The Class Act

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Horizontal Drains Recover Bypassed Oil in the Dundee Formation of Michigan

by J. R. Wood, Michigan Technological University, and W. B. Harrison III, Western Michigan University

Rejuvenating an Oil Field

In October 1995, a research consortium consisting of members of the Department of Geological Engineering and Sciences at Michigan Technological University, the Department of Geology at Western Michigan University, Terra Energy Inc. (Traverse City, Michigan), and the U.S. Department of Energy drilled the horizontal TOW 1-3 demonstration well in Montcalm County, Michigan (see Fig. 1).

This well was drilled to try to recover bypassed oil from a shallow shelf carbonate reservoir in Crystal Field. Before the TOW 1-3, Crystal Field was an example of a "worn-out" field that once had been a prolific producer (in the 1930s) and now was reduced to a handful of wells producing only 5–10 barrels of oil per day (BOPD).

The TOW 1-3, however, brought new life to Crystal Field. This well was completed successfully in October 1995 and has produced more than 70,000 barrels of oil since then at rates from 50 to 100 BOPD with zero water.

TOW 1-3 a Full Success

Tests have shown that unchoked the TOW 1-3 will flow at better than 500 bbl/day. Initial production was set at 100 bbl/day, which was 20 times better than the best conventional well in the field, but the well is now choked back to 50 bbl/day because of economic conditions.

Total recoverable reserves from the TOW 1-3 are estimated at 200,000 barrels of oil. At full development, Crystal Field is expected to produce an additional 2 million barrels.

The success of the well has spawned a miniboom in the Dundee Formation. Following the TOW 1-3, more than 20 new horizontal wells have been drilled in the Dundee Formation (see Fig. 1) as of spring 1998, including 2 more at Crystal Field.

New Horizontals Drilled

The new horizontal wells drilled in the Crystal Field to date were both drilled perpendicular to the TOW 1-3, and both missed being completed in the porous portion of the reservoir. As a result, these wells have not been economic successes.

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They are producing only a small amount of oil and large amounts of water (the water probably comes from fractures connected to the water table). One well has already been plugged and abandoned. These wells are not adequate tests of the other portions of the field. Two more wells have been permitted for Crystal Field, but are not yet drilled.

In addition to the new horizontal wells in the Dundee Formation, 17 wells in the next stratigraphic unit below the Dundee, the Dundee/Reed City, have been completed as of April 1, 1998, and 9 more are pending. These 17 wells have reported initial production ranges from 5 to 127 bbl/day, with an average of around 30 bbl/day/well.

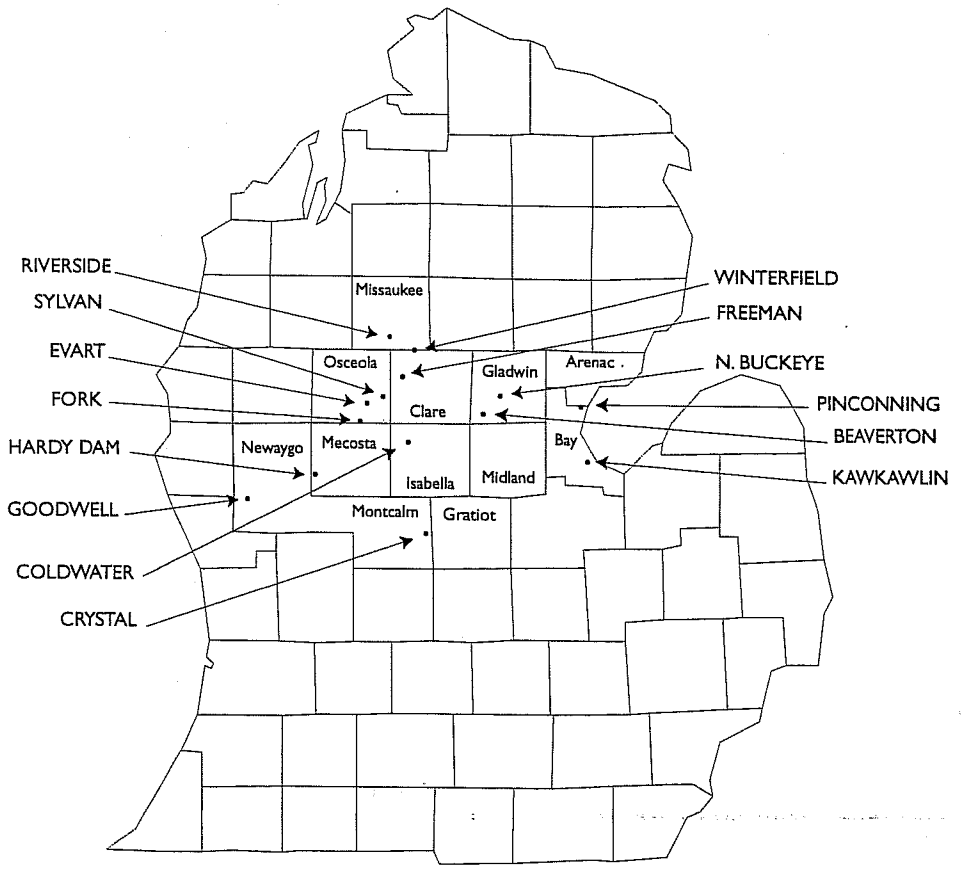

Figure 1 Location of new horizontal wells drilled in Dundee Formation, Michigan, following DOE's demonstration well at Crystal Field (TOW 1-3 HD) in October 1995. In all, 18 wells have been drilled by spring 1998 (some fields have multiple wells).

Scorecard for the New Horizontal Wells

Since January 1, 1995, 151 horizontal wells have been completed in 10 different formations in the Michigan Basin. An additional 90 horizontal wells are pending as of April 1, 1998.

