = 67 MMSbbl

Material Balance Monte Carlo Simulation

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

$$N_i = a \times Np_i + b$$

where N_i is an apparent estimate of initial oil in place at different time steps, i. Assuming no water influx, Np_i 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 monotonically increasing linear correlation with Np_i. The true value of OOIP may be obtained by plotting N_i versus Np_i and extrapolating the straight line to Np_i = 0. In this study, a least squares approach was used to calculate the intercept of the straight line. The data generated during early periods of reservoir development were excluded from the least squares approach. Correlations were used to estimate PVT properties. Average initial fluid parameters were assumed to produce a bubble point pressure very close to initial reservoir pressure. Porosity was assumed to be normally distributed with a mean of 24.75 % and a standard deviation of 2.48%. Water saturation was assumed to have a normal distribution with a mean of 40% and standard deviation of 3%. Initial reservoir pressure (triangular distribution) was assumed to have a most likely value of 1500 psig, and minimum and maximum values of 1440 and 1560 psig, respectively. Further a triangular distribution of pressure values was made to cover a range of 95 to 125% of the historical pressure data.

The Monte Carlo simulation resulted in a mean OOIP of 168 MM STB

Difficulties in Applying Material Balance Equation

The Carpinteria field is a complex sequence of turbidite sedimentation. The productive section of the Repetto formation consists of three major horizons, each containing multiple productive sands. A thrust fault divides the structure into two reservoirs, the supra-thrust and subthrust. The supra-thrust consists of thirty separate, sands with multiple oil water contacts. Eleven sands comprise the sub thrust portion of the field. The analysis of sub-surface fluid samples taken from a few sands indicates that the initial reservoir fluids are of differing API gravities. The large contrast between the bubble point pressures and the initial gas in solution makes the selection of one PVT data set very difficult. Static pressure measurements in some peripheral wells indicate very long shut-in time requirements in order to reach static conditions. Commingled production from the wells and partial depletion of the sands add to the complexity of pressure build-up analysis which is required for making reasonable estimates of static reservoir pressures. Finally, the water and gas injection into a selected number of sands adds to the difficulties of using the material balance equation.

Summary and Comparison of OOIP Calculation Methods

The comparison of OOIP in P-0166 calculated by the volumetric method and the two material balance methods is shown in Table 8.

TABLE 8
COMPARISON OF ORIGINAL OIL IN PLACE FOR P-0166

Method of Calculation	OOIP, MM STB
Volumetric	157
General Material Balance Equation	159
Material Balance - Monte Carlo Simulation	168

Productivity of Horizontal Wells

When a horizontal well is first put on production, it produces under unsteady state conditions, where its production rate and pressure change with time. It takes some period before the entire sand is affected by that production. Then, depending on the conditions at the boundary of the reservoir, a new flow regime develops. In other words, the unsteady state conditions evident at production onset ultimately resolve themselves into a steady state regime for constant pressure or pseudo steady state when no flux boundary is present. For the calculations made, we assme that a horizontal well has a radius, r_w, and length, l , drilled in a box shaped drainage volume parallel to the y direction. The The pseudo steady state method presented by Babu and Odeh (SPERE Nov. 1989, p.417-421) was used to estimate the productivity indices. A horizontal well of 1500 feet long and 0.25 feet radius is assumed to produce from a sand block of 2,000 feet wide and

3,000 feet long. Average net sand thickness, average corrected core permeability and sand fluid PVT data have been used. The horizontal permeability in the x and y direction are assumed to be equal. The vertical to horizontal permeability ratio is assumed to be 80% in all cases.

