Operators raise downhole fluids expectations as they push boundaries with HPHT, ERD wells

FOR DRILLING FLUID companies, working on today’s ERD wells is often like “playing on the knife’s edge,” said Nick Braley, director of technology at Baroid. Management of the equivalent circulating density (ECD) is critical on extended-reach drilling (ERD) wells, and that has evolved into a tough balancing act on wells with very narrow windows between pore pressure and fracture gradient.

“You don’t want the well to kick so you stay above pore pressure. At the same time, you don’t want to fracture the formation and induce losses,” he said.

“Operators are starting to push the horizontal displacement of their ERD wells to a degree that is testing the limits of current technology. From a fluids perspective, we’re being asked to design fluids to do things we haven’t had to achieve before,” he continued.

Operators also continue to push the drilling envelope with high-pressure, high-temperature (HPHT) wells. One of the biggest challenges there, he said, is getting fluids to maintain their properties over time, under high pressures and high temperatures, and in both dynamic and static environments. While fluid is circulating, it doesn’t heat up to its maximum temperature. Then when pumps are shut down and the fluid is static, there can often be significant temperature changes in the wellbore. And it doesn’t help that as wells get deeper, trip times are getting longer, which means longer static periods at higher temperatures.

Considering these challenges, Baroid has been working on several fluid technologies to accommodate operators’ evolving expectations, he explained.

One important focus has been on micronized weighting materials. Barite is easily found and used to be the predominant weighting agent of choice for drilling fluid companies. However, in modern HPHT wells with 18 lb/gal or heavier fluids, he pointed out, “there are a lot of solids just from the weighting material in the fluid.”

Baroid has been looking into alternative weight additives other than barite, including micronized weighting material with smaller particles, and they’re bringing their own sets of challenges, such as additional surface charges with different chemistries that can interact. It can also be difficult to make these materials stay oil-wet yet be able to be pulled into the oil water in the phase.
“In the process we’ve learned that it’s important to get as stable an emulsion as possible,” Mr Braley said. “We do that chemically, using emulsifiers, and by making sure we pull the solids in, which provides greater stability over time. Adding heat to the system means adding kinetic energy, and that makes things break down more easily. So it’s important to stabilize as much as possible.”

A second focus at Baroid has been around completions, particularly for deepwater applications. In deepwater, uncontrolled heat transfer and heat loss from the production tubing can damage outer annuli integrity, and paraffin and asphaltene deposits can impact production rates.

There were existing solutions, such as non-aqueous packer fluids or vacuum insulating tubing (VIT), but they carried associated density and cost issues. Historically, it’s been difficult to keep the packer fluid gelled for extended periods of time at high temperatures. “Once you pump packer fluid down, it can be in the well for 10 or 20 years, depending on the life and production of the well,” he said.

Operators began challenging Baroid to develop a solution, Mr Braley said, and the company responded with a new thermally activated polymer technology that can reduce both conduction and convection heat loss. The new N-SOLATE packer fluids have heat transfer measurements between 0.12-0.17 BTU/hr ftºF and can provide long-term stability at 275ºF and beyond. A 400ºF version is also being tested. The first commercial N-SOLATE 275 system is expected to be used on a deepwater Gulf of Mexico location in the second quarter of 2008.

One significant challenge in developing these and other high-temperature products has simply been the lack of appropriate testing equipment, Mr Braley said. Equipment development at FANN, also a Halliburton company, has provided HPHT testing capability with the FANN ix77 rheometer. The FANN ix77 rheometer increases testing capabilities to 600ºF and 30,000 psi, simulating real downhole environments. “(The testing) gives us a better comfort factor knowing it will work once it’s actually put into a well,” he said.

THE DIGITAL ASSET

Halliburton has been aggressively developing a “digital asset” focus, centered around the ability to gather rig-site data on a real-time basis. That focus is no different for drilling fluids, Mr Braley said.

Baroid will soon launch DFG, a predictive tool that will allow real-time fluid monitoring for improved hole-cleaning and ECD management. It will use the InSite platform from Sperry Drilling Services for real-time capabilities, and a field trial is expected in 2008.

In conjunction with that, though further down the road, Baroid is also looking into the possibility of real-time mud testing, Mr Braley said. The company is working on new equipment – the first two are an automated HPHT cell and a real-time emulsion stability reader – on the rig to take samples and test them on a continual basis. Field trials are possible this year as well.

“Fluid properties play such a key part in ECD management,” he remarked. “It doesn’t make sense to get real-time downhole data, only to combine it with 6-hour-old fluid data. This automated testing ability will really give us the full picture as we’re drilling.”