The success rate for completions of all Michigan horizontal wells is 93%. Initial production rates for oil wells have been reported from a few barrels per day to more than 500 bbl/day. Natural gas wells have been completed for 10 to 4,000 mcf/day.

This horizontal activity represents about 30% of the oil wells and 2% of the gas wells drilled in Michigan since 1995.

A Major Impact

Horizontal drilling has had a significant impact on oil and gas production in Michigan. The main result has been two new wells being drilled in reservoirs that had been previously viewed as depleted or nearing their economic limit.

Having seen the benefits of employing new technology, operators in the area are now more willing to try new ideas. They are now voicing the opinion that the combination of three-dimensional (3-D) seismic technology with improved fracture analysis will have an even greater impact in the Michigan Basin. Many Michigan operators are now convinced that understanding fractures is the key to successful reservoir development.

Exploiting Reservoir Compartments in the Red River, Southwestern Williston Basin

by Mark A. Sippel, Petroleum Engineer,
Mark Sippel Engineering, Inc.

Recording 3-D seismic surveys and drilling demonstration wells were performed under a cooperative project with the U.S. DOE's National Petroleum Technology Office and Luff Exploration Company. The areas in the southwestern Williston Basin investigated cover structures at the Red River Formation that have areal extent of less than one square mile and relief from 50 to 100 ft.

There are four porosity benches in the upper Red River, labeled in descending order A, B, C, and D zones. The Red River B and D zones contain the principal reservoirs in the area. Primary reserves from the Red River B zone average 162,000 bbl per well, while Red River D zone completions recover an average of 372,000 bbl per well.

Seismic Survey Goals

The surveys aimed to determine if structural and porosity compartments can be observed and whether there is potential for developing additional reserves on small-bump features with previous production.

Targeted drilling of three wells during the project term resulted in commercial production of poorly drained reserves at offset distances of less than 1,300 ft and down-dip from mature wells nearing depletion. The developed and probable reserve additions of existing wells exceed the ultimate recovery expected before the 3-D seismic was acquired.

Williston History

Exploration for Red River oil reserves in the southwestern portion of the Williston Basin began in the 1940s with drilling on the Cedar Creek anticline. This major feature of the Williston Basin was identified by surface mapping. In the early 1950s, single-point seismic data were used to extend Red River exploration along trend with the axis of the Cedar Creek anticline into Harding County, South Dakota.

The advent of common-depth point (CDP) two-dimensional (2-D) seismic technology in the 1960s allowed delineation of small, deep structures. With this technology, operators began to develop many small structural features in the area. Exploration methods traditionally involved mapping time structure and isochrons of various horizons to identify paleo thinning and structural growth.

Exploration and development strategies involved drilling one or two wells at crestal positions on small features. Well spacing has been 160 or 320 acres per well with producing depths from 8,500 to 9,500 ft. With the emergence of 3-D seismic, it is becoming apparent that there probably are many opportunities to develop additional oil reserves in mature areas.

What 3-D Seismic Offers

Exploitation of poorly drained reserves is possible using seismic amplitude anomalies, indicative of better porosity development. Reserves must be found at sufficient structural position to be above an oil-water contact, and not have been penetrated by existing wells.

One conclusion is that 3-D seismic can provide a much-improved interpretation of structure and information about porosity development. It was found that amplitude variation

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within the Red River interval is primarily diagnostic of porosity development in the D zone.

Amplitude variation and development relating to the Red River D zone porosity are spotty and tend to be located in structurally low areas and along flanks of positive features. The area of the amplitude anomalies ranges from 40 to 160 acres. The random distribution and small size of these anomalies make it difficult for interpretation with 2-D seismic, even with a dense grid of 0.5-mile spacing.

Seismic Survey Coverage

Seismic surveys using 3-D coverage were obtained in Bowman County, North Dakota, over areas that are typical of the high-relief, small-structure setting and have mature wells with good to above-average production.

A seismic-time cross-section over one of the structural features at Cold Turkey Creek Field is shown in Figure 1. The cross-section shows the amplitude variation of troughs and peaks at the Red River time horizon. The figure also shows how amplitude response of porosity in the Red River D zone can be preferentially developed on the flanks of a feature and poorly developed on the crest.

