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The Class Act

DOE's Reservoir Class Program Newsletter

Reactivation of the Idle Pru Lease of Midway-Sunset Field, San Joaquin Basin, CA

Steven Schamel, University of Utah

A PREVIOUSLY IDLE PORTION of the Midway-Sunset field, Aera Energy's Pru Fee property, has been brought back into commercial production through tight integration of geologic characterization, geostatistical modeling, reservoir simulation, and petroleum engineering. This property, shut-in in the mid-1980s as economically marginal using conventional cyclic steaming methods, has a 200-300 foot thick oil column in the Monarch Sand, part of the uppermost Miocene Belridge Diatomite Member of the Monterey Formation. However, the sand has a shallow dip (about 10º), thus inhibiting gravity drainage, lacks effective steam barriers within the pay interval, and has a thick water-saturated transition zone above the oil-water contact. These factors have required an innovative approach to steam flood production design that balances optimal total oil production against economically viable production rates and performance factors, such as OSR and OWR. The methods used in this DOE Class III oil technology demonstration are accessible to most operators in the Midway-Sunset field and could be used to revitalize properties with declining recovery of heavy oil throughout the region.

The Midway-Sunset field was discovered in 1894, however, it took nearly a decade for commercial production to begin. The original 13 wells drilled on the Pru Fee property in the early 1910s were operated in primary production by Bankline Oil Company prior to 1959, then Signal Oil Company until 1969, when infill drilling and cyclic steaming was initiated by Tenneco. During the half century of primary production nearly 1.8 MMBO was produced from the Pru property, 114 to 151 MBO per well, but production declined steadily reaching insignificant quantities by the late 1960s. Cyclic steaming was partially successful in extracting the remaining viscous 13 ºAPI oil until the Pru Fee property was shut down in 1986 as uneconomic. Total secondary recovery from the 40-acre site peaked at about 300 BOPD in 1972, but by the time the property was shut-in the oil rate had dropped to less than 10 BOPD. At this point in time, about 2.4 MMBO had been produced from the property, which was just 22.1% of original oil in place. ARCO Western Energy (AWE) acquired the Pru Fee in 1988 along with many other producing properties in the region. On October 31, 1998 all of the AWE properties in the southern San Joaquin basin, including Pru Fee, were passed through Mobil with simultaneous closing and transfer to Aera Energy LLC, a Shell-Mobil joint-venture company. AWE continued to operate the property on contract to Aera Energy LLC until December 31, 1998, at which time operatorship passed to Aera Energy LLC.

What's Inside

Figure 1: View from southwest to northeast across the 40 acre Pru Fee property with two large steam generators in the middle ground. All of the project area is encompassed in the view. The Pru-344 well is in the foreground. The steam generators are located near the center of the 8 acre steam flood pilot array shown in the location map (Figure 2).

In June 1995, the shut-in Pru Fee property (Figure 1) was selected for a DOE Class III oil technology demonstration. The work to reactivate the property started in October 1995. Initially, this resulted in the renovation of old wells and cyclic production facilities at the site and the drilling of two new wells, Pru 101 and TO-1 (Figure 2). Pru 101 was cored, steam stimulated, then put into cyclic production. Several old wells in the center of the property were recompleted and put into cyclic production to evaluate the overall feasibility of additional thermal recovery at this marginal site. In January 1997 the project entered its second and principal phase with the completion of 11 new producers, 4 injectors and 3 temperature observation wells arranged into an 8-acre nine-spot, four-pattern pilot. The objective of the pilot was to test whether steam flood could be an effective mode of production of the heavy, viscous oils from marginal, low-dip portions of the Monarch Sand reservoir where conventional cyclic steaming appeared, from prior experience, to be non-commercial.

The early production success of the pilot and the discovery of significant quantities of oil in the Pleistocene Tulare Formation during the preparation of the steam flood pilot led AWE early in 1998 to expand operations elsewhere in the Pru Fee property. Thirty-seven additional wells (300-series) in the Monarch Sand surrounding the steam flood pilot (Figure 2) were put on line in 1998 and early 1999. By mid-1999 these cyclic wells had reached oil rates in the range 363 to 381 BOPD. In just a year, they had already produced an additional 129.7 MBO over and above production from the steam flood pilot. Upon acquiring the property in January 1999, Aera Energy LLC began modifications to the infrastructure at Pru Fee and all adjacent properties that a year later resulted in conversion of all "300-series" cyclic wells into 10 additional steam flood patterns.

Monarch Sand Reservoir

Heavy oil production at Pru Fee is from the uppermost Miocene Monarch Sand, part of the Belridge Diatomite Member of the Monterey Formation. The pay interval is only 1100-1400 ft deep. Like other sand bodies within the Monterey Formation, it is a basin submarine channel or proximal fan deposit encased in diatomaceous mudstone. The sand is derived from an elevated portion of the Salinas block, which during the late Miocene lay immediately to the west of the San Andreas fault, now just 15 miles to the west of the site. The top of the Monarch Sand is actually a lower Pliocene unconformity that dips at less than 10° to the southwest. The unconfor-

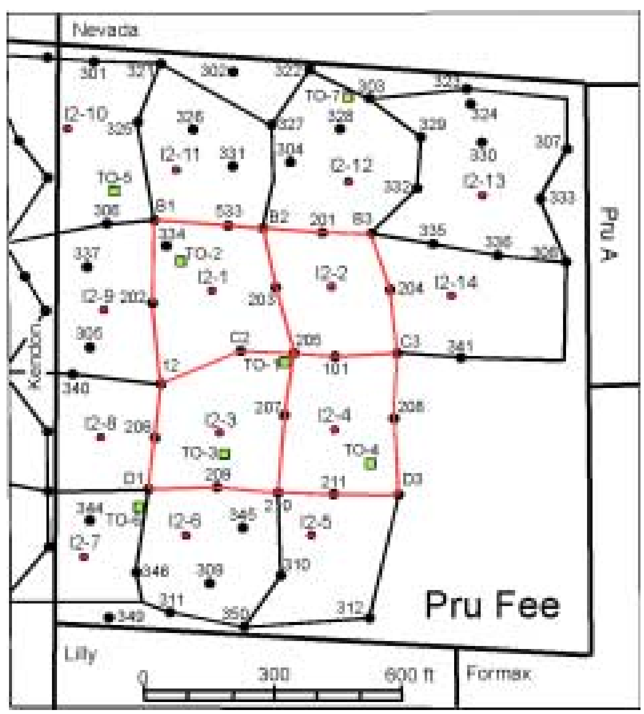

Figure 2: Map of the Pru Fee property showing the bottom hole locations of project producers (black), injectors (red) and temperature observation wells (green). The four-pattern pilot array is delineated in red. The property is located in the southern half of the Midway-Sunset field about one mile south of Taft. It occupies all of T32S-R23E, Sec. 36, NW1/4, NW1/4.

