INCREASE WATERFLOOD RESERVES IN THE WILMINGTON OIL
FIELD THROUGH IMPROVED RESERVOIR CHARACTERIZATION
AND RESERVOIR MANAGEMENT

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Increase Waterflood Reserves in the Wilmington Oil Field through Improved Reservoir
Characterization and Reservoir Management

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Foreword

This project is intended to increase recoverable waterflood reserves in slope and basin reservoirs through improved reservoir characterization and reservoir management. The particular application of this project is in portions of Fault Blocks IV and V of the Wilmington Oil Field, in Long Beach, California, but the approach is widely applicable in slope and basin reservoirs. Transferring technology so that it can be applied in other sections of the Wilmington Field and by operators in other slope and basin reservoirs is a primary component of the project.

Abstract

This project used advanced reservoir characterization tools, including the pulsed acoustic cased-hole logging tool, geologic three-dimensional (3-D) modeling software, and commercially available reservoir management software to identify sands with remaining high oil saturation following waterflood. Production from the identified high oil saturated sands was stimulated by recompleting idle production and injection wells in these sands using conventional means as well as a short radius redrills.

Although these reservoirs have been waterflooded over 40 years, researchers have found areas of remaining oil saturation. Areas such as the top sand in the Upper Terminal Zone Fault Block V, the western fault slivers of Upper Terminal Zone Fault Block V, the bottom sands of the Tar Zone Fault Block V, and the eastern edge of Fault Block IV in both the Upper Terminal and Lower Terminal Zones, the top sands of the Tar Zone Fault Block IV all show significant remaining oil saturation. Each area of interest was uncovered emphasizing a different type of reservoir characterization technique or practice. This was not the original strategy but was necessitated by the different levels of progress in each of the project activities.

Executive Summary

Waterflood oil recovery in the Wilmington Field has historically been inefficient due to a variety of factors, including reservoir

heterogeneity, poor sweep efficiency, high water cut, and poor injection profiles. Sands with high remaining oil saturation are still present despite extensive waterflooding, but locating these sands has been difficult.

Reservoir management software has identified areas of potentially high remaining oil saturation in the Upper Terminal Zone and the Lower Terminal Zone of Fault Block IV, and the Tar Zones of Fault Blocks IV & V. In Budget Period 1 (BP1) a pulsed acoustic cased-hole logging tool was run in potential recompletion candidates and recovered compressional wave data from which porosities were calculated. Unfortunately, shear wave data were not recovered therefore acoustically derived saturations could not be accurately predicted for the logged wells.

Examination of recent electric logs (E-logs) revealed sands with high remaining oil saturation in the Tar Zone and Upper Terminal Zone of Fault Block V. Deterministic 3-D models were built around the Upper Terminal Zone recompletion candidate Well J-120 in BP1 and expanded and improved in Budget Period 2 (BP2). Well J-120 was recompleted and returned to production. Production results have greatly exceeded expectation. Based on these data the short radius horizontal redrill J-17 was placed in this modeled reservoir at the end of BP1. This well is the most prolific producer in the reservoir. Additional production points are planned for BP2.

A deterministic 3-D geologic model was built around the Tar Zone short radius horizontal candidate Well A-112. This well was designed to drain an area which had not seen any drainage and had only minimal exposure to injected fluids. The well was drilled in April, 2000, with conventional LWD tools. The survey and recording instruments were 60' behind the bit which makes the bit hard to control and geosteering difficult. The well penetrated the F_1 , F_0 then the lower F_1 , F_0 again and finished with the F_02 sand. The second F_1 penetration was unintentional but the interval shows good oil saturation throughout.

It is recommended that recording devices nearer the bit be used on future wells where accurate placement of horizontal laterals is critical. Although these tools are more expensive, the chances of mechanical success is greater due to better feedback while steering the bit. To determine the future well locations, the geological understanding revealed by this work should be combined with further work on where water has been injected.

Introduction

This project used advanced reservoir characterization tools, including the pulsed acoustic cased-hole logging tool, geologic (3-D) modeling software, and commercially available reservoir management software to identify sands with remaining high oil saturation following waterflood. Production from the identified high oil saturated sands were exploited by recompleting existing idle production and injection wells in these sands using conventional means as well as a short radius redrills. The idle wells were in danger of abandonment.

Discussion

● Reservoir Characterization

The Reservoir Characterization Activity was completed prior to this reporting period. A detailed summary of the work can be found in the previous yearly report for this project which covers the time period March, 1997 through March, 2000.

● Reservoir Engineering

The main task of Budget Period 2 (BP2) is to review production and injection data from Budget Period 1 (BP1) and locate individual sands with high remaining oil saturation. During this process several old wells were discovered missing from the data set. Researchers reviewed all injection associated with the "F₁" and "Fo" sands in the Tar Zone, Fault Block 5. The missing data was added to the data set and updated maps were generated.

Researchers gathered old and new electric logs from an area of potential bypassed oil in the "F₁" and "Fo" sands in the Tar Zone, Fault Block 5. The area of interest is in the northeast corner of the reservoir (FIGURE 1). The logs show residual oil saturation ranging from 53% to 63% with no associated bottom water. Wells located further down structure do show an oil-water contact and associated bottom water. The area of interest has not had substantial activity in the subject sands over the last 25 years.

Researchers also looked at 30 years worth of spinner-tracer surveys for 11 injectors located in the A-112 project area. This historical research indicated injection into the "F₁" and "Fo" sands took place before 1985, with the bulk of the injection from 1968 to 1980. The surveys also showed a good distribution of water across both sands.

A review of the Tar Zone surrounding idle penetrating production well Z-47 indicated bypassed waterflood oil. The "S", "T", "D1", "F₁", & "Fo" sands in this area of the Tar Zone have not been effectively drained. Electric logs from nearby penetrating wells FZ-29 (1980 log, 122 m (400 ft) from Z-47) and Z1-24 (1983 log, also 122 m (400 ft) from Z-47) show peak resistivities of 17 ohms and 8 ohms in the "S" & "T" sands respectively. These sands have not been flooded out subsequently as the only nearby "S" & "T" sand injection is in wells FY-150, FZ-214, and FJ-55. These injectors are all at least 442 m (1450 ft) away from well Z-47. The bulk of the cumulative injection into the "S" & "T" sands has taken place in the far north of the Tar 5 reservoir.

Currently, there are three active production wells surrounding Z-47 which are completed in the "S" & "T" sands. They are wells Z-237, Z-202, & Z1-40. Production from these wells is as follows:

Z-237 25.7 m³/d (161 b/d) gross, 1.1 m³/d (7 b/d) net, 95.7 % water cut, 245 m (803 ft) FOP

Z-202 30.5 m³/d (191 b/d) gross, 1.9 m³/d (12 b/d)net, 93.7 % water cut, 164 m (538 ft) FOP

Z1-40 81.9 m³/d (513 b/d) gross, 3.5 m³/d (22 b/d)net, 95.7 % water cut, 115 m (377 ft) FOP

Gross production from wells Z-237 and Z-202 is lower than most "S" & "T" sand completions and is likely short due to scale. These wells could benefit from a small acid job and pump change the next time they go down. Production from well Z-47 should be similar to the three wells listed above and is estimated at 95.7 m³/d (600 b/d) gross and 4.8 m³/d (30 b/d) net for a 95% water cut.

