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Development of the Offshore East Wilmington Oil Field

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ABSTRACT

The East Wilmington Oil Field, comprising approximately 5930 productive acres, is located just off-shore Long Beach, California, and contains oil reserves of approximately 800 million barrels. It is being developed by THUMS Long Beach Company as contractor for the City of Long Beach, the Unit Operator. Development is from four, 10 acre, man-made islands and two on-shore locations. Approximately 575 wells have been drilled to date, producing from eight zones. Cumulative oil production as of June 30, 1969 was 93,485,157 barrels.

HISTORICAL BACKGROUND

The East Wilmington oil field is located in the south central part of the Los Angeles basin, on the southeasterly plunge of the Wilmington anticline (Plate 1). The Wilmington oil field overlies a basement high that extends in a southeasterly direction from Torrance oil field to Huntington Beach oil field, a distance of 21 miles. The Ranger Petroleum Co., Well No. "Watson" 2, completed January 26, 1932, for 150 barrels per day of 14 degree gravity oil was the first commercial well completed in the field. However, recognition and development of the Wilmington structure awaited the completion of General Petroleum Corporation, Well No. "Terminal" 1, in December, 1936, for 1419 barrels per day of 20.5 degree gravity oil. Rapid development followed this event, and prior to initial drilling in the Long Beach Unit in July, 1965, approximately 3500 wells had been drilled and had produced about one billion barrels of oil from 7825 acres.

Subsidence began in the center of the field shortly after inception of production, and rapidly became a major problem. Pilot water injection was initiated in Fault Block VB in the Upper Terminal zone in June, 1953, and was quickly extended to other zones and fault blocks. In 1956, the City of Long Beach prohibited drilling east of Pine Avenue until the subsidence was controlled, the excluded area including all the present Long Beach Unit, exclusive of Tract 2. The success of the early pilot floods, both in the local arresting of subsidence and in secondary recovery, led to the

References and illustrations at end of paper.

creation of four fault block Unit Agreements between January, 1959 and April, 1964, providing for water injection in the various zones[1]. This injection program has successfully arrested subsidence in the older Wilmington area.

The City of Long Beach conducted an off-shore seismic survey in 1954, extending southeasterly from the then legal limit of production at the Parcel A boundary. This survey established the southeasterly continuation of the Wilmington anticline for at least four miles to the Orange County line.

The voters of the City of Long Beach lifted the ban on off-shore drilling by referendum on February 27, 1962. Shortly thereafter, the City of Long Beach drilled eight off-shore core holes to verify the structure and the productive limits of the different zones. Based on the results of these core holes, the Department of Oil Properties staff reinterpreted the seismic survey, and originated a comprehensive study for the development and exploitation of the off-shore area.

In early 1964, the City of Long Beach, the upland property owners and the townlot operators concluded a Unit Agreement for the operation of the eastern area. A Field Contractor's Agreement was prepared, under which the drilling and production operations would be carried out for the Unit under City direction. After extensive hearings, the California State Lands Commission approved both the Unit Agreement and the Field Contractor's Agreement late in 1964. Bids were called for by the City in early 1965 to select the Field Contractor for the Unit. THUMS Long Beach Company was the successful bidder, offering 95.56 per cent of the net profits plus a ten million dollar bonus, 17 million dollars in advance royalty payments in the first year, and one million dollars a month thereafter until payout. The Field Contractor receives three per cent of Unit expenses as overhead. THUMS was a newly created company owned equally by Texaco Incorporated, Humble Oil and Refining Company, Union Oil Company, Mobil Oil Corporation, and Shell Oil Company. The first well in the new unit, J-145, was completed from Pier J in August, 1965. This well has subsequently produced 849,000 barrels of oil.

The Long Beach Unit contains 6700 acres of which approximately 5930 are productive. The Unit is divided into: Tract 1, the Long Beach Tideland area; Tract 2, the Alamitos Beach State Park; and Tracts 3 to 91, the townlot area. The total Unit is now estimated to contain approximately 870 million barrels of recoverable oil.

STRUCTURE

The broad Wilmington anticline plunges southeasterly across the entire Long Beach Unit. In the vicinity of islands Bravo and Delta, the Junipero and Long Beach Unit faults produce local flattening of dip and change of strike, but the regional plunge is uninterrupted (Plates 2 and 3). The anticline is asymmetrical, with beds on the south flank dipping as steeply as 60 degrees, while the maximum dip on the north flank is about 20 degrees. Below the top of the Ranger zone, the axial plane of the anticline shows little or no migration with depth.

At least eleven faults with displacements in excess of 40 feet have been recognized in the Long Beach Unit. The largest of these and the largest in the entire Wilmington field is the Long Beach Unit fault with a displacement of 100 feet on the north flank, increasing to about 600 feet on the south. Approximately 2000 feet of right lateral movement is found on this fault. Moody and Hill[2] describe the Wilmington anticline as a second order drag fold resulting from movement on the Inglewood fault zone. The average strike and the right lateral movement of the Long Beach Unit fault conform to Moody and Hills' definition of a second order wrench fault.

All Wilmington field faults are of the normal or wrench type, cutting the axis of the anticline at angles of 30 to 45 degrees, with the strike usually being found in the NW-SE quadrants.

A major change in oil-water contacts of all zones is found across the Long Beach Unit fault, and minor to major changes are associated with the other recognized faults. Detailed interpretation of the faulting east of the Belmont B-1 fault and north of the C-608 fault has not been satisfactorily resolved. Significant differences in the Tar, Ranger, and Upper Terminal zone limits are known in this area, apparently related to faulting of such small displacement as to be unrecognizable in electric log correlation of the highly directional wells.