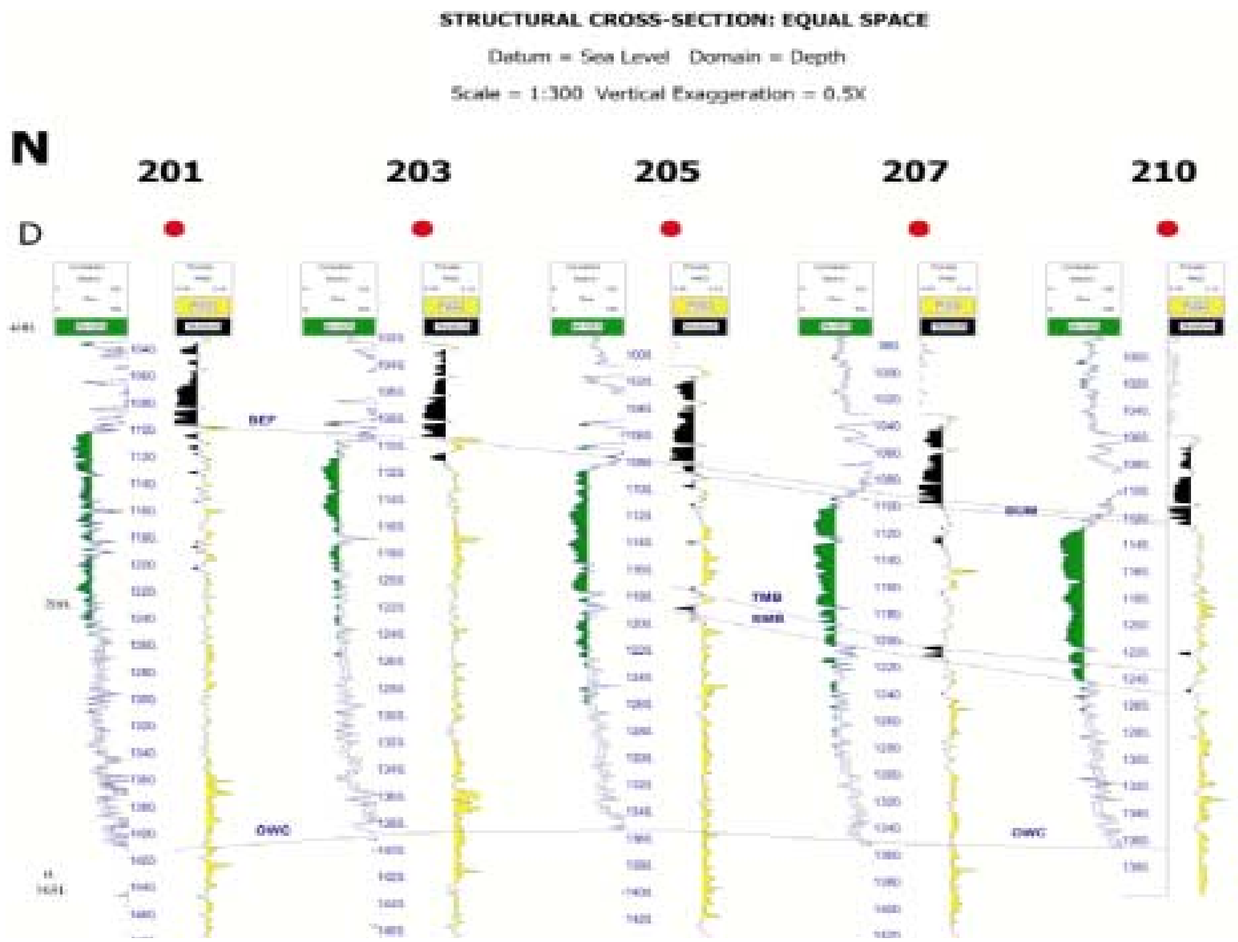

Figure 3: Representative wells through the Monarch Sand reservoir in a north-south structural cross section showing the thick transition zone of downward decreasing oil saturation in the pair of curves to the far left. The green cutoff depicts intervals with oil saturation greater than 50%. From left to right the curves are (1) project-modified Archie Sw calibrated against the Pru-101 core, (2) "standard" Archie Sw, and (3) density porosity with the yellow cutoff being sand and the black indicating highly porous diatomite and/or shale.

mity bevels down section at a very low angle (1-2º) to the northwest across the upper portion of the Monarch Sand body. (Figure 3).

The net pay zone, which averages 220 ft at Pru Fee, thins to the southeast as the top of the sand dips through the nearly horizontal oil-water contact (OWC). In the southeast half of the Pru Fee property a thin wedge of Belridge Diatomite overlies the Monarch Sand beneath the Pliocene/Miocene unconformity providing a somewhat more effective steam barrier than the Pliocene Etchegoin Formation, a silty to sandy mudstone. However, it is the overlying Etchegoin Formation that forms the essential unconformity trap for the Monarch Sand reservoir in this part of the Midway-Sunset field.

Average Monarch Sand reservoir characteristics derived from core and the log model developed for this project are 31% porosity and 2250 md permeability. The "initial" (1995) average oil saturation was estimated to be 59% based on the nearly complete core from Pru-101. However, almost all wells have a transition zone more than 100 ft thick of downward decreasing oil saturation in the bottom half of the pay interval. The oil is both heavy and viscous, about 13 º API gravity and 2070 cp at the initial (1995) reservoir temperature of 100 º F. The Pru-101 core reveals a dominance of sand-on-sand contacts with only a few relatively thin intervals of diatomite and silt. The wire-line logs in wells penetrating up to 350 ft of the reservoir also suggest that the Monarch Sand at this site is essentially a single sand body with interspersed discontinuous remnants of diatomite beds, rather than stacked sand lenses encased in diatomite.

At a reservoir-scale within the bounds of the Pru Fee property, the Monarch Sand is remarkably homogeneous with respect to porosity and permeability. Significant variation is observed only on a foot-to-foot basis vertically reflecting changes related to sand texture which varies from medium to pebbly within the relatively thin, partially graded depositional units. Oil saturation, on the other hand, exhibits significant lateral, as well as vertical, variability. Oil-depleted pockets are encountered in the north-central and northwest portions of the property adjacent to the actively producing Nevada and Kendon properties, respectively.

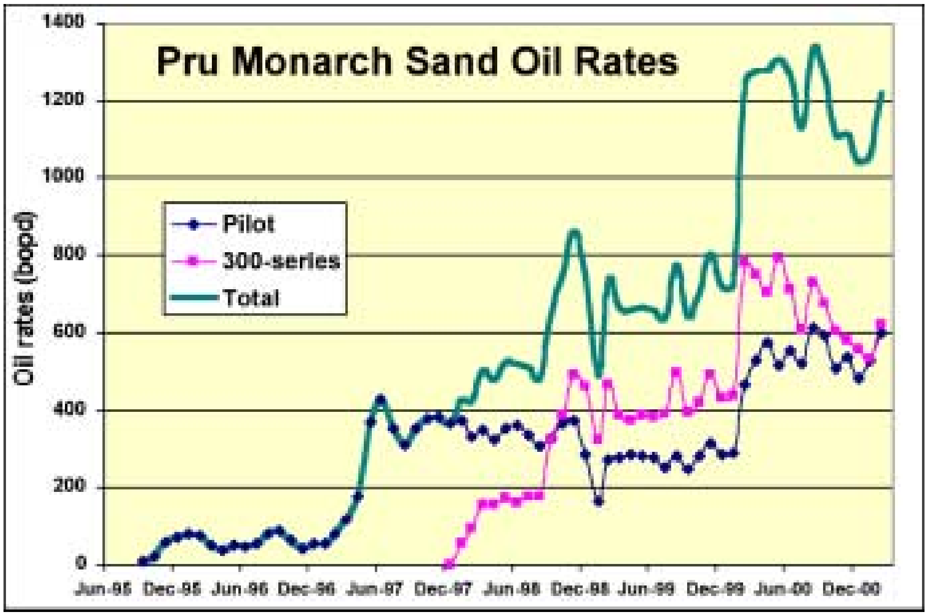

Figure 4: Growth of average daily oil rates (BOPD) for production from the Monarch Sand. Pilot steam flood production began early in 1997. The "300-series" wells were drilled and completed as cyclic producers in 1998. These same wells were put into steam flood production at the beginning of 2000. Since that time the average daily oil rate has ranged between 1,100 and 1,300 BOPD.

Additional evidence of recent thermal production activity is observed in several of the temperature observation (TO-n) wells. In the most extreme case, temperatures in excess of 300 °F were logged through an 80 ft interval in the TO-7 well within just weeks of being drilled adjacent to the Nevada lease in the north-central part of the property (Figure 2). The pre-steam ambient temperature in the pay interval of the Monarch Sand is in the range 90-110 °F. In general, the TO wells within the pilot and the southwest corner of the property were "cool" at the start of the project, just slightly warmer than the normal ambient reservoir temperature. However, the TO-5 and TO-7 wells record initially "hot" sectors of the reservoir.

Production Strategy and Performance

Reservoir simulations with geostatistically generated data sets revealed that the initial fluid distribution in the reservoir has the most significant impact on the economics of the steam flood process. The production strategy adopted in the steam flood pilot targeted steam injection to the upper third to one-half of the oil column, where the oil saturation (So) is greater than 50%, so as to avoid undue loss of heat to formation water. It was subsequently learned from examination of wells drilled for the "300-series" cyclic to steam flood conversion that the "initial" fluid distributions in the Monarch Sand are highly variable. Optimal production required a more flexible strategy for completion of the new injectors than that adopted for the pilot. As a consequence, the steam injection points were placed in top two-thirds of the pay interval. In retrospect, steam injection string may be too deep in several of these injectors. Prior to this project it was standard practice in AWE to inject steam into the deeper parts of the oil column. This was done with the expectation that the steam would quickly rise up to the top of the reservoir. It has been our experience that the steam stays rather close to the stratigraphic intervals in which it is injected.

