INNOVERT® fluid high-performance invert emulsion fluid system

INNOVERT® fluid demonstrates stability and resilience in challenging deepwater Angola project

Location: Offshore Angola

Operator challenge

While drilling an offshore deepwater well, an operator encountered a well control situation followed by two periods of inactivity for rig repair, each lasting, on average, for seven to 10 days. During each of these events, Halliburton's INNOVERT® downhole mud system was put to the test to help maintain hole integrity. The stability of this high-performance invert emulsion fluid was tested by facing higher--than-expected static bottomhole temperatures (up to 130° C) while operating with a higher-than-programmed mud weight.

HAL40700

Static-aged INNOVERT® fluid after 72 hours at 130°C

Halliburton solution

The Baroid Angola team worked tirelessly both on and offshore, initiating a field and laboratory test program designed on the basis of a hopper or funnel with the end goal of providing a fit-for-purpose treatment plan. The operator played an integral role with the development of such a plan and worked with Baroid to set the initial objectives. The project followed Baroid's problem-resolution process outlined in the Baroid technical process.

A kick during drilling led to an increase of the mud weight from the programmed 9.9 ppg to a final density of 14.9 ppg, which, in turn, increased the percentage of high-gravity solids from 8 percent to 24 percent. This required a thorough review of the fluid's parameters. The INNOVERT fluid's ability to provide a well barrier might have been put in jeopardy if proper treatments for barite suspension were not put in place. "Light spots" in a circulating system can lead to catastrophic results. Close attention was paid to the sag behavior of the fluid, and the design and maintenance of the system was primarily aimed at reducing the risk of both static and dynamic sag to their lowest possible levels.

CHALLENGE	SOLUTION	RESULT
The deepwater Angola project had long periods of inactivity with higher-than-expected downhole temperatures	Halliburton Baroid applied a customized INNOVERT fluid system with 14.9-ppg density to maintain hole integrity	During two occasions of 10 days of rig repair, there were no indications of fluid breakdown, thus saving the operator eight days of NPT for potential cost savings of US$9.6 million

The objectives of the INNOVERT treatment plan were to:

- Maintain a homogeneous well barrier with minimal risk of sag
- Add barite to raise the mud density
- Oil-wet barite with additions of emulsifier
- Keep a tight filtrate at elevated SBHT up to 130°C
- Design a rheological property plan, ensuring suspension of barite and avoidance of sag; Tau 0 to remain above 12 lbs/100 ft^2
- Ensure that the concentration of Baroid's SOURSCAV® scavenger remained at 2 lb/bbl in the active fluid due to possible H_2S presence in the target section
- Ensure that the excess lime concentration was held at a minimum of 0.5 lb/bbl due to the risk of CO_2 influx

When the kick was experienced, the fluid system was 9.9 ppg. The 13.4 ppg INNOVERT from previous section that was on the supply vessel on its way to town was turned back and the well was displaced back to 13.4 ppg INNOVERT. On the rig initially, 350 bbl of this INNOVERT was treated with the required products concentrations to deliver a more resilient 13.4 ppg system. Successful sag testing and High Pressure/High Temperature (HP/HT) testing to 130 deg C, demonstrated a stable and resilient fluid. Additionally lab testing was carried out in the onshore Luanda lab on Active INNOVERT from the rig weighted up to 14.9 ppg, treated with an agreed products mixture and aged in the oven for 24, 48 and 72 hours respectively, no indications of sag were observed, and only slight evidence of top oil separation was seen after 72 hours (see image). From these results, the entire 5,000 bbl of 13.4 ppg system offshore was treated thoroughly to be more resilient and gradually weighed up to 14.9 ppg. Following two logging campaigns spanning five and eight days, respectively, and two occasions of 10 days of rig repair, there were no indications of INNOVERT fluid breakdown.

Maintaining the integrity of the well during logging operations and the two periods of inactivity had an estimated potential saving of eight days of nonproductive time (NPT). This was calculated assuming a two-day check trip and treatment program after each well control event. By avoiding the trip and treatment programs, the operator was able to save an estimated US$9.6 million.