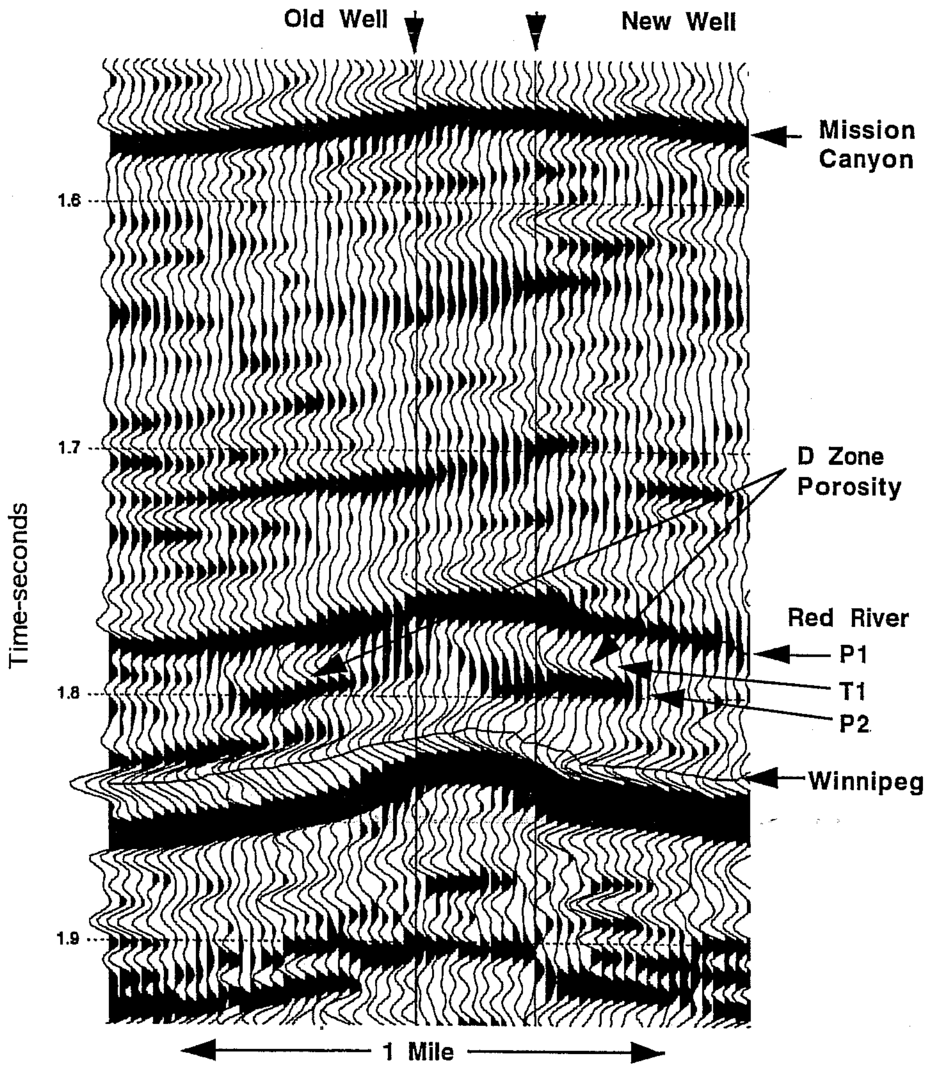

Figure 1 Structural cross-section from seismic data at Cold Turkey Creek Field

A time-structure map at the Winnipeg horizon across Cold Turkey Creek Field is shown in Figure 2. Superimposed on the time contours is shading that represents the amplitude variation of one Red River seismic event. Darker shading indicates stronger amplitude. Each of the three structural features exhibits a low-amplitude area at or near the crest of the Winnipeg time structure. The strongest amplitude response is indicated in low areas; however, the amplitude blooms are random and spotty.

Testing Seismic Predictions in D Zone

Two wells were drilled to test seismic predictions of porosity in the Red River D zone on the flanks of one structural feature at Cold Turkey Creek Field where there was one well that had been producing more than 20 years.

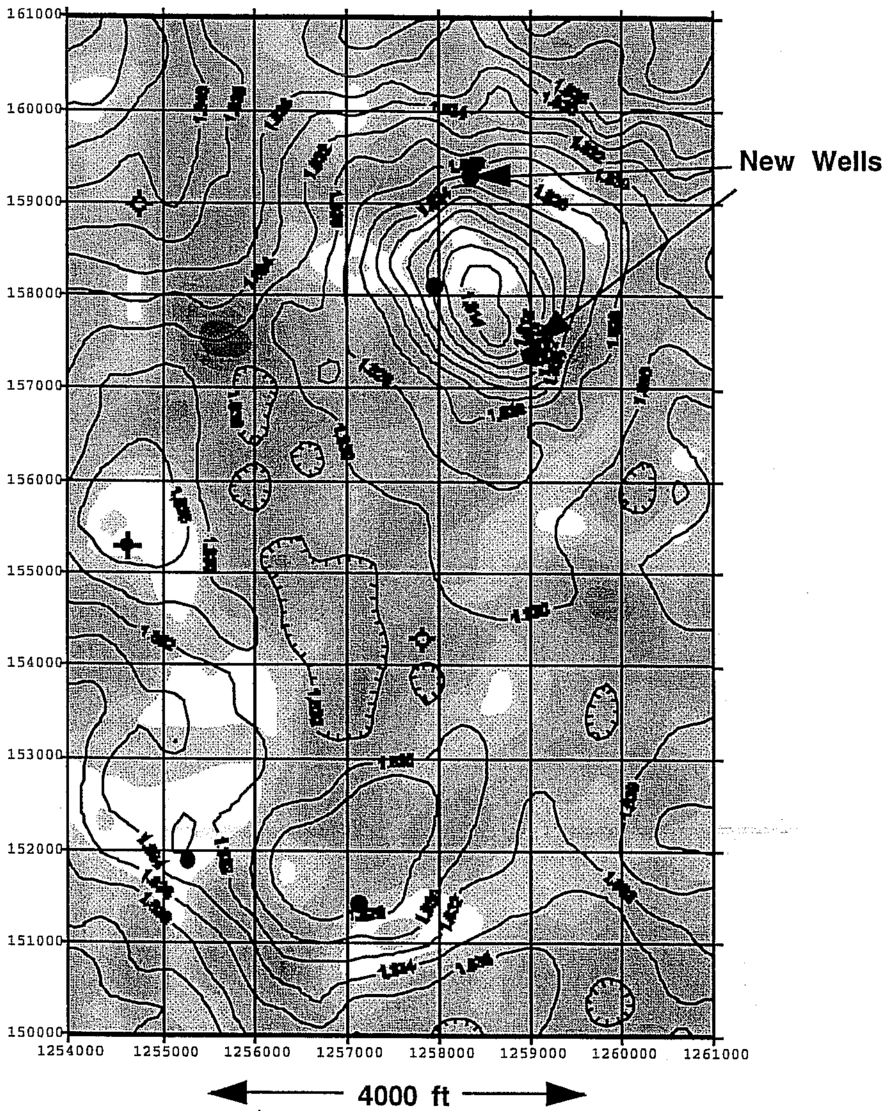

Figure 2 Winnipeg time structure contours at Cold Turkey Creek Field with Red River D zone amplitude (T1). Contour interval is 2 msec; darker shading indicates increasing amplitude intensity.

Cumulative oil production from the old well was more than 375,000 bbl.

