FIELD DEVELOPMENT

Producers monetize assets with UBD

A new technology allows producers to develop unrecognized reserves.

AUTHORS

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Asset managers can choose from an array of techniques for field development and redevelopment: vertical and horizontal wells, multilaterals and hydraulic fracturing, to name a few. Typically, however, they don't consider underbalanced drilling (UBD) a primary method in their development toolbox.

Wayne field in the Williston Basin, developed by GeoResources Inc., illustrates why UBD should be considered from the outset as a potentially profitable option for field development. After more than 5 years of production, four horizontal wells drilled underbalanced are on track to more than triple the expected ultimate recovery (EUR) of previous vertical wells and nearly double the EUR of a conventional horizontal well drilled into the same geology.

UBD can help increase production (initially and in the long term) by:

- revealing productive zones that might not otherwise be detected;
- improving zone contributions within a well;
- reducing abandonment pressure; and
- providing access to areas that cannot be reached with conventional overbalanced mud systems.

Wayne field is an excellent example of the access issue.

Reservoir and fluid properties

Wayne field produces 28° API oil from the Mission Canyon formation, a fractured carbonate reservoir at a depth of 4,000 ft (1,220 m). This 15- to 20-ft (5- to 6-m) thick reservoir averages 24% porosity and 100-md permeability. The original reservoir pressure, 1,900 psi in 1957, had dropped to about 900 psi by 1994 when the operator's development effort commenced.

The reservoir's active bottom-water-drive mechanism quickly became evident in the pattern of production. The original vertical wells showed an initial production of 70 b/d of oil, but the oil cut declined rapidly during the first year and stabilized at 10 b/d (90% water cut). By the end of 1985, 33 of these vertical wells were on production, and through 1994 the field produced 2.5 million bbl of oil and 24 million bbl of water. This equated to a recovery factor of only 10.4%.

Decline curve analysis indicated the EUR would be about 3.5 million bbl of oil (106,000 bbl of oil EUR per well), or only about 14.6% of the original oil in place.

The dramatic and quick increase in water cut in these wells was evidence of water coning, a fact of life in such thin, bottom-water-drive reservoirs. The coning led to high oil recovery from a small well-flushed zone around the wellbore, but limited the amount of drawdown pressure that could be applied to the reservoir. As a result, the average drainage radius of the wells was only 240 ft (73 m). Since the wells were drilled on 40-acre spacing, this left more than 50% of the reservoir area unproduced. Horizontal wells appeared to be a logical solution.

Overbalanced horizontal drilling

GeoResources drilled the first well, the **Oscar Fossum H-1**, as a conventional lateral drilled with an overbalanced polymer mud system having a density of about 8.4 lb/gal. The H-1 well horizontal section was drilled with a rotary steerable assembly as a 6 1/8-in. hole out of 7-in. production casing.

Steering proceeded with no problems in the first half of the lateral, but after that point the overbalanced situation led to increasingly severe steering and differential sticking problems. Steering the tools in the last 300 ft (92 m) of the hole became extremely difficult. While rotation was still possible, sliding and steering were necessary to keep the hole in the target zone. Although the well reached total depth near the planned horizontal length of 1,808 ft (551 m), it became clear future wells would require a different drilling technique if longer laterals were to be accomplished.

Initial production of the H-1 well was satisfactory, but not as high as had been expected for its well length. Thereafter the well's production profile began a moderate decline, and both of these factors were considered indications of possible reservoir damage.

