Case study: Offshore, Brazil

Fluid bridging process delivered excellent wellbore stability and minimized formation damage

The operator's objective was to drill a 2,460 ft (750 m) horizontal section through a reservoir interval with a diameter of 9.5 in., ensuring a high-quality well without formation damage, imparting wellbore stability avoiding any fluid losses.

The reservoir is in a post-salt oil field located in the Santos Basin 115 miles (185 km) off the shore of Rio de Janeiro, in 5,079 ft (1,548 m) of water depth.

The reservoir is formed by very high porosity and unconsolidated sandstone with an average porosity of 38% and a high permeability of 5 darcies with an extra heavy crude oil of 14° API. The oil has a very strong acid character that, in the presence of mud filtrate, can cause formation damage.

Twice competitors have attempted to drill and test the well, resulting in a damaged reservoir with high skin damage and a low productivity index (PI) of 4.0 $m^3/d/Kgf/cm^2$. A drill-in fluid was used to drill offset wells in order to provide borehole mechanical stability, resulting in equivalent circulation densities (ECD) above 10 lb/gal (1198.3 kg/m^3).

As a result of the high ECDs, massive downhole lost circulation around 120 bbl/hr (19 m^3/hr) was experienced, resulting in an average of 4,780 bbl (760 m^3) of fluid lost.

Significant lost-circulation materials with different concentrations were used without success.

Due to severe losses and difficulty maintaining hole inclination, the well had to be abandoned and a sidetrack was done to reach final depth.

Losses caused by the fluid's inability to reach total depth (TD) during the second attempt to drill the well again required abandonment.

Based on information from both of the offset wells and reservoir characteristics, Baker Hughes proposed a solution that included the use of the **PERFFLOW™ CM water-based drill-in fluid**, which is specially formulated to overcome challenges similar to those encountered on this project.

The solution also included analyses using the Baker Hughes **BRIDGEWISE™ engineering software** to formulate the best product combination, and the Baker Hughes **SOLUFLAKE™ calcium carbonate**, which is effective in controlling circulation losses and seepage.

Tests using the SOLUFLAKE calcium carbonate were performed in a 30/50 micron sand pack. The optimized formulation, a combination of 10 ppb of Soluflake fine, 5 ppb of Soluflake medium, and 30 ppb of fine calcium carbonate, showed no fluid losses.

In order to reduce the possibility of fluid filtrate and formation oil interaction, tests were performed in the Baker Hughes Rio Research and Technology Center to optimize the fluid system and ensure a drilling fluid formulation compatible with the strong acid character of the formation oil.

The operator drilled the interval with a low-fluid density of 9.3 lb/gal (1114.4 kg/m^3)—close to the formation pore pressure—adding the SOLUFLAKE calcium carbonate while drilling to

Challenges

- Ultra-deepwater well at 5,079 ft
- Sandstone reservoir with high permeability of 5-6 darcies and porosity at about 38%
- Narrow operational window with high risk of lost circulation and formation collapse
- Unsuccessful attempts in two offset wells with severe fluid losses, resulting in high skin damage and low PI
- Drill and condition the well without fluid losses
- Avoid formation damage and maximize PI
- Ensure gravel packing operation occurs without fluid losses

Results

- Drilled and conditioned well without formation losses
- Reduced overall drilling NPT
- Increased wellbore stability by allowing higher ECD values
- Performed gravel packing operation without formation losses
- Avoided reservoir damage
- Custom particle size distribution minimized skin damage
- Maximized reservoir production (productivity index was greater than offset wells)

provide high wellbore stability and avoid lost circulation.

The well was drilled to a horizontal section length of 2,460 ft (750 m) and a diameter of 9.5 in. (23.1 cm), as planned.

No losses were observed while drilling the interval, even as ECDs approached 10 lb/gal. At TD, the well was conditioned and the PERFFLOW CM fluid was displaced by a completion fluid and no losses were observed.

The horizontal part of the well was then completed with screens and packed with gravel. The operation was performed without any losses.

A drill stem test (DST) was then successfully performed with two different flow periods. The first flow was more restricted in order to collect bottomhole samples of oil and gas; the secondflow had less restrictions.

The two flow periods produced oil flow rates of 1,250 bbl/day (198.7 m^3/day) and more than 5,000 bbl/day (794.9 m3/day), respectively.

These flow rates were subject to considerable constraints associated with the set-up of the DST and the limited capacity of the surface facilities (storage, short term flaring limitations, and low-capacity electrical submersible pump).

Furthermore, the test confirmed a PI higher than estimated during reservoir simulation studies with negative skin damage.

A customized solution using the PERFFLOW CM fluid and the SOLUFLAKE calcium carbonate was the key to meeting the multiple challenges posed in this project. The solution minimized downhole losses by sealing off the highly permeable reservoir sand.

Previously, the average downhole loss was 4,780 bbl per 8½-in. section in one well, compared with no losses on two wells in the same field drilled with the SOLUFLAKE calcium carbonate.

The Baker Hughes solution increased wellbore stability by allowing higher ECDs of up to 10 lb/gal (1198.3Kg/m^3), eliminating differential sticking, and increasing reservoir productivity by avoiding formation damage. The results obtained using this technique exceeded the operator's expectations.

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