● Deterministic 3-D Geologic Modeling

Horizontal well A-112 was drilled with conventional LWD tools with the survey and recording instruments 18.29 m (60 ft) behind the bit. The well was geosteered by plotting the position of the surveys on an Earth Vision cross section cut through the proposed well course and on maps of selected horizons. Both cross sections and maps were extracted from the geological model. The LWD was correlated using the stratigraphic cross sections and comparing where the well plotted on the Earth Vision cross section and maps. The azimuth of the well followed the plan very closely and therefore only one section was needed. The well penetrated the "F₁", "Fo" then the "F₁ B", "Fo" again and finished with the "Fo2" sand. The "F₁ B" penetration was unintentional but the interval shows good oil saturation throughout. FIGURE 2 shows the eight resistivity curves along with the annotated well path and cross section from the geological model. The dashed lines on the resistivity tracks represent the deeper reading amplitude curves and the solid lines are the shallow reading phase resistivity curves. For the actual resistivity values see FIGURE 3. FIGURES 2 & 3 are at the same scale so the log values and geology can be more easily compared and interpreted.

The cross section through the well course and logs were reviewed. It was discovered that the signature of the ten LWD curves did not make sense with the geological model between approximately 1,234 m to 1,385 m (4,050 ft to 4,545 ft). The logs show the following sequence:

1. A polarization horn on the 2 MHz resistivity log at 1,250 m (4,100) indicating a sand/shale boundary which is a mirror of the "Fo" first crossing.
2. Shale from 1,256 m to 1,267 m (4,120 ft to 4,155 ft) indicated by Gamma-Ray also shows mirror of "Fo" first crossing.
3. Sand from 1,267 m to 1,335 m (4,155 ft to 4,381 ft) with nearly the same 2 MHz phase resistivity value as the "Fo" sand just penetrated but the polarization horns have different magnitude.
4. Long shale section from 1,335 m to 1,385 m (4,381 ft to 4,545 ft).
5. Sand starting from 1,385 m (4,545 ft) with lower resistivity than observed up the hole.

At the time of drilling Well A-112 it was thought that the shales at 1,256 m (4,120 ft) and 1,335 m (4,381 ft) were probably an unmapped small shale inside the "Fo" sand. This meant that the sand at 1,267 m (4,155 ft) would be the upper "Fo" sand. Further scrutiny of the cross section, TVD log, and mapped area suggested that the well was structurally higher and that the "F₁ B" sand was intersected at 1,267 m (4,155 ft). It was reasonable to assume that the shale intersections at 1,256 m (4,120 ft) and 1,335 m (4,381 ft) belong to the same shale because the well path moved up and then down in section. If "F₁ B" was crossed then the shale intersections belong to the shale above the "Fo" sand and not an unmapped shale within the "Fo". A closer look at the data was necessary.

It was suspected that the offset well A-192's markers were causing the modeled structure to be too high. This observation was based on a subtle difference of the "Fo" VSS values between A-192 and other offset wells. The "Fo" appeared slightly high but the correlation was verified as true. This meant that the well survey was most likely the problem. The shale above the "Fo" was sketched in, lower than originally shown on the cross section, to connect across the questionable interval in the well section. The horizontal lateral for Well A-112 then appeared to enter and traverse the lower "F₁ B" sand from 1,267 m (4,155 ft) to 1,335 m (4,381 ft). This hypothesis was tested by eliminating all A-192 markers and building a new model. The well cross section extracted from the revised model appeared more consistent and made much better sense with the log curves. The model was further refined by making the "Fo" shale thinner in the problem area and using tops correlated on to the A-112 log. The "Fo" shale thickness was estimated by averaging the thicknesses of the shales in surrounding wells. In addition, vertical thickness was calculated from the Well A-112 LWD between 1,253 m (4,110 ft) and 1,267 m (4,158 ft) MD. The thickness value was calculated to almost 0.9 m (3 ft) (instead of 1.2 m (4 ft)), however the strata is falling away in this interval giving a lower than actual value calculated from vertical depths. The final cross section makes good sense with the logs (FIGURE 2).

The net result of the modeling changes was that the top of the "Fo" shale moved down 1.98 m (6.5 ft) at the highest point. The structure turned out to be flat in the area of A-192. The original 1.98 m (6.5 ft) of rise was over a 183 m (600 ft) length in cross section. This magnitude of warping should be searched for before drilling any future horizontal wells in the Tar Zone, Fault Block V.

Due to the realization that the well entered the lower part of the "F₁ B" sand, the perforating procedure was changed to perforate 'high side' instead of 'low side' in the area of the "F₁ B" sand. A 'low side' perforation may have resulted in perforating the shale on top of the "Fo" sand. The final log with marker tops can be seen in Enclosure 2. Note the perforations and cement plug annotations are also shown in FIGURE 3.

It should be noted that the bottom of the "F₁ B" sand was entered below measured depth 1,266 m (4,155 ft) and exited at 1,335 m (4,381 ft) at which point the "Fo" shale top ("Fo"SHR) was re-entered. The 'R' designation shown on FIGURES 2 & 3 indicates that the horizon was repeated on the log. The 1 and 2 after the 'R' indicates multiple intersections. For example, "Fo"R1 means that the "Fo" top was repeated for the first time and the "Fo" top intersected a second time. As can be seen on FIGURE 3, the tops match fairly well with the model in the "F₁" to "F" interval.

Review of FIGURES 1, 2, & 3 reveals that Well A-112 occupies a high structural position and that there is still good oil saturation in the "F₁" to "F" interval. There is also good oil saturation in the interval above "F₁" but that interval is beyond the scope of this study. The "F₁" to "F" interval has 15 ohms resistivity in all but the "Fo"R2 and lower "Fo2" sands. The latter was expected but the former was not. The "Fo"R2 shows 9 ohms, which is a 6 ohm decrease over a 4.6 m (15 ft) loss in structure compared to the "Fo"R1. The 15+ ohms resistivity in the "Fo" / "Fo"R1 and the "Fo2" is higher than seen in Well FR-110 (FIGURE 4). A comparison of the 1988 FR wells and Well A-112 is shown in Table 1 below. The wells are arranged so they proceed up structure.

Well	"F1"	"F1B"	"Fo"	"Fo2"
FR-110	9 ohms	12 ohms	9 ohms	14 ohms
FR-109	9	14	9	10
FR-111	9	13	12	14
A-112	9	11 & 14	16 & 9	15

Table 1

The resistivity for Well FR-110 appears anomalously high in the "Fo2" and the resistivity of the "F₁" for all the wells is constant. Otherwise, the best saturation is up structure but not significantly

greater up structure than down structure for most of this interval. This suggests significant reserves may remain down structure. The area of "No Fo production" was barely penetrated and only by the "Fo2". Because the resistivity shown in Table 1 is fairly consistent in the "Fo2", one could conclude that the probe into this area was successful and that another drainage point is justified.