STRATIGRAPHY

The age of the producing formations found within the Long Beach Unit ranges from questionable Jurassic for the Catalina schist basement to Lower Pliocene, Repetto, for the Tar zone. A hiatus exists between the lower 237 zone and the schist. Some middle Miocene sediments may be found between the lower Mohnian and basement, but have not yet been positively identified. A major unconformity exists between the middle and upper Miocene in the Los Angeles basin. This unconformity probably represents the time of initiation of the ancestrial Wilmington anticline. Upper Miocene and Repetto sediments are "drape folded" over the middle Miocene and basement core, with the younger zones usually displaying thinning on the axis of the structure. Approximately 7000 feet of sediments were deposited in a deep water environment between the lower Mohnian and the lower Pico. Several minor unconformities are present, notably at the top of the upper Miocene, in the middle of the Ranger zone.

Eight productive zones are found in the Long Beach Unit area of the Wilmington field; these are:

(1) Tar zone, 200-400 feet thick, Repetto age (Pliocene). Unconsolidated fine- to coarse-grained, fairly well sorted lenticular sands, with soft, light brown to olive green siltstone.

(2) Ranger zone, 600-900 feet thick, Repetto and Delmontian age (Pliocene and Upper Miocene), with the top of the Miocene being found near the "G" marker. Unconsolidated to easily friable, fine- to coarse-grained, fairly well to poorly sorted, subangular sands. Repetto siltstones are firm, sandy, brown to olive green. Miocene siltstones and shales are dark brown to grey, sandy, becoming dark grey to black, well laminated and locally diatomaceous in the lower part. Occasional thin beds of hard, marly shell.

(3) Upper Terminal zone, 700-750 feet thick, Delmontian in age (Upper Miocene). Soft to easily friable, silty, fine- to medium-grained, fairly well sorted, arkosic sands with grey to black siltstone and laminated shale. Occasional beds of marly shell up to one foot thick. Middle of interval never completely oil saturated.

(4) Lower Terminal zone, 750-800 feet thick, Delmontian in age. Sands are similar to the Upper Terminal, but somewhat coarser and more massive, becoming firmer in the lower portion. Grey to black, well indurated shales and siltstones, with occasional marly shells.

(5) Union Pacific zone and (6) Ford zone, 2000-2250 feet thick, Upper Mohnian in age. Thin bedded to massive, fine- to coarse-grained, pebbly, fairly well to poorly sorted, firm to easily friable, arkosic sands and sandstones, with hard, dense, dark grey to black siltstones and shales. Frequent hard marly shells. Sand percentage lower and sands more thinly bedded in the Union Pacific zone, with the sands becoming massive, coarse and pebbly in the lower part of the Ford zone. Most of the Union Pacific and Ford zones' production is restricted to the area east of the Long Beach Unit fault.

(7) 237 zone, 2650 feet thick. The upper 2000 feet consists of massive, poorly sorted, locally friable to well cemented, arkosic, coarse, pebbly to conglomeratic sandstone, with minor dense, black shale interbeds. It becomes very well cemented in the lower portion, with low porosity and permeability. Only the top 75 feet is oil productive in the Long Beach Unit. The age is Upper and Lower Mohnian.
The lower 650 feet is produced with the Basement and consists of black, dense, locally fractured, well bedded shale, with brown phosphate nodules and occasional thin interbeds of hard, medium- to coarse-grained sandstone. The fractured nodular shale and the fractured upper 100 feet of basement is oil productive in several wells east of the Long Beach Unit, and is known as the D-118 sub-zone. The age is Lower Mohnian or Luisian.

(8) Basement zone, 100 feet ± thick, Tithonian (?) in age, by correlation with the Catalina Franciscan (?) schist. Bluish or greenish, fractured, glaucophane schist, with common quartz and calcite veinlets. Combined with the nodular shale to form the D-118 sub-zone.

Plate 4 gives the net oil sand thickness and productive acres for the various zones. All zones except the Tar thicken between the old Wilmington field and the Long Beach

Unit. The fractured nodular shale of the D-118 sub-zone is either missing or non-productive in the old developed area. The Ranger zone is by far the largest, both in reserves and areal extent (Plate 5).

SPACING

The preliminary spacing plan for the Long Beach Unit was developed by a sophisticated computer model, using parameters that were modified from known data in the older developed portion of the field (Plate 6). After drilling commenced in the Long Beach Unit, additional runs were made utilizing data obtained from the new wells. Since drilling is now almost completed, no major additional spacing plan modifications appear necessary.

Spacing for all the zones is variable, ranging from about six acres in crestal locations to 40 acres on the flanks. Well locations were determined by the estimated productivity and oil in place, and therefore vary, depending on the structural position and fault block.

The latest spacing plan calls for 680 wells, including 505 producers and 175 injectors. However, this number is subject to revision as more production and injection data are obtained.

DRILLING AND COMPLETION TECHNIQUES

Initial drilling was from four sites on Pier J, an earth-filled extension in the Long Beach harbor, which abuts the Long Beach Unit on the west. Conventional portable diesel rotary rigs were used, and transportation and servicing of wells were simple. The four, 10 acre islands constructed in the harbor presented some problems in logistics. On islands Alfa, Bravo, and Charlie (now named Grissom, White, and Chaffee) four all-electric rigs were designed and built to THUMS specifications. The masts were built to resemble high-rise apartments to reduce noise and present an attractive appearance when viewed from the shoreline. Extensive landscaping and free-form sculptural designs were added to disguise the drilling and production operations. Due to the distance from shore, island Delta (now named Freeman) was able to utilize six conventional diesel rotary rigs; landscaping was kept to a minimum. All electrical power, water, oil, and gas lines are buried beneath the ocean floor, and connect the four islands with Pier J.

All personel and equipment are transported to the islands by a fleet of crew boats, tugs, and barges, operated under contract to THUMS. Equipment and supplies are stored in a warehouse on Pier G, where two barge ramps are located for loading and unloading material and equipment.

