Characterization of a Shallow Horizontal Fracturing Treatment in Western Missouri

A research project, sponsored by the U.S. Dept. of Energy, was undertaken to demonstrate a development method for the heavy-oil reserves that exist at ultrashallow depth in southwestern Missouri and southeastern Kansas. The principal objective was to demonstrate an economically viable method of producing the shallow heavy oil by use of a combination of microbial-enhanced oil-recovery treatments and horizontal fracturing in vertical wells.

Introduction

Heavy oil (8 to 25°API) exists in the shallow Pennsylvanian sands that occur over approximately 8,000 sq miles along the Kansas/Missouri border. The area covers portions of the northeast Oklahoma platform and the Cherokee and the Forest City basins. The Cherokee group is a sequence of alternating shales and sandstones with thin coal and limestone beds. The main productive units within the Cherokee group are the Bluejacket and Warner sandstones.

The Warner sand has been drilled throughout Vernon County, Missouri, and several areas of known oil deposits have been defined. In the latter part of 2000, seven boreholes were continuously cored to a total depth (TD) of approximately 220 ft. All wells encountered heavy oil in both the Bluejacket and Warner sandstones. The Bluejacket sand occurred at approximately 130 to 135 ft with 8 to 12 ft of net pay, and the Warner sand occurred at approximately 160 to 170 ft with 15 to 30 ft of net pay. Warner-sand porosity ranged from 14 to 25%, and permeability in the Upper Warner ranged from 100 to 400 md.

Five wells were drilled to produce the shallow heavy-oil deposits in the Warner sandstone, the Fauvergue Wells 1 through 5 **(Fig.1).** The Cushard Wells 4 and 5 were cored wells in the project area. These wells were cored to TD and the cores analyzed as part of the project. Although it was believed that older wells drilled in the Warner sandstone had been fracture stimulated, no information regarding any historical fracture treatments, execution, or performance was available.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 102342, "Characterization of a Shallow Horizontal Fracturing Treatment in Western Missouri," by ***L.K. Britt,*** *SPE, NSI Technologies Inc.;* ***S. Dunn-Norman,*** *SPE, U. of Missouri-Rolla;* ***M.B. Smith,*** *SPE, NSI Technologies Inc.;* ***E. Atekwana,*** *U. of Missouri-Rolla;* ***L. Slater,*** *Rutgers U.;* ***A. Gupta,*** *SPE, and* ***D. Numbere,*** *SPE, U. of Missouri-Rolla;* ***J.V. Fontana*** *and* ***J.H. Viellenave,*** *Direct Geochemical; and* ***J. Pelger,*** *SPE, J-Environmental Inc., prepared for the 2006 SPE Annual Technical Conference and Exhibition, San Antonio, Texas, 24–27 September.*

Geomechanical Data Set

The geomechanical data set includes profiles with depth of Young's modulus, in-situ stress, and fracture-fluid leakoff. Core from the Bluejacket and Warner sandstone formations and surrounding shales was available from the coreholes drilled, and static triaxial compression tests were conducted on samples to determine Young's modulus. Evaluation of the triaxial compression tests indicated that the Bluejacket and Warner sandstones have an average Young's modulus of 3.1×10^6 and 1.3×10^6 psi, respectively. The Rowe coal and the bounding shales have an average Young's modulus of 2.0×10^6 and 1.8×10^6 psi, respectively.

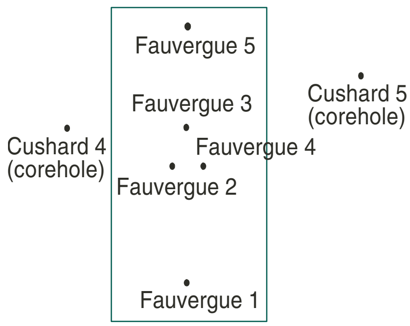

Fig. 1—Drilled well locations.

In-situ stress and leakoff-coefficient estimates were developed on the basis of experience in similar shallow heavy-oil reservoirs. Because of the high viscosity of the hydrocarbons in place (1,000 cp) and moderate permeability (100 to 300 md), a low value of fracture-fluid leakoff was assumed. For preliminary design purposes, a leakoff coefficient of approximately 0.002 ft/min$^{1/2}$ was assumed.

The in-situ stress contrast was assumed to be minimal given the shallow nature of the reservoir and limited production and subsequent lack of depletion from the Warner sandstone formation in the area. As a result, a radial fracture geometry (either vertical or horizontal) was assumed. Well logs from the Cushard Well 4 corehole were used in developing the geomechanical data set because the wells to be fracture stimulated had not been drilled yet.

Hydraulic-Fracture Design

The geomechanical data set developed was used to generate the fracture-stimulation design for the Warner sandstone formation in Fauvergue Wells 1 and 5. The fracture design consisted of pumping 94,500 lbm of 20/40-mesh Brady sand in 23,000 gal of linear-

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gel fracturing fluid. The treatment was designed for a proppant addition schedule from 0.5 to 10 lbm/gal. The purpose of the 0.5 lbm/gal proppant stage was to mitigate the detrimental effects of potential near-wellbore pressure loss (NWPL) as a result of the anticipated complex fracture geometry. A 15-bbl/min constant injection rate was planned on the basis of net-treating-pressure and fracture-conductivity projections found using fracture-performance simulations with commercial design software. Net treating pressure was planned to increase from 100 psi to 1,000 psi, with the intent of creating 3,000 md-ft of fracture conductivity at closure. The design was intended to create a fracture penetration of approximately 100 ft. The objective of the hydraulic-fracture design was to achieve tip screenout (TSO), thereby creating a highly permeable pathway for subsequent microbial treatments.