Underbalanced horizontal drilling

The next four horizontal wells were drilled either near-balanced or underbalanced (Table 1). The **H-2** well (drilled with native crude) was nearer to being balanced, but it is included because UBD techniques were used (a rotating head and fluids with a circulating density lower than that of

TABLE 1. HORIZONTAL WELLS DRILLED IN WAYNE FIELD

Well	Mud system	Lateral length (ft)
Oscar Fossum H-1	Starpac polymer (overbalanced)	1,808
Oscar Fossum H-2	Native crude (near-balanced)	2,500
Oscar Fossum H-3*	Nitrified native crude with parasite string	
	Leg 1	
	Leg 2	3,886
	Leg 1R (sidetrack to Leg 1)	1,629
		678
Oscar Fossum H-4	Nitrified native crude	3,608
Ballantyne-State/ Steinhaus H-1	Nitrified native crude	3,708
	Total length	**17,817**
	Total length attributable to UBD	**8,009**

* *Legs 1 and 2 formed a dual lateral. Leg 1R was a reservoir extension of Leg 1.*

TABLE 2. ECONOMIC PROJECTIONS AFTER COMPLETION OF DRILLING PROGRAM

	Vertical	Conventional Horizontal	UBD Horizontal
Cost	$200,000	$500,000	$750,000
Estimated ultimate recovery	85,000 bbl of oil	175,000 bbl of oil	275,000 bbl of oil
Net present value*	$185,000	$460,000	$950,000
Return on investment	38%	42%	56%
Payout in years	2.5	2.0	1.5

* *Based on $14/bbl oil price*

conventional drilling fluids).

The most immediate benefit of UBD in Wayne field was access. Underbalanced techniques were responsible primarily for doubling well lengths compared to the first overbalanced well (**Fossum No. 1**), where the operator reached the practical limit of overbalanced drilling. One also can argue construction of multilaterals would have been difficult or impossible with conventional overbalanced techniques. Using 2,000 ft (610 m) as the technical limit for overbalanced drilling in this formation, and adding in the additional legs of the **H-3**, underbalanced techniques added an incremental 8,009 ft (2,443 ft) of lateral length in the remaining four wells.

The high initial oil and total fluid rates in the four UBD wells are attributable primarily to the longer horizontal well lengths, but may be indicative of reduced formation damage. The underbalanced wells averaged 156 b/d of oil and 422 b/d of fluid during the first year, compared to 117 b/d of oil and 248 b/d of fluid for the H-1 well.

Long-term benefits

Roughly 6 months after completion of the drilling program, decline curve analysis suggested the conventional horizontal well should recover about 175,000 bbl of oil and the underbalanced wells should recover 275,000 bbl of oil, compared to an EUR for vertical wells of 80,000 bbl of oil (Table 2).

The overbalanced Fossum H-1 well has continued to underperform compared to the other wells (Figure 1). This cannot be attributed to geology, since the H-1 is in a zone geologically as good as, or possibly better, than the H-2, H-3 and **Ballantyne State** wells. Artificial lift also has been similar for each well.

The EUR numbers in Figure 2 (based on production to February 2002) compare well to initial predictions for EUR, with the exception of the **H-4** well, where the geology is believed to be inferior. The H-3 well, with its longer reservoir exposure, may exceed 300,000 bbl of oil EUR.

If one assumes the H-1 EUR represents a typical overbalanced well, one can argue most of the recovery greater than 150,000 bbl of oil is attributable to the additional well length and reduced skin damage achieved with underbalanced drilling. Using the figures above, that adds up to 450,000 bbl of oil incremental EUR due to UBD.

Although the four underbalanced wells cost more to drill, they paid out nearly twice as fast as the conventional horizontal well, and are expected to deliver about twice the reserves and net present value (NPV). In today's oil price and well cost environment, a similar project could achieve even better economic results.