For the purposes of modeling and drilling, the T through T7 sands were picked on logs in the proximity of well L-610. While investigating the extent of the high resistivity seen in the L-610 e-log (FIGURE 5), another sand was identified and mapped to the West and Southwest. The stratigraphy and model area are as follows:

Stratigraphy

Name	Lithology	Est. Thickness	Modeled	Method
T	Shale	9 feet	Yes	Well Data
T1	Sand	5	Yes	Well Data
T2	Sand	10.5	Yes	Well Data
T7	Shale	10.5	Yes	Well Data
	Total	24.5 feet		
OR	Sand/Shale	5	Yes	Well Data f/ EV data base
ORSH	Shale	8	Yes	Well Data f/ EV data base
RED	Sand/Shale	4	Yes	Well Data f/ EV data base
REDSH	Shale	15	Yes	Well Data f/ EV data base
TU	Sand/Shale			
	Total	32.0 feet		
FO	Sand	19	Yes	Well Data
FSH	Shale			Well Data + F reference
F	Sand	Varies	Yes	Well Data

Model Range: (Ford Coordinates)

	X	Y	Z
Minimum	9000	-12000	-2800
Maximum	15000	-6500	-1800

One fault was modeled - the Daisy Avenue B-1. The horizons modeled are those shown above. The goal of the modeling is to define the extent and geometry of the geology. Within the sands, the oil saturation will be modeled to determine the best place to drill.

The Geologic modeling consisted of the steps as follows:

1. Correlate sands using "paste up" stratigraphic sections throughout area. Sections corrected to vertical by shrinking based on well drift angle at "T" sand. Hang on "T".
2. Load Newilma data base and create Earthvision data base for local markers. Export data from both data bases.
3. Create initial model using stratigraphy shown above. Identify erroneous data.
4. Check correlation and entry for all erroneous data.
5. Create 3D geological model with and without smoothing.
6. Quality control using 3D model and cross sections.
7. Create data set with points in middle of sand targeted for modeling.
8. Add parameters to data points and model saturation in 3-D.

After the stratigraphic sections were correlated, it was noticed that there were two sands showing resistivity in an area not previously produced. The sands were designated orange and red. While the orange sand was traced to the Northwest and appeared to be from a channel trending Northwest-Southeast, the red sand did not appear to be channel derived.

The first model was created and revealed that the Orange and Red sands were on lapping the Wilmington anticline similar to that seen in Fault Block II. There is also a 'pod' of orange sand seen in the eastern portion of the reservoir (FIGURE 6). In cross section it can be seen that there is a low that was filled with sand probably sourced from the east. Coincidentally the T2 highly saturated oil sand seen in penetrating well L-610 is in this same area.

An oil water contact is suggested by wells L-202, L-213, L-230, L-506, L-504. These wet wells have an Orange sand that lies below -2860 vss. Well L-229 also lies below this point but the orange sand is partially oil saturated as indicated by the log. The log for well L-229 looks a lot like the log for well L-226. This suggests the survey for L-229 is incorrect. L-229 is the farthest east with the longest section for any of the Pier G wells. The east-west orientation may have influenced the magnetic survey placing the well too far south. An inertial survey would give the true position to L-229. Well L-225 may also be slightly out of place.

The red and orange sands were studied. Full size copies of the logged interval were made and a computer spread sheet was created. Entries to the spread sheet include the following:

1. Resistivity of deep induction tool (e.g. Schlumberger 6FF40) read from log.
2. Sand percentage calculated from SP using S, FO and Shale in between as baselines.
3. Measured depth Sand thickness.
4. Angle of well bore at Orange sand.
5. Resistivity of wet sand - lower S sand.
6. Corrected resistivity of deep induction tool 6FF40 read from log. Corrections read from Schlumberger Log Interpretation Charts Page 6-12 under the Rcor section. The specific chart read was for a shale resistivity = 2 ohm-m. It should be noted that the shales encapsulating the studied sands have a resistivity of 1.8 ohm-m.

Sand thickness, water saturation (S_w), oil saturation (S_o) and corrected oil saturations were calculated. The sand thickness was calculated from the measured depth thickness * Cosine of the well angle at the Orange sand. The calculated saturations assumed clean oil sand so the Archie formula could be used.

Archie formula: $S_{wn} = F \cdot R_w / R_t$.

F was calculated using the Humble formula $F = 0.62/\phi^{2.15}$.

Porosity from up structure well FJ-204 Neutron Density average porosity in sand time equivalent to Orange sand.

Rw was calculated from the wet 'S' sand in each well

where $S = 1$, $n = 2$, R_t = log resistivity of wet sand, F calculated using 'S' sand average porosity from Neutron Density in well FJ-204.

There was some concern that the sands might be shaley and that the Archie method of S_o calculation is inaccurate. The SP for a large number of the wells shows something other than a clean sand. The deflection is not the same as the oil saturated 'Fo' or water saturated 'S' sand. Sand thickness was plotted vs S_o but no clear correlation was found. Sand percentage vs height above the oil water contact (OWC) was plotted and a trend could be seen. The well logs showing wet sands show 100% sand whereas the logs indicating oil sands show something less as in the L-225 e-log (FIGURE 7). This suggests the SP is being suppressed by the oil content therefore the sand percentage calculation is incorrect. Well FJ-204 has a small sand at 842 m (2762 ft) time equivalent to the Orange sand. The neutron and density curves lie directly on top of each other indicating a very clean oil sand. Lacking Neutron-Density or sonic logs in the study area, the only evidence for sand cleanliness is the wet sand SP deflection and clean time equivalent sand shown in FJ-204.

● Pulsed Acoustic Logging

The Pulsed Acoustic Logging activity was completed prior to this reporting period. A detailed summary of the work can be found in the previous yearly report for this project which covers the time period March, 1997 through March, 2000.

● Recompletions

A rig moved on Budget Period Two horizontal Well A-112 in late November, 2000, in order to remove the steam injection equipment and install the production equipment. A-112 steaming was completed in October, 2000. A total of 19,483 m³ (121,800 bbls) of cold water equivalent steam was injected into the well in order to

consolidate the sand. The well was RTP'd in early December, 2000.

Initial production was 126 m³/d (791 b/d) gross, 0.5 m³/d (3 b/d) net, for an 99.6% water cut with 528 m (1,733 ft) of fluid over the pump. Production temperatures averaged 103°C (218°F). In December, 2000, the well averaged 150 m³/d (940 b/d) gross, 2.4 m³/d (15 b/d) net, for an 98.4% water cut. It is very typical that steamed wells produce at very high water cuts for the first four to six weeks of its productive life.

As of March, 2001, the well averaged 157 m³/d (984 b/d) gross, 9.3 m³/d (58 b/d) net, for a 94.1% water cut with 456 m (1,497 ft) of fluid above the pump (FIGURE 8). The production temperature as of March 31, 2001, was 69°C (157°F). Due to injection production restrictions we will not increase the gross production of A-112 until injection can be increased in the surrounding reservoir.