Productivity Forecast of a Horizontal Well

The productivity of horizontal wells producing from E-1, F-1, F-3, G-1 and G-3 sands in the Carpinteria field were estimated under pseudo-steady state conditions. A drainage area of 137 acres was assumed in all cases. We also assumed a horizontal well of 7.75 inches in diameter and length of 1,500 feet. Reservoir fluid properties were estimated based on a current reservoir pressure of approximately 1000 psig. It was assumed that horizontal permeability in the x and y directions were equal and the ratio of vertical to horizontal permeability was 0.3. The pseudo-steady state method was used with Monte Carlo simulation to forecast the horizontal well productivity of each sand. Table 9 shows the rock and fluid properties used in the calculations. A normal distribution of horizontal permeability with a standard deviation of 10 % was assumed. A triangular distribution of net sand thickness was made with the most likely values given in Table 9. The minimum and maximum values were equal to 90 % and 110% respectively. Log-normal distribution of vertical to horizontal permeability ratio with a 10 % probability of 0.5 and 90% probability of 0.1 was assumed. Also, log normal distribution of relative oil permeability with a probability of 90% at current producing water cut was chosen. Table 10 presents the results of the Monte Carlo simulation.

TABLE 9
ROCK AND FLUID PROPERTIES

Parameter	E-1	F-1	F-3	G-1	G-3
Sand thickness, feet	40.9	100	34	60.6	104
Oil viscosity, cp	17.6	6.86	6.86	6.33	6.33
Water viscosity, cp	0.6	0.6	0.6	0.6	0.6
Oil formation volume factor, bbl/STB	1.076	1.091	1.091	1.107	1.107
Porosity	0.258	0.223	0.202	0.216	0.22
Total compressibility, psi^{-1}	$115x10^{-6}$	$100x10^{-6}$	$100x10^{-6}$	$79x10^{-6}$	$79x10^{-6}$
Current Platform water cut	0.816	0.816	0.816	0.755	0.755
Oil-water relative permeability ratio	6.61	2.58	2.58	3.42	3.42
Estimated water saturation	0.40	0.484	0.484	0.427	0.427
Estimated Oil relative permeability	0.353	0.2	0.2	0.352	0.352
Average core permeability, md	707.5	367.6	367.6	266.5	157.7
Corrected sand permeability, md	399.7	190.8	179.1	119.3	67.7

TABLE 10
MONTE CARLO SIMULATION
OIL FLOW RATE FORECAST, STB/DAY

Sand	Median
E-1	327.0
F-1	438.6
F-3	226.3
G-1	340.2
G-3	241.1

Allocation of Production to Individual Zones

The majority of the wells in Carpinteria field were completed in multiple sands. In order to find the remaining oil in each of the sands, an allocation program was developed. The program assumed five acre drainage area for each well. The log derived net productive intervals, with pertinent average effective porosity and water saturation, were used to calculate the OOIP for individual wells. The remaining oil in a given sand was found by subtracting the amount of oil produced by each well from the OOIP estimate.

Historical pressure data for P-0166 was obtained from static pressure measurements and pressure build-up analysis from 1968 to 1986 and then extrapolated to 1995. A similar pressure decline trend was assumed for the State leases which were put on production in 1966. Core analysis data was divided into groups where enough data was available. Lab-derived, relative permeability data was also incorporated. Finally, average oil properties at reservoir pressure and temperature for each sand were obtained from sub-surface and surface fluid analysis.

Oil Production Allocation Scheme

In order to allocate historical oil production back to individual sands, the total well openings and the effective time duration for each perforation were first identified in all wells. Cumulative oil production for each time interval was calculated by utilizing actual well production data. The sand for every perforation interval was identified by using the marker's tops and bottoms data. The oil transmissibilities of individual perforation intervals were then calculated utilizing formation average water saturation and pertinent sand group's oil and rock properties. Effective average water saturation of 0.423 and effective average porosity of 0.2097 obtained from previous study on P-0166 have been assumed for the subthrust sand. The total effective transmissibility for every well at each time interval was obtained by adding the active perforation transmissibilities during that time interval. The oil production from a given sand during each time interval for a producing well was obtained by multiplying the oil production from the well during the time interval by the effective formation transmissibility and dividing the product by the total effective well transmissibility. The water saturation at the end of every time interval (one month of production) was updated by replacing produced oil by water. The drainage volumes for individual wells in each sand were also updated at the end of every time step. It was assumed that the drainage volumes are directly proportional to the well's cumulative oil production and inversely proportional to the initial hydrocarbon column. Finally, the oil production from each sand for every well was simply calculated by adding the oil productions obtained from all of the time intervals.

