Total E&P Norge benefits from new fluid strategy for drilling and completions

Total required a new fluid strategy to solve a multitude of issues associated with the high-pressure Martin Linge gas reservoir, in the North Sea. A low-solids cesium/potassium formate fluid was proposed, because of its ability to produce easily through sand screens and successfully deliver a challenging well.

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In 2017, Martin Linge field, in the central North Sea, was operated by Total E&P Norge (now by Equinor). It’s in Northern Viking Graben Blocks 29/9 and 30/7 of production license (PL) 043 and Blocks 29/6 and 30/4 043B, at a water depth of 115 m, Fig. 1. The overburden contains interbedded shale and coal layers, with an over-pressured reservoir between 3,800 and 4,150 m, TVD.

A heavy, 2.05 g/cm³, non-aqueous based mud (NABM) was selected initially as drill-in and screen-running fluid, based on good results from qualification testing. Cesium formate had been considered initially, but it was discounted, due to several factors, including risk of subsurface drilling losses, concern over wellbore stability using WBM, and high unit cost. Additionally, Total’s lack of experience using cesium formate as a reservoir drill-in and screen-running fluid also was a concern.

By end-of-year 2017, four gas producers were drilled and completed. During operations, potentially unstable shale and coal beds, high formation pressure, and surprisingly high permeability (2.6 Darcy avg) contributed to the challenge of drilling the wells successfully. An unconsolidated sandstone and high temperatures, ranging between 135° C and 145° C, also were concerns.

REASSESSING FLUID STRATEGY

Cleanup from the first three gas wells that were drilled and completed using NABM was difficult, including an exhausting coiled tubing operation. These difficulties were enough for Total to reassess its fluid selection for the fourth well.

Most importantly, the new fluid would need to flow easily through screens and allow easy clean-up. Second, it should provide good fluid-loss control to reduce seepage and differential sticking, low equivalent circulating density (ECD), and minimal swab/surge pressures. Third, it should provide optimal wellbore stability while drilling through shale and coal zones.

Attention was focused again on formate fluids. Beneficially, no solids are required, as the base 2.20 g/cm³ cesium formate and 1.57 g/cm³ potassium formate brines are solids-free. They have very low water activity ($a_w = +/–0.25$) and provide a low-rheology drill-in system with non-progressive gels. This is ideal for optimizing rate of penetration (ROP) and for stabilizing shales. Furthermore, formate fluids have a proven track record for drill-
ing and completion operations in over 50 challenging fields, such as Equinor’s Kvitebjørn and Huldra in the North Sea.

Total decided on 2.07 g/cm³ cesium/potassium reservoir drill-in fluid with purified xanthan gum to provide viscosity and high-temperature modified starch, combined with two grades of calcium carbonate bridging agents, to deliver fluid-loss control, Fig. 2. The formulation was tested thoroughly, with strong results delivered on all key criteria. Following these test approvals, the drilling operation was given the green light. The full list of fluid performance targets is shown in Table 1.

Drilling with formate fluids. The drilling performance in the fourth reservoir section, drilled with cesium/potassium formate fluid, was substantially better than in the first three drilled with NABM. A true comparison is possible, as the same hybrid drilling bit was used for all but one of the 8½-in. reservoir sections. ROP almost doubled in Well 4, even though weight on bit (WOB) was approximately 50% less than on previous wells. ROP would have been even higher, if restrictions hadn’t been set, Fig. 3. Rates were limited to around 15 m/hr in shales and 5 m/hr in pay zones and coal beds, based on earlier experience controlling gas levels, lowering stuck-pipe risk, and managing drilling torque with the NABM. Furthermore, there were no signs of bit balling or clay accretion.