Well A-112 was originally spudded in mid April, 2000. A 25.1 cm (9-7/8 in) hole was drilled down to the target interval using long radius directional tools. The directional plan included building angle slowly at 4 degrees per 30.49 m (4 degrees per 100 ft) rate to a final angle of 87.3 degrees inclination and then dropping the angle near the end of the well to 79.3 degrees. Well A-112 was drilled using Logging while Drilling (LWD) and Measurement while Drilling (MWD) tools from surface casing to a total measured depth of 1,497 m (4,910 ft), 727 m (2,385 ft) vertical depth. Approximately 274 m (900 ft) of net sand within the intended zones of completion was penetrated over a gross interval of 351 m (1,150 ft). Casing size 19.4 cm (7-5/8 in) was run from surface to 1,497 m (4,909 ft) in a 25.1 cm (9-7/8 in) hole using hour glass type centralizers and a floatation collar 488 m (1,600 ft) off bottom.

The directional proposal for Well A-112 was revised at the last moment for political rather than engineering reasons. For permitting reasons, the surface location needed to remain unchanged, but the bottom hole location was moved approximately 427 m (1,400 ft), or two locations South from the original downhole target location. The directional drilling contractor worked rapidly to respond to our request to alter the plan. The additional potential conflict wells were identified by Tidelands and provided to the directional contractor who in turn entered them into the database. Within days we had a workable directional plan and maps. This

contractor, after their previous directional project with Tidelands, made the effort to archive the necessary formulas needed to rotate and translate Tidelands' directional data.

The cross-section derived from Tidelands' geologic modeling was also rapidly modified to reflect the new bottom hole target. This was possible because the area originally modeled covered the new location. Having sufficient area modeled and personnel available to rapidly respond to requests for change is essential.

Even with the most sophisticated 3-D modeling, your plan is only as good as your data. Most of the data used to map the target structure was gathered using 40 to 50 year old instruments. The greater the horizontal displacement, the greater the margin for error, (no vertical wells have been drilled in the vicinity of the bottom hole target). One such error impacted the cross-section used to drill Well A-112. At one point during the drilling, the cross-section indicated that the well should be in the middle of a sand, yet the LWD tools indicated we were in a shale interval. Just one well with erroneous data can significantly impact a thin bed horizontal well plan. After the well was drilled, the culprit well was identified and removed from the model; the log and model were now in agreement.

Removing the need to drill out the float collar and squeeze cement near the end of the well during completion operations is a big time and money saver. In previous horizontal wells, a lot of money and effort was spent cleaning out the last 24 m (80 ft) of casing to uncover the bottom of the well for completion. This usually resulted in the shoe leaking and subsequent installation of a tubing set bridge plug. For this well, the bottom 30 m +/- (100 ft +/-) was drilled into the bottom of the sand and shale below the target sand to preclude completion and verify well location relative to the sand/shale interface. The end of the well was also too close to the lease line to be completed according to California Department of Oil and Gas statutes.

The casing of A-112 was perforated with 0.74 cm (0.29 in) holes, alternately phased 60° off low side, and selectively spaced over the interval from 1,132 m (3,712 ft) to 1,451 m (4,760 ft). The total number of perforations was nineteen. The perforations were pressure washed with an opposed cup tool. A string of thermal

insulated tubing with a thermal packer on bottom were installed for the sand consolidation by steam process. A-112 took steam at an average rate of 191 m³/d (1,200 b/d) of cold water equivalent steam.

Incremental oil production for this DOE project is 27,706 m³ (173,624 bbls) as of March, 2001.

● Technology Transfer

Tech transfer has taken place throughout the course of the project. Technical papers and presentation have been given at local, regional, and national meetings of professional societies such as the Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG), Society of Professional Well Log Analysts (SPWLA), Society of Exploration Geophysics (SEG), American Geophysical Union (AGU), European Association of Geoscientists & Engineers (EAGE), and Petroleum Technology Transfer Council (PTTC).

Activities during the current project reporting period include the following paper:

Researchers wrote and presented a paper to the Gulf Coast Section Society of Economic Paleontologists and Mineralogists Foundation 20th Annual Research Conference Deep-Water Reservoirs of the World: Clark, D., Phillips, C., "3-D Geological Modeling and Horizontal Drilling Bring More Oil Out of the 68-Year-Old Wilmington Oil Field of Southern California". December 3-6, 2000 (Appendix 1)

References

None

FIGURE 1

FIGURE 1

FIGURE 2

FIGURE 3

FIGURE 3

FIGURE 4

WELL FR-110 MD LOG

Vertical Scale: 1 inch = 20 feet

Atlas Wireline Log run in 1988

FIGURE 4

FIGURE 5

FIGURE 5

FIGURE 6

FIGURE 6

3-D model showing Orange sand on lapping shale. There is also a “pod” of sand shown near L-610. This “pod” fills a structural low. Vertical exaggeration = 2.

FIGURE 6

FIGURE 7

L-225 0

FIGURE 7

FIGURE 8

06/19/2001

Tidelands Oil Production Company Oil, Water & Gas Production

A -112

T 5

T.....

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FIGURE 8

ATTACHMENT 1

3-D Geological Modeling and Horizontal Drilling Bring More Oil out of the 68 Year Old Wilmington Oil Field of Southern California

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ABSTRACT

The giant Wilmington oil field of Los Angeles County California, on production since 1932, has produced over 2.5 billion barrels of oil from Pliocene and Miocene age basin turbidite sands. The seven productive zones were subdivided into 52 subzones through detailed reservoir characterization to better define the actual hydrologic units. The asymmetrical anticline is highly faulted and development proceeded from west to east through each of the ten fault blocks. In the western fault blocks water cuts exceed 96% and the reservoirs are near the economic limit. Several new technologies have been applied to specific areas to improve the production efficiencies and thus prolong the field life.

Tertiary and secondary recovery techniques utilizing steam have proven successful in the heavy oil reservoirs but potential subsidence has limited its application. Case history 1 involves detailed reservoir characterization and optimization of a steam flood in the Tar Zone, Fault Block II. Lessons learned were successfully applied in the Tar Zone, Fault Block V (4000 meters to the East). Case history 2 focuses on 3-D reservoir property and geological modeling to define and

exploit bypassed oil. Case history 3 describes how this technology is brought deeper into the formation to capture bypassed oil with a tight radius horizontal well.

INTRODUCTION

This paper describes three drilling projects where computerized mapping, modeling and simulation programs, used in conjunction with detailed reservoir characterization and advanced geosteering technology, have helped to successfully tap bypassed, heavy oil in California's mature supergiant the Wilmington oil field. To date, the Wilmington oil field has yielded over 2.5 billion barrels of oil of the original 9 billion barrels of oil in place. This paper focuses on how detailed reservoir characterization and 3-D visualization tools applied to horizontal drilling have improved Tidelands Oil Production Company's recovery factor in the "Old Wilmington" or western portion of the field. Background data from THUMS' Long Beach Unit (the eastern portion of the field) are included where needed to provide a thorough field overview. The methods and technologies described herein have the capability of increasing the ultimate reserves of the Wilmington oil field by hundreds of millions of barrels and will find immediate application in other mature oil fields.