The first test well encountered a thicker and more porous section in the D zone with a loss of structure of about 30 ft from the structural crest. After perforation and acidizing the D zone, the first test well was completed with a production rate of 166 BOPD and 133 BWPD during December 1996.

During July 1997, a second test well was drilled on the opposite flank of the feature from the first test well. This well penetrated the Red River at a depth about 53 ft below the structural crest. A drill-stem test in the D zone recovered about 7,200 ft of mostly oil with a shut-in pressure of 3,500 psi, which indicates slight pressure depletion. The Red River D zone was perforated and flowed 175 BOPD at 100-psi wellhead pressure with no water during July 1997. The cumulative oil produced from the two new wells was about 62,000 bbl through December 1997. Both wells also have behind-pipe reserves in the Red River B zone.

Redrilling to Tap Hidden Reserves

In a nearby area, similar results were later found by drilling a Red River amplitude anomaly off-structure from a mature well. The encouraging results from the targeted drilling and successful prediction of porosity development from 3-D seismic have led to Luff Exploration Company evaluating many other small structures in the area for similar exploitation efforts.

Throughout the Williston Basin, there may be significant oil reserves hidden on the flanks of previously drilled structural features, and 3-D seismic will play an important role in exploiting these hidden reserves. This appears especially true where recording high-frequency seismic data is possible, as in the southwestern portion of the Williston Basin.

The keys to successful interpretation of 3-D seismic data are understanding the reservoir response from seismic modeling and proper processing.

Fluvial-Dominated Deltaic Petroleum Reservoirs in Oklahoma

by Charles J. Mankin,
Director, Oklahoma Geological Survey

The Oklahoma Geological Survey, in cooperation with Geo Information Systems and the School of Petroleum and Geological Engineering at the University of Oklahoma, has completed a very successful petroleum play–based workshop program. This effort, supported with matching funds from the U.S. DOE's NPTO, was a part of the Class I Fluvial-Dominated Deltaic (FDD) Petroleum Reservoir Near-term Program.

This program was established by DOE to find ways to improve recovery from light-oil reservoirs in danger of abandonment because of declining recovery and increasing operating costs. Collectively, FDD reservoirs in Oklahoma account for about 15% of total oil production and are among the earliest discovered fields in the state.

The Project's Goals

The proposal submitted by the Survey and its partners planned to identify all the light-oil FDD petroleum reservoirs in Oklahoma, organize the reservoirs into plays, and examine selected reservoirs in each play to find ways to improve recovery from those reservoirs. Another goal was to identify opportunities for additional development in those plays.

The results of these investigations would be developed into reports, and workshops would be held on each play to convey the findings to operators and others who were interested. A database would be created containing the information developed for each play.

What the Reports Offer

Each report resulting from the project contains a general description of the play, including its location and extent. A discussion of the geologic setting, depositional environment, distribution of reservoir, and exploration history is provided together with a more detailed description of selected reservoirs to aid in characterizing the general properties of the play.

For most plays, a more detailed characterization and simulation are presented for one or more reservoirs. An extensive collection of maps and cross sections was developed for each play to depict regional structure, sand distribution, producing fields, and stratigraphic correlations.

Ten Plays, Eight Reports

Ten plays were identified. A total of eight reports were produced. Two pairs of the smaller plays that were stratigraphically related were combined: the Prue and Skinner plays were combined into one publication, as were the Cleveland and Peru plays. The identified plays in the order of completion and presentation are:

- Morrow
- Booch
- Layton and Osage-Layton
- Prue and Skinner
- Cleveland and Peru
- Redfork
- Tonkawa
- Bartlesville

14 Workshops Held

Eight different one-day workshops were held during the last two-and-one-half years of the project. Because of demand, several workshops were held more than once. In all, 14 workshops were held in various parts of the state with 1,600 operators and other interested parties attending.

A typical one-day workshop consisted of an introduction to FDD deposition that included examples from the literature, as well as current data from selected streams in Oklahoma that illustrated a variety of appropriate bar-type deposits very well. This introduction was followed by an overview of the play to portray its general depositional characteristics. Maps and cross sections were used to illustrate particular features that related to hydrocarbon accumulations in the play.

This was followed by a detailed description of one or more reservoirs that were judged to be representative of the production from the play. Where possible, cores were used to aid in interpreting well-log signatures.

Low Recovery Linked to Heterogeneity

Characterization and simulation for one or more reservoirs in each play were presented to help operators understand some of the factors that contribute to low recovery from these fields. An analysis of the reservoirs examined in detail from the 10 plays of this study indicated an average recovery factor of less than 15% of the estimated original oil-in-place. Recognition by operators that the low recovery is related to internal reservoir heterogeneity is an important first step in the path to increasing recovery from these important producing fields.

Operators Want More

Operators and other interested parties have made it abundantly clear that this program has been extremely important to them. They have urged the Survey to continue to develop plays for other important petroleum and natural-gas-producing intervals in the state. To that end, the Survey is now engaged in developing the Hartshorne natural-gas play in east-central Oklahoma.

The results of that effort will be presented in workshops in early fall, together with an optional field trip to exposures of the Hartshorne Formation to view the rock properties of units that produce in the nearby subsurface.

In addition, because many operators and others were not able to attend the FDD workshops when they were originally held, each play is being repeated on a half-day basis as a joint effort of the Oklahoma City Geological Society and the South Mid-Continent Region of the Petroleum Technology Transfer Council (PTTC), managed by the Survey in cooperation with Geo Information Systems and Oklahoma's Marginal Well Commission.

Hopes for Additional Recovery

The FDD petroleum reservoirs have been important contributors to Oklahoma's production since well before statehood. Given the low recovery factors of currently producing reservoirs and the early history of many fields in these places, the opportunity for substantial additional recovery from these fields, as well as the development of new production in a very mature producing area of the state, is very attractive.

