HISTORY OF ADVANCED RECOVERY TECHNOLOGIES IN THE WILMINGTON FIELD

George E. Otott Jr.
Thums Long Beach Company, Long Beach, California

Onshore Wilmington Field

Thermal Recovery

The application of thermal enhanced recovery in the Old Wilmington Field dates back to October 1964. Steam was used for stimulating producing wells by the "Huff and Puff" or cyclic injection process. This was done in conjunction with waterflood operations. Most of the stimulation was in the more viscous oil-bearing Tar Zone (12°-15° API), but the Ranger Zone (17° API) was also steamed.

A steamflood project was initiated by the Union Pacific Resources Company in the Tar Zone in 1981. (Figure 1 shows the locations of EOR projects covered in this article.) It was a 20-acre pilot containing four inverted five-spot patterns, with steamflooding confined to the "D" sand. During 1981, nine producers and four injectors were drilled. Steam stimulation of producers began in June 1982 with continuous injection beginning in September 1982 in all four injectors. Oil response from steamflood was very good, with the oil rate increasing from less than 200 BOPD to 700 BOPD approximately one year after injection began. In the seven years of pilot operations (1982-1989), the pilot area recovered 1.1 million barrels of oil from the injection of 7.2 million barrels of steam. This is equivalent to a recovery of 75 percent of the oil in place when the pilot began. Because of the success of the pilot project, it was expanded to over 150 acres in the northern half of Fault Block IIA. A variety of production problems, including poor sweep efficiency and early steam breakthrough, prevented the expansion from being as successful as the pilot.

Carbon Dioxide

Immiscible CO₂, water alternating gas (WAG) projects have been implemented in the Tar Zone of the Old Wilmington Field.

Long Beach Oil Development Company initiated a tertiary immiscible CO₂ project on 330 acres of the south flank of the Fault Block V Tar Zone in 1981 (Spivak and others, 1988). When CO₂ injection began in March 1982, there were 42 producing and 8 injection wells. The area had been waterflooded since 1961 and the water cut was greater than 95 percent. A total of 8.2 BCF of stack gas purchased from a local refinery (85% CO₂ and 15% N₂) was injected. Alternate gas and water injection began in March 1982. The initial contract amount of gas (7.5 BCF) was injected by November 1985. An additional 0.72 BCF was injected after this, with CO₂ injections ending in July 1986. Oil response began in early 1985. Oil production increased from about 1000 BOPD to 1650 BOPD in early 1986. The oil response then declined with the decrease in CO₂ injection. Incremental enhanced oil recovery as of the end of August 1987 was estimated at 498,000 barrels of oil. Due to the economic uncertainties following the oil price collapse of 1986, the operator was not willing to enter into a long term contract for additional gas and the project was terminated.

Champlin Oil Company initiated a 40.5-acre CO₂ pilot in the Tar Zone of Fault Block in 1981, using four producers and four injectors. The boundaries of the pilot area were faults on the west and east and water injection wells on the north and south ends of the block. Alternating CO₂ and water injection began in March 1981 and oil production increased from 28 BOPD to 200 BOPD over a two-year period. Thereafter, production declined about 22 percent/year. Based on the pilot, an expansion took place in 1984.
However, leakage of CO₂ (noted in the pilot) increased significantly. The location of producing wells and injector wells proved unsatisfactory in many areas of the project and a need for better reservoir characterization was realized. Consequently, the CO₂ project ended in 1985.

In 1983, XTRA Energy started a CO₂ project in the Ranger Zone of Fault Block I. The project consisted of twelve 14-15 acre inverted five-spot patterns using 32 wells (12 injectors and 20 producers). The injection interval was about 35 feet of net sand in the H-F interval. Initially there was good oil response. However, the oil price collapse in 1986 made the project uneconomic and it was terminated.

Chemical Enhanced Oil Recovery

Several polymer, micellar polymer, and alkaline enhanced recovery pilots have been implemented in the Old Wilmington Field.

A Mobil Oil Company polymer project covered approximately 300 acres in the Fault Block V Ranger Zone, using 18 injection and 50 producing wells. The plan was to inject a 250 ppm polymer (polyacrylamide) slug equivalent to 4 percent of the pore volume. Calculations indicated that the mobility ratio would be decreased from 14.2 to 1.3 and that oil recovery would be increased by 175 B/ac-ft. However, polymer injection resulted in loss of injectivity in injectors and an associated decrease in gross production. Early polymer slug breakthrough also occurred, leading to high water-oil ratios. Acid stimulations were used to restore injectivity and productivity, but these made it difficult to calculate incremental oil recovery due to polymer alone. This increment was estimated to be only 10-20 B/ac-ft and the project was terminated after 2.5 years of injection due to poor performance and high operating costs.

