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Conformance through chemistry

Relative permeability modifiers deliver significant reduction in post-frac water production.

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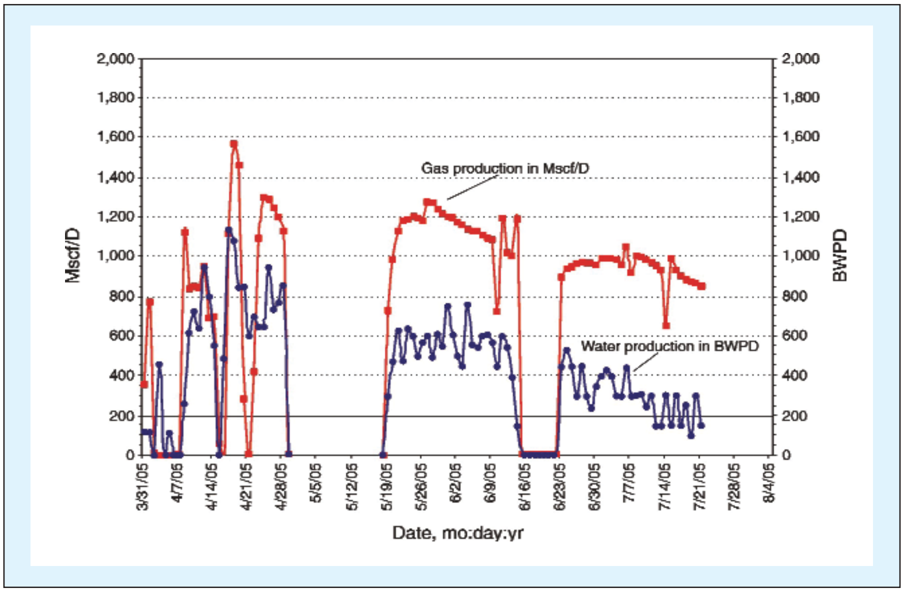

Figure 1. Water cut declined after treatment. (Graphic courtesy of Halliburton)

Although hydraulic fracturing has proven to be extremely successful, one problem has continued to plague operators for years: increased water production after a treatment has been pumped. Typically, this produced water results from uncontrolled fracture height growth that contacts a water-bearing interval. In other cases, the treated zone contained moveable water along with the hydrocarbons. Excessive water production typically will shorten the life of a producing well and severely decrease its economic potential.

When excessive water production threatens the economics of a well, the operator typically attempts to resolve the problem using products that plug the portion of the reservoir where water is entering the propped fracture. Consequently, the operator runs the risk of not only shutting off unwanted water, but also of damaging the hydrocarbon-producing portion of the reservoir.

This article describes a case history involving a post-frac process to decrease excessive water production that used a relative permeability modifier (RPM) that is non damaging to hydrocarbon flow.

How it works

The fourth-generation RPM is a water-thin fluid that works by adsorbing onto the rock surface, reducing permeability to water 7 to 10 times more than it does to hydrocarbons. In effect, the RPM creates resistance that holds back water while allowing oil and gas to pass freely. It can also act as a self-diverter, helping to ensure total coverage of the well bore. In addition, the RPM enhances reservoir drainage and can justify prolonged and sustained production. These unique properties make it one of the best options when accurate placement is not feasible.

Applications

This treatment typically does not require any special placement techniques. It is unaffected by multivalent cations, oxygen and acids. Placement normally does not require rig time, zonal isolation, or a catalyst, and the product does not gel. The application design of the RPM post-frac treatment is affected by temperature. Lab tests showed the upper temperature limit could be as high as 325°F (163°C).

Wells having the following conditions are potentially good candidates for post-frac treatments with the RPM system:

- Bottomhole temperatures below 325°F (163°C);
- Permeability >0.10 mD and <6,000 mD;
- Sandstone, layered formations without crossflow. It has also proved effective in carbonates; and
- Capable of sustained production if the water-oil ratio (WOR) can be reduced (i.e., adequate reserves).

RPM post-frac treatment can be used for (1) water reduction treatments in production wells when the hydrocarbon section(s) cannot be protected from the treating fluid, (2) high-permeability streaks, and (3) layered formations with no reservoir crossflow.

Case history background

The treated well was situated in both the Mesa Verde and Wasatch formations in the **Natural Buttes** field near Vernal, Utah. Permeability of the Mesa Verde formation was 0.05 mD, while the permeability of the Wasatch formation was 0.10 mD.

The well was drilled and completed in March 2005. Over a 3-day period, five different intervals were fracture-stimulated in five stages. The total amount of proppant placed was 326,000 lb of 20/40 white sand. After the frac treatments were pumped, the load recovery consisted of a total 2,639 bbl. Over the next 10 days, a total of 2,772 bbl of water was produced. This amount was approximately 5% more than that pumped into the different intervals. The well was allowed to flow and still continued to produce excessive water.

Eventually the well waterlogged and a swab unit was used in an attempt to get the well to flow. After the well began to flow again, it was producing 1 MMscf/d to 1.2 MMscf/d of gas and 700 b/d of water. The cost for disposal of this water was US \$1.70/bbl if it was removed to the customer's facility. If the water was transported to another facility, an additional \$0.95/bbl was required. As a result, the operator decided that an attempt should be made to curb the excessive water flow at its source.