Drilling parameters. Flowrates were similar in all four reservoir sections, ranging from 1,080 to 1,215 l/min., while average surface string RPM went from 130 to 160. Stand-pipe pressure (SPP) is significantly lower in Well 4, with a 35% drop, Fig. 4. This reduced wear on surface mud equipment and paved the way for even higher ROP. ECD for Well 4 is reduced by over 25% (0.016 g/cm³), compared to the first three wells. In addition to lower annular pressure loss, the well drilled with cesium formate fluid had a smoother ECD pattern and was completely free of pressure spikes, Fig. 5. Bottomhole circulating temperature was also around 5° C to 15° C lower than the first three wells. This was due to the higher heat capacity and thermal conductivity of cesium/potassium formate-based fluids, compared to non-aqueous-based muds. These beneficial fluid properties enable improved hole stability and greater operational efficiency.

Fluid properties. Keeping within drilling fluid specifications was effortless. In fact, measured field properties surpassed laboratory test results for both rheology and fluid loss, with the latter showing an average high-pressure, high-temperature (HPHT) fluid loss through a 50 μm ceramic disk of 7 mL/30 min. and a spurt loss of 2.8 mL. Both were significantly below expectation and were achieved with a minimum of chemical additives.

Static density remained stable and only once, at the start of the section, was a small amount of 9 m³ cesium formate added to increase density by around 0.05 g/cm³. Potassium carbonate and potassium bicarbonate pH buffer, which was added,

<table>
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<th>Table 1. Performance targets for formate fluid.</th>
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<td>Fluid performance targets</td>
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<tr>
<td>Problem-free operations</td>
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<tr>
<td>No downhole seepage or losses</td>
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<tr>
<td>Very strict parameters on above-surface losses</td>
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<tr>
<td>High ROP with low WOB</td>
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<td>Low ECD</td>
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<td>Minimal fluid treatments</td>
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<td>High degree of safety</td>
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<td>Excellent wellbore stability</td>
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<td>No spikes in pump pressure</td>
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<td>Uniform transient downhole pressure</td>
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<td>Excellent hole cleaning</td>
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<tr>
<td>Proven ability to successfully run screens</td>
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<tr>
<td>Stable flowrate</td>
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Fig. 3. The ROP increased significantly, using formate fluid, even with lower WOB.

Fig. 4. Pump pressure comparison on the four Martin Linge wells (8½-in. sections).
to minimize the effect of acid-gas influx, dropped slightly from 14.8 to 12.3 kg/m³, with a corresponding insignificant fall in pH from 10.4 to 10.0.

FORMATE FLUID RESULTS

The new cesium formate fluid used in Well 4 significantly differs from the NABM used previously on rheology, solids content and filter-cake quality. It displayed a more pseudo-plastic (shear thinning) rheological behavior compared to the NABM, both at ambient and HPHT conditions. This means less system pressure loss inside the drillstring and annulus.

The thin, non-elastic filter cake produced by the formate fluid is far superior to those from the first three wells, and lowers risk of differential sticking. However, on the other side of the equation, mechanical friction experienced during drilling of the fourth reservoir section was higher than in the first three sections, and increased drilling torque by 25%, compared to the NABM.

Wellbore stability was vastly improved, using the low-solids formate fluids, with no indication of a reduction in hole cleaning performance. In the first three wells drilled with NABM, Total encountered stuck pipe in the coal sections, with one requiring a sidetrack. By comparison, there were no incidents in Well 4 whatsoever. In fact, the appearance of coal in the cuttings was the only indicator that a coal zone was being drilled.

Wireline logging objectives were not realized in the first three open-hole sections with tools hanging up, various restrictions encountered and tool strings stuck. Equally, running sand screens proved problematic. For Well 4, logging-while-drilling, a separate logging run on pipe and screen running were all problem-free, without any sign of hole enlargement or well fill.

Well control. Interestingly, formate fluids provided clear well-control benefits, compared to NABM and other WBM. Solubility of methane gas in cesium/potassium formate was even lower than in water, which means potential kicks are detected earlier. Furthermore, gas diffusion rates were lower in formate fluids than NABMs, which again benefits well control.

The 11 flow checks performed during drilling of the reservoir sections with formate fluids were all stable, with no influx. Gas levels were low throughout the section; no connection gas was observed. Maximum trip gas was 2.8% from bottoms-up, using an LWD bottomhole assembly. Very little time was spent confirming stable flow checks or circulating, due to the impressive thermal stability of cesium/potassium formate fluids.