In 1975 Long Beach Oil Development Company implemented a 10-acre micellar polymer pilot project in Fault Block V based on the MARAFLOOD process, using a line-drive pattern with four new injection and six new producing wells. A micellar slug (sulfonate) which reduces interfacial tension between oil and water preceded the injection of polymer. The pilot project achieved an oil increase and decrease in water-oil ratio. Oil production went from 50 BOPD to 267 BOPD followed by a steep decline. Incremental oil of about 150,000 barrels was obtained. This represented 10 percent of the pore volume, or about two-thirds of the recovery expected from core floods and simulation model results. The relatively high oil recovery was less than optimal because of production problems associated with unconsolidated sand and bacterial corrosion. In addition, the cost of the polymer was quite high. Ultimately, the project was successful in increasing oil recovery but not to the degree required to economically continue.

Exxon implemented a polymer project in Fault Block I from 1981 through 1984. Oil response was unsatisfactory and some plugging problems occurred, resulting in an unsatisfactory project. No published data are available.

Offshore Wilmington Field – Long Beach Unit

Caustic Waterflood

A caustic waterflood was conducted in the Long Beach Unit from 1977 to 1986. Initiated by the City of Long Beach (Unit Operator) and Thums Long Beach Company (Field Contractor) in association with the U.S. Department of Energy, the objective of the caustic flood was to improve recovery efficiency by using a two-phase alkaline flooding process. The caustic waterflood design called for a preliminary test, to insure that caustic could be injected into the reservoir, followed by a small field test. Both tests were designed to evaluate the feasibility and economic benefits of caustic flooding in a stratified, heterogeneous, heavy oil reservoir.

Beginning in June 1977, a preliminary, caustic-injection, single-well pilot test was started. The two-month test was successful and a full 95-acre pattern test flood with 23 producers and eight injectors began in 1978. The test was conducted in the Ranger Zone, Fault Block VII in an area confined between two sealing faults, the Junipero Fault and Temple Avenue Fault (Figure 1). The first phase of the caustic flood consisted of a preflush of softened salt water followed by injection of softened fresh water containing 0.1% by weight of caustic. The injection of the caustic mixture was expected to improve reservoir conformance by in-situ emulsification of the crude and subsequent entrapment of the oil droplets in pore channels. The second phase consisted of softened water containing 0.1% by weight caustic and 1.0% by weight salt to entrain the emulsified oil and improve displacement efficiency.

The caustic pilot flood continued until 1986 when the project was terminated due to a large amount of scaling at the producers, later found to be the result of
an insufficient preflush of softened salt water. The caustic flood did not improve oil recovery over the existing conventional waterflood in use at the Long Beach Unit. Further testing of caustic flooding has not been recommended.

Tar Zone Steam Flood

A pilot steam drive project was initiated in the Long Beach Unit in December 1980, in the Tar Zone of the LBU Fault Block VI reservoir (Jung, 1984). The Tar reservoir is about 200 acres, has a vertical gross thickness of 185 feet, and a maximum vertical net oil sand thickness of 90 feet comprised of 8 to 10 separate sand units. Oil in place in Tar at the time the project was initiated was estimated at 27 MMSTB.

The project design was based on an in-house model developed from the Marx-Langenheim method. The model was constructed using inverted 5-spot patterns based on different pattern sizes and varying injection rates. The sizes of the patterns ranged from five to fifteen acres in two and one-half acre increments.

On March 21, 1980, the project was self certified to the U.S. Department of Energy under the Tertiary Enhanced Recovery Program as an unconventional steam drive. The study area was 9.2 acres with an average net oil sand thickness of 82 feet. A six-well pilot steam drive started on December 24, 1980, as an isolated 5.6 acre inverted 5-spot pattern. The 9.2 acre study area included two off-pattern wells that were affected by the steam drive process.

Oil in place in the study area at the start of injection was estimated at 1.17 MMSTB. The oil recovered during the project until November 30, 1983, was 210 MSTB (18.0% of the original oil in place).

The conclusions of the study were: 1) steam can effectively move heat through the Tar reservoir; 2) study area volumetric sweep was estimated at 50%; 3) isolated patterns need to be surrounded by more pattern producers as soon as possible to prevent waste of injected heat and loss of oil to areas outside the pattern; and 4) the major difficulty in achieving a viable thermal recovery operation was maintaining a continuous, adequate rate of heat input.

