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TITLE: ECONOMIC RECOVERY OF OIL TRAPPED AT FAN MARGINS USING HIGH ANGLE WELLS AND MULTIPLE HYDRAULIC FRACTURES

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Objective

This project attempts to demonstrate the effectiveness of exploiting thin-layered, low-energy deposits at the distal margin of a prograding turbidite complex through the use of hydraulically fractured horizontal or high-angle wells. The combination of a horizontal or high-angle well and hydraulic fracturing will allow greater pay exposure than can be achieved with conventional vertical wells while maintaining vertical communication between thin interbedded layers and the wellbore.

A high-angle well will be drilled in the fan-margin portion of a slope-basin clastic reservoir and will be completed with multiple hydraulic-fracture treatments. Geologic modeling, reservoir characterization, and fine-grid reservoir simulation will be used to

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select the well location and orientation. Design parameters for the hydraulic-fracture treatments will be determined, in part, by fracturing an existing test well. Fracture azimuth will be predicted by passive seismic monitoring of a fracture-stimulation treatment in the test well using logging tools in an offset well.

Summary of Technical Progress

The long radius, near horizontal well has been drilled. After reviewing open hole logs, the three hydraulic fracture treatments originally planned for the well were reduced to two. Completion operations are in progress. Cement bond logs indicated a very poor bond between the 5 in. liner and the formation, and now only one hydraulic fracture treatment is planned.

After pumping a remedial cement squeeze, all pay behind the 5 in. liner was perforated and stimulated. The well is currently producing approximately 170 BOPD and 70 BWPD. Pressure transient analysis will be utilized to assess whether the reservoir is tight, or if there is near wellbore damage. The perforations will be restimulated if necessary.

Once wellwork is complete for the existing perforations, a hydraulic fracture treatment will be pumped through a short interval of clustered perforations in the 7 in. liner. Following this frac, all pay behind the 7 in. liner will be perforated and completion operations will be final.

Completion Operations

Progress

After drilling out cement above the 5 in. liner top, drilling mud was cleaned out to bottom at 14,271 ft. Tubing-conveyed cement bond logs were then run in the 5 in. and 7 in. production liners, and a short interval of the 9-5/8 in. intermediate casing. The 9-5/8 in. casing and the 7 in. liner were shown to be well bonded to the formation. The 5 in. production liner was found to have a very poor cement bond. Without a good bond, a single hydraulic fracture plane extending 150 to 200 ft on either side of the wellbore probably could not be achieved. Therefore, plans were changed to perforate all pay behind the 5 in. liner and not frac. Only the pay behind the 7 in. liner would be hydraulically fractured (Fig. 1).

While tripping in the hole after bond logging to circulate out heavy fluid, the casing was found to be losing fluid at an unknown depth. A 5 bbl cement plug consisting of Class G plus additives was placed at the bottom of the 5 in. liner. This plug was successful in eliminating the fluid loss.

Prior to perforating pay behind the 5 in. liner, a remedial cement squeeze treatment was designed to establish isolation from high water saturations in Sands D and E (Fig. 1, Tables 1 and 2). After perforating four squeeze holes at 13,752 ft (12,394 ft TVD), a cement retainer was set at 13,746 ft. The 5 in. liner was squeezed with 15 bbls of Class G cement plus additives in two stages.

Cement was drilled out to the top of the retainer, and 2% KCl water was spotted to 10,700 ft. Tubing-conveyed perforating guns were assembled and loaded to perforate all pay behind the 5 in. liner with 4 shots per ft and 90° phasing at the following depths: 13,320-13,362 ft; 13,371-13,394; 13,405-13,482; 13,499-13,520; 13,546-13,556; 13,568-13,620; and 13,673-13,730 ft. The true vertical depth of this interval ranged from 12,360-12,403 ft.

The guns were run in the hole on 2-7/8 in. tubing. A 6800 ft cushion of 2% KCl water was established to perforate approximately 2000 psi underbalanced. After setting a retrievable packer at 11,895 ft, the guns were fired by applying 1500 psi pressure to the casing.

The well was swabbed for two days, recovering load water plus formation water at low entry rates. The oil cut was approximately 15% at the end of swabbing. The tubing, packer, and perforating guns were pulled out of the hole. All guns had fired, and drilling mud or contaminated, unset cement was observed on the perforating guns. A retrievable packer and hydraulic jet pump bottom hole assembly (BHA) were run in the hole to lift the well. The packer was set at 11,702 ft, placing the top of the BHA at 11,636 ft (11,621 ft TVD). The well was placed on hydraulic lift.