Budget Period II Results

A total of six wells were redrilled during budget period II of Pacific Operators Offshore, Inc.s Class III contract. During Budget Period I a reservoir study incorporating the latest reservoir description technology was completed. The aim of this study was to provide a basis to redevelop the field using modern drilling and completion technology. The initial focus was the application of a trilateral horizontal well to increase economic recovery from the field. A workover program was initiated in December 1996 (which was not a part of the Class III project) to evaluate the model's initial conclusions and provide data for the continuing study, in addition to improving production rates.

The reservoir study was refined to the point that drilling locations were chosen and actual field redevelopment could begin. The trilateral concept was discarded due to the geologic complexity and active water encroachment in the field, complicating the ability to isolate productive sands from excessive water. An alternative approach utilizing the multiple shut-in producers for redrilling single horizontal lateral wells was chosen instead. The main driver for this decision was the ability to exploit more drilling locations for the cost of a single grass roots well. Six locations were chosen: two vertical wells to determine current saturations and states of depletion in multiple sands within two fault blocks; followed by four horizontal redrills to exploit the opportunities identified in the vertical wells. The vertical wells were also completed as producers, with favorable structural position and minimal incremental costs of completion.

Beginning in March, 1998, the completions of the six redrill candidate wells were abandoned. Beginning in June, 1998, the first vertical redrill was drilled. The redrilling program continued until late October, 1998 when the program was completed.

Drilling Operations

In July, 1998, the first pilot well was kicked off from the existing A-14 well bore to test Area 1. The well was drilled out of a window in 7" casing using 6 1/8" bits and 4 3/4" tools. The pilot had an inclination of less than 25 degrees through the interval of interest. Conventional electric logs were run at total depth. The well took approximately two weeks to drill and log. One of the pre-planned target zones, F4, was found to be wet, eliminating F4 as a target in this fault block and demonstrating the need for pilot wells. While the pilot was being completed, planning was begun on shifting the discredited F4 redrill to the F3 zone, which the pilot had shown to have good remaining saturation. The pilot well had also verified good saturation in the F1 and F2 zones in area 1. While drilling plans were being revised for area 1, a second near-vertical pilot well was drilled into area 2. This second pilot showed good saturation in the F3 sand, and a pre-planned horizontal redrill to that target was commenced. In all, 4 horizontal redrills were completed in different zones of area 1 and 1 in area 2 (Figure 22). These four horizontals and their two pilots required four months to drill and complete. All were oil productive, adding a total of 760 barrels of oil per day to Platform Hogan production.

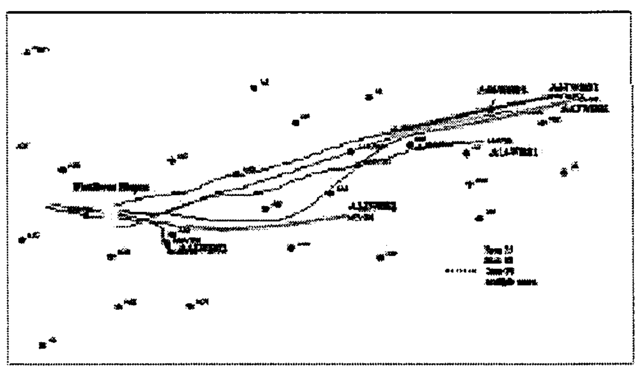

Figure 22: Plan view of Budget Period II redrills showing completed intervals.

Drilling operations were driven by the necessity to redrill the new wellbores from existing 7" casing to access the portion of the reservoir desired. Due to the large numbers of shut-in wells, it was fairly easy to locate a well in an advantageous position for redrilling. A modified workover rig with a 240,000 lbs. mast rating was mobilized for this work. This rig held the advantage of light weight, minimizing expensive platform modifications, and would be simple to use for well servicing operations.

Two wells were chosen for vertical pilot wells. These wells were motivated by the desire to punch a vertical wellbore quickly at the updip portion of a fault block and evaluate the fluid saturations at a point in the fault block. The data from the pilot wells would be used to choose the final targets for drilling the horizontal wells.

The vertical pilot wells were completed with 5" casing, after underreaming the hole to 7 ¾". The casing was cemented in place and perforated for production.