As of the close of the project in March 2001, after 5 years of steam flood production of the four-pattern pilot and 4.5 years of cyclic/steam flood production of the surrounding 10 "300-series" patterns, the total cumulative production of oil from the Monarch Sand stands at 1,064,723 bbls. This represents 9.8% of the original oil in place, or 12.6% of the remaining oil at the start of this reactivation project. The cumulative oil production from the 8 acre four-pattern steam flood pilot alone has reached 562.4 Mbbls and the cumulative oil production from the "300-series" wells is 502.4 Mbbls (Table 1). The oil rates have increased steadily from zero to the range 1,100-1,300 BOPD during the past year (Figure 4). Including production from the Pliestocene Tulare sands, the tiny Pru Fee property has yielded more than 1.2 million barrels of oil since the project began at the end of 1995. Even without the addi-

Table 1: Summary of fluids produced and steam injected at the Pru Fee property since late 1995.

Pru Fee	Oil (bbls)	Steam-C	Steam-F	Water (bbls)	OSR	OWR
Pilot: cyclic	28,975	200,268		183,774	0.14	0.16
Pilot: flood	533,391	443,824	1,468,374	2,749,265	0.28	0.19
300-series: cyclic	195,241	774,867		890,578	0.25	0.22
300-series: flood	307,116	435,328	2,236,295	1,074,525	0.11	0.29
Tulare: cyclic	139,470	517,420		1,380,326	0.27	0.10
Totals =	1,204,193	2,371,707	3,704,669	6,278,468		

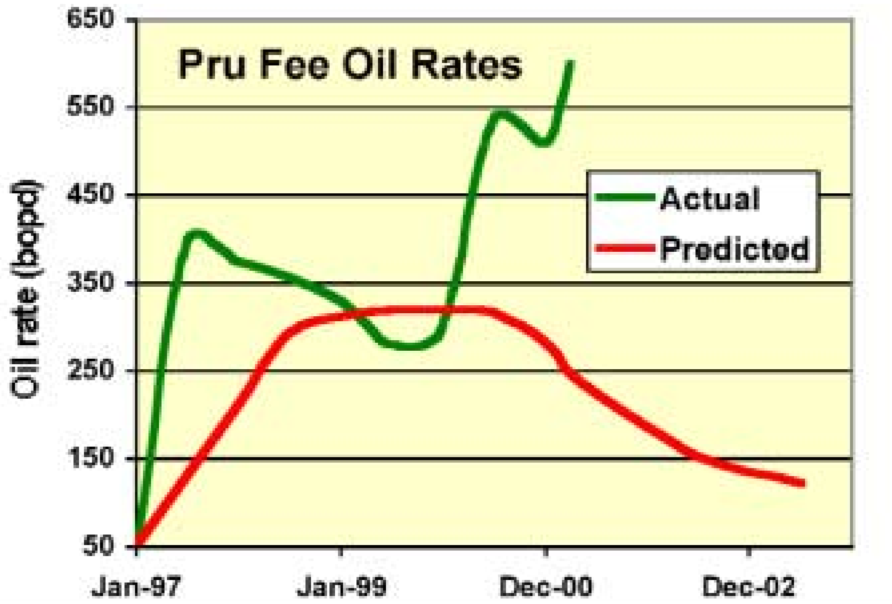

Figure 5: Actual versus predicted oil rates for the 8 acre, four pattern pilot. The time of predicted maximum oil rates has passed and yet the pilot is showing no indication that production is in decline.

tional oil from the "300-series" wells and the Tulare sands, production has exceeded initial predictions. Simulations of the pilot in 1996 had predicted a cumulative oil recovery by the end of 2000 of 409.5 Mbbls, whereas the actual production was 512.8 Mbbls, 25% greater than expected. The same simulations indicated peak oil rates in 1999 with the economic limit being reached in mid-2003 (Figure 5). The actual performance of the Monarch Sand in the four-pattern pilot has been considerably better. One surge in oil rate coincides with onset of steam flood in the pilot in early 1997 and another surge in early 2000 is tied to conversion of the "300-series" wells from cyclic to flood. As of the close of the project at the end of March, the average daily oil rate in the pilot was 600 bopd, and the economic limit was as yet nowhere in sight. There can be little doubt, however, that the exceptional production performance of the pilot has benefited from the intensive development of the remaining parts of the property.

The per-well oil rates vary widely across this 40-acre property, but on the whole they are substantially higher in the pilot patterns than in the "300-series" patterns. The average oil rate for the pilot wells is 31.2 ± 17.3 bopd (range = 2-62; median = 33.0) and for the "300-series" wells it is 17.6 ± 12.1 BOPD (range = 0-48; median = 16.5). This difference is readily observed on a map of contoured oil rates for the month of March 2001 (Figure 6). The principal reason that the pilot wells outperform those of the surrounding patterns is that the former are gravel packed, whereas the "300-series" wells were completed bare, without gravel pack. The single "300-series" well that was completed with gravel pack, the Pru-334 well which anchors the northwest corner of the pilot as a substitute for the non-performing Pru-B1 producer, has an oil rate of 56 BOPD. Additional contributing factors include the fact that many of the "300-series" patterns are in portions of the property depleted by prior or adjacent production activity and many of the injectors in the patterns are perfed a bit too deep resulting in less than optimal placement of heat. With the exception of the "pre-heated" northern and western patterns, many of the new steam flood patterns have not yet reached optimal temperatures, as evidenced by systematically low average flow line temperatures (FLT) in the east and south. Here the FLT is in the range 140-180° F in contrast to >200 °F common to the other patterns.

A significant and unanticipated aspect of the spatial variation in per-well oil rates is displayed in the contour map (Figure 6). The highest oil rates, those in excess of 35 BOPD, generally are from wells along the margin of the pilot patterns where since early 2000 they have been experiencing steam flood drive from all directions. In fact, in recent months even under-performing old recompleted producers, such as Pru-12 and Pru-D1, have become star performers with March 2001 rates of 62 and 39 BOPD, respectively. In large part, this additional stimulation of the pilot wells by aggressive steam injection in the adjacent "300-series" patterns is responsible for the surge in overall oil rates reported for the pilot (Figure 5). The oil rate increase for the pilot is expected to continue while the patterns on the east and south of the pilot warm sufficiently to contribute to the steam drive in these sectors.

Project Results

It is highly likely that without the incentives to ARCO Western Energy (AWE) to partner with the DOE Class Program in carrying out this oil technology demonstration, the Pru Fee property never would have been brought back into production. Based on historic performance and the existing geologic evaluation, it was known to be a highly marginal property. Yet, in just little more than five years since the initiation of project the total production from this 40 acre shut-in tract has gone from zero to over 1,200 BOPD. In addition, the two operators, AWE and Aera Energy LLC, have invested, without a DOE matching contribution, in a total of 54 new producers external to the steam flood pilot, 10 new injectors increasing the