Don't Use CO_2 Huff'n'Puff for Waterflooded Shallow Shelf Carbonates

by Scott C. Wehner, Project Engineer,
Texaco Exploration and Production Inc.

Texaco Exploration and Production Inc. (TEPI) was awarded a cost-sharing contract by the U.S. DOE in the first quarter of 1994. The goal of this joint project is to demonstrate the carbon dioxide (CO_2) huff'n'puff process in waterflooded, light oil, shallow shelf carbonate (SSC) reservoirs (Grayburg and San Andres formation) within the Permian Basin.

The selected sites are the TEPI-operated Central Vacuum Unit (CVU) waterflood in Lea County, New Mexico, and the Sundown Slaughter Unit (SSU) in Hockley County, Texas. The CVU produces from the Grayburg and San Andres formations; SSU produces primarily from the San Andres Formation.

Hopes for Huff'n'Puff

The eastern portion of Sundown Slaughter Unit is now under miscible CO_2, while the rest of the field remains under waterflood. TEPI has recently implemented a full-scale miscible CO_2 project in the CVU. However, the current market precludes acceleration of such capital intensive projects in many similar reservoirs.

This is a common finding throughout the Permian Basin SSC reservoirs. In theory, it is believed that the "immiscible" CO_2 huff'n'puff process might bridge the longer-term "miscible" projects with near-term results. A successful implementation of CO_2 huff'n'puff would result in revenue from near-term production to help offset cash outlays for the capital-intensive miscible CO_2 project.

Not Viable for Waterflooded Shallow Shelf Carbonates

The DOE partnership provides some relief to the associated research and development risks, which allowed TEPI to evaluate a proven Gulf-coast sandstone technology in a waterflooded carbonate environment. A successful demonstration of the proposed technology would likely be replicated within industry many fold–resulting in additional domestic reserves.

Although the huff'n'puff process still has promise for other pressure-depleted reservoirs, it does not appear to be viable at CVU or SSU–waterflooded shallow shelf carbonates.

Project Goals & Hopes

The main objective of the CVU and SSU CO_2 huff'n'puff projects was to determine the feasibility and practicality of the technology in a waterflooded SSC environment. The results of parametric simulation of the CO_2 huff'n'puff process at CVU, coupled with reservoir characterization, assisted in determining if this process was technically and economically ready for field implementation.

The ultimate goal was to develop guidelines based on commonly available data that operators within the oil industry could use to investigate the applicability of the process to other fields. The technology transfer objective was to disseminate the knowledge gained through an innovative plan in support of the DOE's objective of increasing domestic oil production and deferring the abandonment of SSC reservoirs.

The application of CO_2 technologies in Permian Basin carbonates may do for this region in the 1990s and beyond, what waterflooding did starting in the 1950s. With an infrastructure for CO_2 deliveries already in place, a successful demonstration of the CO_2 huff'n'puff process could have wide application. The technology promises these economical advantages:

- Maintaining the profitability of marginal properties until pricing justifies a full-scale CO_2 miscible project
- Maximizing recoveries from smaller isolated leases, which could never economically support a miscible CO_2 project
- Reducing up-front negative cash-flows, when applied during the installation of a full-scale CO_2 miscible project, possibly even allowing a project to be self-funding while increasing horizontal sweep efficiency

CO_2 Miscible vs. CO_2 Huff'n'Puff

Because most full-scale CO_2 miscible projects are focused on the *sweet spots* of a property, the CO_2 huff'n'puff process could concurrently maximize recoveries from nontargeted acreage. An added incentive for the early application of the CO_2 huff'n'puff process is that it could provide an early measure of CO_2 injectivity of future full-scale CO_2 miscible projects and improve real-time recovery estimates–reducing economic risk.

It was hoped that the CO_2 huff'n'puff process might bridge near-term needs of maintaining the large domestic resource base of the Permian Basin until mid-term economic conditions support implementing more efficient, and prolific, full-scale miscible CO_2 projects.

The major simulation results suggest that reservoir characterization of flow units is not as critical for the CO_2 huff'n'puff process as for a miscible flood.