The exist 7" casing was section milled and cemented for kickoff or a whipstock was set. Section milling was less efficient than the use of a whipstock and future drilling will utilize a whipstock.

The horizontal wellpaths were geosteered with a gamma ray resistivity tool. The wellpath was a "U" shaped pattern, to cut across all geologic layers of the turbidite sands (Figure 20). The turbidites' depositional environment resulted in sand-shale intervals several inches to several feet thick with poor vertical communication.

It was desired to limit the build angles to $10^{O}/100'$. Above this limit, excessive pipe stresses were expected. In one well in which the build section exceeded $16^{O}/100'$, some pipe collapse has been noted.

A water-based low solids mud was used to drill to the top of the pay zone. The water loss on this mud system was held below 10 cc/30 min. A polymer system was then used to drill the payzone. This mud system had excellent performance.

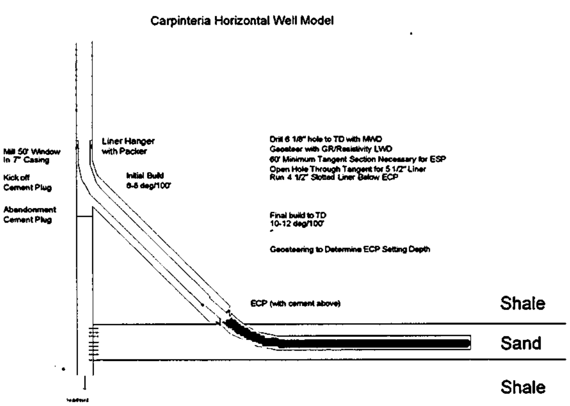

Figure 23: Typical horizontal completion used for Budget Period II redrills.

The horizontal sections were completed with 4 1/2" slotted liners (.025" slots) through the production interval. This was accomplished by running a 5 1/2" - 4 1/2" combination liner, with an external casing packer ECP above the slotted liner. Cement was pumped to fill the ECP and the 5 1/2" annulus (Figure 23). This completion was very problematic, with numerous failures of the ECP. The failure of the ECP was primarily caused by the inability of the combination wiper plug to successfully fill the ECP and operate the cementing valves necessary to fill the 5 1/2" annulus. Future drilling operations will use the following procedure.

1. Abandon existing wellbore with daylight crews
2. MIRU with contract drilling crews
3. Exit existing wellbore with Whipstock

4. Directionally drill well through the pay zone
5. Underream wellbore from window to TD
6. Run 5 ½" Hydril liner and cement
7. Cleanout wellbore and change to filtered produced water
8. Run CBL to top of pay zone
9. Perforate with tubing conveyed perforating guns
10. Run production equipment.

Production of these wells has been accomplished by rod driven systems. The pumps were run directly above the 5 1/2"- 4 1/2" crossover in the liner. This would place the intake within several hundred feet of the productive interval, but would protect the pumps from sand fill, which might cause a fishing job. Two wells were produced with hydraulic rod pumps and 4 wells were equipped with rod driven PCP systems. ESP systems were initially contemplated, but tight clearances and the need to produce moderate sand amounts eliminated them from consideration. Wells with perforated completions have been relatively sand-free, with some wellbore cleanouts accomplished with a conventional tubing bailer. The slotted liners have successfully prevented sand production, though some plugging of the .025" slots has been suspected by a combination of sand and asphaltene deposition.

Predicted Results versus Actual

The results from the redrill program were better than we had anticipated, more than doubling our initial expectations on a per well basis. One of the keys to the success of the program was the reservoir characterization efforts that were completed during budget period I but also the two vertical redrill wells that were drilled as pilot wells prior to drilling the four horizontal wells. From the reservoir characterization efforts during budget period I we obtained a good understanding of the configurations of the potential target reservoirs for drilling, the original oil in place and an estimate of the cumulative production from each reservoir. However, since the Carpinteria field had been produced in a commingled fashion, there remained a question about the allocation of production on a well by well basis back to the reservoir level. In other words, as many as 10 separate reservoirs were completed in an individual well and all the production was commingled. It was a difficult task at best to determine production from each reservoir. We did create a computer program that allocated the production from each well on the basis of net feet of pay and permeability, but this was an estimate that needed to be verified before committing to drill horizontal wells in targeted sands. In order to verify our model of remaining reserves on a reservoir basis, we redrilled two existing wells in a vertical (or near vertical) configuration and ran a wireline logging suite. The results were unexpected, indicating that some of the sands that were considered potential horizontal targets were wet,