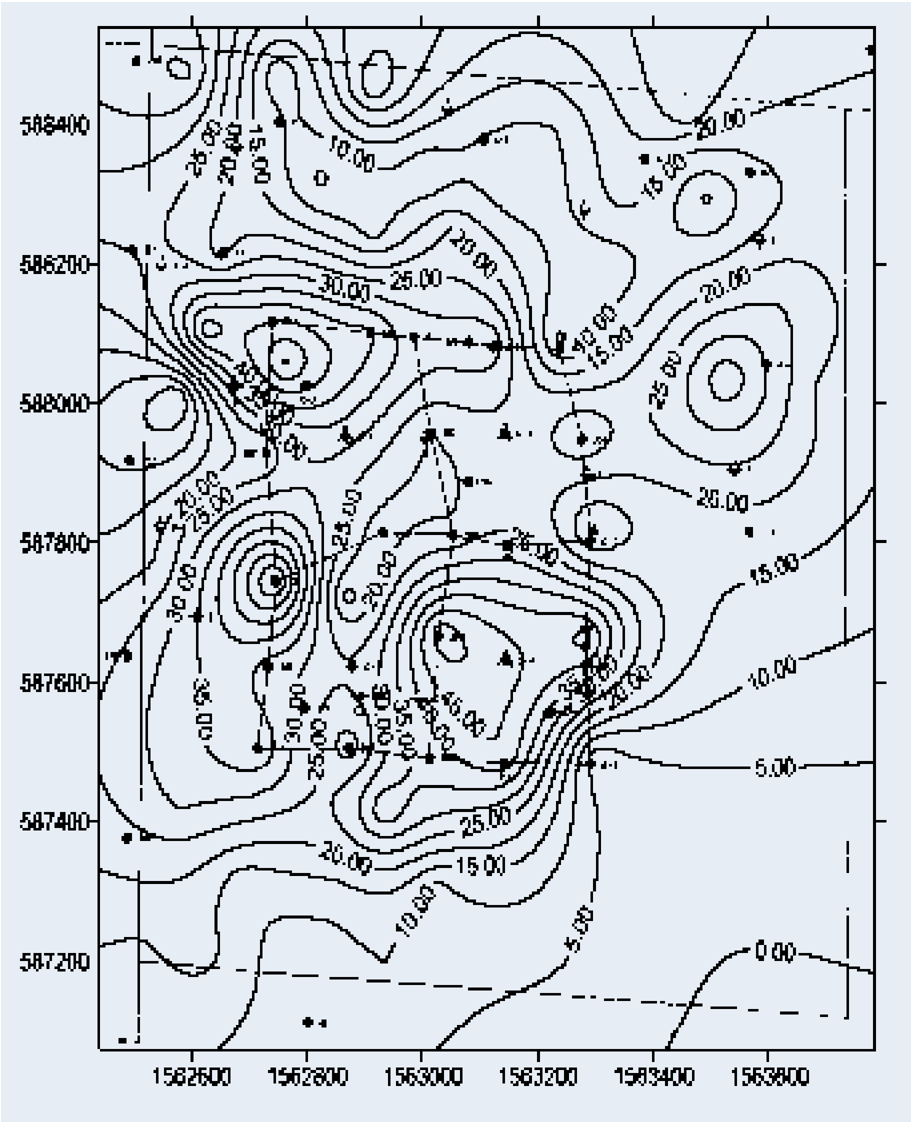

Figure 6: Contour map of per-well average daily oil rates (BOPD) for March 2001, the last month of record for this project. Note the especially high rates along the periphery of the four-pattern pilot. The map is based on data from 53 of the project producing wells; the other 5 producers were being cycled during the month.

number of steam flood patterns from 4 to 14, and three additional temperature observation wells. Total production from just the Monarch Sand reservoir at the Pre Fee property since the end of 1995 is in excess of one million barrels.

Aera Energy LLC, observing the manner in which the injectors in the Pru Fee pilot were completed, adopted the concept of a large stand-off from the OWC in injector workovers in the "low dip" portion of the Kendon lease immediately west of Pru Fee. The new perforations were placed in the uppermost one-third to one-half of the Monarch Sand, well above the OWC and the Sw transition zone, and deeper existing perforations sealed. It is reported that response from the injector workover using the recommended standoff from the OWC has been outstanding. Increases in oil rates in the renovated patterns average 25 BOPD per well with a total increase being over 900 BOPD. The OSR increased from 0.20 to 0.35 and the oil cut improved. In addition, Aera Energy LLC is now actively developing the Lilly property immediately south of Pru Fee. This was one of the 29 properties in the Midway-Sunset field that were shut-in at the start of this DOE-sponsored project. Over the past several months exceptionally high gas prices in California have forced many thermal recovery projects in the southern San Joaquin Basin to be shut-in, even in a period of near record high oil price. However at the time of this writing, Pru Fee, a property once shut-in as economically marginal, continues to operate.

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This project has benefited immeasurably from the many contributions of past and current project team members:

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- GeoGraphix: *GeoGraphix Explorer* and *Prizm* workstation modules
- Biecep Inc.: *Heresim* geostatistical modeling tools
- Computer Modeling Group Ltd.: *STARS* thermal reservoir simulator

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TCA

Cost-effective Technology for Independent Producers

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The 1,786 Mississippian reservoirs in Kansas are a major source of oil production with cumulative production exceeding 1 billion barrels. The majority of Mississippian production occurs at or near the top of the Mississippian just below a regional Pennsylvanian unconformity. A typical Kansas Mississippian reservoir, discovered during the 1960s, has a relatively thin reservoir interval (14 feet), and is located at a depth of just less than 4,000 feet. Today, small independent producers operate the majority of Kansas Mississippian production. The extremely high water cuts and low recovery factors place continued operations in Mississippian reservoirs at or near their economic limits.

Our independent producer does not have the extensive resources and ready access to a research lab to develop and test advanced technologies. Ninety percent of the 3,000 Kansas producers have less than 20 employees. For the Kansas oil and gas industry, access to new technology remains a critical component to sustained production and continued economic viability. A major emphasis of the Kansas Class II project was collaboration of University of Kansas scientists and engineers with Kansas independent producers and service companies. The goal was to develop and modify cost-effective new technologies and to accelerate adaptation and evaluation of technologies, which are appropriate to Mississippian reservoirs in Kansas.

This article focuses on technologies of reservoir characterization and simulation that were used to target and drill a horizontal well in a small Mississippian reservoir. The Kansas Class II project introduced a number of potentially useful technologies and demonstrated these technologies in actual oil field operations. Advanced technology was tailored specifically to the scale appropriate to the operations of Kansas producers. These approaches emphasize cost-effective technologies capable of dealing with the limited data characteristic of smaller and older Kansas reservoirs. One objective of the project was to use a combination of existing data and low-cost new data to rapidly characterize the reservoir, simulate the field with a PC-based (black-oil) reservoir simulator, and demonstrate the results through the drilling of a horizontal infill well. The characterization and simulation study was completed in less than 45 days and used only existing data. The results of the study were used to predict and optimize the performance of an infill horizontal well. Based on the results a horizontal well was drilled by the field operator **Mull Drilling Inc**. of Wichita Kansas.

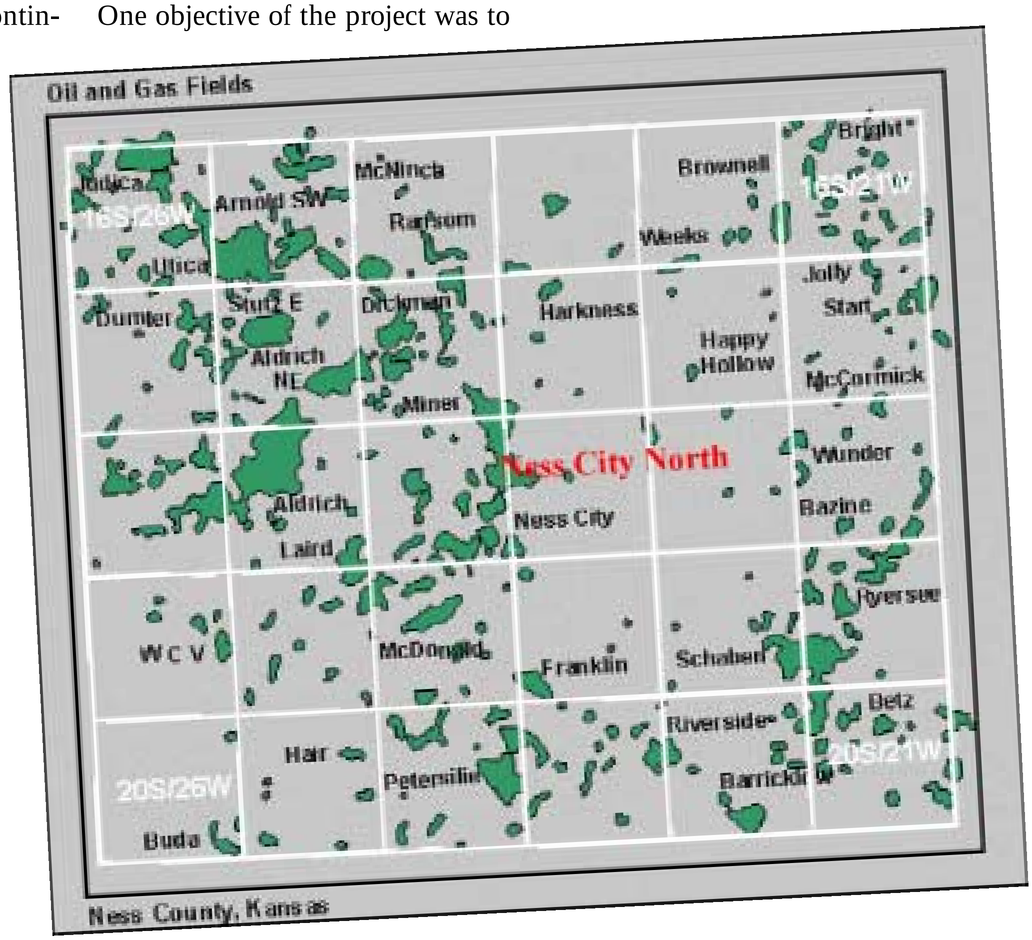


Figure 7 Map for Ness County, Kansas showing townships, producing oil fields and the location of the Ness City North Field (highlighted). The Ness City North Field is one of numerous Mississippian reservoirs in this county, and was the site selected for reservoir characterization, simulation and potential horizontal infill well.