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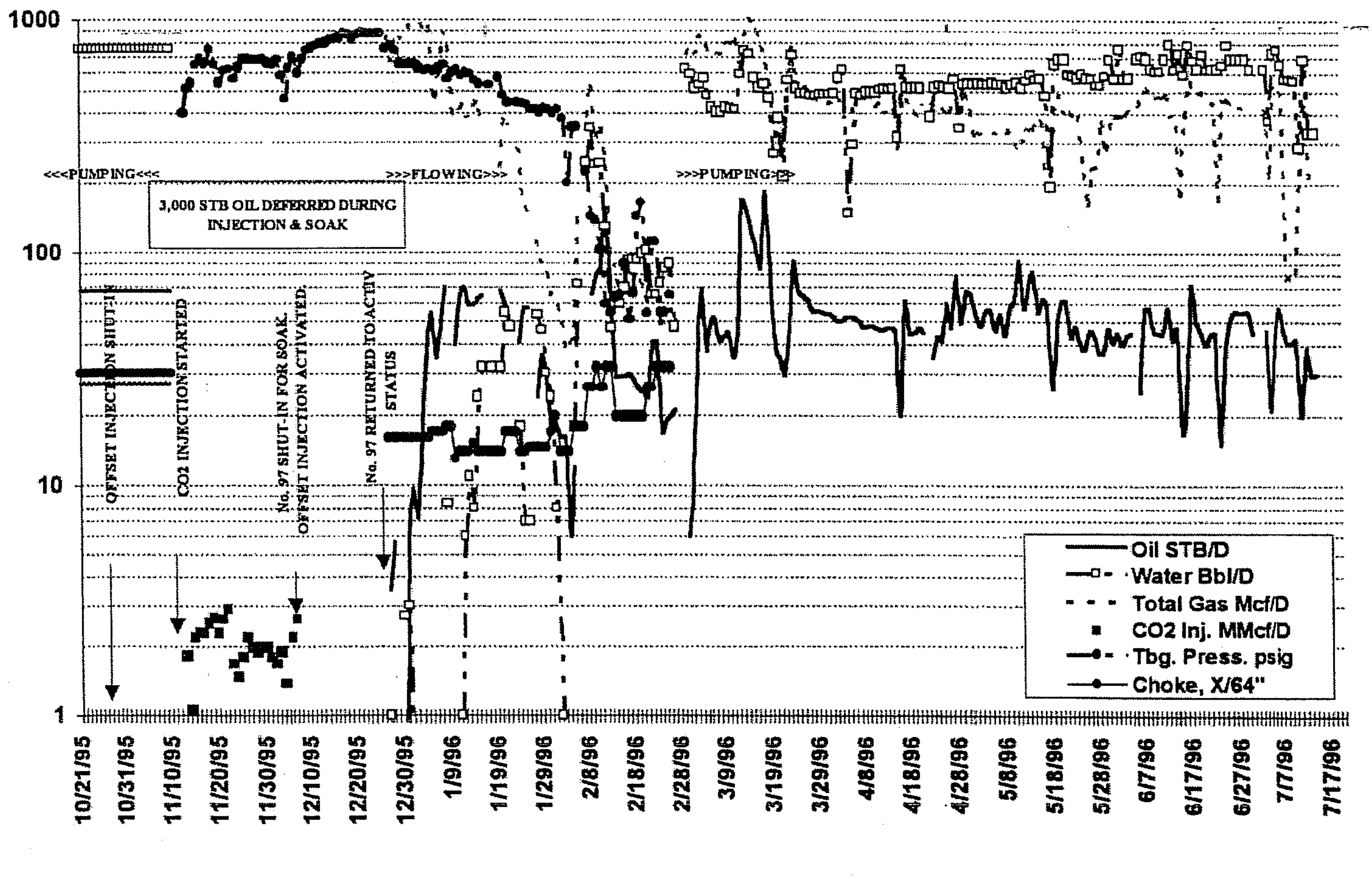

Figure 1 Central Vacuum Unit Demonstration Site Results – Well No. 97

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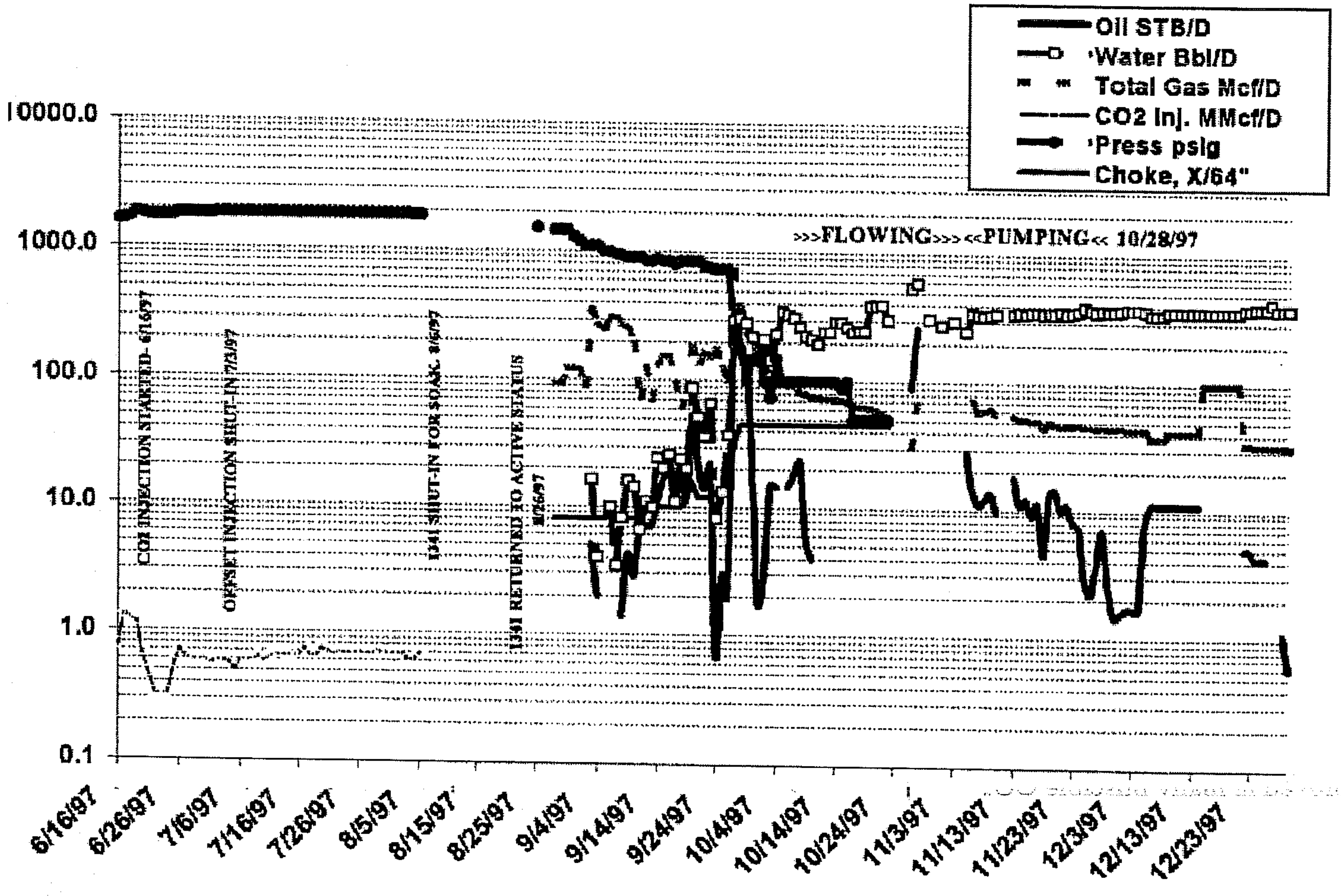

Figure 2 Sundown Slaughter Unit Demonstration Site Results – Well No. 1341

Entrapment of CO_2 by gas hysteresis was considered the dominant recovery factor for a given volume of CO_2. Repetitive application of the process was found to be unwarranted in a waterflooded environment. Production rate limitations have an impact on ultimate recovery.