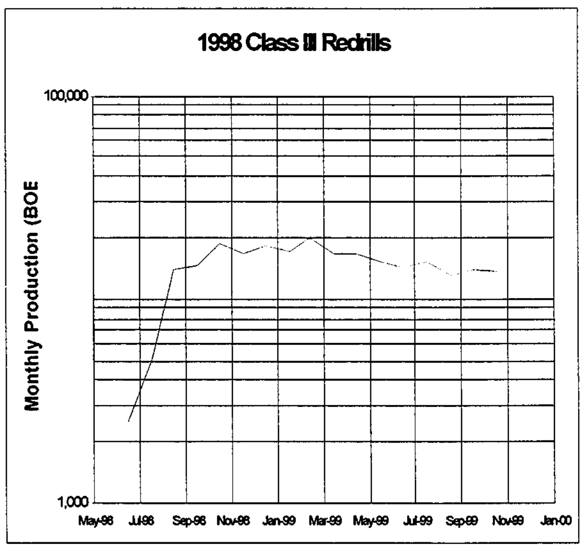

Figure 24: Production history summary for six wells redrilled under Class III project.

while others had considerable remaining oil saturations, much higher than our model had predicted. Two of the horizontals contemplated in the Budget Period I study described above were retargeted from F4 and G1 to F3, greatly enhancing the success of the first drilling phase.

Production Results

Figure 24 is a production history summary of the 6 wells that were redrilled as part of the Class III project.

In addition, table 11 shows the cumulative production through October, 1999 for the same wells.

TABLE 11

1998 Class III Drilling Program
Production Results to Date (10/1999)

1st Production	Well Name	Cum. Oil (MBO)	Cum Gas (MMcf)	Cum Water (MBW)	Water Cut (%)
Jul-1998	A14WB01	45	31	17	28%
Jul-1998	A48WB02	5	5	4	46%
Aug-1998	A22WB01	50	34	14	23%
Sep-1998	A49WB01	53	26	43	45%
Oct-1998	A43WB01	38	23	3	7%
Oct-1998	A44WB02	18	17	14	43%
	Totals	**209**	**136**	**97**	**32%**

A significant point about the production results are best illustrated by comparing the current production from the existing producers in the west Hogan area (where the redrill program took place) with the six new redrilled wells. Table 12 is such a comparison.

TABLE 12
1998 Class III Drilling Program
Comparison of West Hogan Water Cuts

Existing West Hogan Wells

Well Name	98' Oil Rate (Boepd)	Water Rate (Bwpd)	Water Cut (%)
A14	46	314	87%
A18	62	129	68%
A23	37	164	82%
A4	88	434	83%
A6	140	230	62%
Totals	**373**	**1,271**	**77%**

Redrilled West Hogan Wells

Well Name	98' Oil Rate (Boepd)	Water Rate (Bwpd)	Water Cut (%)
A14WB01 *	109	25	19%
A48WB02 *	71	10	12%
A22WB01	162	56	26%
A49WB01	161	118	42%
A43WB01	149	8	5%
A44WB02	91	55	38%
Totals	**743**	**272**	**27%**

* indicates vertical redrill (pilot wells)

As you can see, when comparing the five producers that existed in the west Hogan area prior to drilling (see project map for location of these wells) with the six redrill wells, the water cut dropped dramatically. The average water cut of the five existing producers was 77% and 75 boepd / well. The redrilled wells, which are three horizontal and three vertical wells have an average water cut of 27% and a production rate of 123 boepd / well. Not only is this a significant improvement, but most importantly it proved up the theory that resulted from the BP 1 study. That is:

1. High water cut production was inhibiting oil production rates
2. That horizontal wells in selected sand members that still contained good oil saturations could produce at higher rates than the existing vertical completions
3. That vertical redrills were very necessary to drill to better understand the saturation state of the reservoirs prior to drilling any horizontal completions.