BACKGROUND

The Wilmington oil field of southern California (Figure 1), the largest oil field in the Los Angeles basin (Biddle, 1991), has produced over 2.5 billion barrels of oil (California Department of Conservation, 1999). Discovered in 1932, it produces from semi- and unconsolidated Pliocene and Miocene clastic slope and basin turbidite sandstones (Henderson, 1987; Blake, 1991). The

individual reservoirs are defined by graded sequences of sandstone interlayered with siltstones and shales (Slatt et al, 1993). The entire sequence is folded and faulted (Mayuga, 1970; Clarke, 1987; Wright, 1991). Even the typically rhythmically deposited sequences have lenticular lobate shapes and are complicated by basal scour, amalgamation, onlapping and channeling. The result is a sequence of rocks that often appears to be uniform, but is not. These complexities also result in permeability variations that hinder the producibility of the sandstones, impact waterflooding and result in a substantial amount of bypassed oil.

The Wilmington field has been divided stratigraphically into seven producing zones, 52 subzones, and locally into even finer sub-subzones (Henderson, 1987). A serious effort was made to establish stratigraphic continuity in as fine detail as possible. The finer subdivisions are defined as hydrologic bodies or depositional sequences. Many techniques and tools were applied to characterize the thinner sand bodies into unique units, including core description combined with log-rock typing, detailed log correlation, production/injection history matching, bypassed pay saturation analysis on recent pass-through wells, and reservoir simulation (Otott, 1996; Davies and Vessell, 1997; Davies et al, 1997). Six geologists spent the better part of one year working with thousands of old logs and assorted base maps to sort out a consistent and logical stratigraphic sequence. Besides the authors Keith Jones, Mike Henry, Linji An, Rick Strehle and David K. Davies performed a significant portion of the characterization.

We are still learning about the intricacies of Wilmington Field's reservoirs, although today's computerized visualization tools combined with advanced measurement-while drilling (MWD) have significantly contributed to the collective knowledge base about this field. Meanwhile, the field's poorly drained sands remain ideal targets for horizontal drilling.

History of the Long Beach Unit

The Wilmington oil field is a faulted asymmetrical anticline. There are 10 larger fault blocks whose reservoirs have been managed independently. The City of Long Beach, through the Department of Oil Properties operates most of these fault blocks in the Wilmington Oil Field (Figure 2). The Wilmington Townlot Unit (WTU), a portion of the westernmost fault block, fault block I is operated by Magness Petroleum Company. Pacific Energy Resources operates a portion of fault block II. Tidelands Oil Production Company is the field contractor for most of the western portion (fault blocks I-V). THUMS Long Beach Company is the field contractor for the eastern portion of Wilmington oil field (fault blocks VI-90N), which is called the Long Beach Unit (LBU). The LBU was originally produced with more than 1,000 wells drilled between 1965 and 1982 (Otott and Clarke, 1996). Even given the very long completion intervals used and water injection for pressure support, oil remained in pockets of tight thin sands, as well in areas with poor injection support. Widely ranging permeabilities and faulting caused typically viscous oil (12.5^0 to 16^0 API) to be left behind in 20 to 50 ft (6 to 15 m) thick sand units.

An additional 460 wells were drilled in the Long Beach Unit from 1982 to 1986 using a “sub-zone” approach to improve sweep efficiency, which allowed another 160 million barrels (bbl) or 25.4 million cubic meters (m^3) to be produced. Then, after 1986 bypassed sands were selectively perforated in even finer intervals. The first horizontal well was completed in November 1993 as part of the optimized water flood project and 39 other wells have been drilled since then using a combination of computerized mapping and digitized injection surveys to identify the dominant unswept flow units, real-time analysis of MWD data to update cross sections, and geosteering supported by logging-while-drilling (LWD) data to ensure accurate

wellbore placement.

Typically, the wells were placed 10 to 15 ft (3 to 5 m) below the top of the sand. Initial oil production rates from the best horizontal wells exceeded 600 bbl/ day ($95.4 \text{ m}^3/\text{day}$) and from the average wells about 300 bbl/ day ($47.7 \text{ m}^3/\text{day}$), at 80% water cut, stabilizing at about 100 bbl/day ($15.9 \text{ m}^3/\text{day}$) after 300 days. Total unit oil production is 38,000 bbl/day. Blesener and Henderson (1996) describe several of the new engineering technologies that have been applied to the Long Beach Unit. These include coiled tubing drilling, drill cuttings injection and reclaimed water injection. In 1995 the LBU ran a 3-D seismic survey to help define the subsurface in greater detail (Otott et al, 1996). The survey did not provide the desired results but it did serve as a valuable tool for deep work. Several exploratory prospects were identified. One or more of these may be drilled in the next year.

THUMS was purchased from Arco by Occidental Oil and Gas Corporation in May of 2000. Occidental plans to conduct more detailed reservoir studies and possibly a new 3-D seismic survey.

History of the “Old Wilmington” Area

The history of the Wilmington oil field has been detailed by Mayuga, (1970); Ames, (1987); Otott and Clarke, (1996). Over 5000 wells have been conventionally drilled in the 68 years “Old Wilmington” has been on production. The entire field is on secondary recovery and oil production is down to 7000 bbl/day ($1113 \text{ m}^3/\text{day}$) with an average water cut of 96.9%. Because of the steep 14% per year decline it was decided to investigate new ways to produce more oil. As part of this effort Tidelands Oil Production Company has drilled 14 horizontal wells since 1993 in four heavily drilled (3000+ wells) fault blocks (Phillips and Clarke, 1998; Phillips et al, 1998). The first horizontal well project was a “Huff n’ Puff” conducted in 1993 in fault

block I Tar zone. Two 900-foot long horizontal wells were drilled into the D₁ sand. The second project was a steamflood in fault block II Tar zone. In 1995 for project two, four horizontal wells were drilled on average 1600 feet within the D₁ sand. A fault block IV Terminal zone waterflood well was drilled 1100 feet within the Hxb sand in 1995 as the third project. Again in 1995 five horizontal wells were drilled into the fault block V Tar zone as part of a steamflood. The wells were drilled on average 1500 feet horizontally within the S₄ sand. In 1997 a 1000-foot horizontal was drilled into the Hxo sand of fault block V Terminal zone to complete the fifth project.

For each project, the horizontal laterals for the waterflood wells were placed at the top of the sand to recover attic reserves. The laterals for the steamflood wells were placed at the bottom of the sand to maximize capture of oil through steam-assisted gravity drainage.

Except for the first project, 3-D modeling and visualization were used from planning through completion. To be effective, horizontal wells require precision placement. The studied areas required significant geological evaluation and characterization. The area was then modeled with software that provided 3-D visual displays of stratigraphic and structural relationships and also enabled excellent error checking of data and grids in 3-D space. The geological model was revised and modified in 3-D space. The 3-D model provided a visual reference for well planning and communicating the spatial relationships contained within the reservoir. Accurate 2-D and 3-D visualization were used for interpreting the LWD response and monitoring well progress while drilling. Map and section plots brought to the rig site allowed the drilling team to relate to the geology, thus providing a strong confidence factor. Accurate and rapid post-drilling analysis for completion interval selection and LWD analysis completed the process.

CASE HISTORIES

Three case histories will be presented. Case history 1 describes a thermal enhanced recovery

project that expanded on an existing steamflood project. The expansion area was subjected to detailed characterization with 3-D modeling and visualization, and the development project was completed. The technologies developed in the steamflood project were applied to the areas in fault block V and are described as case histories 2 and 3.

