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Increased Production Results From Pilot Horizontal Waterflood in Osage County, Oklahoma

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Abstract

This paper details the results of a three-year project to test horizontal waterflooding as a means of improving oil recovery from the Bartlesville sandstone in an abandoned 100-year-old oil field in Osage County, Oklahoma. Supported by a grant from the Department of Energy (DOE), this work was conducted by Grand Resources, Inc., an independent operator in Tulsa, Oklahoma. The project was initiated based on the concept of using three parallel horizontal wells (an injector straddled by two producers) in a heel-to-toe configuration. The pilot test evolved into an oil rim recovery project with pressure support coming from a vertical injection well, due to reservoir heterogeneities and lower-than-expected oil saturations.

Key technical aspects are discussed, including reservoir screening and the selection process; substantiating the primary and secondary production history; interpreting the depositional environment, including natural fracture orientation and a wellbore stability evaluation. Reservoir characterization is initially based on vertical logs and is modified when horizontal openhole logs become available. Characterization provides the details necessary for the reservoir simulation used to predict oil recovery and assess the economic viability. The simulation process is ongoing and updated as additional data is acquired.

Once waterflooding operations have begun, the technologies and methods employed to evaluate, manage and adjust both injection and production performance include:

- Evaluating production results.
- Conducting step rate and injection profile tests in the horizontal injection well.
- Running a full suite of open hole logs through the short radius curve, including an acoustic borehole

televiewer, to determine fracture frequency and orientation.

- Adjusting injection water volume to assist in reducing operating expenses yet maintain adequate reservoir pressure support for high fluid withdrawal rates.
- Re-drilling the horizontal producing wells closer to the top of the reservoir to significantly increase the oil cut.

The short radius drilling system is explained, in addition to the drilling of the lateral wellbores.

Oil recovery from the originally designed pilot was disappointing due to the unexpectedly high water saturations that were encountered. However, results from the modified pilot are much more encouraging, with 15 to 20 BOPD being produced from a thin oil column overlaying water.

Introduction

This paper is an update of SPE 89373 "Enhanced Oil Recovery with Horizontal Waterflooding, Osage County, Oklahoma" by Westermark, *et al.*¹, published in 2004, which discussed a DOE supported field test using parallel horizontal water injection and production wells to improve oil recovery. Horizontal waterflooding, and specifically horizontal injection wells, have been the subject of numerous studies and technical papers in recent years.^{2–6} Joshi, in a follow up to his 1991 book⁷, investigated and summarized the current applications of horizontal technology in 2003.⁸

This paper emphasizes the lessons learned in the process of conducting the project and the adjustments made to further enhance oil recovery.

Background

Reservoir Candidate Screening

Prior to choosing a location for the horizontal waterflooding pilot, numerous aspects are examined to enhance the likelihood of having a successful project. Screening the candidates is a relatively quick process which involves the following:

- Determine the cumulative oil production (primary and secondary).
- Calculate the expected remaining recoverable reserves.
- Characterize the reservoir (single layer or stratified).
- Estimate the number and cost of vertical and/or horizontal wells needed to produce the estimated reserves, assuming openhole completions.
- Evaluate the remaining infrastructure for return to service.

If the property appears to have sufficient reserves to justify the estimated expenditures to produce an acceptable return on investment, it passes the screening process and moves forward to the selection process.

Data Acquisition for Initial Reservoir Simulations

The selection process involves:

- Performing an in-depth review of the geology.
- Summarizing the operating history, including the location and number of existing wells and dry holes, drilling/completion dates and practices, and the plug and abandonment records.
- Evaluating available logs, core reports and engineering reports (including past waterflood activities on subject acreage or in offset leases).
- Evaluating wellbore stability.

This information provides a detailed reservoir characteristics description, necessary to perform reservoir simulations. Reservoir simulation results determine the expected producing rates and recovery factors.

Based on simulation results, the following questions can be answered. Does the reservoir have:

- Sufficient remaining oil saturation, which allows for oil to be mobilized? Oil saturation based on log values should be greater than 40% with a mobile oil saturation of at least 15% pore volume.
- Some vertical permeability, to allow injected fluids to be distributed through the entire interval?
- Sufficient permeability (>10md), to permit large volumes of water to be injected at low pressures through a horizontal lateral?

If the pilot area has an attractive economic prognosis based on the initial reservoir simulations, the project will move forward.

Initial Pilot Selected

Satisfying the above criteria, the initial pilot test site chosen was in the Woolaroc Field, located in T25N-R11E, Osage County, Oklahoma and shown in **Figure 1**. A vertical well was drilled in this field and logs and cores were collected to further evaluate the reservoir characteristics at the proposed test site. The intent was to plug back and drill a horizontal well in the desired orientation. Unfortunately, the rock was tighter than anticipated, with an average permeability of only 1 md rather than the expected 20 md. Simulation studies were

redone with the core analysis and log values indicating that a horizontal waterflood would increase recovery over conventional waterflooding, but the economics would not be attractive due to low injectivity and productivity. This was a critical decision point in the project. It was decided that another test area needed to be selected. Although the original pilot site proved to be unsuitable, it did illustrate two points:

- The value of having decision points built into the project to minimize unnecessary expenditures.
- Management's confidence in the methodology used to determine a pilot project's applicability.