Using such natural high-density brine meant no weighting solids were required. A minimal amount of low-density (2.70 g/cm³) calcium carbonate bridging solids was used, so sag was not a concern. No density variations in the drilling fluid were observed after longer static periods.

Fluid losses. The total amount of cesium/potassium formate fluid lost was only 37 m³, which includes surface losses, fluid lost during tripping and displacement interphases, as well as fluid left below the lower completion plug.

Prior to the operation, concern about subsurface losses was paramount, because of a potentially narrow mud-weight window and high unit cost of fluid. Total’s strategy was as follows:

- Retain twice the hole volume of fluid and chemicals on the rig.
- Transport pre-blended fluid to the rig.
- Continuously mix bridging agents with the fluid during drilling and circulation operations.
- Pre-mix LCM pills in dedicated mud pits for quick response to possible losses.
- Keep NABM on the rig, in case of full circulation loss.

These emergency measures were not used, as there were no seeps or circulation losses during the drilling operation. In fact, actual losses, including surface losses, were lower than expected and lower than the first three gas wells drilled with NABM. This is due to: 1) higher rig awareness of fluid unit cost; 2) careful monitoring by fluid engineers; and 3), lower solids content and rheology that aid cuttings separation on the shale shakers.

In addition, shale-shaker screen blinding did not occur during the drilling operation. Screen blinding can typically lead to excessive losses over screens, and its elimination is a further benefit of low-solids content in drilling fluids.

Screen running. A series of seven consecutive production screen tests (PSTs) showed the drilling fluid system’s suitability as screen-running fluid, with no signs of screen plugging. Following a second successful series of PSTs, the lower completion sand screens were run in hole successfully with no obstructions, and the full fluid volume returned. After setting, the lower completion was placed without difficulties. After the screen-hanger packer was set, fluid density was increased to 2.10 g/cm³ to offset gas migration, in case of packer leakage during upper completion installation.

In the case of Well 4, 250-micron stand-alone sand screens replaced expandable sand screens used in the first three gas wells.

Clean-up. As improved well performance was the main driver for Total to pursue a new fluid strategy, so it was clearly rewarding when Well 4 demonstrated significantly better clean-up than the first three wells. Start-up was much smoother, flow stabilized faster, and there were no indications of screen plugging during the clean-up operation. As expected, flow from Well 4 was sluggish, which was in direct contrast to the piston-like flow from
Well 2 and Well 3, and complete lack of movement in the first well.

Although clean-up time was greatly reduced, the productivity index (PI) of Well 4 was more than double that of the previous two wells. The pressure derivative of the fourth well build-up pressure confirms excellent connectivity to the reservoir, which is confirmed through permeability data derived from petrophysical logs. The build-up pressure derivatives from the earlier wells, show the opposite (i.e. plugging of the formation, the screens or both).

**CONCLUSIONS**

Replacement of NABM with cesium/potassium formate drilling and screen-running fluid for Well 4, drilled and completed in Martin Linge field, met or surpassed all objectives set for the fluid.

Cesium/potassium formate fluid facilitated a stable well, which delivered beyond target on key operational aspects.

**Drilling hydraulics**

- ROP was significantly higher, with lower WOB than was required to drill the first three wells. ROP would have been higher still, but was restricted, based on earlier experience with the NABM.

- Time-consuming sieving circulation operations were eliminated with cesium/potassium formate fluid, which passed PST criteria the first time around.

- Test results from Well 4 showed full connection to the reservoir. This is in stark contrast to the earlier wells, where data indicated partial plugging of the screen and/or formation.

- Clean-up time was considerably shorter for Well 4 compared to earlier operations.

- PI more than doubled in Well 4, compared to the wells drilled with NABM.

In summary, the operator considered Well 4 a technical and commercial success, based on lower-cost drilling and tripping operations, problem-free installation of the lower completion and significantly reduced clean-up time.

**Sieving**

- SPP was considerably lower in Well 4 than those drilled with NABM with a 35% reduction.

- ECD was an average 0.016 g/cm³ lower than in the earlier reservoir sections drilled with NABM.

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