Project Background

The field used in the demonstration project is Ness City North located in Ness County, Kansas (sections 23, 24 and 25 of T18S-R24W: Figure 7). Ness City North Field is a typical small Mississippian reservoir (i.e., buried positive erosional feature beneath the Pennsylvanian unconformity). The field was discovered in 1963 and a total of nine wells were drilled into the reservoir (Figure 8). Average production is approximately 3.25 BOPD from 6 wells (Data from Kansas Geological Survey; http://www.kgs.ukans.edu/PRS/County/nop/ness.html). Based on reservoir characterization, estimated recovery for the bottom water drive reservoir at Ness City North is estimated at less than 14% of original-oil-in-place. The focus of the reservoir simulation was evaluation of the field for an infill horizontal well to recover additional oil in place (Figure 8).

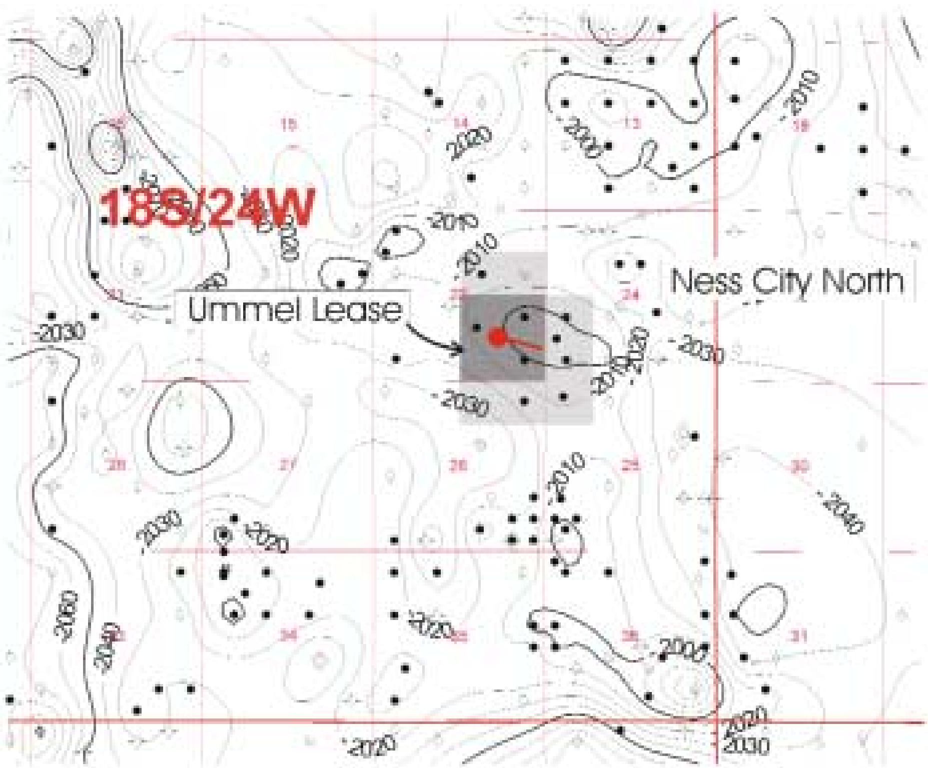


Figure 8: Structure map on top of Mississippian reservoir unit showing field outline, leases and wells in the Ness City North Field. The Ummel lease and Mull Ummel #4 well are highlighted. The Ummel #4 is completed, but is not producing. The Ummel #4 was evaluated as a candidate to reenter and drill a horizontal lateral toward the center of the field (possible well path is shown schematically). Numerous other Mississippian wells and reservoirs surround the immediate vicinity of the demonstration site.

Horizontal drilling has become a key technology to reduce costs and enhance recoveries from producing reservoirs.

In the United States, over 10,000 horizontal wells have been drilled. However, these wells are concentrated in only small number of plays (e.g., Austin Chalk of Texas and Red River of the Williston Basin). Through 2000, very few horizontal wells have been drilled in Kansas.

Reservoir Simulation

The field was simulated using a PC-based simulator (CMG-IMEX). The simulation exercise based on the reservoir geomodel developed from the limited available log, core, petrophysical, and production data. Oil and water production data were available for only three of the nine wells in the field. In the absence of recorded well production data, the oil and water production was estimated by using lease sales volumes of oil and production tests.

Using the only available porosity log in the study area (Mull Ummel #1-24), a simplified reservoir model was constructed using 5 layers with constant porosity and permeability values within the individual layer. Simulator output was tuned to match available production and pressure histories, at each well in the study area. Good matches were obtained in some wells, (Figure 9). The effectiveness of history matching for wells with limited water production records is difficult to evaluate. The simulation output was used in consultation with the field operator to locate a horizontal well in the reservoir model and the simulator was used to predict performance (Figure 10). The horizontal well is located on the boundary of drainage areas of two adjacent wells. Moving the position of the horizontal well simulated different scenarios. The well positions for the two scenarios are no more than 200 feet apart laterally. The simulation output summarized was based on an effective horizontal well length of 400 feet, a uniform skin of 4.5 across the producing length, and a P_{wf} of 675 psi.

In addition, the simulation identified a potential bypassed zone in a nearby well (Pfannenstiel A 2-24). Additional

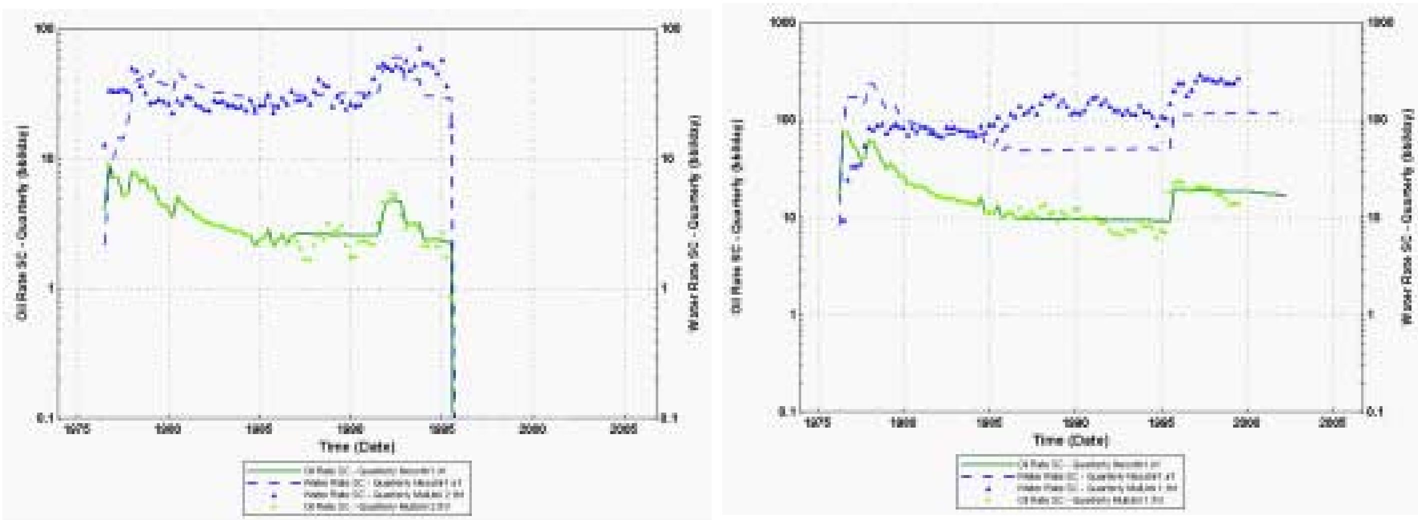


Figure 9a & b: Examples of history matches and performance predictions for wells in the Ness City North Field.

perfs were added, and production was increased from 2 BOPD and 20 BWPD (91% water) to 23 BOPD and 125 BWPD (84 percent water).