Second Pilot Selected

The next pilot location selected was the Blake lease in the NE/4 of Section 25-T24N-R11E, part of the old Wolco field, as seen in Figures 1 and 2. This test area was considered suitable based upon well logs from Blake 1A, drilled in 1979, and Blake 2A and 3A, both drilled in 1985. These logs indicated a thick vertically continuous sand of approximately 80 ft with oil saturations greater than 40% at the top, decreasing with depth. Porosities were typically in the range of 16 to 18% at the top, grading to approximately 20% toward the bottom. This formation is known locally as the "C" zone of the Bartlesville reservoir. A porosity-permeability relationship was determined using nearby core analysis, which ranged from 15 to 50 md for these porosity values. A water supply well was available in an adjacent quarter section. Fortunately, in the Blake 1A well, there existed a "D" zone in the Bartlesville. This zone had a porosity of approximately 28% and an estimated permeability of 600 md, therefore, the Blake 1A was selected to be the produced water disposal well. The pilot area was positioned in a part of the reservoir with only the "C" zone present. The horizontal injector would be located in the southwest corner of the quarter section with the two horizontal producers parallel and heel-to-toe with the injector. This is similar to the Toe-To-Heel Waterflooding described by Turta⁹ and Zhao¹⁰.

Historical Relevance of Previous and Adjacent Waterflooding

The old Wolco field had never been waterflooded, but it was adjacent to previous waterfloods in and around the North Avant Unit (NAU).

The NAU was formed in 1937 with Shell Oil Co. as the operator. They began pressure maintenance operations in the quarter sections adjacent to the south and east of the selected pilot area, using a combination of pulling vacuum on the casing heads and injecting gas into gas injection wells (known as key wells) located throughout the field. In the 1960s, Shell investigated the possibilities of waterflooding the NAU by drilling and coring 15 test holes in the 4480 acre unit. They concluded that waterflooding would probably not be successful and sold the field.

In the quarter section to the west, the Ohio Oil Co. also pulled vacuum on the producing well's annulus and used that gas for pressure support successfully. They later attempted to waterflood the NW/4 of Section 25 with only 10,000 bbl of oil produced after injecting over 2,000,000 bbl of water. Water injection pressures were higher than designed and injection rates below the design volume. The water cut increased to 95% very early in the project. Soon afterwards the property exchanged hands numerous times. This attempt at conventional waterflooding in shallow, low permeability reservoirs, typical of the Bartlesville sandstone, was not successful because of the inability to establish adequate injectivity below the fracture parting pressure. To obtain adequate injection volumes, the fracture parting pressure is often exceeded, resulting in the channeling of the injection water and the bypassing of reserves.

A NAU waterflood began in 1983 when a new operator, Premiere Operating Co., drilled and/or recompleted over 120 wells. Six wells were converted to water injection immediately south of the former Ohio Oil Co. lease. Over the next five years these wells had nearly 700,000 bbl of water injected into them. During that period, there was zero reported injection into the NW/4 Section 25, but the production jumped from less than 3 BOPD in the remaining three unplugged wells up to 30 BOPD. The operator at the time was encouraged to drill four more producing wells over the next six years, however the production quickly declined after the waterflood activities to the south were terminated. The operators of this quarter section benefited by nearly 100,000 bbl of oil, due to the waterflood activities to the south.

Immediately to the south of the selected pilot area, four old producers were converted to water injection wells. During the life of the waterflood, these four wells had nearly 800,000 bbl of water injected. Immediately south of these injectors was a row of producing wells followed by another row of injection wells. For these three rows of wells, the volume of water injection totaled more than 1,250,000 bbl with a total withdrawal from the producers of only 320,000 bbl. Over 97.5% of this production was water, meaning only 8,000 bbl of oil were recovered. Interestingly, a large volume of injected water remains unaccounted for in this area. The poor oil/injection ratio and the drop in the price of oil, led to the waterflood being shut down and the lease changing hands a number of times.

It should be noted that the proposed pilot area quarter section's production history did not have an appreciable response to the 1983 NAU waterflood, as the lease to the west did. But the operator at the time was encouraged by his neighbor's oil production and drilled the Blake 2A and 3A wells in 1985 to capture any response that might travel across the lease lines. The Blake lease produced a total of less than 10,000 bbl over the next five years.

The operators of the quarter sections to the north of the Wolco field did not conduct any pressure maintenance operations.