Reservoir Simulation

Starting in 1986, City of Long Beach reservoir engineers and an outside consulting firm, Petresim Integrated Technologies, began reservoir simulation studies of the Upper Terminal VI, Terminal East, and Ranger VI areas.

The Upper Terminal VI water-throughput model was the first in the Long Beach Unit. The objectives were: 1) to show that the water-throughput modeling approach could be successfully applied to the Upper Terminal VI reservoir; 2) to achieve a good understanding of reservoir production history and the processes and reservoir parameters that influenced that history; 3) estimate current reservoir conditions; 4) predict future reservoir performance; 5) evaluate potential alternative operating strategies on a coarse basis; and 6) determine the need for a more detailed modeling approach for evaluating individual well strategies.

Model results showed the lower subzones in Upper Terminal VI to be at higher water cuts than the upper subzones, and confirmed that significant volumes of fluid had previously migrated from the Unit area to non-Unit areas. The model did not support a postulated sealing fault between the eastern and western model areas. It was further concluded that a more detailed model could provide accurate forecasts.

A more detailed Terminal East model was begun in October, 1986. The objectives of the study were: 1) help clarify a complex geological picture, with several proven and postulated fault locations, by investigating the sealing nature of the numerous small-displacement faults and; 2) determine the effectiveness of peripheral subzone aquifer injection to maintain pressure in the crestal area and maximize oil recovery. The model history match was fair, but it was concluded that the model could be improved through enhanced reservoir description.

The Ranger VI detailed model was constructed after building two small, coarse Ranger VI water throughput models, one small Ranger VI fault block flux model, and two small Ranger Zone detailed flank models. Several major objectives of the Ranger VI model were achieved: 1) the more detailed modeling approach worked well in the Ranger VI area; 2) a better understanding of the reservoir production history and remaining oil in place by layer was derived; and 3) several potential alternative operating strategies were evaluated.

All of the models led to a better understanding of the reservoir production history and remaining oil in place by layer. They supported the concept that redevelopment of injection patterns is required to capture oil in unswept zones and improve areal sweep. The improved reservoir characterization of the
proposed LBU-DOE project will identify redevelopment targets that can be realized with advanced recovery techniques.

Profile Modification

Throughout the Wilmington field, operators have tried numerous methods of improving vertical fluid profiles in injection and production wells. Some methods have been more successful than others in improving profiles. In the past, it was preferred to utilize mechanical methods to improve profiles rather than to rely on chemical techniques.

Historically, several methods have been used to complete injection wells in the Wilmington Field and LBU. Selectively jet perforating cemented liners is now the method preferred in the Long Beach Unit. Providing adequate blanks between sets of perforations allows for injection packers to be set in different locations in the completion interval to improve vertical sweep efficiency. Dual injection strings are also used to direct injected fluids into shorter intervals and to allow for higher injection pressures in the deeper intervals if required. The Unit has also used injection side-pocket mandrels in conjunction with packers to limit injection into thief intervals with some success. Dual injection strings have proven to be an effective method of improving injection profiles.

Cement squeeze techniques have been used in the Wilmington Field and Long Beach Unit, but with limited success.

In past years, various chemical methods have been applied to improve profiles. WORCON, a product introduced by Halliburton, was intended to reduce permeability in water saturated layers. It was used with limited success in reducing water production; however, it usually shut off oil production along with the water, making producers marginally economic projects. Cross-linked polymers were also applied in injection wells to divert injection into some of the unswept intervals and improve vertical sweep efficiency. Due to difficulties in achieving adequate placement in the formation, these treatments were risky and usually the results did not last long.

In 1993, the Long Beach Unit formed a multi-disciplinary Profile Modification Task Force charged with researching methods of chemically reducing thief intervals in injection wells. One method currently being field tested is an internally catalyzed sodium silicate solution that gels in place while developing a low compressive strength. The treatment has been used in eight wells through early 1996 and was successful in five of them. The Task Force plays a key role in optimizing the economics of profile modification techniques and in maximizing our understanding of the results of those techniques.

Waterflood Pattern Realignment

The North Flank area of the Ranger West unitized formation originally contained approximately 290 million STB of oil in place. Much of this oil was bypassed during the 27 years of waterflooding before 1992, due to poor conformance from peripheral and line-drive injection and lack of profile control. High development costs from long-reach wells required coarse producer spacing, resulting in poor recovery.