Horizontal Well Demonstration (The Good, The Bad and The Ugly)

The Mull Ummel #4-H horizontal well was drilled as a reentry to an abandoned vertical wellbore. The process involved drilling out the cement plugs and milling a window in the 5-1/2" casing. After setting a whipstock a 4-3/4" hole was drilled to the top of the Mississippian. The build rate of the curve section was 42.5° per 100' and the final lateral length within the Mississippian formation was 533 feet. A 3-1/2" liner was hung through the build section. The open hole was from 4400 to 4828 feet and was not stimulated (Figure 11). Based on the gamma ray log, shale intervals are evident along the lateral length of the well (Figure 12). These vertical shale intervals appear to be solution-enhanced fractures extending from the erosional surface at the top of the reservoir. The fractures are filled with shale from the overlying Pennsylvanian formation and probably form effective lateral barriers in the reservoir. The productive (clean) length is approximately 440 feet. Average fluid levels recorded in the well, over a period of one month, show an average bottom hole pressure (P_{wf}) of about 650 psi. The average monthly oil and water production rates recorded at the well are located on the lower boundary of both the simulated oil and water values. Average daily production rates for the first month was 54 barrels oil and 50 barrels of water. The observed production rates from the Mull Ummel #4-H horizontal well significantly exceed observed initial production

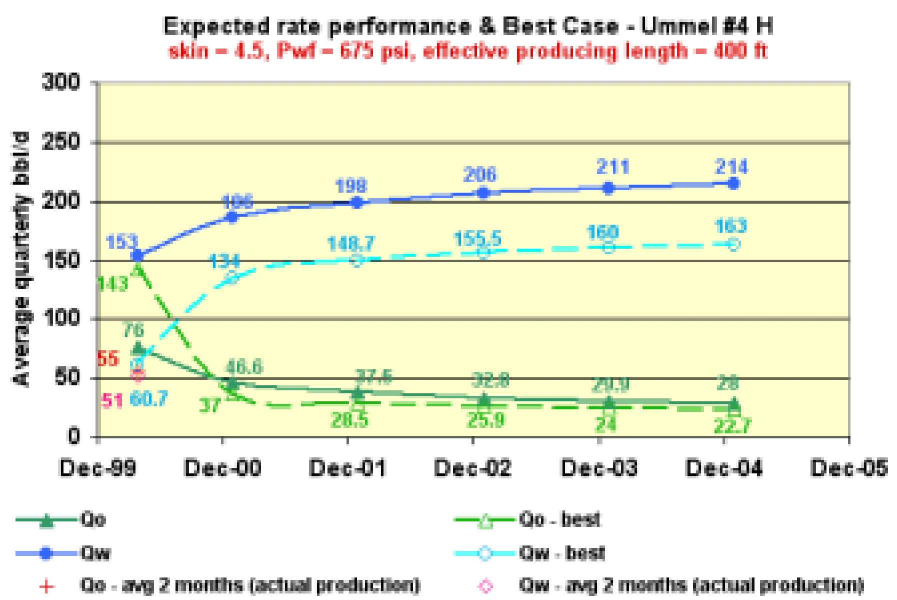


Figure10: Simulation output for Ummel #4H (horizontal well) showing production rates for oil and water. In the simulation study, the horizontal lateral is 400 feet with an uniform skin of 4.5 and the well produces under a bottom hole flowing pressure of 675 psi. Fluid production rates are plotted for the expected (Qo, Qw) and the best-case (Qo-best, Qw-best) scenarios. Oil and water production from the well, averaged over the 1st 2-months, is also plotted for comparison with the performance predicted from the simulation study. The actual average oil production is close to that predicted while the average water production recorded at the well has been less than that predicted by the simulation study.

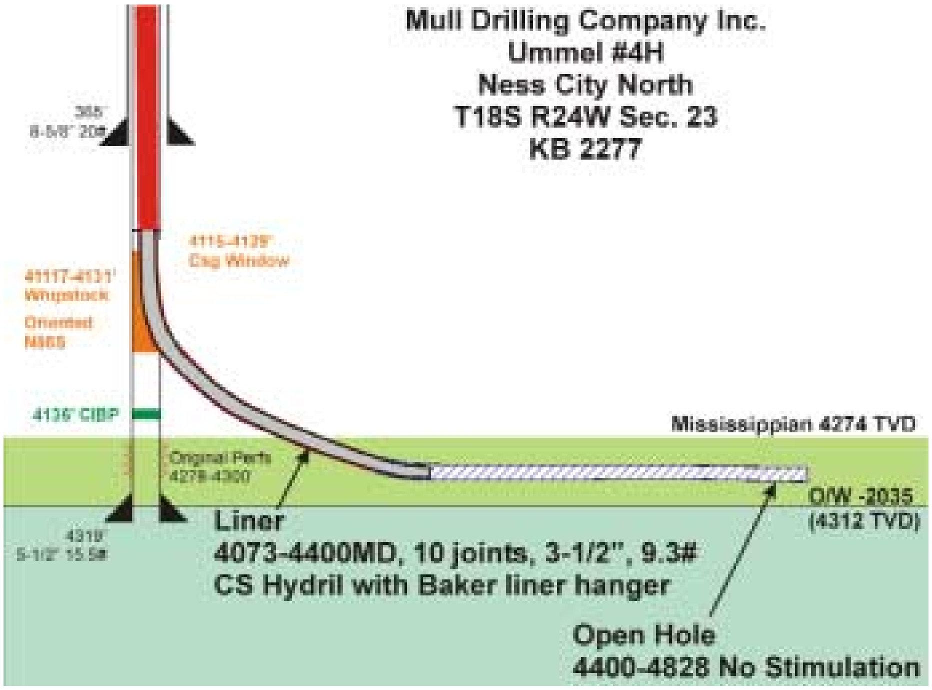


Figure 11 Mechanical plan for the Mull Ummel #4H horizontal reentry showing the milled casing window in the original vertical well the build section, and the open hole lateral section.

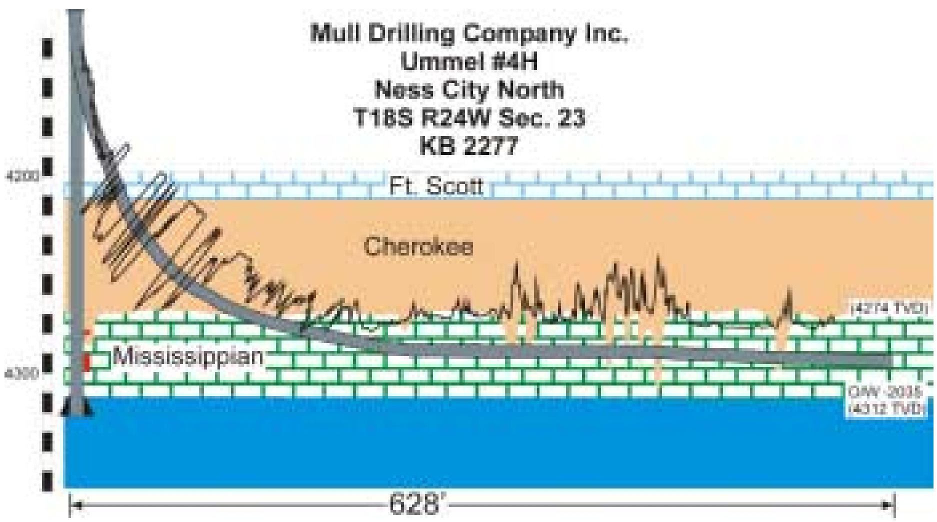


Figure 12 Interpreted reservoir geology for the Mull Ummel #4H horizontal reentry showing the gamma-ray measured-while-drilling log. Based on cuttings and gamma-ray values, the vertical shale zones are interpreted as shale-filled solution enhanced fractures. The shale-filled fractures provide vertical barriers with the reservoir and probably contribute to the poor recovery efficiency. Also, fractures are the areas where blockage was encountered in the lateral section.

rates for previous vertical infill wells in the Ness City North Field. Based on post-well simulation, estimated ultimate recovery over ten years should have exceeded 100,000 barrels of oil. The improvement in estimated ultimate recovery is very significant as compared to the typical vertical infill in Mississippian reservoirs of Kansas.