Thus, for the DOE project parameters, the NE/4 of Section 25 met the selection criteria of an acceptable pilot test area being near or adjacent to a waterflood but not having been waterflooded.

Geologic Interpretations Depositional Environment

The Bartlesville formation has been the subject of numerous investigative reports done by Federal and State government agencies, graduate students at universities and technical papers released by operating and service companies. In the 1990s the Oklahoma Geological Survey (OGS), with support from the DOE, contracted studies and reports for the Fluvial-Dominated Deltaic (FDD) Oil Reservoirs project.¹¹ "Reservoir the DOE sponsored the Additionally, Characterization of Pennsylvanian Sandstone Reservoirs" project at the University of Tulsa.¹² The sequence stratification of the Bartlesville sandstone was further discussed by Ye in an American Association of Petroleum Geologists' article in 2000.¹³ This most recent study characterizes the Bartlesville sandstone as "mainly a fluvial incised valley fill deposited in a transgressive manner from a low braided fluvial to an upper tidal-influenced meandering fluvial deposition system". Most of the deposition within the NAU Bartlesville occurred in a transgressive system tract (TST), dominated by meandering fluvial deposits and crevasse splay deposits. The porosity and permeability tend to be low in the TST and reservoirs producing from these deposits tend to have low productivity and recovery. Other portions of the Bartlesville were deposited in a lowstand system tract (LST), dominated by high-energy braided fluvial deposits. Areas that produce from LST deposits tend to have higher porosity, higher permeability, higher productivity and better oil recovery. The locally used terms for the different zones within the Bartlesville are the "C" zone for the TST sands with porosity in the 15 to 20% range and the high-energy or "D" zone for the LST environment that has the porosity of greater than 20%.

Figure 3 illustrates the Bartlesville stratification with the density log from Blake 1A.

Natural Fracture Identification and Orientation

Guo and Carroll¹⁴, with the support of a DOE grant, studied and mapped the surface fracture pattern in northeast Oklahoma, covering the entire Osage County area. The fault, fracture, and lineament recognition was done using satellite imagery. Guo's report closely follows work done in the early 1900s by the United States Geologic Survey and OGS and subsequent surface geologic surveys of the area. The predominant direction of the main fractures is N35E. It should be noted that this is a general azimuthal heading. Local fracture orientation may change, however, particularly when there is a significant anticlinal structure present. In these cases, primary fractures on the surfaces have been seen to rotate around the nose of the anticline. The Wolco field is on a gently dipping terrace. Surface investigations of fracture patterns along creeks with flat rock bottoms and other undisturbed large rock plates in the vicinity of the pilot area show consistent orientation of the major fractures to be N35E. Figure 4 presents the existence and orientation of surface lineaments in the vicinity of the pilot. The determination of subsurface fracture orientation was based on the assumption that fractures at depth are parallel to fractures found at the surface.

Rock Mechanics

Wellbore stability is a major consideration in the well planning process when deciding how to complete the horizontal wells. An openhole completion in the lateral portion of the wells would result in a less complex, less expensive completion and was desirable. As part of the DOE project team, Dr. Leonid Germanovich, Georgia Institute of Technology, reviewed the core from the Woolaroc well and cores from the adjacent NAU wells. His rock mechanic studies indicated the Bartlesville sandstone would have adequate rock strength to allow for openhole completions and would not require a liner in the horizontal section.

Additionally, a quick look method to estimate the borehole stability of the Bartlesville reservoir in the Wolco field was made using sonic logs in nearby wells. Sonic logs typically measure the compression wave response in travel time; the units are sec/ft. The compressive strength of rock is typically measured with the shear wave response rather than compression waves. Mason¹⁵ developed a methodology to use sonic log values and convert them to shear wave travel time values for specific rock type and grain size.

Intuitively, the denser rock (lower porosity) should have a higher estimated compressive strength. This is borne out by the sonic log response, which shows shorter travel time for the lower porosity zones. The zones having 15 to 20% porosity have an estimated compressive strength of 30 to 50 kpsi, while the zones with greater than 20% porosity have an estimated compressive strength of 10 to 25 kpsi.

Our analysis indicates that the zones having greater than 15 kpsi should have the strength to remain open without failure. The layers having greater than 25% porosity would need additional core sample rock strength analysis to complete the borehole stability evaluation process. The planned horizontal sections in the pilot area wells all have porosities under 25%.

Planning the Project

Designing the Horizontal Waterflood Pilot Field Test

The NE/4 of Section 25 of Wolco field initially had 18 wells, cabled tool drilled in the early 1900s; most had been plugged and abandoned by the 1960s. The three existing wells, the Blake 1A, 2A and 3A, each had a suite of modern openhole logs and were used to model the pilot test area.