Redevelopment of the North Flank was implemented in 1992-93 and focused on injection realignment from peripheral and line drive patterns to inverted 7- and 9-spot patterns (Figure 2). A total of 17 new injectors and 15 new producers were drilled along with 2 conversions resulting in 16 new patterns. Reservoir characterization and drilling optimization technologies successfully employed include:

1. material balance prediction of layer water cuts and cumulative production for each producing well to target under-depleted sands for recompletion;
2. drilling cost optimization via reduced casing sizes (7" and 5-1/2");
3. selectively perforated cased hole injectors for profile control;
4. combined lower open-hole slotted liner producers with upper cased-hole gravel packs (allows selective control of water entry in shallow, massive sands while maximizing productivity of deeper, thinner, interbedded sands); and
5. cost effective logging while drilling (LWD) in high-angle wells.

Economic success from the project exceeded expectations. Oil rate increased from 4500 BOPD to 8000 BOPD in two years (Figure 3). Many of the new technologies and tools first used in Ranger West pattern realignment have since been adapted to other development opportunities in the Long Beach Unit.
Figure 2. Long Beach Unit, north flank Ranger West Zone waterflood patterns.

Figure 3. Oil rate, gross rate and injection rate increases due to north flank Ranger West waterflood pattern realignment.
Horizontal Drilling

An extensive infill drilling program during the early to mid 1980s, together with renewed drilling in the 1990s, revealed bypassed oil even in heavily waterflooded areas. The undrained reserves are due to highly stratified turbidite sands and poor injection well profiles. The situation is further aggravated near faults where poor areal sweep conditions exist. The bypassed oil is typically in 30- to 50-foot thick flow units that generally have lower permeability than adjacent depleted flow units. Also, the bypassed oil tends to be lower gravity oil (12.5° to 16° API). These flow units, especially in the FO sand of the Ranger Zone, are being targeted for horizontal drilling.

The first horizontal well in the LBU was well D-709 drilled and completed in November 1993 to drain the upper flow units in the Ranger FO sand (Figure 4). The project integrated advanced reservoir description tools and drilling technology to yield a financial success in the Unit's first attempt at horizontal drilling. Advanced geologic computer correlations combined with digitized injection surveys were used to identify the dominant unswept flow units on the crest of the anticline. Penetrating logs confirmed a significant untapped oil accumulation. Reservoir simulation studies of the area were also conducted.

Since D-709, more than 15 FO-sand horizontal wells were drilled in the LBU. Typically, the horizontal wellbore is located between 10 and 15 feet below the top of the sand and ranges between 800 and 1000 feet in length. The drilling success of the FO horizontal wells prompted expansion of the program into thin-bedded flow units to expose more formation to the wellbore to achieve economic production rates. Well lengths increased to 1500-1800 feet and structural trend was used to advantage. Where needed, probes were designed to penetrate the target sand before setting intermediate casing. One bilateral well was drilled in late 1995, but had to be abandoned due to completion problems.

Horizontal well design was dictated by economics. Some horizontals were redrilled from 9-5/8" casing strings. An 8 1/2" hole was drilled with clay base mud and 7" intermediate casing was cemented at the top of the completion interval. The horizontal section was drilled with salt or oil base mud using a 6-1/8" bit. Sand control was a potential completion problem because high-angle gravel packing has not been perfected. Thums implemented a cost-effective completion using either a 0.012" slotted liner or wirewrapped screen. These completions are durable, relatively simple to implement, have reduced wellbore skin potential, and are inexpensive compared to elaborate pre-packed liners. Four of the horizontal wells were redrilled from existing casing strings using coiled tubing drilling. The completions consisted of 3" slotted liners in 3-3/4" hole.

Geosteering is routinely performed with LWD (logging while drilling) using a 2 MHz dual-propagation resistivity tool to the casing point. In the completion interval, a gamma-ray LWD tool is used and a tool-pusher resistivity log is run to confirm expected resistivities. Despite the many well penetrations in the LBU, it is difficult to drill within a five to ten foot cylinder around the projected wellbore. The accuracy of MWD data is not always dependable and geosteering is done by TVD log correlation.

In the Long Beach Unit 22 horizontal production wells have been drilled to date. On the better wells, initial production rates averaged 300 to 600 BOPD. However, most of these wells experienced very steep hyperbolic declines to a steady rate of 100 to 120 BOPD. Some of the horizontal wells have not produced at expected levels and are thought to have formation damage. A team has been formed to investigate the performance of these wells relative to reservoir location and drilling/completion practices.

The horizontal well program targeting bypassed reserves is an innovative attempt to bring new life to a mature reservoir.

REFERENCES CITED


Figure 4. Thumps Well D-709 Horizontal Well.