After nearly 45 days of steady production averaging over 50 barrels of oil and less than a 50 percent water cut, production suddenly deceased to near zero amounts of fluid (water and oil). The probable cause was assumed to be caving within the shale filled fractures within the open hole of the horizontal section. An attempted coiled tubing workover confirmed numerous blockages coincident with the vertical shale intervals. The workover attempted to clean out and stabilize the horizontal portion of the well bore, so that 2-3/8 inch slotted liner could be run in the horizontal hole. The workover was unsuccessful and the well remains a low fluid rate well. Lessons learned include; drilling a new vertical well in order to maintain the operational flexibility provided by a larger wellbore, the need to case the curve in order to drill the lateral under balanced, and the need in the Mississippian reservoirs of Kansas for a liner in the horizontal lateral. Additional reports and presentation material including graphics on the horizontal well and workover are available on the Class II homepage at http://www.kgs.ukans.edu/Class2/index.html.

Summary

The technologies used have been adapted to be cost-effective for independent operators in mature fields with a focus on the Mississippian reservoirs of Kansas. Technologies not discussed in this article include petrophysical analysis (PfEFFER), visualization (Pseudoseismic), and core analysis using NMR. In general, the horizontal well at the Ness City North Field supported the reservoir characterization and simulation. Failure to understand the significance of the shale-filled solution enhanced fractures and mechanical problems resulted in an uneconomic horizontal well. A horizontal well still remains a potential method to increase recovery in the mature Mississippian reservoirs of Kansas. Incorporating the lessons learned from the Class II Project, another horizontal well is planned for later this year. **TCA**

Slowing America's Oil Decline

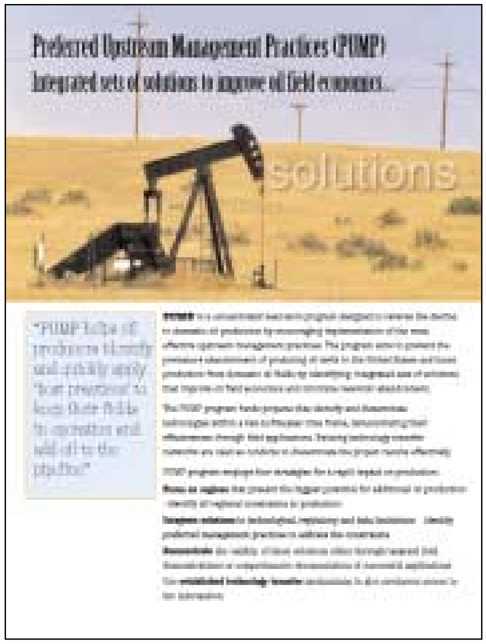
America's best chance for slowing the decline of its domestic oil fields will likely be a combination of *"best practices"* – improved technologies, better data, streamlined regulations, etc.– applied by the thousands of small producers that now make up the core of the nation's oil industry.

The U.S. Department of Energy took a key first step in a concentrated, 5-year effort to identify and disseminate *"best practices."* The department's National Petroleum Technology Office selected the first six projects in its **PUMP** program – a new oil technology demonstrations and technology transfer initiative that stands for **Preferred Upstream Management Practices**. Run as a national competition, **PUMP** will share the costs of industry-proposed projects that identify technologies that can be deployed rapidly and inexpensively to endangered U.S. oil fields. As the improved techniques are put to use, results will be widely reported to other domestic producers.

The goal is to show how an integrated set of solutions can improve oil field economics, prolong the productive life of many of the nation's marginal reservoirs, and slow the rate of well abandonments in the United States.

The selected projects are:

Gas Technology Institute (GTI), Chicago, IL, will develop computer-assisted practices for optimizing oil field operations based on neural networks, genetic algorithms, and "fuzzy" logic. This approach, originally used to successfully develop gas projects, will be adapted by GTI to oil research.



GTI researchers teaming with specialists from West Virginia University, Intelligent Solutions Inc., and TechnoMatrix Inc will develop a Virtual Intelligence Technique that will enable operators to optimize current practices. The goal of the project is to increase oil production by an average of 15% over a period of five years at a cost that will be equal to or lower than that of common practices. The reduction in production cost will be achieved by producing oil that is not currently commercial to produce.

The Virtual Intelligence Technique will be developed in Oklahoma, working in cooperation with Oklahoma producers, and will be demonstrated in two field projects. Results from the tests will be compared against common practice baselines provided by participating industry members. Oklahoma currently produces 181,000 barrels of oil per day. The projected increase in Oklahoma is more than 27,000 barrels per day.

The primary intended users of the "intelligence engine" are independent petroleum producers, and the software packages are designed so that the inner workings will be transparent to the user and will not require special training to apply them to the operations of the oil field. GTI will make project results publicly available on the Internet and in written and electronic reports, and will also provide extensive technology transfer through publications, workshops, and presentations at technical meetings.

The Department of Energy will provide $577,000, and GTI will contribute $620,000 in cost sharing for the 24-month effort. The project technical contact is Brian Gahan at 773-399-5481.

The **Texas Engineering Experiment Station**, at Texas A&M, College Station, TX will apply preferred practices for improving the effectiveness of injecting water to increase crude oil production from the Texas Spraberry Trend, a giant half-million acre oil-bearing formation in Midland, Martin and surrounding counties in West Texas.

The Texas A&M researchers will work with a team from Pioneer Natural Resources to significantly and quickly increase field-wide production in the Spraberry Trend by application of preferred practices for managing and optimizing water injection. The economic benefit of waterflooding in this naturally fractured unit has been the subject of speculation for nearly five decades. The project goal is to dispel negative attitudes and lack of confidence in water injection and document the methodology and results for public dissemination to motivate waterflood expansion in the Spraberry Trend. A secondary objective is the purification and injection of produced waters to minimize downhole casing failure caused by corrosive waters from the San Andres formation.

The project will begin with gathering data from the Shackleford Unit. Tracer tests will be run on four injection patterns, two with new wells and two with conversion wells, and the water movement simulated to update and refine pattern alignment and help determine the well density required for maximum waterflood sweep efficiency. After initiation of water injection, oil, water and gas production will be carefully monitored in wells along the perimeter of the area expected to respond.

Results from the project will be transferred to industry at a workshop in Midland, TX, which is targeted for 150 operators of Spraberry wells. A website containing the details of the preferred management practices will be developed. The Department of Energy will provide $500,000 to the 24-month project, and Texas A&M will contribute $1.5 million in cost sharing. The project technical contact is David Schechter at 979-845-2275.

The **Texas Engineering Experiment Station**, at Texas A&M, College Station, TX will develop and demonstrate a new practice for increasing oil production by deliberately producing sand from a reservoir, creating an underground cavity around the wellbore that allows oil to flow more easily from the surrounding formation.

Texas A&M with the **Global Petroleum Research Institute** will demonstrate a new oil production technique for wells completed in weak sands - deliberate production of sand from a reservoir, forming a cavity-like completion zone. The technique will be demonstrated in the Long Beach Unit of the Wilmington Field in Long Beach, CA. The technology is incorporated into a unified model of cavity-like completion that can be used to design other advanced completions in the Wilmington Field, where the technology may recover an additional 4.7 million barrels of oil. The process is applicable onshore and offshore reservoirs in California and in other regions of the U.S.

This project offers new reservoir operating practices for the exploitation of unconsolidated or poorly consolidated reservoirs, and has the potential to be a "new-generation" stimulation methodology. It also has relevance to other technically driven business issues, including mitigating/controlling/exploiting sand production, increasing injectivity for produced water reinjection, and underbalanced drilling/perforating applications.

The Long Beach Unit operator, THUMS, and the program sponsors (BP, Phillips, Schlumberger, Texaco and TotalFina Elf) will contribute $130,000 (70% cash, 30% in kind services) to the 12-month project, and the Department of Energy will provide $130,000. The project technical contact is D. Burnett at 970-845-2274.

The **University of Kansas Center for Research, Inc.**, Lawrence, KS, will demonstrate several techniques for modeling an oil reservoir in a Central Kansas oil field. Using the information, the university and its partners will then drill horizontal wells (a technique called "horizontal infill drilling") to recover oil that traditional vertical wells may have missed.

The **University of Kansas**, the **Tertiary Oil Recovery Project**, the **Kansas Geological Survey**, **Mull Drilling Company, Inc.**, and **Maurer Engineering, Inc.**, will combine integrated reservoir modeling with horizontal infill drilling to increase production efficiency in Central Kansas Mississippian carbonate reservoirs. These reservoirs currently provide nearly 43% of Kansas annual production, but they are generally operated by small independents with limited resources for research and development. Low average recovery factors of 13 to 15% result in high abandonment rates, threatening a potential five-billion barrel loss of reserves.

