Baker Hughes

Case study: Offshore, Gulf of Thailand

MAGMA-TEQ SBM system delivers high-temperature wells to target for optimized production, saving $95K USD

An operator drilling high-temperature wells offshore Thailand struggled to deliver wells to target depth (TD) with conventional synthetic-based mud (SBM) systems. Drilling through a section with bottomhole static temperatures (BHSTs) above 420°F (216°C) presented mud stability challenges. It also created well logging problems in the form of stuck tools, frequent tool breakdowns, barite sag, and high break circulation pressure—all of which resulted in significant non-productive time (NPT) and failure to reach TD in several wells.

The operator reached out to Baker Hughes to develop a high-temperature drilling fluid solution that would remain stable under both dynamic and static conditions. The solution would also have to deliver a high-quality wellbore to TD, thus minimizing the risk of stuck pipe and lost tools, ensuring efficient wireline logging, and maximizing the full production potential of the well.

Designing an optimized fluid solution

Baker Hughes proposed its MAGMA-TEQ™ synthetic-based invert emulsion drilling fluid system for the drilling operation. This high-temperature synthetic-based mud (SBM) demonstrates superior rheological stability and filtration control properties beyond the temperature limits of standard emulsion systems. Different MAGMA-TEQ formulations have been successfully deployed in development and exploration wells in many Gulf of Thailand wells.

Baker Hughes drilling fluids experts worked with the operator to acquire the necessary formation data to guide the lab testing and formulation designs.

An in-house simulation software was also used to predict the optimal equivalent circulating density and hole cleaning criteria for the fluid.

Based on the lab testing and simulation work, a MAGMA-TEQ formulation was selected containing the MAGMA-VERT™ high-temperature emulsifier, MAGMA-TROL™ fluid loss control additive, and additional emulsifiers and viscosifiers. This formulation would meet the key performance indicators related to low fluid rheology, low-gravity solids content, minimal mud weight variation, and normal break circulation pressure after 72 hours of static hole conditions at BHSTs of 390°F to 420°F (199°C to 216°C).

Executing with high efficiency

The operator and Baker Hughes fluid experts agreed that the MAGMA-TEQ solution would be implemented while drilling a 6 1/8-in. section of the well, which was where excessive BHSTs were typically encountered in other wells.

Drilling commenced with a more traditional SBM, until the bottomhole circulation temperature reached 350°F (177°C). At this point the traditional fluid was gradually replaced with the MAGMA-TEQ formulation. As the fluid circulated back to surface,

Challenges

- Bottomhole static temperature (BHST) exceeding 390°F – 420°F (199°C – 216°C)
- Increased risks of mud instability, hole problems, and stuck tools that could increase NPT and limit ROP
- Separate wiper trips threatening higher rig costs and longer logging times

Results

- Successfully drilled to TD and reached all targeted production zones
- Eliminated lost circulation and maintained fluid stability under dynamic and static conditions
- Ensured wellbore conditions for wireline logging and tubular running operations
- Minimized mud weight variations
- Saved the operator an estimated $95k USD on rig and mud costs

its properties were continuously monitored to ensure that the KPIs related to mud weight, solids content, and rheology were being met.

Meeting all metrics to deliver a high-quality well

The MAGMA-TEQ formulation fully met the operator's KPI requirements and delivered excellent rheological properties, filtration control, and filter cake quality while drilling the 6½-in. intervals with BHSTs exceeding 420°F (216°C).

The system maintained its properties while the hole was static for up to 48 hours. Excellent hole cleaning was achieved in accordance with the hydraulics simulations. The MAGMA-TEQ formulation did not chemically degrade at high BHST, allowing the fluid to be recaptured and reconditioned for additional cost savings.

The high-quality wellbore was fully logged and evaluated without any stuck tool challenges or extra wiper trips required—minimizing NPT while **saving an estimated $95K on rig and mud costs.** The well was efficiently completed to target TD, allowing the operator to maximize production rates.