Simulation studies were conducted to confirm the suitability of the Wolco site and also to determine the optimum placement of the horizontal wells. The Bartlesville sandstone in the Blake 3A well has a thickness of 80 ft, porosity in the range of 16 to 20% and estimated permeability in the range of 30 to 100 md. The simulation was based on the oil saturation levels and reservoir properties found in the Blake 3A well logs.

Results indicated that a combination of high injection rates below fracture parting pressure (then assumed to be a 0.50 psi/ft gradient) and the horizontal producing wells should allow for attractive producing rates during the life of the project, assuming the horizontal injection well was drilled 20 ft from the bottom of the sand with the two producing wells drilled 20 ft from the top of the sand. Based on this study, the oil would be recovered quickly, which is highly beneficial in achieving an economic operation. The water/oil ratio would also increase quickly, however.

Figure 5 is a topographic map of the pilot test area, showing the location of the wells being discussed; the three existing wells and the three new wells - the Wolco 4A, 5A and 6A. The new wells were to be drilled parallel to the suspected prevailing fracture orientation within the field. This was done as a precaution in the event that open fractures were encountered. In such a case, good sweep efficiency can still be maintained while injecting water to displace oil toward the adjacent horizontal producing wells. The horizontal wells are presented as black dashed lines trending from southwest to northeast and are shown to be 1000 ft in length with spacing of 500 ft between wells, drilled in a heel-to-toe orientation to minimize heel-to-heel interaction between the injection well and the horizontal producers.

Figure 6 is a structure map of the Bartlesville sandstone in the Wolco field showing the location of the pilot area and the subject wells.

Drilling Method

Cost effective drilling operations are important to achieve an economic horizontal waterflooding program. Openhole completions provide the least expensive method of completing horizontal wells in the Bartlesville sandstone.

The directional drilling is accomplished by using the rotary drilling system developed and licensed by Amoco (now BP). This process consists of two drilling assemblies: a curve drilling assembly (CDA) and the lateral drilling assembly. The CDA drills a very predictable curve based on tool configuration. These wells were drilled with the CDA, using fluid as the circulating medium and configured to drill a 70 ft radius curve; the well path goes from vertical to horizontal following a curve scribed by a 70 ft radius. Thus, by drilling 110 ft measured depth (MD), the inclination increases from zero (vertical) to 90° (horizontal). The CDA is removed from the well and the lateral drilling assembly is run in to drill the horizontal, or lateral, section of the well.

Drilling the Wells General Well Plans

The drilling procedure focused on drilling the horizontal wells while minimizing the formation damage associated with drilling mud invasion into the near wellbore area. A contractor air drilled the vertical portion of each well and the 5 $\frac{1}{2}$ " production casing was run and cemented above the kickoff point (KOP). The short radius curve was drilled using water as the circulating medium, while the lateral was drilled using air/foam to circulate the well, minimizing formation damage.

Wolco 4*A* – *Horizontal Injection Well*

The Wolco 4A vertical portion was drilled in April 2003. The 5 $\frac{1}{2}$ " casing was run and cemented to the surface. The float equipment was drilled out and the hole drilled to KOP of 1635 ft MD. The CDA was oriented with a gyro survey and the curve drilled to 1670 ft MD where circulation was lost. After adding lost circulation material to the drilling water, the curve was finished at 1733 ft MD with true vertical depth (TVD) of 1704 ft. The first section of the lateral was drilled with an air hammer, using air/foam as the circulating medium. No sloughing or collapse was noted during drilling, however, the drillpipe parted and was fished from the well. The lateral was finished using a packed bottomhole assembly with a total depth (TD) of 2732 ft MD; TVD of 1673 ft, for a total lateral length of 999 ft. Openhole logs were pushed into the lateral with sucker rods out to 2215 ft MD, 500 ft into the lateral, where friction prevented the logs from reaching TD.

Wolco 6A – Horizontal Production Well

The vertical drilling of Wolco 6A began in June 2003. TD was 1664 ft, where the 5 $\frac{1}{2}$ " production casing was set and cement circulated to the surface. The float equipment was drilled in August 2003. An attempt to core the well resulted in a jammed core barrel with only 3 inches of core recovery. Drilling was continued to the TD of 1862 ft. Density and induction logs were run in the vertical openhole section of the Bartlesville to confirm geology and refine target depths for the lateral portion of the wellbore. A cement plug was set and dressed off to desired KOP of 1678 ft.

The CDA was picked up, oriented and the curve was drilled from 1678 ft to 1785 ft MD; TVD of 1749 ft. The curve maintained the planned direction and inclination of 88 degrees. The lateral section was drilled to 1964 ft with a packed hole assembly when the survey taken showed the well was building angle (rising in the formation) at an unacceptable rate. The CDA was re-run and the inclination was corrected. Drilling continued, but two drillpipe failures occurred on consecutive days. Fortunately, fishing operations successfully retrieved the parted pipe each day. An air hammer was used to drill to TD at 2620 ft MD, TVD of 1759 ft, when again, the drill pipe parted. The pipe was fished successfully and drilling operations on Wolco 6A ceased, with the lateral drilled to a length of 835 ft. No sloughing or collapse was noted during drilling. Logging the lateral was not attempted at this time.