To effectively treat the well, the first step was to determine which intervals were producing water. The intervals were isolated and each one was produced and/or swab tested to determine its water and gas cut. The following zones were identified as high water producers:

- Zone 1 — 5,558 ft to 5,567 ft (1,695 m to 1,697 m).
- Zone 2 — 6,535 ft to 6,547 ft (1,992 m to 1,996 m) and 6,852 ft to 6,855 ft (2,089 m to 2,090 m).
- Zone 3 — 7,709 ft to 7,715 ft (2,350 m to 2,352 m); 7,751 ft to 7,757 ft (2,363 m to 2,365 m); and 7,767 ft to 7,771 ft (2,368 m to 2,369 m).

When the water-producing zones had been identified, the second step was to review the fracturing treatments to determine how much proppant had been pumped into these intervals. The following amounts were determined:

- Zones 1 and 2 — 24 ft (7.3 m) net; 40,000 lb.
- Zone 3 — 16 ft (4.9 m) net; 100,000 lb.

The operator then asked the service provider for treatment solutions that would not plug up the newly placed proppant pack because the well was still producing gas from those intervals.

Post-frac treatment design

The intervals had been hydraulically stimulated with 20/40 sand. Permeability for 20/40 sand can be as high as 120 Darcies, depending on closure stress and the amount of proppant pack in lb/cf. It was recommended that an RPM treatment be pumped into the intervals responsible for the excess water production. This post-frac treatment was initially designed, and stringently lab tested, for permeabilities from >10 mD to <2,000 mD, and <0.10 mD. If left in the sand pack, the treatment would probably have little or no effect. Therefore, it would have to be pumped through the sand pack and into the formation. This requirement was a major consideration in designing the treatment.

The permeability of the formations to be treated was extremely tight: 0.05 mD to 0.1 mD. At the normal recommended concentration, it would have been possible for the size and amount of polymer to actually plug up and damage the reservoir rock. Therefore, it was recommended that a much lower concentration be used. In addition, when the amounts of pumped sand were determined for each interval, a 35% porosity level was assumed to aid in determining the overflush volume needed to pump through the sand pack.

Using this porosity 62.3 bbl of fluid was the minimum volume determined to displace the RPM in the sand pack and then flow into the formation. Therefore, a minimum of 1.5 by 62.3 bbl, or 93.5 bbl, more than the tubular displacement was required. To simplify the process, 100 bbl overflush was used for each zone.

The amount of RPM product to be pumped also had to be determined. Based on discussions with the operator, it was decided that the RPM treatment would be 390 bbl or 16,380 gal (about 400 gal/ft). It was also recommended that each interval be isolated using a retrievable test treat squeeze (RTTS) packer on the treatment tubing string and retrievable bridge plug (RBP) below the zone. The following approximate amounts of RPM treatment would be used for the three zones to be treated: Zone 1 — 3,600 gal; Zone 2 — 6,000 gal; Zone 3 — 6,400 gal.

Post-frac treatment application

The three intervals were treated with a low concentration of fourth-generation RPM in June 2005. Three tanks were on location; two of the tanks were used for flush fluid and the third used for mixing and holding the RPM fluid. Initially, the packer was set at 5,470 ft (1,668 m) after the RBP was placed at 5,675 ft (1,730 m). Before each treatment, the well was filled with 2% KCl water. Injection was established below the frac pressure into Zone 1 (the maximum allowable pressure (MAP) was 1,500 psi). Next, 3,600 gal of RPM treating fluid was pumped, followed by 952 gal of flush, then 4,300 gal of overflush. The packer and plug were then moved to 6,453 ft (1,967 m) and 6,936 ft (2,115 m), respectively.

Injection was established into Zone 2 (MAP: 1,800 psi). Next, 6,000 gal of RPM treatment was pumped, followed by 1,310 gal of flush and 4,300 gal of overflush. The packer and plug were moved to 7,617 ft (2,322 m) and 7,842 ft (2,391 m) respectively. The final injection was established below the frac pressure into Zone 3 (MAP: 2,100 psi).

Finally, 6,400 gal of RPM treatment were pumped, followed by 1,338 gal of flush and 4,300 gal of overflush.

Results

Within 10 days after the RPM post-frac treatment, water production had decreased about 60%, and within one month after the treatment, water production had decreased about 80%. Gas production appeared to stabilize at about 900 Mscf/d (Figure 1).

The initial water production after fracturing was 700 b/d, and current water production is 150 b/d. Using the lower transporting cost estimate of \$1.70/bbl to truck the water, this post-frac treatment could potentially save the operator \$935/day or \$341,275/year. Adding the additional \$0.95/bbl for trucking to an outside location, this treatment could save the customer a total of \$1,457.50/day, or \$531,987/year, for this single well.

Conclusions

Significant past-treatment results indicated:

1. The operator was able to pump a post-frac treatment without causing further damage to the reservoir;
2. Water production was reduced;
3. Hydrocarbon production increased;
4. Water disposal costs were cut; and
5. The economic producing life of the well was extended.

Excessive water cut is not a problem on every well. Nevertheless, this RPM treatment potentially offers operators the option of having a remedial treatment readily available to reduce post-frac water production without losing the benefit of a fracturing stimulation treatment. The RPM post-frac treatment offers operators the opportunity to transform an uneconomical well into an economical one. Another treatment has been applied to a similar well, but as of this writing, it is still too early to determine the results. E&P