**CASE STUDY: Drill-in fluid and delayed breaker deliver 104% return permeability**

**Reservoir Drill-In Fluids / Filter Cake Breaker Systems**

**BARADRIL-N® drill-in fluid and N-FLOW™ 408 filter cake breaker help operator maximize productivity in a mature field**

Location: Sarawak, Offshore East Malaysia

**Overview**

An operator planned to drill a horizontal well in a mature field. The low reservoir pressure prompted the operator to design an openhole completion consisting of a stand-alone screen installed in the horizontal leg of the wellbore in order to maximize reservoir contact and hydrocarbon output.

The reservoir was a high-permeability, relatively clean sandstone. The field had been in production since 1984 and was now considered a mature asset. Offset data showed that the field was developed using a conventional cased-hole completion strategy.

In 2015, a drilling campaign was initiated by drilling four wells, three of which were designed originally as horizontal laterals with stand-alone screen completions.

For the proposed well, the operator’s main objective was to maximize production from the reservoir by using a non-damaging reservoir drill-in fluid followed by treatment with a filter cake breaker system.

**Halliburton’s Solution**

The Baroid team performed extensive testing to optimize the formulation for BARADRIL-N® non-damaging, water-based, reservoir drill-in fluid. Data gathering included chemical analysis of connate water, along with evaluation of reservoir core samples, which were sent to the Baroid lab in Houston for detailed analysis and reservoir return permeability studies. Initial screening on the connate water indicated an abundance of dissolved carbonate species and high pH, which prompted Baroid to avoid using divalent brine systems as carrier fluid to mitigate the precipitation of calcite scales within the reservoir formation rock.

The minimum mud weight required to drill the horizontal leg in the reservoir section was 9.2–9.5 ppg. However, geomechanics studies conducted in the field showed a low but significant probability of requiring mud densities up to 11.5 ppg.

<table>
<thead>
<tr>
<th>CHALLENGE</th>
<th>SOLUTION</th>
<th>RESULTS</th>
</tr>
</thead>
<tbody>
<tr>
<td>The operator wanted to maximize production in a low-pressure reservoir in a mature field.</td>
<td>The reservoir was drilled with engineered BARADRIL-N® drill-in fluid and then acidized with N-FLOW™ 408 filter cake breaker.</td>
<td>Testing showed 104% return permeability after the breaker treatment, and production exceeded expectations.</td>
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</tbody>
</table>
Therefore, the fluid design needed to incorporate an easy weight-up process, if required. A potassium chloride (KCl) monovalent brine system was selected as carrier fluid for the lower-density case, whereas the intermediate or higher densities could be easily achieved by incorporating sodium chloride (NaCl) into the mud system. Alternatively, sodium bromide (NaBr) would be added for densities up to 11.5 ppg.

Reservoir rock analysis revealed the occurrence of small but significant clay deposits. Investigation using energy dispersive spectroscopy (EDS) and X-ray diffraction (XRD) showed mainly kaolinite and illite clays (Fig. 1). In a parallel rock analysis using scanning electronic microscopy (SEM), the core rock sample average pore throat size was estimated at 30 µm, with a D90 value at 48µm and a D10 value estimated at 17µm (Fig. 2).

These results demonstrated the need for clay inhibition and a bridging strategy. CLAYSEAL® PLUS shale stabilizer was selected to help minimize clay migration and swelling mechanisms while drilling the reservoir section, and to avoid polymer blockage of the planned in-situ filter cake breaker treatment (N-FLOW™-408 delayed-reaction filter cake breaker).

Based on results from the WellSET® treatment module of Drilling Fluids Graphics (DFG™) modeling software, the bridging package for the BARADRIL-N drill-in fluid was engineered to provide tight filtration control. BARACARB® sized ground marble was added at different proportions to minimize filtrate, after testing the blend on a broad range of pore sizes on ceramic disks (Fig. 3). Further engineering for filtration control included N-DRIL™ HT PLUS filtration control agent and N-VIS® viscosifier. BARABUF® pH buffer was used for alkalinity control.

The final BARADRIL-N drill-in fluid formulation was subjected to return permeability testing to ascertain the risk of damage to the reservoir formation and to validate the fluid design. The results indicated a 96% return permeability value, as depicted in Fig. 4.

The second phase of the reservoir fluids design involved the use of a filter cake breaker system. Baroid formulated an N-FLOW 408 in-situ acid-generating system to provide optimal wellbore clean-up and maximum delay time during the completion phase of the project. The completion program required 14–18 hours to install the production screen, and unlatch wash pipe, and finally close a reservoir isolation valve (flapper valve).
Lab testing with N-FLOW 408 breaker system showed a delay time of more than 24 hours at 217°F (static bottomhole temperature). Further, the reservoir rock core sample was exposed to the BARADRIL-N fluid followed by an N-FLOW breaker treatment for 72 hours. The return permeability value was shown as 104% as compared to previous results in which the core sample was only exposed to the designed BARADRIL-N drill-in fluid, indicating that the N-FLOW breaker treatment has the ability to stimulate the reservoir rock.

The reservoir section was drilled after setting 9 5/8-in. casing. The well was displaced from ENVIROMUL™ oil-based mud to 9.0-ppg BARADRIL-N drill-in fluid. The operator drilled the 8 1/2-in. interval to total depth (TD), with a total footage of 1,180 ft. Particle size distribution (PSD) analysis using a laser diffraction apparatus was monitored while drilling the reservoir section to ensure that the target PSD was maintained.

At interval TD, the well was displaced to a screen deployment fluid (a newly mixed BARADRIL-N fluid tested with production screen test kit to ensure that screen would not be plugged). The production screen was deployed and the N-FLOW 408 breaker treatment was displaced downhole.

No losses were reported during production screen deployment or N-FLOW treatment displacement. The flapper valve was closed approximately 16 hours after the N-FLOW 408 displacement. The well was tested and produced seven days later.
Economic Value Created

Using BARADRIL-N non-damaging drill-in fluid (instead of ENVIROMUL oil-based mud) to drill the reservoir section on earlier wells could have potentially saved the customer an average of $208,211 per well. In addition, the skin factor of the well treated with N-FLOW breaker was negative (-2) and the expected production rate was also higher.

Together, the combination of BARADRIL-N drill-in fluid and N-FLOW 408 delayed-reaction filter cake breaker treatment represented a significant savings to the customer while also increasing hydrocarbon output from this mature field.

Fig. 6. N-FLOW 408™ breaker effect on BARADRIL-N® system filter cake, with disks showing before (left) and after (right) treatment.

Fig. 7. Lab testing with N-FLOW 408 breaker system showed a delay time of more than 24 hours at 217°F (static bottomhole temperature).