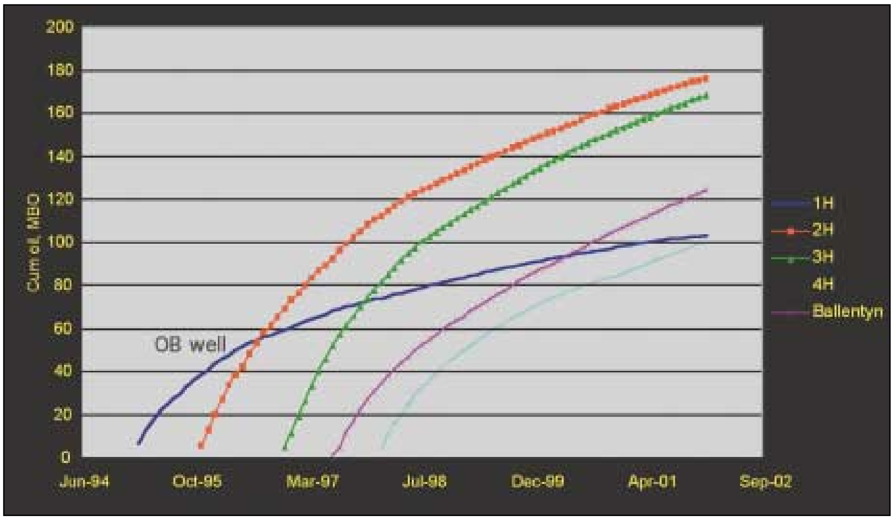

Figure 1. Cumulative production through February 2002 of four underbalanced wells and one overbalanced wells in Wayne field reveals significant expected ultimate recovery.

Lessons learned

Underbalanced techniques can offer significant improvements in EUR and NPV, and improvements in the technology have cut costs substantially. The challenge of using underbalanced techniques is that they are somewhat more complex and less well known than conventional methods, so good project economics depend on good planing and execution.

For example, if an operator doesn't have expertise on staff for planning underbalanced wells, third-party expertise should be considered, at least for the first few wells. This will reduce the cost of the project, not increase it. Experienced field supervision also is important, especially for the first few wells.

In addition, good estimates of reservoir pressure are crucial in creating a well design that will prevent skin damage. Create a flexible fluid design if reservoir pressure is in doubt. And as with any infill project, the time spent studying the reservoir to confirm reserves, target zones and reservoir pressure is time well spent.

Contingency planning is crucial, especially if significant and unexpected influxes are possible during underbalanced operations. Finally, corrosion control is often a necessity when membrane nitrogen is being used in the drilling fluid.

UBD is a good example of the application of a new technology to reach and recover assets that otherwise would remain in the ground. Although initially more expensive (especially at the beginning of an operator's learning curve), the technology offers quicker payouts and significantly higher returns on investment. E&P

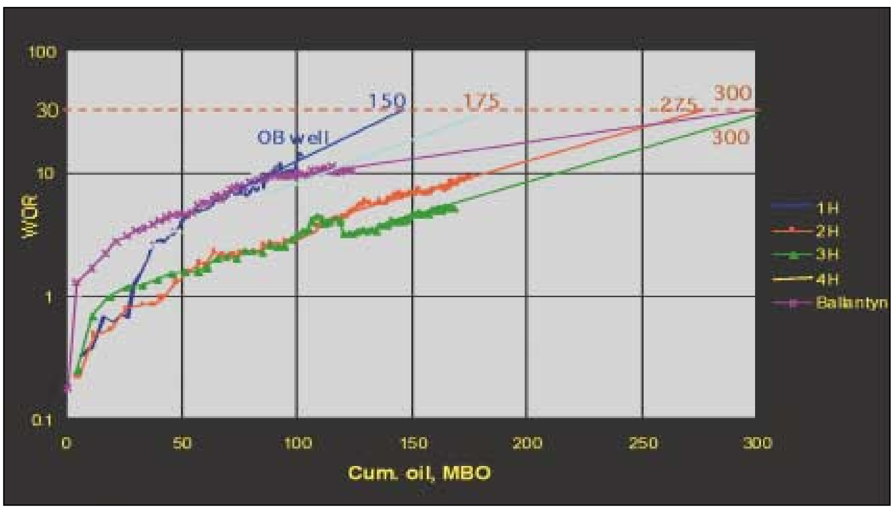

Figure 2. The expected ultimate recovery is estimated by projecting the water-oil ratio to the economic limit for an area.