Wolco 5A – Horizontal Production Well

The vertical drilling of Wolco 5A began in June 2003. After the 5 ¹/₂" casing was run and cemented, drilling continued to TD of 1844 ft and density and induction logs were run. A cement plug was set and dressed off to the desired KOP of 1656 ft. The CDA was picked up, oriented and the curve drilled from 1656 ft to 1754 ft MD; TVD of 1723 ft. The curve had drifted too far from the planned direction and it was decided that a correction run was necessary. This was done utilizing a rotary steerable assembly to drill from 1754 ft to 2140 ft MD. At the end of the correction run the direction of the wellbore was on target at 204 degrees and inclination was at 87 degrees, following the structural dip of the formation towards the southwest. Drilling continued using an air hammer assembly to 2643 ft MD, 1763 ft TVD, for a lateral length of 889 ft. No sloughing or collapse was noted during drilling. Logging the lateral was not attempted at this time.

Evaluating the Initial Project Results

Wolco 5A and 6A began producing at the end of December 2003. Combined production from both wells was approximately 8 BOPD and 700 BWPD. Both wells were producing at the maximum fluid production rate the Bartlesville sandstone could produce (pumped off condition) within two weeks of field startup.

Oil production realized from the horizontal waterflood project for the first six months of operation (January 2004 – June 2004) fell short of expectations. High initial water cuts and early water breakthrough to Wolco 6A were the primary problems encountered. The field well tests and re-drilling operations presented below were conducted to answer the following questions:

- 1. Why is the oil production below expectations?
- 2. What is the parting pressure of the reservoir?
- 3. Is water injection occurring below that parting pressure?
- 4. How can we increase oil production to realize economic operations?

The *total* fluid production realized from the horizontal producing wells was consistent with simulated results, but oil production was disappointing. Additionally, there was an immediate adverse effect on Wolco 6A when water injection commenced as the oil cut went to 0% two weeks after injecting into Wolco 4A. It was decided to perform both a step rate test and a spinner survey in the injection well.

Diagnostic Tests and Analysis of Injection Well Performance

Step rate tests were conducted on both Wolco 4A (the horizontal injector) and Blake 1A (the vertical disposal well) to determine the reservoir parting pressure and to better establish operating parameters for water injection and disposal in the pilot horizontal waterflood. The high porosity zone in Blake 1A did not display the expected slope change during its step rate test as injection rates were not sufficiently large enough to obtain any injectivity limitations, but the Wolco 4A step rate test provide valuable injection operating information.

Wolco 4A Step Rate Test

A step rate injection test was conducted on Wolco 4A to determine the parting pressure for the horizontal injection well. This test was designed to increase injection rates in 500 BWPD increments while monitoring the bottomhole injection pressure, using a surface readout downhole pressure gauge run on an electric line. The downhole pressure gauge was suspended at 1600 ft, which is near the shoe of the production casing in the vertical section of the well.

Figure 7 shows the increase in injection rate with the corresponding changes in downhole pressure in Wolco 4A.

The surface injection pressure remained at 0 psi throughout the test. The liquid level in the well rose slowly as the injection rate increased, which is reflected in the rising bottomhole pressure with respect to injection rate. After the injection rate exceeded 1725 BWPD the slope representing the rise in bottomhole pressure with respect to injection rate declined, indicating a new permeability system was being accessed; most likely natural fractures. The parting pressure for Wolco 4A was measured at 573 psi. With a formation depth of 1700 ft, this is equivalent to a fracture gradient of 0.35 psi/ft. The measured parting pressure was considerably less than the anticipated 0.50 psi/ft used in the model for simulations. This confirmed that with sufficient injection rates, even with zero surface pressure, the rising liquid level in the tubing builds sufficient pressure for opening the natural fractures thereby allowing greater injectivity and exacerbating water channeling.

When the injection rate surpassed 1725 BWPD, the parting pressure of the reservoir was exceeded. One of the primary technical objectives of conducting a successful horizontal waterflood is to keep the injection pressure below the reservoir's parting pressure, allowing injected volumes to sweep through the matrix permeability rather through the reservoir's natural fractures. Based on the step rate test results, the injection rate was reduced to 1200 BWPD.

The step rate test on the horizontal injection well established two important operating parameters:

- "0 psi", or vacuum, surface injection pressure is not an adequate parameter to operate a conventional or horizontal waterflood below parting pressure. Downhole recording gauges are necessary to properly record the bottom hole pressure during a step rate test in this situation.
- 2. The horizontal injection well was capable of injection rates of up to approximately 1700 BWPD while still being able to stay below parting pressure, providing an injectivity ratio of about 3.0 BWPD/psi_{bhp}.