Budget versus Actual Expense

As a result of the change in Budget period II discussed above, which changed the BP II activity from drilling a single trilateral well to several horizontal wells, the BP II cost budget changed significantly. As a result of some of the reservoir uncertainties discovered in BP I, Pacific Operators felt that an expanded Budget Period II program was in order. The risk of a single trilateral well in just one location was too high, so several horizontal wells were planned to test various portions of the east Hogan area. As a result, 4 horizontal wells were planned and 2 vertical pilot wells. DOE's initial cost share for this project was approximately 50/50. At the end, because of the expanded program, the DOE's cost share was 27%. Table 13 shows the original budgeted costs versus the actual costs.

TABLE 13

Class III Costs - Budget Vs. Actual

	Budget period I	Budget period II	Total
Original Budget	$814,718	$3,358,968	4,173,686
Actual Cost	$991,653	$6,235,365	7,227,018
DOE Share	$407,359	$1,569,945	1,977,304
Proposed DOE %	50.0%	46.7%	47.4%
Actual DOE %	41.1%	25.2%	27.4%

Drilling Problems / Lessons Learned

As with most new drilling operations, an initial program always identifies areas of needed improvement, need for design changes, etc. During the Budget Period II field demonstration portion of Pacific's Class project, several such areas were identified as follows:

1. MIRU expense greater than expected because more extensive location upgrades were required than we originally considered during our proposal in 1994. The platform that we conducted the drilling operation from, Hogan, had not had any drilling operations since 1983 and many of the drilling systems were in a poor state of repair.

2. Casing Exit – The redrill procedure called for an exit from the existing 7" casing by employing a cement kick off plug, a 60' section mill and an undereaming procedure. The objective with this casing exit strategy was to minimize high dog leg severities so excessive rod and tubular wear could be minimized with the production system. Unfortunately, the directional drillers all wound up getting kicked off very rapidly (within 20' instead of the 60' available). The last well employed a one trip whipstock assembly, which overall resulted in a lower dogleg severity and significantly reduced costs.

3. One of the primary considerations in the completion of the horizontal wells was to eliminate or control sand entry into the wellbore. In order to accomplish this and at the same time be cost effective, we employed a combination 5 1/2 - 4 1/2 liner. The 4 ½ " liner was slotted and separated from the 5 ½" liner by an external casing packer. The last horizontal completion was perforated instead of slotted. This well did not make excessive sand, so future completions will employ a single size 5 ½" cemented liner and a perforated completion.

4. In addition to the sand control issue mentioned in 3 above, the combination liner also required several hardware items, such as an external casing packer, special cement wiper plugs, cementing collar, etc. Many of these items were the source of setting failures during

the completion of the horizontal wells. So, by switching to the single liner size we will also same considerable funds by reducing the amount of equipment and accessories required for the completion.

Conclusions

1. Horizontal slimhole redrills reclaiming some of the casing strings from existing boreholes is an effective way to redevelop low dip sand /shale reservoirs in mature fields where surplus well bores exist.

2. The 6 redrills drilled under Budget Period II of the Carpinteria Class III project added 760 bbl/day of initial production to the lease total.

3. Production from Budget Period II wells initialed at 24.8% water cut compared to the pre-drilling lease average of 74%.

4. Sand production was reduced on a per-barrel basis because less total fluid was moved in the low water cut horizontals to achieve equivalent oil production compared to conventional completions.

5. Pilot wells are mandatory in cases where current saturation conditions of target reservoirs cannot be determined from historic or other data.

6. Pilot wells, if properly located, can serve both as confirmatory tests of target zones and as infill producers using conventional completion techniques.

7. Measurement While Drilling (MWD) steering and logging techniques are effective in drilling and evaluating slimhole horizontal wells in sand layers as thin as 30 to 40 feet.

8. Small independent operators can leverage limited staff and capital resources through the aggressive use of technology, including commercially available computerized drafting and modeling and electronic communication and data management systems.

9. Completions using external casing packers (ECPs) and slotted liner are problematic in slimhole operations and future slimhole completions at Carpinteria will be completed by perforation of blank casing using tubing conveyed guns.