Studies have shown that fractured and compartmentalized reservoirs with limited drainage radius for vertical wells and high water cuts are suitable for horizontal drilling. This project will demonstrate preferred management practices by drilling a horizontal infill well in a Mississippian reservoir. Emphasis will be on the use of inexpensive screening of recovery assets, integrated characterization of sites, fracture modeling from core and log data, PC-based modeling and simulation, and post-drilling monitoring to optimize horizontal well production. The goal is to develop a learning curve and build confidence among independent operators of the mid-continent to use cost-effective horizontal infill applications and modeling techniques in these mature reservoirs. The technologies will be transferred to operators through Internet access, publications, workshops, presentations at technical meetings, and one-on-one meetings with operators.

The Department of Energy will provide $406,000 for the 24-month project, with cost sharing of $407,000 from the University of Kansas. The project technical contact is Saibal Bhattacharya at 785-864-2058.

The **Petroleum Technology Transfer Council**, Houston, TX, will organize a team of mentors to work with regional producers in Oklahoma and California to identify and transfer preferred practices that can increase oil production, slow or reverse production declines, and extend the life of marginal wells through workshops, publications and an interactive Internet web site. The PTTC Regional Lead Organizations, the South Midcontinent RLO in Norman, OK, and the West Coast RLO in Los Angeles, CA encompass areas with significant oil resources where production is constrained.

The PTTC team will refine understanding of production constraints, search globally for integrated solutions that can serve as preferred management practices and guide small producers on cost-reduction measures for implementing the solutions. Well-known mentors, respected in their regions, will network with industry companies, associations and regulatory groups to identify and prioritize constraints. The mentors and topical working groups will review the options, with the producers determining the solutions that best fit.

PTTC estimates that applying the identified preferred management practices could increase oil production by as much as 100,000 barrels of oil per day in the target areas.

Results will be relayed to independents through personal contact, one-on-one or small group meetings, workshops, newsletters, and the Internet with an interactive information system at the two RLO websites. The system will allow producers to search not only the PTTC archives but also the global Internet.

The Energy Department will provide $500,000 for the 24-month project, and the PTTC will contribute $504,000 in cost sharing. The project technical contact is Donald Duttlinger at 713-688 -0900.

West Virginia University Research Corporation, Morgantown, WV, will organize a regional council to identify and communicate to operators preferred practices through workshops, contacts with engineers and geologists, publications and an interactive Internet web site. West Virginia University Research Corporation under the sponsorship of the **Appalachian Oil and Natural Gas Research Consortium (AONGRC)**, the **West Virginia Geological and Economic Survey** and the **Petroleum and Natural Gas Engineering Department** at the **West Virginia University** will pursue three objectives:

(1) Preferred management practices currently in use in the region, or that can be transferred from other regions, will be identified through workshops, interviews with engineers and geologists, and a literature search.

(2) An Appalachian Region Preferred Management Practices Council will be created to provide information directly on problems faced by industry within the region. The Council will include members of the Petroleum Technology Transfer Council's Appalachian Regional Producer Advisory Group, other oil industry representatives, and state geologists on the AONGRC Advisory Board.

(3) An interactive PTTC web site will list preferred management practices for the region, and relevant information on the oil reservoirs in the Appalachian region.

The Department of Energy will provide $362,000 to the 24-month project, and the West Virginia University Research Corporation will contribute $362,000 in cost sharing. The project technical contact is Douglas G. Patchen at 304-293-2867 ext 5443. For information about the PUMP program: Rhonda Lindsey, e-mail: **Rhonda.Lindsey@npto.doe.gov** or 918-699-2037. TCA

The Class Act

The Department of Energy's National Petroleum Technology Office is proud to bring you information on field demonstrations that benefit domestic producers.

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Contributing to *The Class Act*
If you have a news item or project to feature in an upcoming issue of *The Class Act*, please contact the editor.

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History of DOE's Field Demonstrations

In the Fall of 2000 DOE asked the National Petroleum Technology Office to prepare a summary of twenty-two years of progress in the oil program's field demonstration projects. This information was part of a summary effort by the National Research Council. Highlights of the field demonstration summary of success follow and will continue to be highlighted in future issues of *The Class Act*.

From 1978 to 1985 twenty-six field demonstration projects were operated as part of the oil program by the Bartlesville Project Office at NIPER concentrating in three main areas: Chemical flooding, Carbon dioxide and Thermal/ heavy oil recovery. Emphasis of the program was to take processes and technologies that had been developed and tested in the laboratory to the field and demonstrate the viability of these technologies under actual reservoir conditions. The black and white well site photo above was part of an EOR field demonstration in Kansas in 1978.

The most significant conclusion of these early field demonstrations was that reservoir characterization was an essential part of any successful field demonstration. Technologies that work in one field or type of reservoir may fail completely in other field situations. The Reservoir Characterization group was developed in Bartlesville in the mid 1980s to improve methodologies for reservoir characterization research. The lab photo below shows the core lab and gamma ray scintillometer.

Chemical flood experiments and demonstrations indicated that micellar polymers were not cost effective during the period (1978-1985). The amounts of expensive micellar-polymer necessary to produce oil in the field greatly exceeded the laboratory estimates of the quantities of micellar polymer to be injected.

CO_2 projects made significant contributions in understanding immiscible application of carbon dioxide flooding technology. DOE's funding of CO_2 research from 1978 to 1985 defined the necessary criteria for future successful CO_2 flood projects in the United States.

Early development of thermal recovery projects sponsored by DOE led to the U. S. becoming the world leader in heavy oil recovery in the late 1970s and early 1980s. Steamflooding has proven to be the dominant EOR process in the United States. DOE's support of a project in the Midway-Sunset field beginning in 1976 provided a major stimulus for commercial steam flooding in California.

The EOR field demonstrations were responsible for the software development of various simulators to assist the industry in predicting performance of secondary or tertiary recovery projects. Modifications of the DOE's BOAST simulator for 3-dimensional, 3-phase black oil simulation are in wide industry use including BOAST 3 and 4, BOAST-VHS and MASTER.

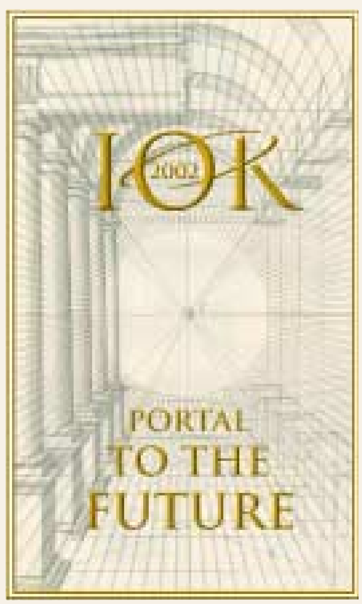
Field demonstrations of the 1990s and beyond incorporated the important lessons learned regarding the absolute need for reservoir characterization when implementing a new process. It also changed the focus to producing oil that would be abandoned in the ground without the impetus of DOE funding and new technologies. Preservation of the national petroleum resource was the main goal of the Reservoir Class Program, and the Demonstration Program with Independents. The nitrogen flood field demonstration by Binger Operations below is part of the ongoing Class Revisit program. **TCA**

FREE CD

An overview of DOE's Reservoir Class I projects is now available on CD-ROM. The CD offers the final reports of the field demonstration projects that were funded in the Class I program.

To order your free copy, contact Oletha Thompson at 918/699-2034 or email: Oletha.Thompson@npto.doe.gov or return the enclosed card.

SPE/DOE THIRTEENTH SYMPOSIUM ON IMPROVED OIL RECOVERY



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CALENDAR

Meetings and Announcements

June 3-6 AAPG Annual Meeting, Denver, CO

June 17-20 Professional Well Log Analysts (SPWLA) 42nd Annual Symposium, Houston, TX

July 15-18 AAPG Regional International Meeting St., Petersburg, Russia

September 9-14 SEG Annual Meeting, San Antonio, TX

September 22-25 AAPG Eastern Section Meeting, Kalamazoo, MI

October 1-4 SPE Annual Meeting, New Orleans, LA

October 17-19 AAPG Gulf Coast Section, Shreveport, LA