Hydraulic-Fracture Treatment

Microbes were not included in the fracturing fluid because of the electrical-resistivity tomography (ERT) work. ERT arrays were placed in three openhole wells (Fauvergue Wells 2, 3, and 4) after the hydraulic fracturing. Well 1 was stimulated according to plan. Initial breakdown and step rate tests were performed first. Following the step rate test, formation pressure was allowed to bleed off until closure pressure was observed. A minifracture then was pumped to determine fluid efficiency. The main fracture stimulation follows the minifracture. Well 1 was stimulated according to plan, but a TSO was not possible.

A similar procedure (breakdown, step rate test, minifracture, and main treatment) was followed on Well 5. However, blender problems were encountered while pumping on Well 5. The treatment was shut down after the slurry pumping schedule had begun. When the treatment was restarted, the slurry schedule also was restarted. Hence, there was insufficient fluid to pump the entire treatment as planned. Approximately 25% of the proppant was not placed in the formation. In addition, control problems with the blender resulted in erratic concentrations, with values as high as 17 lbm/gal pumped near the end of this treatment, but no TSO could be effected. It was concluded that the leakoff rate in the Warner was too low to accommodate a TSO and/or the fracture geometry made TSO difficult to achieve.

Hydraulic-Fracturing Analysis

A step rate test was conducted on Well 1 with the 30-lbm/gal linear gel and pump rates in increments from 2 to 15 bbl/min (treatment design rate), with a step down to 4 bbl/min. Formation-breakdown pressure for Well 1 was 770 psi. Analysis of the step rate test revealed that the entire test was conducted above fracturing pressure, but the step-down portion of the test was used to estimate a fracture-extension pressure of approximately 140 psi. The 1.75 slope of the pressure-rate curve during step down also indicated there was considerable perforation friction.

Closure pressure was found to be 107 psi, which agrees well with the closure pressure found from falloff data following the step rate test. Pipe friction is evident in the early portion of the data, and this friction may be explained by the complex fracture geometry caused by the horizontal fracture orientation. Fluid efficiency was found to be 85%. This high fluid efficiency is a result of low leakoff rate.

A minifracture net-pressure history match was prepared, comparing the predicted net pressure to the actual net pressure of the treatment. Early-time data are not in agreement, but late-time data do agree with the predicted net pressure. Early-time data are affected by frictional effects, which occur through the perforations because of tortuosity. Again, this is attributed to the creation of a horizontal fracture.

The actual treatment performed on Well 1 was exactly according to the treatment schedule prescribed in Table 2 in the full-length paper. A 2,000-bbl pad was pumped. Following the pad, a sand-slurry schedule of 0.5, 1.0, 2.0, 4.0, 6.0, 8.0, and 10.0 lbm/gal was pumped. A 15-bbl/min constant injection rate was used. Treating pressure increased slightly every time sand concentration was increased, indicating that the perforations or formation was reacting adversely to the increased concentration. During the treatment, bottomhole treating pressure declined continuously, indicating radial fracture geometry. The treatment never indicated a TSO had been achieved.

Knowing the fluid efficiency was 85% in the first fracture treatment, and that TSO was not achieved, the decision was made to reduce the pad volume by 50% (to 1,000 gal) in Well 5 in an attempt to achieve a TSO in the second treatment. Because of equipment malfunctions, it was not possible to pump the treatment as planned on Well 5. The pumps were stopped at a 2-lbm/gal slurry rate and then restarted. Proppant addition could not be controlled, and the addition of proppant was erratic throughout the treatment.

Despite the high sand concentrations applied to Well 5, the continuous decline in pressure also indicated that a TSO did not occur. On the basis of the results of the two fracturing treatments, it was concluded that high-permeability fracturing would not be feasible in the Warner sandstone at this depth.

Tiltmeters and Tilt Analysis

Fifteen self-leveling tiltmeters were placed in prepared surface holes configured in a circular array around Well 1. The tiltmeters were used to confirm fracture morphology. Tilt signals obtained during treatment execution and pressure falloff were extremely clear because of the shallow depth of the formation. Analysis of the tiltmeter information showed that the deformation was located approximately 80 ft east and 20 ft north of Well 1. The primary feature induced was near horizontal, and elliptical, with dimensions of 200×300 ft.

There appeared to be a vertical fracture that accompanied the horizontal fracture, with an azimuth of approximately N 73° E. The existence of a vertical fracture is somewhat unclear, and it is no larger than 25% of the injected fluid volume. It is not present above 150 ft.

The tiltmeters used in the fracturing treatments confirmed that the resulting fracture geometry was horizontal. However, tiltmeter data could not confirm the exact depth of the fracture. It was assumed that the fracture remained at the same depth as the perforated intervals. However, the NWPL suggests that the horizontal fracture may not have been in direct contact with the perforations. **JPT**