Because of the logistics problem, THUMS has installed a data transmission system utilizing telephone lines. Units capable of sending and receiving are installed on each island, at the Pier G production office, in the City of Long Beach Harbor Department building, and in the Development Engineering section in the main office. Drilling programs, field memorandums, survey results, and most important, wire-line logs can be sent over this system, with a resultant saving in time and man-power.

Directional Drilling Control and Problems Involved

Almost all the wells in the Long Beach Unit are directionally drilled (Plate 7). A large number of wells have hole angles in excess of 60 degrees from the vertical and several exceed 75 degrees. Initially, whipstocks were used for directional control, but due to inherent disadvantages, they have been replaced by down hole mud motors and the Rebel tool which have proven very successful. Maximum programmed build-up is limited to 5 degrees per 100 feet, and drop-off to 2-1/2 degrees per 100 feet. Single shot surveying instruments are used for drilling control, with drop-type multiple shot instruments run at surface casing point, water string setting point, and at total depth. The multiple shot is considered the "official" survey of the hole, and is used for calculating all geologic markers. Both single shot and multiple shot stations are taken every 30 feet ± during build-up portions of the hole, and every 90 feet ± during the remainder of the drilling. Single shot stations are reread by a THUMS employee to verify the directional company's results. They are then run through a computer program via a remote terminal in the building, tied to a master computer. Multiple shot stations are read by the service company, and are reread by a THUMS engineer or geologist only when large discrepancies are noted compared to the single shot. The service company provides THUMS with a complete calculated survey.

The final surveys are then run through THUMS' computer program for permanent storage, and geological markers and other survey data output are machine calculated at the same time.

Initial methods for calculating points were done by the tangential, terminal angle method, which was the procedure in general use in the area. The terminal angle method assumes that the drift angle (or bearing) changes abruptly at the top of the course length and maintains the terminal angle drift (or bearing) for the entire course to be calculated, a condition obviously seldom encountered. It was decided to use the average angle method for calculating vertical depth and direction (Plate 8). The average angle method assumes that the average drift angle (or bearing) for the course to be calculated is the average of the drift angles (or bearings) at the top and bottom of the course. This method removes much of the error inherent in the terminal angle method. The main disadvantage encountered is in tying control points calculated by the one method with points calculated by the other. Plate 9 shows an actual well course in section view calculated by both methods.

Even with the improved technique, it must be realized that vertical depths between adjacent control points can vary by as much as 20 to 25 feet, due to one or more of the following factors:

(1) Differences in hole angles between adjacent wells (high angle hole next to a low angle hole, or one well dropping angle through zone next to one holding constant angle).
(2) Bearing of well course; magnetic influence of the drilling string is greatest in the East and West directions.
(3) Errors in wireline and/or drill pipe measurements.
(4) Lack of proper alignment between surveying instrument and drill pipe, and drill pipe and hole.
(5) "Hot" (magnetized) drill collars and/or drill pipe.
(6) Local magnetic anomalies, including down-hole motors, casing, tubing, etc.
(7) Skill and technique of the operator reading the shots.
(8) Unreported accidental dropping of survey instruments, affecting calibration.
(9) Location of survey stations.

The data derived from the current methods of surveying directional holes are probably the weakest link in sub-surface geological interpretation. Some geologists in the area have adopted the "purist" approach - ie., honoring all control points without regard to the above mentioned errors. This presents many problems when dealing with oil-water contacts, since even small contact differences in adjacent wells (10 to 20 feet) must be explained by faulting, permeability barriers, or tilted water tables. This in turn tends to indicate geologic conditions which probably do not exist, and could possibly lead to erroneous reservoir interpretations and the drilling of unnecessary wells. G. J. Wilson[3] encountered similar problems with directional surveys and presented his own solution. THUMS geological staff, aware of the inaccuracies present when working with deviated wells, uses the "averaging" approach in constructing maps and cross-sections. Questionable points are simply not honored when adequate evidence is present to justify their exclusion.

Types of Wireline Logs and Problems Encountered by High Hole Angles

Early in the development of the Long Beach Unit, it was found that conventional wireline logging tools would not go down many of the wells because of the high hole angles. Below 60 degrees in open hole, most conventional logging tools will go, provided great care is made to condition the hole and mud adequately. Above 60 degrees hole angle, the percentage of "no-gos" increases greatly, and above 65 degrees very few tools will go. In cased hole, logging sondes have occasionally gone in 72 degree angle holes. Because many wells have drift angles in excess of 60 degrees, it is necessary to run small diameter (2-3/8 inch) sondes, and pump the tool through the drill pipe. The general procedure is to run open-end drill pipe to a point a few hundred feet above the top of the zone, and pump the sonde through the pipe with the mud pumps. The pumps are shut off just prior to the sonde going out the end of the pipe, and usually the tool will fall to bottom unaided. Most of the wells are drilled in an "S" shape, and generally the drill pipe can be hung at a point where the drop-off has started. Where a log of the entire hole is needed, it is often necessary to run it in 90 foot segments. Drill pipe is run to a point just below the previously logged segment; the sonde is pumped out the end of the pipe (usually stopping there), the pipe is pulled up a stand, and the hole is logged up to the end of the pipe. The sonde is then pulled out of the hole, a stand stood back, and the process repeated. There have been as many as 35 separate runs made by this method in order to obtain a log of the entire hole. The upper part, from kick-off point to maximum hole angle, is usually logged with a conventional sonde.

At the start of drilling operations in the Long Beach Unit, the only logging tools small enough to go through 4-1/2 inch drill pipe were a conventional Electric log sonde and a Gamma Ray-Neutron. Because of the need for quality logs, small diameter Induction-Electric log sondes were developed by the major logging companies, which enabled THUMS to obtain either an Induction-Electric or Induction-Gamma Ray log in all wells, regardless of the hole angle.