However, the step rate test could not determine where the injection fluid was entering the reservoir and if that injection profile would be altered after exceeding fracture-parting pressure. To acquire injection profile information, a spinner survey was conducted.

Wolco 4A Spinner Survey

The spinner survey was run through casing and out into the horizontal openhole using sucker rods to transport the spinner tool into the horizontal section of the well. Depth control for the logging tool is based on rod count and tally rather than on the conventional depthometer reading off a wireline truck. This is a unique method of conducting a spinner survey, since the up and down motion of the logging tool is limited to the length of rods the rig can pull at one time without making a connection.

With the spinner positioned at 1300 ft, which was below the static standing fluid level of the well, injection was resumed into the well at a rate of approximately 1000 BWPD. Initially, the spinner was working fine, with indications of correct response when either run in or pulled up against the downward flow of the injection water. After going to a depth of 1685 ft, the tool began to be erratic, and then it quit functioning properly. The rods and logging tool were pulled from the well. A piece of rubber was stuck in the propeller of the spinner, causing it to be inoperative. The tools were cleaned up and run the next day.

The spinner and rods were again run into about 1300 ft before injection was resumed at 1000 BWPD. The spinner responded as expected. The flow readings while inside the casing were consistent. Just below the casing shoe at 1627 ft, the flow rate began to drop off and by 1800 ft the flow of the injection water appeared to go to zero. To substantiate that the tool was still working properly, the rod string was quickly stroked up and down the length of two rods (50 ft) and the spinner tool responded as expected.

It was decided to push the tool out to the end of the lateral before increasing the injection rate to 2800 BWPD and log with the spinner on the way out of the well. This activity was also done to check wellbore stability as this was the first time any tools had been run the full length of the lateral since drilling in May 2003 and after 89,000 bbl of water had been injected. The end of the lateral was reached with no difficulty with the aid of roller rod guides (a technique described later in this discussion). The injection rate was increased to 2800 BWPD and the spinner survey was repeated as the rods were pulled from the well.

On the way out of the well, there was no injection fluid motion until 1770 ft, where the spinner indicated flow and then remained constant as the spinner was pulled up into the casing.

Results of the Spinner Survey

All injection fluids entered the formation within a short interval of 15 ft from 1760 ft to 1775 ft. This corresponds to the depth where circulation was lost while drilling the short radius curve with fluids. By increasing the injection rate from 1000 BWPD to 2800 BWPD, no change was indicated of the interval where the water entered the formation. Excessive water entry into the heel of horizontal injectors has been investigated by Popa¹⁶ and others recently. Since this area has natural fractures, that is the assumed problem and not a temperature induced phenomenon¹⁷. Regardless, there was no additional injectivity provided by the horizontal section of the well.

This information, along with the quick water breakthrough observed in Wolco 6A, led to the decision to shut down the water supply well and stop injection into Wolco 4A.

Logging Short Radius Wells

It was important to develop a method to log the entire horizontal well through short radius curves. For the first attempt, this was done by simply deploying the logging tools via sucker rods. A crossover connection was made to attach the logging tools to the sucker rod connection. The wireline was taped to each rod above and below each rod box connection. Gamma ray, density, induction and acoustic borehole televiewer logs were run to determine fluid saturations, identify fractures and confirm geology in the horizontal sections of the wells. When logging the first project well, Wolco 4A, the logs were run into the horizontal section of the wellbore approximately 500 ft, where friction and the flexibility of the sucker rods prevented the logs from going any further.

Other available means of conveying the logs to the entire length of the lateral were investigated, but eventually another simple solution was implemented to overcome the distance/friction limitation of the sucker rod conveyed logging technique. Off-the-shelf roller rod guides were placed on each of the rods that would go into the horizontal section of the well. This reduced the frictional drag to the extent that logs have now been conveyed over 2500 ft horizontally on other projects. This same development allowed the spinner survey to be conducted on Wolco 4A.

In March 2004, a full suite of logs was obtained for the lateral sections of Wolco 5A and Wolco 6A. Based on the log evaluations of both producing wells, it was concluded that the laterals were drilled too deep with respect to the total vertical depth into the Bartlesville reservoir. The majority of both laterals showed at or below residual oil saturations, and thus substantiated the low initial oil production.

Re-Drilling Operations

Grand Resources requested and received a one-year, no-cost extension to reconfigure the operation of the pilot.

Based on the log evaluations and updated reservoir simulations, the decision was made to plug back Wolco 5A and 6A with cement and re-drill the curve and lateral sections. The planned re-drilled horizontals would stay in the top 10 ft of reservoir to encounter the highest oil saturation and have the best chance of realizing economic oil production.