Fault Block II Tar Zone Steamflood Project

Figure 3 shows the location of the three case histories. Case history 1 is in the Tar Zone of fault block II (Figure 4). The Tar zone of the lower Pliocene Repetto formation (Figure 5) has been interpreted to consist of large, lobate submarine fan deposits (Redin, 1991). It is the shallowest of the major oil-producing zones in the Wilmington field and consists of interbedded siltstones, shales, and unconsolidated fine- to medium grained arkosic sands. The sand bodies were deposited as a set of compensating turbidite lobes as opposed to the sheet sands (or larger sheet lobes) that occur lower in the section. The section is actually composed of smaller sand lobes that are generally limited to less than two miles in lateral extent. The sequence is also complicated by onlap and channeling. In fault block II, the Tar zone is 250-300 ft (76-91 m) thick and occurs at depths of 2300-2800 ft (697-848 m) below sea level. The T and D sands (Figure 5) are the best developed and most productive. Oil gravity ranges from 12⁰ to 15⁰ API, with a viscosity of 260 cp at the ambient reservoir temperature of 125⁰F (51.7⁰C).

Fault block IIA is located in the western portion of the field between the Wilmington and the Ford faults (Figure 3) and is down-plunge from the crest of the Wilmington structure (Figure 5). The fault block is bounded to the west by the Wilmington fault and to the east by the Cerritos fault, both of which are permeability barriers (Figure 3). The faults show normal displacement, with vertical offsets that range from 50 to 100 ft (15 to 30 m) but, they may have complex histories of movement. In addition, several smaller-scale faults (Ford, Ford A-1, Ford A-1B

faults) exist in the northeastern portion of the block (Figure 5). These faults exhibit vertical offset on the order of 15-30 ft (4.5-9.0 m) and are only partially sealing. The north and south limits of production are defined by oil-water contacts within the productive sands.

A Tar Zone steamflood in Fault Block II was initiated in 1982 and expanded in 1989, 1990, 1991 and 1993. In 1995, a plan was created to expand the steamflood to the south (Figure 4). Instead of the inverted seven-spot pattern used in the earlier phases, it was decided to use horizontal wells, carefully laid out so that each horizontal well would replace three to four vertical wells. Five temperature observation wells would be interspersed for monitoring the distribution of the thermal energy.

The four horizontal wells were drilled into the bottom of the 60 ft (18.3 m) thick D₁ sand. Two steam injectors and two producers were placed about 400 ft (122 m) horizontally apart as part of a pseudo-steam assisted, gravity drainage project. This innovative Fault Block II steamflood project received partial funding from the U.S. Department of Energy as part of a Class III Mid-Term Project (Koerner et al, 1997; United States Department of Energy, 1999).

The existing maps were not detailed enough for the planned development. The only way to obtain success was to perform a detailed geologic analysis of fault block II. The well tops, coordinates and fault data was entered into a computer modeling package, and after a rough 3-D model was constructed to assess the problems, it was clear that a complete revision of the geology from scratch was necessary.

The existing six subzone intervals were further divided into 18 sub-sub zones and the faults were reevaluated. A team of geologists spent months on detailed log work to define the 18 horizons and six faults. The log data ranged from electric logs from the 1930's through complete

log suites of the 1980's. Each sub-sub zone was hand mapped as to lateral extent. The faults and horizons were then three-dimensionally modeled and compared to the original interpretation.

A significant amount of the well planning was performed using this 3-D working model, which had enough detail for planning purposes. The 3-D model made visualization of the inconsistent data very easy. The data inconsistencies came from differentially subsiding horizons, caused by intraformational compaction from oil withdrawal over a 60-year period and an assortment of data entry and coordinate conversion errors. These errors were rapidly identified and corrected.

Subsidence was probably the toughest problem to solve. The intraformational compaction of the producing reservoirs varied over time and directly impacted the surface (and the distance to the producing horizons). Between 12 and 22 ft (3.7 - 6.7 m) of surface elevation was lost above the proposed horizontal lateral locations (Figure 6). The subsidence varies, increasing from west to east toward the center of an elliptical subsidence "bowl," where the maximum subsidence to date is 29 ft (8.8 m).

To compensate for the errors, the data were adjusted for ground level change and internal compaction. These adjustments are time dependent. For example, a well drilled in 1940 could be drilled to 2,500 ft (762 m) below sea level to reach the "T" marker. The same well drilled today to the same x, y position might require drilling to 2,480 ft (768 m) below sea level to reach the "T" marker (Phillips, 1996). The ground level is lower now due to subsidence and the depths to the other markers are also different (intraformational compaction). The stratigraphic section has been compressed. Figure 7 illustrates the corrections that are applied.

After the data were modified, the mapping software facilitated the rapidly generated new geologic models by using the predefined geologic criteria. This data was quickly integrated into

a more comprehensive structural model (Figure 8). The structural model was then edited and modified where necessary. The 3-D model was recalculated many times during this iterative process. Not only was the resulting model excellent at showing the subtle differences in the geology, but it also was an invaluable tool for finding data errors.

When the acceptable 3-D deterministic model was established, cross sections along the well courses were constructed and used for geosteering (Figure 9). The cross sections derived from the model proved to be very accurate and were used extensively. The combination of detailed sequence characterization and 3-D modeling allowed us to accurately map a previously unrecognized channel (Figure 10) and onlap (figure 11).

The computerized 3-D displays greatly enhanced communication between the geologist, petroleum engineer and the driller. The geologist could rotate, slice and change the “look” of the model to improve the visualization. The geologist also displayed the offset log information on a cross section along a well course that had been scaled-up to match the real-time LWD logs. This was invaluable during drilling because the geologist was capable of accurately following the drill-bit by plotting the MWD data directly onto the computer generated cross section.

In Fault Block II the bottom of the D₁ sand was targeted. Instantaneous drilling rates up to 600 ft/hr (183 m/ hr) were achieved because the accurate geological model helped the well site team bypass slow-drilling, problematic shales, and otherwise modify the drilling program for improved efficiency. In the end, steam-assisted, gravity-drainage horizontal wells UP-955, UP-956, 2AT-61 and 2AT-63 were successfully drilled within a 15 ft (4.5 m) target window (Figure 12).

The steamflood project had to be terminated in January 1999 because ground elevations had dropped nearly one foot! Subsidence has been a historical problem and the continuation of

activities that may cause subsidence is not permitted by the City of Long Beach. This project was marginally economic, but we feel that it was a technical success. Basically, the project started with a steam/oil ratio of 7 and by the time the steam project was shut down the steam/oil ratio was 14. More drilling would have helped greatly, but expansion was not possible at the time. In October 1999 flank wells were converted to cold-water injection. A 3-D deterministic reservoir simulation model that calculated mass balance and heat balance was used for injection conversion. Subsidence was halted and the area is currently very profitable, producing 1000 bbl/day net (159 m³/day) with a gross of 21,000 bbl/day (3339 m³/day). The next step was to see if these techniques could be applied to Fault Block V.

Fault Block V Projects (Case Histories 2 and 3)

There are two horizontal well projects in Fault Block V. The first is in the Tar Zone where five horizontal wells were drilled. The second project is in the Upper Terminal Zone where a single well was drilled into the thin, shaley Hx₀ sand. The excellent accuracy of the 3-D geological model generated, and the usefulness of the computerized tools used to extract information from the model, greatly enhanced the success of both projects.