Correlations in the Wilmington field are generally quite good, and an Induction-Electric log is the only log run in most wells. Auxiliary logs are generally run only for specific reservoir information, and include: Gamma Ray-Neutron, Pulsed Neutron, Acoustic, Density, and occasionally the Microfocused log. In wells that are cored for equity purposes, an Acoustic, a Density, and a Gamma Ray-Neutron are run in addition to the Induction-Electric (Induction-Gamma Ray). In these wells, the suite of logs is run through a special computer program to give calculated porosity and water saturation values. Porosity values obtained from both the Acoustic and Density logs are in good agreement with core-derived values in the Union Pacific and Ford zones, but in the upper zones log porosities are generally lower than core porosities. Due to the unconsolidated nature of the sands in the upper zones, cycle-skipping is a problem with the Acoustic log, and the Density log is more reliable.

Because of adverse hole conditions and the difficulty in obtaining good Spontaneous Potential values, it became necessary to initiate strict log quality control procedures. The SP curve is extremely important, since sand counting is based primarily on the SP, combined with certain resistivity values, and Unit equities are determined from the sand counts. Difficulty was encountered in logging wells on Pier J, particularly on certain drill sites. It was often necessary to relog the hole several times in order to get an SP curve that would meet THUMS standards. Mud properties were often unsatisfactory, and logging crews were unfamiliar with the high angle holes. Stray electrical currents were frequently encountered, and it was occasionally necessary to shut off all motors in the vicinity of the well in order to obtain a satisfactory log. Equipment malfunctions were common, and many man hours were spent in order to obtain quality logs. Initially, logging problems were common on the islands, but because of the strict log quality control procedures, logging problems are now infrequent.

CORING TECHNIQUES

The Unit Agreement specifies that each of the productive zones in Tracts 1 and 2 must have one full-zone core for each 320 acres, and the townlot area must have one full-zone core for each 160 acres. The reservoir information obtained from the cores is used for determining and assigning equities among the various participants in the Unit. This requirement has necessitated an extensive coring program, and over 45,866 feet of core have been cut as of July 1, 1969, with an average recovery of 86 per cent. Because of the importance of this program, rigid and thorough supervision is necessary. Each core must be met by a THUMS geologist, and because of transportation problems and the speed with which cores are cut (especially in the Ranger zone) four men are needed full-time when two or more wells are coring at the same time (which is often the case). In the four upper zones, 30 foot cores are cut using a drag type core head. In the deeper zones a 60 foot core barrel is used utilizing a diamond core head. Core bits are either 7-5/8 inch or 8-1/2 inch diameter, and core barrels are 3-1/2 inch or 4-1/2 inch diameter. After the geologist has tagged, measured, and described the core, samples are taken every two feet of sand by a representative of the laboratory doing the core analysis. The cores are then transported to permanent storage facilities on shore. A few rubber sleeve cores have been taken, but it was felt that the time and cost involved was not justified.

CORE ANALYSIS PROCEDURE

Because the consolidation of the sands varies from loose to very hard, two methods of core analysis are used by THUMS:

(1) Soft, unconsolidated sands. The sand sample is encased in a 1-1/4 inch long x 1 inch diameter lead sheath, and the ends are covered by 120 mesh screen using a pressure of 350 psi. Saturations are determined using the distillation method. For determining porosity, the helium porosimeter is used, and permeabilities obtained are air permeabilities. 90 psi is applied to the sample during analyzing.

(2) Harder consolidated sands. Plugs are cut or drilled out, and measure about 1 inch long x 1 inch diameter. No mounting or compacting is necessary. A down-draft retort is used to obtain saturations. Porosity is measured by the gas expansion process using a Kobe porosimeter. Permeability values are air permeabilities.

A sample is also taken every 10 feet of sand, wrapped in foil, dipped in plastic, and stored for future use.

RESERVOIR CHARACTERISTICS

Average permeability and porosity values for the various zones derived from core analysis are tabulated below:

Zone	Porosity	Permeability	Oil Gravity
Tar	35.93%	1405 md.	19.3°
Ranger	33.76%	1088 md.	17.9°
Upper Term.	37.2 %	1188 md.	19.1°
Lower Term.	33.82%	584 md.	20.3°
Union Pacific	24.29%	148.5 md.	28.4°
Ford	21.10%	159.5 md.	28.4°

DRILLING AND COMPLETION PRACTICES

A typical drilling and completion program for an upper zone well is as follows:

1. Drill 12-1/4 inch hole to 950 feet (20 inch conductor previously set at 90 feet ±) using clay-water mud.
2. Run multiple shot survey.
3. Open 12-1/4 inch hole to 18-1/2 inches, and cement 13-3/8 inch, 48 lb., H-40, Buttress thread casing with returns to surface.
4. Install and test B.O.P.E.
5. Drill 12-1/4 inch hole to top of zone (depth varies depending on angle of hole and structural position - usually 2500 to 5000 feet), and run multiple shot survey.
6. Run Induction-Electric log.
7. Cement 8-5/8 inch, 32 or 36 lb., J-55, 8-rd thread Buttress casing with API Class "G" cement and pozzolan admix. Cement to fill to 50 feet above base of fresh waters.
8. Run Water shut-off test (a requirement of the State of California).
9. Drill 7-5/8 inch hole to total depth and run multiple shot survey.
10. Run Induction-Electric log.
11. Change over to completion fluid and wall-scrape 7-5/8 inch hole to 8-1/2 inches and 14 inches.
12. Run Caliper log.
13. Hang 6-5/8 inch, 28 lb., 8-rd thread T & C and flush joint shop perforated liner (24-2-6-60) fitted with external casing packer assemblies.
14. Set, test, and cement between external casing packers.
15. Gravel flow-pack 6-5/8 inch x 14 inch annulus with 6-9 Tyler Mesh gravel.
16. Displace completion fluid with NaCl-$CaCl_2$ brine, and wash and repack as necessary for gravel fillup.
17. Run hydraulic or submersible pump on tubing and place well on production.