The production rate after several days had stabilized at approximately 40 BWPD and a trace of oil. The expected rate was at least 200 BPD liquid with minimal water. The perms were believed to be damaged as evidenced by the low production rate and the mud or cement observed on the perforating guns. To remove the damage, the perforations were stimulated with a non-acid reactive fluid consisting of a blend of KCl water, iron chelating agents, mutual solvents, and surfactants. This fluid was preferred over mud acid due to the high clay and feldspar content of the Stevens sand. The perforated interval was treated with a volume of one-half barrel per ft of perforations. After pumping a nitrogen preflush, the treatment fluid was nitrified with 500 SCF per bbl to assist flowback and cleanup. The treatment was pumped through 1-1/4 in. coiled tubing below fracture pressure while slowly reciprocating the coiled tubing tail across the perforated interval.

The well was returned to production, initially making approximately 220 BOPD and 20 BWPD (Fig. 2). The low water cut was in line with log analysis and fractional flow calculations from core data (Table 2). A producing bottom hole pressure measurement was obtained and found to be 850 psi, corrected to the perforations. The Vogel inflow performance relationship (IPR) for the existing perforations (Sand C) is shown on figs. 3 and 4.

Future Plans

The well will continue to produce from the existing perms for a short period of time to observe oil decline and water cut trends. Pressure transient analysis (PTA) will be utilized to assess how tight the reservoir is, and whether or not there is still near wellbore damage. Pending these results, the perforations may be restimulated.

Once wellwork has been completed on the existing perforations, the remaining pay in Sands A and B will be completed. A hydraulic fracture treatment will be pumped in the 7

in. liner through four ft of clustered perforations at approximately 13,200 ft (12,351 ft TVD). Following the fracture treatment, all pay behind the 7 in. liner will be perforated.

An analytical technique was used to predict the initial production rate and IPR of the planned hydraulic fracture treatment. Joshi's constant boundary solution for a horizontal well^{1,2} was used in combination with Darcy's Law to predict the production rates of each major sand interval. The Joshi equation was used to predict the performance of a horizontal well without fracs. The frac was considered to be a stimulated vertical well tied into the horizontal well and was represented by Darcy's Law adjusted by a productivity improvement ratio (J/J_o) of 1.78. The J/J_o ratio was based upon a fracture treatment in offset well 57X-34, which had a calculated fracture half-length of 200 ft. The planned frac is assumed to penetrate Sands A and B, as shown in fig. 1. Figures 3 and 4 show the total liquid and oil IPR for Sands A and B. Oil cut is based on log analysis and fractional flow calculations from core data (Table 2).

Technology Transfer

Dr. Mike Clark presented the reservoir characterization aspect of this project on September 24, 1997 at the ARCO Geoscience Conference in Plano, Texas.

References

1. Joshi, S.D., *Augmentation of Well Productivity Using Slant and Horizontal Wells*, Journal of Petroleum Technology, pp. 729-739, June 1988.
2. Joshi, S.D., *A Review of Horizontal Well and Drainhole Technology*, paper SPE 16868 presented at the 62th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, Dallas, Texas, September 27-30, 1987.

Table 1

Net Sand Properties

Sand	* Gross Sand, ft	* Net Sand, ft	Net-to-Gross, %	Porosity, %	Wat. Sat., %	Perm., md	Water Cut, %
A	110	86	78.2	11.3	44.9	0.5	67
B	367	300	81.7	11.6	37.7	0.9	38
C	303	241	79.5	11.3	40.1	1.3	53
D	389	364	93.6	11.7	65.4	1.5	100
** E	105	95	90.5	12.3	75.9	1.3	100
Tot. / Avg.	1274	1085	85.2	11.6	51.4	1.2	92

* Footages represent measured depths. Net sand based on shale volumes (V_{sh}) < 30%, and effective porosities (ϕ_{eff}) > 8%.

** Sand E not fully penetrated.

Table 2

Net Pay Properties

Sand	* Gross Sand, ft	* Net Sand, ft	* Net Pay, ft	Porosity, %	Wat. Sat., %	Perm., md	Water Cut, %
A	110	86	24	12.8	36.7	1.3	25
B	367	300	188	12.3	33.1	1.2	15
C	303	241	125	12.6	33.5	2.3	15
D	389	364	38	12.8	34.6	1.8	15
** E	105	95	0	-	-	-	-
Tot. / Avg.	1274	1085	374	12.5	33.6	1.7	15

* Footages represent measured depths. Net sand based on shale volumes (V_{sh}) < 30%, and effective porosities (ϕ_{eff}) > 8%.
 Net pay based on net sand with water saturations less than 40%.

** Sand E not fully penetrated.

Figure 1. Actual well path relative to major Yowlumne sand intervals. Also shown are existing perfs and planned frac interval.

Figure 2. Well tests for Yowlumne Unit B 91X-3.

Figure 3. Total liquid inflow performance for different perforations (Sand C). Predicted IPR for a single frac of Sands A and B.

Figure 4. Oil inflow performance for current perforations (Sand C). Predicted IPR for a single frac of Sands A and B.