Case History 1 (Tar Zone)

As with the Fault Block II project, the 60+ year-old electric logs were reviewed and recorrelated dividing the Tar Zone into 14 sub-subzones. The log (Figure 13) shows a portion of the stratigraphic section from probe hole well FJ-204. The “S₄” sand was chosen as the target

because it shows the highest resistivity (oil saturation) and it is the thickest, continuous, clean sand across the fault block. A probe hole was drilled to verify reserves and not for horizontal placement.

A deterministic geological model was created from which the maps and cross sections were extracted and used to geosteer the horizontal wells. The modeling was much more straightforward than the earlier project, as the area where the horizontals were planned is unfaulted (Figure 14).

The experience gained in Fault Block II and improvements to the software made modeling even easier. Areas of “no data” were controlled by adding interpretive “ghost” points through the 3-D viewer and then reconstructing the model. This interpretative technique cut modeling time significantly.

Data from one area of the model indicated an anomalous structural low. The survey and log picks appeared to be correct for a well located in the area of this “low”. The data point was honored and horizontal well J-201 was drilled into the area. It was apparent from the LWD curve separation and bed boundary intersections that the “T” shale was shallower than the model indicated. The offending well data was removed and the model was rebuilt based on the horizon picks from well J-201. Because this remodeling can now be done in almost real-time, the geologist revises the model as drilling proceeds. An improved model is built if needed, as each new well is completed. Well J-201 did not go as planned; determining the completion interval was difficult until the other horizontal wells and their perforations were displayed in 3-D (Figure 14).

The 3-D model in Figure 13 is “bench cut” and shows the five horizontal wells and their perforations. The goal was to keep the wells parallel to the top of the “T” shale to maximize

recoverable reserves from the superjacent “S₄” sand. The maps, cross sections and geological model were all used to place the horizontal wells accurately. Figure 14 shows the cross section for well J-203.

Overall, the Tar V drilling project (case history 3) was a major technical and economic success. Based on what was learned in Fault Block II and the accuracy of the 3-D model, the drilling team was able to plan and drill with confidence. It was easy to anticipate the highs and lows of the horizons and the locations of bed boundaries. No wells were plugged back for geological reasons and drilling time was reduced by spreading out survey lengths, using less time for correctional sets, and rotating the tool string while drilling a large percentage of the horizontal section. Roller reaming prior to running casing was eliminated as shales were avoided, allowing reaming with the bit already in the hole. In addition, no pilot holes (except for FJ-204) were necessary. As a result time and money were saved.

The drilling team appreciated having visuals at the rig site because they stimulated better feedback and established a clearer understanding of the geology encountered. They could see what a particular directional tool set accomplished and thus refine drilling techniques for added efficiency. Previously, the drillers only had numbers to look at which were much less intuitive and informative.

The Tar V horizontal well budget was based on the Fault Block II wells. There was an average savings per well of US\$12,400 on directional costs and US\$18,000 due to fewer drilling days. In total, US\$152,000 was saved on the five horizontal wells drilled. Because of the monetary savings and the drilling team’s confidence in the 3-D model, all of the laterals were extended an extra 12%, on average, effectively increasing the producible area and adding 382, 000 stock tank barrels (STB) or 60,734 stock tank m³ (STCM) of oil.

The five horizontal wells were steam cycled and placed on production (Figure 17). Two of them, FJ-204 and FJ-202, were placed on permanent steam injection. A-186 3, A-195 0 and A-320 0, each a 30+ year-old well, remained on production within the steam project boundaries as of March 1996, averaging 16 bbl/ day ($2.5 \text{ m}^3/\text{day}$) net with 200 bbl/day ($31.8 \text{ m}^3/\text{day}$) gross, at an average water cut of 92%.

When the horizontal project was initiated, this area only had about five years of remaining economic life under waterflood, and recoverable reserves were estimated at 75,000 bbl ($11,924 \text{ m}^3$). The average pool water cut prior to steaming was 95%. The water cut in the project area was 81% in 1998 and is currently 92% (July 2000), and another 1,700,000 bbl ($270,283 \text{ m}^3$) of reserves have been added to the Tar V pool.

Steam communication to the existing waterflood wells, from cyclic steam injection into wells FJ-202 and FJ-204, resulted in a six- to ten-fold net production increase in the old waterflood wells (Figure 17). Peak annual production rates under steam drive are forecast at 590 bbl/ day ($93.8 \text{ m}^3/\text{day}$) for the horizontal project. For the first four months of 1998 the average oil production was 698 bbl/ day ($111 \text{ m}^3/\text{day}$). In July of 2000 the average oil production was 242 bbl/day ($38.5 \text{ m}^3/\text{day}$). The production rates should be several times greater, but each well's performance has been hindered by fluid levels exceeding 1500 ft. The high fluid level suppresses oil production and also cools the produced fluids, resulting in lower recoveries. Plans are underway to replace the pumps. The success of the program can be seen in Figures 16, 17 and 18 which show how the project area has changed over time. Note in Figure 16 that prior to steaming the average net was about 14 bbl/day. By January 1998 (Figure 17) the average net was over 150 bbl/day. In August of 2000 the average net is still over 100 bbl/day.

The 3-D techniques used contributed significantly to the success of the Tar Zone horizontal

project. The importance can be seen by assuming a 50% recovery factor. Every foot above the target is equivalent to 15,876 STB (2,524 STCM) in lost reserves (Phillips, 1996). At US\$14/ bbl oil, being off as much as five feet vertically would equate to U.S.\$1.1 million in lost revenue.

Upper Terminal Zone: Hx_O Thin Sand Sequence

The Hx_O sands of Fault Blocks V and VI were reviewed as part of a U.S. Department of Energy (DOE) Class III Short-Term Project (Phillips, 1998). The project proposed using new reservoir characterization tools and techniques to exploit bypassed oil. The new technologies included detailed reservoir characterization, 3-D geologic modeling, geosteering in thin heterogeneous beds and modeling the LWD responses (MacCallum and others, 1998).

A deterministic geological model was created to define the Hx_O layer and the horizons above and below it (Hx₁ above, Hx₂ and Hx below). The sand percentage was calculated for each data point. A 3-D property model was created by gridding the sand percentage in 3-D space using the top and bottom of the Hx_O as confining surfaces (Figure 19). The original oil saturation (So) was similarly property modeled to identify target areas for exploitation.

A display of the So model and wells drilled in the 1980s clearly showed that Fault Block VI was effectively drained but that Fault Block V still had reserves. The difference between the original So and that indicated by the 1980s wells was quantifiable. The So calculated from the old wells was decremented, the two data sets were combined, and Fault Block V was again property modeled (Figure 20). The sand percentage model and the So model were combined and the original oil in place was calculated to be 3.4 million STB (540,566 STCM). The current oil in place was calculated and the reserves were reduced to 2.8 million STB (445,172 STCM) (Phillips and Clarke, 1998). Obviously, significant reserves remain.