This program applies to the Tar, Ranger, Upper and Lower Terminal zones. For Union Pacific and Ford zone wells, the water string is 9-5/8 inch, 36 and 40 lb., J-55 and N-80. Liner hole is 8-1/2 inch, and 6-5/8 inch, 28 lb., slotted liner is hung with two or more sets of external casing packers. These wells are not gravel packed. Some wells have blank liner cemented through zone and jet perforated.

Early in the development program it became obvious that a good method of zonal segregation was needed. Since the upper four zones require gravel packing to control sand entry, it is not possible to cement blank liner and selectively perforate. Putting blank liner opposite wet sands or segregation points and attempting to cement behind the blank interval has never been satisfactory under ideal conditions, and in high angle holes it is even less successful. It was decided to try the inflatable external casing packer that could be made up as part of the liner assembly, expanded against a reduced portion of the liner hole, and be used to isolate wet sands and separate subzones to enable better control for injection and production. This method has proven so successful that practically all wells have from one to four sets of packers. As added insurance, cement is placed between each set of packers. Plate 10 shows a typical packer installation.

In order to obtain a satisfactory pack, it is desirable to have a drift angle of less than 50 degrees in the liner hole. On long drift wells this requires an "S" shaped curve to the well course, with the maximum angle obtained at approximately 1500 feet to allow dropping angle to less than 50 degrees at casing point. In some long drift aquifer injectors where drift angle cannot be dropped low enough, shop pre-packed 5-1/2 inch liner is run. External casing packers are run on the liner and used for zonal segregation. Generally, two sets are run, permitting separation into three subzones.

The Union Pacific and Ford zones' sands are firm and well consolidated and do not require sand control measures. However, external casing packers are run in these wells for zonal segregation.

The lower 237 and Basement zones' wells are completed in a similar manner to the Union Pacific and Ford zones' wells.

RESERVOIR PROBLEMS

From the inception of production in the Unit, reservoir pressures in the Ranger zone on the north flank were found to be as low as 70 per cent of hydrostatic, both east and west of the Long Beach Unit fault. Pressures on the south flank were 95 per cent hydrostatic to hydrostatic. The lower pressures observed on the north flank have been attributed to: (a) voidage by production from the old part of the Wilmington field, or (b) voidage by production from the Long Beach and Seal Beach fields[5], located about one mile north of the north flank oil-water contact. Both explanations require rapid pressure communication through or around known faults. The authors suggest the following additional explanations: (c) original pressures were never at hydrostatic. The observed pressures are partially fossil, and have been depressed below their original elevation. A semi-active water drive observed on the south flank combined with aquifer injection from the old part of the field has raised south flank pressures to their present level. (d) Leakage along faults in the geologic past lowered original pressures below hydrostatic. South flank pressures were subsequently increased by the mechanism employed in (c). The true explanation may involve a combination of these factors.

The reduction of pressures on the north flank has resulted in gas coming out of solution, and the consequent production of much free gas with the oil. To conserve reservoir energy, wells with gas-oil ratios in excess of 2000 cubic feet per barrel of oil are shut-in. Water injection in the aquifer is expected to eventually increase reservoir pressure to the point where most of the gas may return to solution. Lowering of the gas-oil ratio to the point at which the well could be returned to production has already been observed in some of the previously shut-in wells.

Numerous individual water tables are found in all zones. Within the Ranger and Ford zones, the sands go wet at the bottom first, and the higher sands have the greatest productive areal extent. The Upper and Lower Terminal zones have intermediate sands which go wet before those above and below them, and these must be segregated by external casing packers. To date, three separate water table depths are recognized in the Tar zone, eleven in the Ranger, fourteen in the Upper Terminal, nine in the Lower Terminal, nine in the Union Pacific, ten in the Ford, and one each in the 237 and Basement zones, for a total of 58. Oil-water contacts in individual sands vary in different fault blocks. West of the Long Beach Unit fault, the Ranger zone has an approximate 4000 foot oil-water contact in the "F" to "X" interval. Oil-water contacts east of the fault are higher than those to the west by the approximate throw of the fault. Faulting after migration is implied.

WATER INJECTION

The Unit Agreement, under which THUMS as the Field Contractor must operate, requires that water be injected into all unitized formations from the initiation of production. The primary objective of the injection program is to prevent a recurrence of the subsidence problem which originally plagued the Wilmington field. As a direct result of the early initiation of water injection, the field has been under a pressure maintenance program almost from the inception of production, with no true primary phase. Water flooding by aquifer injection is employed in all zones except the Ranger and D-118 zones. A staggered line drive flood employing both in-zone and aquifer injection is used in the Ranger zone. Production from the Basement zone is from fractured, very dense shale and schist. As it poses no threat of subsidence, the zone is not being flooded at present.

The progress of the flood is followed by spinner surveys in the injection wells. Segregation of groups of sands by external casing packers permit the sleeving of intervals which are receiving excessive water. The future progress of the flood will be followed by the change in electric log properties of logs in re-drilled wells, and by spinner surveys and other types of water entry surveys in producing wells. Much of the future geological work in the field will involve the following of the advancing flood fronts in the various zones. The water has already shown a preferential breakthrough in the sands of lower pressure and higher permeability, and many wells nearest to the injection rows will require early abandonment or extensive remedial action.

A ratio of one injection well for every three producing wells is maintained in the Ranger zone. Sufficient water will be injected to replace reservoir voidage and maintain reservoir pressure.

The current daily rate of water injection into all zones is approximately 400,000 barrels per day from 97 injection wells. The maximum daily rate of water injection anticipated is 500,000 barrels per day.