In each of the sidetrack operations, the laterals were plugged back with cement into the casing. The cement was then dressed off to the KOP. The CDA was picked up, oriented and the curve drilled. An air hammer was then used to drill the laterals.

Wolco 6A

Please refer to **Figure 8** for all the well paths associated with this well.

Wolco 6A-2 July 19, 2004

After the first month of operations, the quick response from the injection well, unacceptably high water cut and oil saturations at or below residual values based on the new logs, plans were made to plug back and re-drill this well. The new well path was to be 15 ft higher in the formation than the original lateral. Unfortunately, the CDA did not build at a sufficient rate so the drilling of Wolco 6A-2 was terminated and the curve plugged back. It was decided that the next curve would be headed to the northeast, essentially 180° from the original well path due to concerns that the exposed shale in the original curve section would be weakened and unable to provide adequate stability for the CDA to function properly.

Wolco 6A-3 – July 26, 2004

Wolco 6A-3, heading northeast, seemed to be building angle and holding the planned direction but the CDA failed. This resulted in an unsuccessful fishing operation and this curve was plugged back with cement.

Wolco 6A-4 – August 9, 2004

Wolco 6A-4 was also planned to head northeast, but slightly further north than Wolco 6A-3. The curve was drilled successfully and the lateral started at 1769 ft MD, 1734 ft TVD, with the cutting samples having good florescence but very little oil on the blow-back pit. After 84 ft into the lateral, oil was clearly visible with bottoms up after making connections. This is another advantage of drilling with an air/foam media; each connection serves as a mini drill stem test. The amount of oil continued to increase during connections for the next 100 ft drilled. The surveys indicated the wellbore was heading to the top of the formation. The nature of the cuttings confirmed the survey information, which indicated that the air hammer was building angle and had drilled to near the top of the formation. The length of the 6A-4 lateral is 202 ft.

Wolco 6A Re-drilling Results

Prior to being plugged back, Wolco 6A was making 2 BO and 350 BWPD, and the log evaluation indicated 17% porosity with less than 5 ohms of resistivity. After re-drilling 6A-4 in the top 10 ft of the reservoir, where there was 17% porosity and greater than 10 ohms of resistivity, production leveled off at 13 BO and 100 BWPD.

Wolco 5A

Please refer to **Figure 9** for all the well paths associated with this well.

Wolco 5A-2 – September 15, 2004

The plan was to drill this lateral higher in the formation, above the original lateral. The lateral was drilled to a total depth of 2227 ft with a small amount of oil recovered during connections. The well was put back on pump; however there was no improvement in oil production and the water cut remained the same during the next two months. The lateral was plugged back and it was decided to head northeast, 180° from original path, in a similar direction as the recently completed Wolco 6A-4 horizontal.

Wolco 5A-3 – November 23, 2004

This well was headed northeast but the curve was drilled too low with respect to TVD. The curve was plugged back.

Wolco 5*A*-4 – *December* 15, 2004

This well was also planned to head northeast. The curve entered the formation at the correct depth and was drilled out an additional 660 ft. There were good shows of oil as connections were made while drilling the lateral.

Wolco 5A Re-drilling Results

The well was put back on production and is currently making 5 BOPD with a water cut of 96%.

Reservoir Simulation Update

Additional simulations using actual pilot data were performed to predict oil recovery for the range of conditions encountered within the pilot operation. These simulations confirmed that oil saturations encountered prior to the re-drilling are close to residual oil levels within the interwell area and that the pilot performed close to expectations with respect to injection and producing rates.

Figure 10 shows some predictions to evaluate the performance of the final resulting pilot consisting of the vertical injection well, Blake 1A, and the two new horizontal producing wells, Wolco 5A-4 and 6A-4. The produced water is injected into Blake 1A which in turn provides pressure support for the pilot. Blake 1A is located in a portion of the reservoir containing the high-energy, high-permeability zone in the lower portion ("D" zone) of the Bartlesville. The two horizontal producing wells were drilled and completed in a thin oil column that exists in the top 10 ft of sand. Reservoir properties were adjusted to match the early 15 to 20 BOPD production observed in the modified pilot, as well as the amount of water being produced. The simulations indicate that most of the injected water flows initially through the underlying high permeability channel and exerts enough upward pressure to allow oil to be produced from the two horizontal producing wells. The comparative case assumes that the horizontal wells are replaced by vertical wells completed only in the upper 10 ft of the reservoir. The simulations indicate that the horizontal wells will recover significantly higher oil recovery, as follows in Table 1.