Based on the geological model, the block engineer proposed that a horizontal well be drilled within and adjacent to the modeled area along the structural high. An existing well bore was sidetracked with a horizontal lateral to capture hydrocarbon reserves uneconomically recoverable with conventional methods. Idle well J-017 was selected for drilling the high dogleg horizontal well and a production rig configured for drilling was used to keep costs to a minimum. By investigating to the west of the original Hx_O project area, it was determined that the target sand thins and shales out to the west, thus reducing oil saturation. Electric logs from wells penetrating the area as far as 1,000 ft (305 m) to the west were correlated and a second 3-D geological model was created.

A facies boundary was delineated to constrain the planned well course within the higher water saturation (S_O) target. The Hx_O layer was subdivided and two sand lobes were identified within the Hx_O layer. The Hx_{OJ} and Hx_{OB} horizons were defined and added to the 3-D model. Maps and cross sections were extracted from the 3-D model and used for well planning (Figure 21).

A cross section along the well course was created for the geologist. The directional vendor required three linear cross sections for drilling because the well plan showed a 'U-turn' (Figure 22). Stratigraphic sections consisting of adjacent wells were also created to help in geosteering. Both "paste up" and digital varieties were used.

Structure maps were created on the Hx_I, Hx_O and newly defined Hx_{OJ} (Figure 23) and Hx_{OB} sands. These plots, as well as the 3-D model were used as tools to help geosteer. Ultimately, they had to be used for directional control due to rig site problems.

A recently introduced, probe-based Multiple Propagation Resistivity (MPR) device was used to provide LWD geosteering as well as directional information. This resistivity sensor was

part of a slim hole, positive-pulse-type MWD/LWD system that was used instead of “carrier wave” tools because of their smaller size (the tool diameter is 4 3/4 in.). These newer tools have well-integrated surface equipment, are battery-powered, and provide more reliable telemetry signals. The MPR tool is a four-transmitter, two-receiver array that provides a total of eight compensated resistivities at 2 MHz and the deeper reading 400 kHz, in boreholes as small as 5 7/8 in. For additional geosteering control an inclinometer and gamma ray scintillation detector are below the MPR sub. The well was successfully placed within two sand lobes of the thin sequence by geosteering using the LWD data.

The interval is thin and shaley (total thickness of 17 ft or 5.2 m) and the LWD showed the “anisotropic” effect throughout the log (Figure 24). The resistivity response in anisotropic conditions is similar to conductive invasion in that the short-spaced measurement reads less than the long-spaced for both the phase difference and attenuation resistivity measurements. However, the shallow-reading, phase difference resistivity curves measure a higher resistivity than the deep-reading attenuation curves for both frequencies and spacings. This curve order is not indicative of conductive invasion, but of anisotropy (Meyer and others, 1996). The presence of anisotropy plus formation heterogeneity complicated the interpretation of the LWD data so the geosteering team had to rely significantly on the geological model.

A simple layer model was used for previous horizontal well projects. The sand package was thick enough for the LWD to give a unique, easily interpretable response. The Hx_O “sand” is divided by a continuous shale. The upper sand, referred to as the Hx_O, is 6 ft (1.8 m) thick and the lower sand, Hx_{OJ}, is 8 ft (2.4 m) thick. Again, the horizontal well was successfully placed into each of these sands.

Post-well analysis and support was excellent. The LWD analyst spent significant time

studying the LWD data and explaining the results. For wells drilled parallel to bedding, adjacent beds and formation anisotropy were significant factors in the log response. The anisotropy was quantified, the horizontal and vertical resistivity was determined, and a mathematical model of the LWD response was created (MacCallum and others, 1998).

The 3-D model was refined based on conclusions reached by collaboration between the LWD analyst and geologist. A significant step toward interpreting the data was to model the shales above the Hx_O and Hx_{OJ} sands. A new anisotropy inversion algorithm and the inclusion of shales in the geological model allowed for a clearer understanding of the 2 MHz resistivity responses to the formation and their boundaries.

A fault was also identified during this process. The fault geometry was determined using the 3-D model and further mathematical modeling of the LWD. There was a good correlation between the tops calculated from the 3-D geological model and the tops selected from the LWU log. The average vertical distance between the bed boundary calculated from the 3-D geological model and the well as determined by the LWD log is less than 0.25 ft (0.08 m)!

CONCLUSIONS

The geologist working with carefully characterized rock data and 3-D modeling and visualization techniques adds greatly to the horizontal drilling team. The highly accurate 3-D visualizations of the reservoir greatly increase the confidence factor of the team thus enabling Wilmington Field reserves to be maximized.

To be effective, horizontal wells require precision placement. 3-D models help isolate data inconsistencies, while 3-D viewers are good for adding data to correct the geological model.

Once the final geological model is created, the drilling team can use the resulting 3-D visuals with confidence to improve drilling techniques and directional control. Post-well analysis of the LWD data also is facilitated using 3-D geological models.

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BOTTOMHOLE LOCATIONS

STEAMFLOOD PHASE	YEAR
PILOT PROJECT	1982
PHASE 1	1989
PHASE 1A	1990
PHASE 1B	1991
PHASE 1C	1993
DOE HORIZ. PILOT	1995

▲ HORIZONTAL INJECTOR
● HORIZONTAL PRODUCER
○ CORE OBSERVATION WELL
○ OBSERVATION WELL

**ACTUAL DOE
HORIZONTAL PILOT
PHASE I-D**

WILMINGTON FIELD
STEAMFLOOD

TAR ZONE, FAULT BLOCK II-A

500' 200' 0' 200' 500'

SCALE

THREE COMPONENTS TO SUBSIDENCE CORRECTION

NOTE

A. Down hole adjustments for subsidence that occurred AFTER well was drilled.

X, Y dependant.

Distance between 1937 marker and 1995 marker increases toward center of subsidence bowl.

B. KB elevation adjustment.

Operator dependant.

Adjustment for subsidence BEFORE well was drilled.

Well head dependant.

C. Compaction adjustment of overlying sands.

B

FJ-204 PILOT HOLE

Bench Cut Geological Model Showing 3-D Relationship of Horizontal Wells. Perforation intervals shown in red.

MARCH, 1996 - PRIOR TO STEAMING OPERATIONS

TAR V STEAMFLOOD AREA - JANUARY, 1998 WELL TESTS

TAR V STEAMFLOOD AREA - AUGUST, 2000 WELLTESTS

Sand Percentage Model Percent Sand of interval between Hx0 and Hx2

Ford North

Percent Sand

0.68
0.64
0.6
0.56
0.52
0.48
0.44
0.4
0.36
0.32
0.28
0.24

Z exaggeration: 2.0
 Azimuth: 65.0
 Inclination: 35.0

Qualitative Oil Saturation modeled as a parameter within Hx0 sand.

Wells drilled in the 1980's shown with oil saturation posted.
Future recompletes labeled with light blue lettering.

Volume of Oil Sand where qualitative current oil saturation (Soc) > 0.40

Z exaggeration: 2.0
Azimuth: 304.6
Inclination: 22.8

STRUCTURE MAP ON TOP OF Hx0J

J-017 4 Horizontal Well LWD and Modeled Logs

GR = Gamma Ray

ATT = Attenuation

ATTSS = Attenuation short spaced

PD = Phase Difference

PDSS = Phase Difference short spaced

MM = modeled resistivity

★ Tops Calculated from 3-D Model