PRODUCTION

The Long Beach Unit is currently producing 145,000 to 150,000 barrels per day of oil and 65,000 barrels per day of water from 433 wells, together with approximately 55,000 MCF of gas. There are 41 wells currently shut-in, mostly due to high gas-oil ratio. The revised maximum daily production forecast is 156,000 barrels per day (Plate 11). Cumulative oil production as of June 30, 1969 was 93,485,157 barrels of oil.

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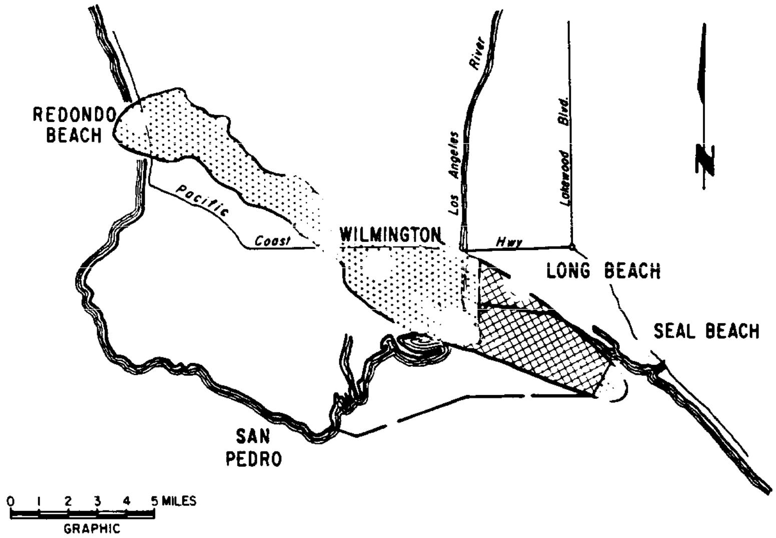

Plate 1 - Wilmington Field.

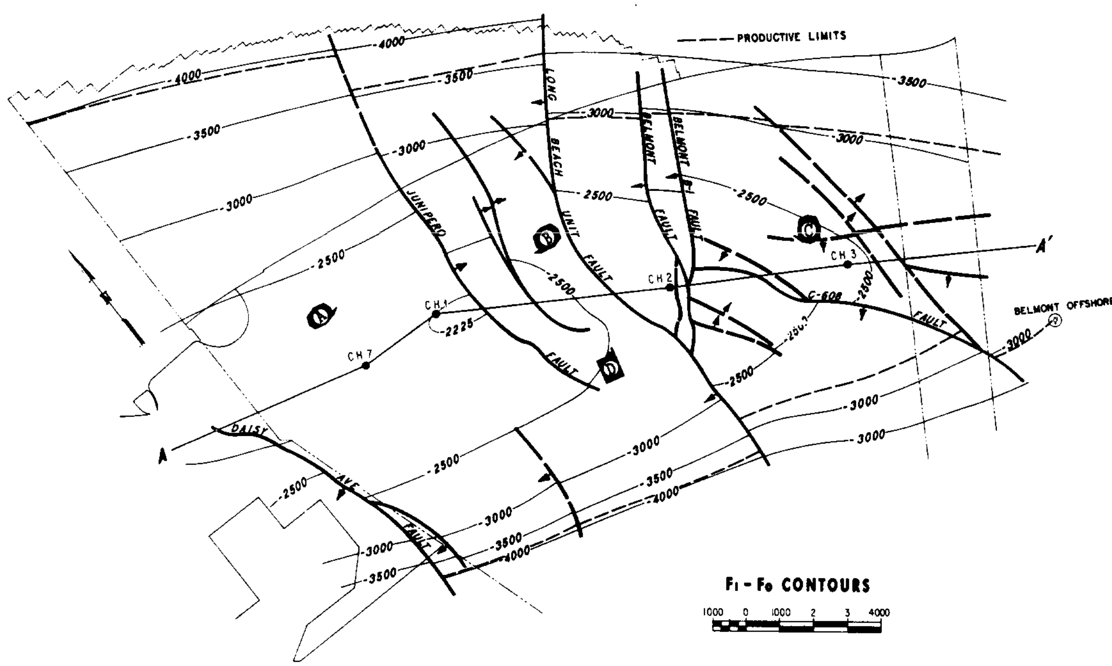

Plate 2 - Ranger zone.

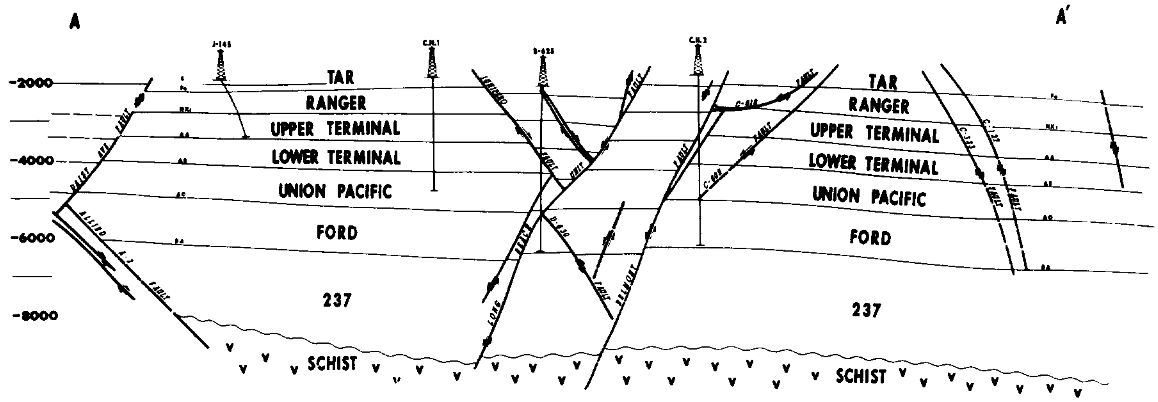

Plate 3 - Long Beach Unit cross section.