What Happened

Field demonstrations at CVU and SSU have not performed as expected (refer to the results in Figs. 1 and 2). Hydrocarbon recoveries appear equal to or slightly above the deferred production of the injection and soak period. The forecast assumed that large trapped gas saturation would occur. The incremental oil recovered was only equal to or slightly more than the deferred production during the injection and soak periods. Furthermore, 100% of the injected CO_2 is being recovered—although slower at SSU. These events signal the lack of trapped gas saturation or very short-lived gas trapping.

Trapped Gas Saturation Deficiency

Previous simulation work indicated that trapped gas saturation was the mechanism required for success. Several possible reasons exist for this deficiency. First, water may have dissolved the CO_2 saturation. Second, the absence of trapped gas saturation might be because of pore-throat size, porosity-type, lithologic characteristics, or a combination of these factors that are not currently understood. In addition, based on simulation exercises, there may exist a rate dependency component to the ultimate success and efficiency of this technology.

Simulation results indicate that the oil production rate is increased when the gas production rate is increased. This suggests that a well be equipped for high gas production rates rather than attempting to initially flow a well before returning production equipment to the wellbore. Restricting the gas rate restricts the oil production rate. Furthermore, because a gas disposal restriction existed at CVU and the unit lacks the capacity to trap gas, CVU should not be considered for further demonstrations.

It is interesting to note that near-wellbore gas trapping of CO_2 has been cited as one possible cause of reduced injectivity following water-alternating-gas (WAG) injection methods employed in many miscible CO_2 floods.

The offset (to CVU) East Vacuum Grayburg San Andres Unit miscible CO_2 flood, which is operated by Phillips, is one of the few Permian Basin CO_2 floods that has not experienced any appreciable reduction in injectivity. There has been no reduction during 12 years of WAG operations even though many of the other Permian Basin shallow shelf carbonate reservoirs have experienced 30–50% reductions in water injectivity following the introduction of CO_2 to the reservoirs.

If it can be inferred that reduced injectivity in WAG operations is related to gas trapping, then Vacuum Field is not a good candidate for further testing of huff'n'puff technology.

Who Might Benefit

Oxy has been experimenting with huff'n'puff technology in the Welch Field of West Texas. Oxy's huff'n'puff results have been favorable enough to consider expansion. An offset miscible CO_2 flood within the Welch field showed reduced injectivity in WAG operations. This further suggests that the technology should be applied to another reservoir that has documented WAG injectivity reductions to validate the hypothesis.

Slaughter Field is such a reservoir in the San Andres Formation. Texaco has seen reduced injectivity in its wells that are currently under miscible flood in the Eastern part of the field. Altura also has experienced reduced injectivity in its wells in the Slaughter Estate Unit adjacent to SSU.

Other Valuable Insights

After the first demonstration at CVU, it was hoped that the huff'n'puff technology might become a valuable indicator of potential injection rates when designing a miscible CO_2 flood. Injectivity is a key parameter affecting the economics of large-scale projects.

The failure of huff'n'puff might indicate favorable expectations of injection, whereas a positive response may suggest injectivity reductions–thus the need for the parallel implementation of huff'n'puff technology.

To an extent, this hypothesis was realized. The CVU site injected at rates well above expectation; the SSU site had subpar injectivity.

Reduced Electrical Load

Also, an associated lifting cost benefit, predominantly at CVU, was realized during the demonstration resulting from the reduction in electrical load. Even though oil recovery was equal to deferred production, the recovery occurred during a period that experienced no electrical costs during injection, soak, and flowing periods. Once the well was returned to pumping, it has continued to experience reduced electrical costs because of reduced water production. These topics might be of further interest to investigators.

The **Class Act** is a quarterly newsletter devoted to providing information about the Department of Energy's (DOE's) Reservoir Class Program. The newsletter is produced by BDM-Oklahoma, which manages the National Oil Program for the DOE National Petroleum Technology Office in Tulsa, Oklahoma.

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Demonstrating Post Waterflood CO_2 Miscible Flood in a Light Oil Reservoir

by Tim Tipton, Petroleum Engineer,
Texaco Exploration and Production Inc.

Texaco Exploration and Production Inc. (TEPI) and the U.S. DOE entered into a cost-sharing cooperative agreement to conduct an enhanced oil recovery demonstration project at Port Neches field in Orange County near Beaumont, Texas. The project would:

- Demonstrate the effectiveness of the CO_2 miscible process in fluvial-dominated deltaic reservoirs
- Evaluate the use of horizontal CO_2 injection wells to improve the overall sweep efficiency and determine the recovery efficiency of CO_2 floods in waterflooded and partial waterdrive reservoirs

Texaco's objective on this project was to (1) utilize all available technologies and develop new ones and (2) design a CO_2 flood process which is cost effective and can be applied to many other reservoirs throughout the United States.

A database of potential reservoirs for the Gulf Coast region was developed by Louisiana State University (LSU) using a screening model developed by Texaco Research Center in Houston.

The PC-based CO_2 screening model was applied, and the LSU database was generated to show the utility of this technology throughout the country. Finally, the results and information gained from this project were disseminated throughout the oil industry via a series of SPE papers and industry open forums.

The Port Neches (Marginulina Area 1) units consist of 2345.1 acres of the tertiary age Marginulina sandstone reservoir. This fining upward sequence consists of highly permeable sand interbedded and surrounded by calcareous shales. The reservoir trap was formed when the sandstone was uplifted by salt after deposition, thus forming a complex array of faulting.