Table 1. Horizontal vs. Conventional Waterflood Performance Predictions

Time In Years	Cumulative Oil for Horizontal Wells (bbl)	Cumulative Oil for Vertical Wells (bbl)
1	5,116	954
5	17,548	4,008
10	28,570	6,927

All of the reservoir studies to date indicate that the most important part of the process is to place the horizontal producing wells close to the top of the sand where the highest oil saturations exist. It is important to provide pressure support to maintain the producing rates and to achieve maximum recovery. In contrast to the original concepts, it now appears less critical to use a parallel horizontal injection well. Part of the needed support comes from the existing pressure (125 psi) within the reservoir. In the case of the Wolco pilot, it appears that the injection of water into a higher permeability lower zone can provide the needed pressure support to achieve good oil recovery.

Pilot Production Summary

Through January 2005, the pilot project has produced 3,492 barrels of oil and 124,440 barrels of water. All produced water has been disposed of into Blake 1A. Oil production after redrilling Wolco 6A-4 and 5A-4 in the higher oil saturated section of the Bartlesville has shown considerable improvement.

Figure 11 presents oil and water production from the Wolco pilot from January 2004 through January 2005.

Conclusions

General Observations

- 1. The original goal to use horizontal injectors and producers to obtain high injection and withdrawal rates was achieved, but due to near residual oil saturations between the producers, very little oil was recovered, which made the results uneconomical.
- 2. As new information from the pilot area reservoir was generated, the pilot was modified to two horizontal wells drilled in the oil rim supported by a vertical well with the injection going into a lower high permeability zone.
- 3. Simulations with the current reservoir characteristics match the present performance and predict an economical project.
- 4. Long abandoned fields can become economical if adequate oil saturations exist along with an attractive combination of bottomhole pressure, permeability and proper placement of horizontal wellbores.
- 5. Greater performance can be expected in other applications where the oil zone is thicker.

Specific Lessons Learned

- 1. Initial production results were disappointing, with an oil cut of 1 to 2%, but total fluid withdrawal and injection rates were as predicted.
- Diagnostic tests on the horizontal injector determined injection parameters, which led operation procedures to keep the injection rates below fracture parting pressure.
- 3. The injection profile survey indicated that all of the injected fluid was exiting at the heel negating the value of Wolco 4A pressure support.
- 4. The 0.35 psi/ft fracture gradient was much lower than expected and confirmed the necessity of using bottomhole pressure gauges when conducting step rate tests.
- 5. Fractures are dynamic and can take large volumes of water; obtaining injection profile information is vital.
- 6. The high capacity and location of the disposal well, Blake 1A, supplied pressure support for the re-drilled horizontal producers.

- 7. Placement of the re-drilled producer (Wolco 5A-2) higher in the reservoir *in* the original pilot area was not successful.
- 8. Re-drilling the producers (Wolco 6A-4 and 5A-4) up structure (heading NE) and *away* from the original pilot area was successful.
- 9. A bottomhole pressure of 125 psi is enough to have economic withdrawal rates with horizontal producers.
- 10. The character of the layered reservoir with high and low permeabilities was able to be managed by injecting into the high permeability "D" zone and producing from the oil rim at top of the "C" zone.

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Nomenclature

voment	παιι	
bbl	=	barrel(s) or 5.61 cubic feet
md	=	millidarcy
WOR	=	water oil ratio
MD	=	measured depth
TVD	=	true vertical depth
TD	=	total depth
BOPD	=	barrels of oil per day [m ³ /d oil]
BWPD	=	barrels of water per day [m ³ /d water]
KOP	=	kick off point
STB	=	stock tank barrels
psi	=	pounds/square inch
1	_	1000 mai

- kpsi = 1000 psi
- bhp = bottom hole pressure
- ohm = Ω

Metric Conversion Factors

bbl	Х	1.589 873	E - 01	$= m^3$
ft	Х	3.048*	E - 01	= m
inch	Х	2.54*	E + 00	= cm
lbf	х	4.448 222	E + 00	= N
md	Х	9.869 233	E - 04	$= m^2$
psi	Х	6.894 757	E + 00	= kPa

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Figure 1. The location of both the initial and second pilot locations.



Figure 2. The Blake lease in NE/4 of Section 25-T24N-R11E, showing the North Avant Unit lease lines and offset operator.



Figure 3. Density log of Blake 1A, showing the "C" and "D" zones of the Bartlesville sandstone.





Figure 4. Location of fractures, faults and lineaments in and near the pilot test area.

NE/4 Section 25-T24N-R11E



Figure 5. Topographic map of NE/4 of Section 25-T24N-R11E showing the locations of the Blake and Wolco wells.

Figure 6. Structure map of NE/4 of Section 25-T24N-R11E, showing the top of the "C" zone of the Bartlesville and the Blake and Wolco wells.



Figure 7. Step Rate Test for Wolco 4A.



Figure 8. Plan view of Wolco 6A, 6A-2, 6A-3 and 6A-4.



Figure 9. Plan view of Wolco 5A, 5A-2, 5A-3 and 5A-4.



Figure 10. Simulation results after re-drilling.



Figure 11. Current oil/water production of Wolco 5A-4 and 6A-4.