LONG BEACH UNIT

ZONE	GROSS THICKNESS	NET OIL SAND	ACRE FT.	PROD. ACRES	STAGE
TAR	200'-400'	50'-95'	71,635	2871	REPETTIAN
RANGER	400'-700'	220'-420'	1,465,412	5931	
U. TERMINAL	700'-750'	400'-500'	244,243	1469	DELMONTIAN
L. TERMINAL	750'-800'	445'	86,044	509	
UNION PACIFIC	900'-950'	230'-285'	172,127	1325	UPPER MOHNIAN
FORD	950'-1200'	500'-600'	323,304	1418	
237 *	2650'	75'	———	———	LOWER MOHNIAN OR LUISIAN
BASEMENT	———	———	———	———	TITHONIAN ?

*INCLUDES D-118 ZONE

Plate 4

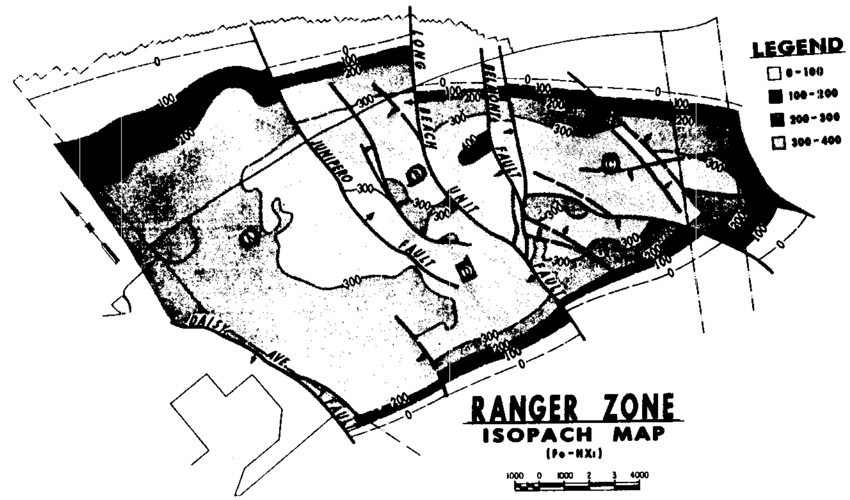

Plate 5

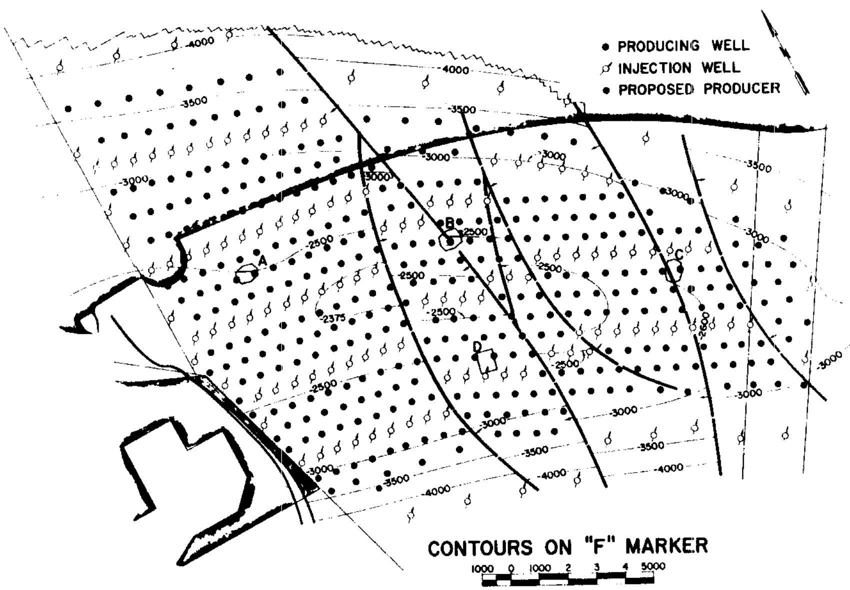

Plate 6

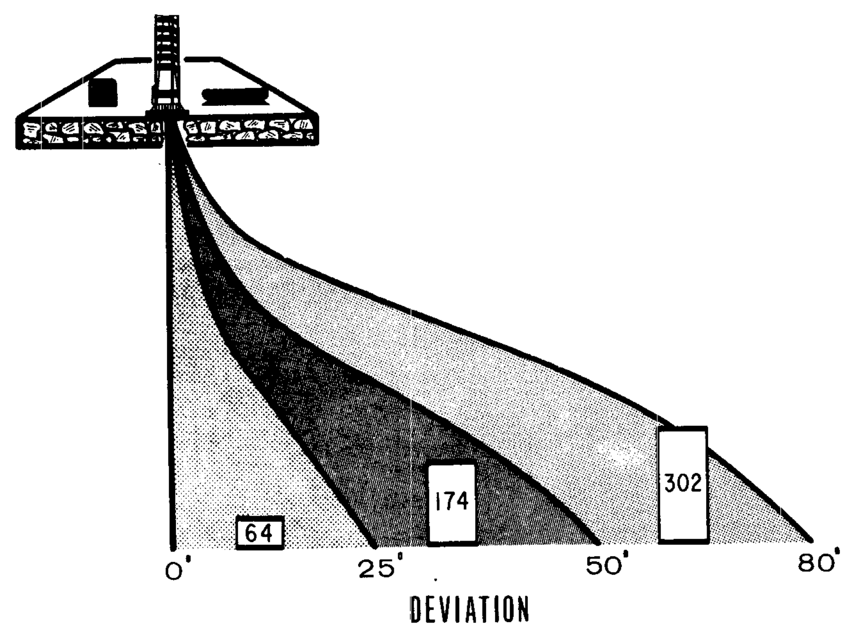

Plate 7 - THUMBS Long Beach Unit 540
drilled wells as of April 1, 1969.