The reservoir had been extensively waterflooded. It was at an average oil saturation of 31%, only 1% above the residual saturation to waterflood 30%.

1994 Production

Production during 1994 closely matched the July 1993 forecast submitted with the Project Management Plan. During the year, Texaco purchased an average of 4.3 MMcf/D of CO_2 from Cardox for injection into three wells.

Production averaged 325 to 400 BOPD from the three wells. This represented a fourfold increase from the production level prior to CO_2 injection. The reservoir pressure increased with CO_2 injection from 2,460 psi in September 1993 to an average of 2,810 in 1994.

Early CO_2 breakthrough from some wells required taking corrective measures, such as alternating water and CO_2 injection. This was the first time a WAG process had been applied, and with pleasant success, in sandstone reservoirs of Port Neches Field.

1995 Production

Production averaged 459 BOPD in early 1995, but declined to an average of 250 BOPD by year-end. The decline was mainly because of fluctuation in gas-oil ratio (GOR) and basic sediments and water (BS&W), low water injectivity in the reservoir, mechanical problems in injection and producing wells, and poor sweep efficiency because of water blockage. The water alternating gas (WAG) process was continued during 1995. The process had proved itself to be effective in diverting the CO_2 in an effort to improve the sweep efficiency.

1996 Production

Production continued to decline during 1996. After nearly four years of the project, performance declined because of several factors, including water blockage, low residual oil saturation, and wellbore mechanical problems. Well No. 15R sanded up because of corrosion problems and was plugged and abandoned.

The project's economics were greatly affected by the cost of CO_2, so an evaluation of continuing to purchase CO_2 was made. Using the compositional reservoir model that was updated with the newly developed geological model and the tertiary performance data from the last three years, the impact of continuous CO_2 purchases on ultimate recovery was determined. Oil saturation based on the new log and core data proved to be lower than the preproject estimate, and fault block 2 was too small for an effective CO_2 flood based on the 3-D seismic data. CO_2 huff'n'puff treatment was begun as an alternative.

1997 Production

Production decline stabilized at 60 BOPD from two wells, Kuhn Nos. 14 and 38, in the first quarter of 1996. However, Kuhn No. 38 went off production because of mechanical problems, leaving Kuhn No. 14 as the only producer. The project was at a negative cash flow because of the workover failure at Kuhn No. 38. The CO_2 recycled volume dropped below 2 MMcf, enabling the company to maintain only one compressor active. Water injection in the project had been discontinued because of low injectivity. That, in turn, caused high backpressure at the wells, which eventually caused mechanical problems at the pump. However, CO_2 injection was discontinued in September to prepare for the end of the project.

The remaining oil in the vicinity of this well is minimal, according to the reservoir simulation and the well's high GOR production history. By the end of the project, the CO_2 processes were deemed too uneconomic to continue.

C A L E N D A R

JUNE

June 16, Horizontal Drilling Applications for Kansas Workshop; North Midcontinent Resource Center-PTTC, Wichita Airport Hilton, Wichita, KS.

AUGUST

August (Early), Economic Recovery of Oil Trapped at Fan Margins Using High-Angle Wells & Multiple Hydraulic Fractures Workshop, 1 day (Class III); Yowlumne Field Project, contact Mike Laue at Arco Western, 805-532-6601.

August 23–25, 3-D Seismic Workshop; North Midcontinent Resource Center PTTC, Wichita Airport Hilton, Wichita, KS.

SEPTEMBER

Sept. 14–17, Annual International Meeting, Society of Exploration Geophysicists, New Orleans, LA.

SEPTEMBER (CONT.)

- Crosswell Seismic Imaging in the Buena Vista Hills, San Joaquin Valley: A Case History (Class III). R.T. Langan, D. R. Julander, M. F. Morea, C. M. Addington, & S. K. Lazaratos.
- Buena Vista Hills 3-D Attenuation and Velocity Tomography (Class III). G. Wang, J. M. Harris, C. Magalhaes, D. R. Julander, & M. F. Morea.
- Crosswell Seismic in 3-D (Class III). J. K. Washbourne & J.W. Rector, III.

OCTOBER

Oct. 4–9, 3rd AAPG/EAGE Joint Research Conference on Developing & Managing Turbidite Reservoirs: Case Histories & Experiences, Almeria, Spain.

- Characterization and Development of Turbidite Reservoirs in a

OCTOBER (CONT.)

Deep-Water Channel-Levee & Lobe System, Ford Geraldine Unit, Permian Bell Canyon Formation, Delaware Basin, USA.

- Subsidence and Old Data Present Unique Challenges in Aging Turbidite Oil Fields. Examples of Successful Technologies Solutions from the Wilmington Oil field, California, USA. D. D. Clark & C. C. Phillips.
- Reservoir Characterization of a Fan-Shaped Turbidite Complex in an Active-Margin Basin, Miocene Stevens Sandstone, Yowlumne Field, San Joaquin Basin, California. M. Clark

NOVEMBER

Nov. 12, FDD Workshop: The Bartlesville Play (Class I); Oklahoma Geological Survey, Postal Training Center, Norman, OK.

ANNOUNCEMENTS

Coming Soon to a Reservoir Near You

Class Revisited

DOE will announce funding for new Class I, II, and III projects during the late summer of 1998. Check on the DOE home page (http://www.npto.doe.gov) for news of the announcement.

Funding will be open to any new project in these three depositional classes: fluvial-deltaic, shallow-shelf carbonate, and slope-basin clastics. Projects in the entire United States will now be considered, including Alaska, and heavy oil projects in all three classes.

Final Reports Available

Final reports on the five Class projects completed in December 1997 and highlighted in this issue will be available from DOE. Contact Herb Tiedemann at htiedema@npto.doe.gov or call 918-699-2017.

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