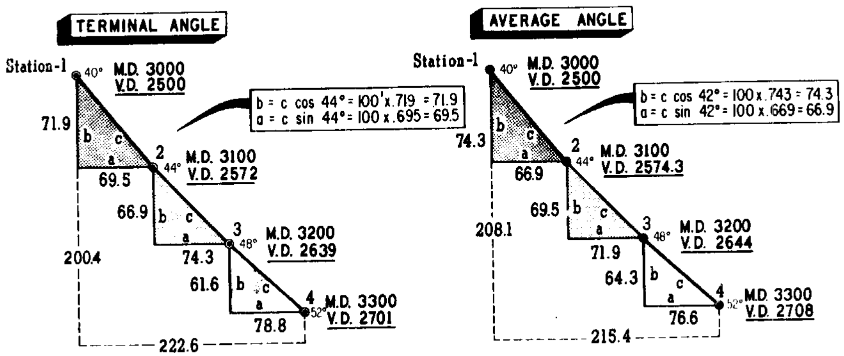

Plate 8 - Comparison of methods of calculating surveys by terminal angle and average angle.

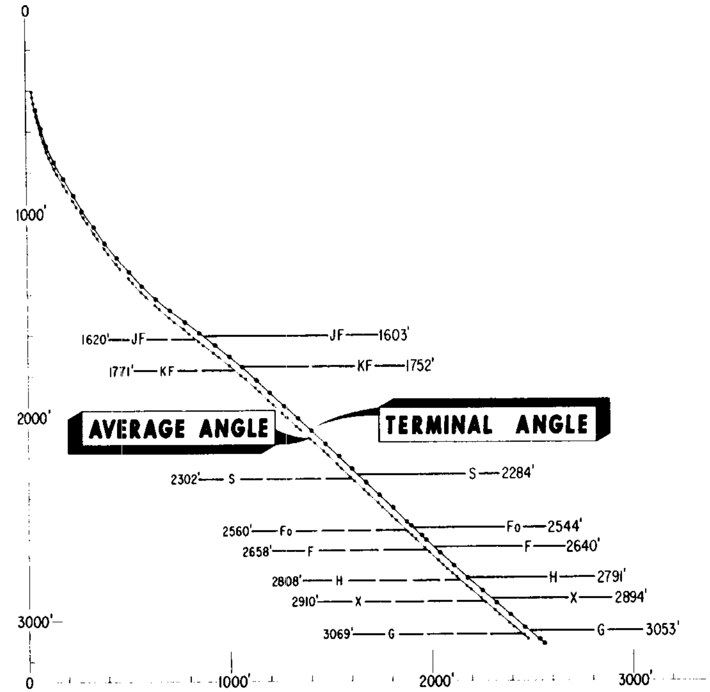

Plate 9 - Comparison of multishot surveys calculated by terminal and average angle methods. Vertical depths shown on both methods.

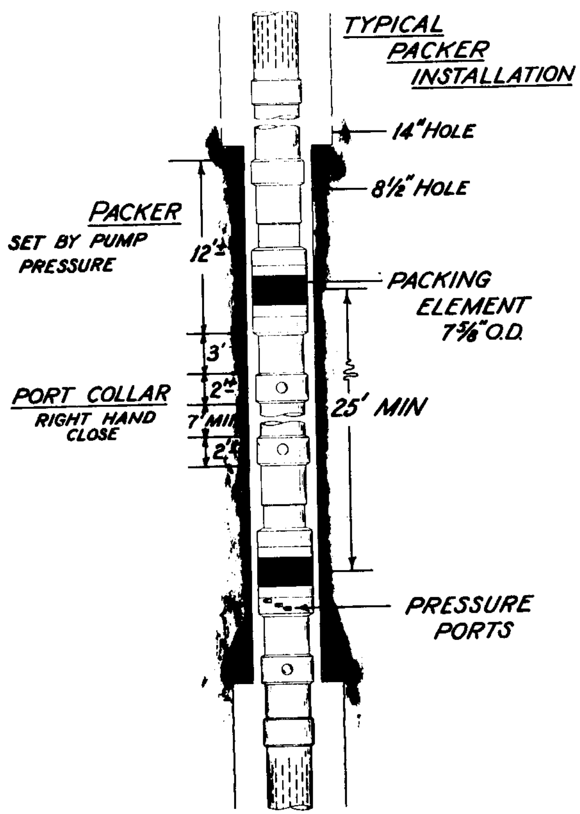

Plate 10 - Typical packer installation.

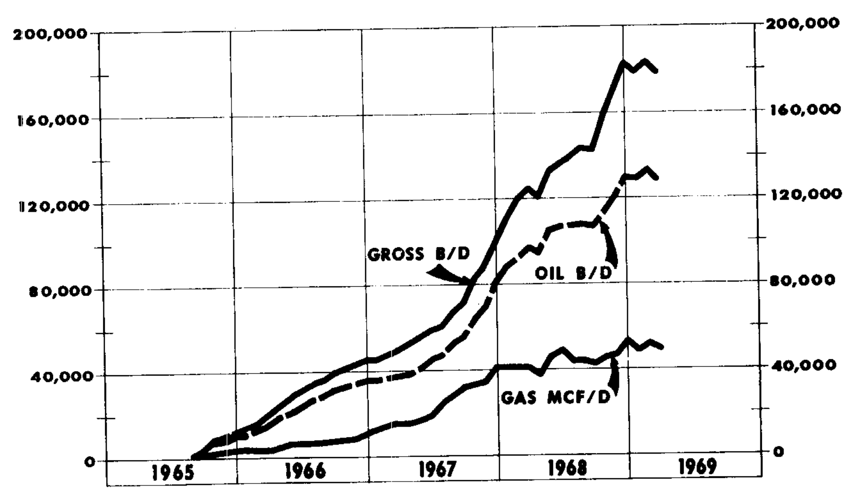

Plate 11 - THUMBS Long Beach unit ptoduction.