Central Graben Extreme Offshore High-Pressure/High-Temperature Cementing Case Study

By: John North

This paper presents six cementing case histories from offshore wells in the Central Graben area of the North Sea. These wells were chosen because they provide valuable information regarding the problems encountered in cementing extreme offshore, high-pressure/high-temperature (HPHT) wells. The Central Graben wells had an average depth of 6000 m true vertical depth (TVD), temperatures greater than 200°C, small fracture/pore-pressure margins, and bottomhole pressures exceeding 1,100 bar. The well deviation varied from near vertical to a maximum of 35°. These downhole conditions are the most extreme yet experienced in a field development in the North Sea.

This study describes how the cementing process was optimized for HPHT field development, thereby minimizing risk and costs. Considerable emphasis is placed on the production liner cement job, because it was the most critical string on the well. Improvements to equipment, slurry testing, placement, and bond logging procedures are also described.

Well Descriptions

Five wells were drilled in the Franklin field, and one appraisal well was drilled in the Glenelg field. These wells were drilled in the Central Graben area of the North Sea (Figure 1). A typical cross-section of a well is shown in Figure 2.
Figure 3 is a schematic of a typical well in the six-well package. Table 1 presents pertinent well data. The openhole coverage of these liners was long, ranging from 660 to 1027 m.

Another feature of the wells, along with the high temperatures, is the rapid increase in formation pressure through the thin transition zone. The setting of the 9 7/8-in. casing is critical to achieving sufficient leakoff for the well to be drilled to total depth (TD) with a 2.15-SG drilling fluid. Even when the casing point is chosen correctly, the narrow window between formation pressure time and fracture gradient time is extremely tight. During the drilling of the 8 1/2-in. section, it is difficult for the drilling fluid to operate within this narrow window (Figure 4).

As seen in Figure 4, the pore-pressure prediction margin is large and rises very quickly at the bottom of the 12 1/4-in. hole section. At the top of the reservoir, the pore and fracture pressures are very close, and the margin between these properties may be smaller than 0.15 SG. The transition zone at the top of the reservoir tends to give and take, causing concerns during drilling. This formation response has been referred to as formation breathing.
**Preplanning**

Because of the extreme HPHT conditions, all aspects of cementing operations had to be carefully evaluated. In addition, new and enhanced equipment, processes, and materials had to be developed.

Even though the potential for gas influx of the cement was high, the cement slurry formulation and placement techniques for resisting gas migration were successfully designed through the use of materials with a low environmental impact. Because the upper formations were weak and unconsolidated, a special cement blend was used at the top of the well. The mixing equipment was modified to withstand the high-density fluids required for the liner section.

For job success, a well-defined top-of-cement (TOC), good casing support, and zonal isolation had to be obtained without exceeding the allowable equivalent circulating density (ECD) limit. Therefore, effective mud displacement, correct slurry placement, and precise rheology measurement were required. Because of the accuracy needed in ECD calculations and the need to have representative downhole rheology, a new HPHT cement rheometer was introduced. This was also used to determine the rheology of the spacer and cement to ensure maximum displacement efficiency.

Formation breathing has been treated in the past as though the well was kicking and the mud density was raised; however, the increase in mud density can invoke losses, and can further reduce the chance for a successful liner-cementing job. The mud properties become vital in securing the best conditions for cementing, both in terms of reduced ECD and desired mud properties for cementing, and they have been crucial in the success of the cementing operations. ECDs were calculated with a special computer-based model that has been proven by downhole pressure measurement.
No remedial HPHT cementing operations were necessary during these operations, which was an important objective. Remedial operations could have posed extreme risks and high associated costs.

Because the conditions encountered in these developments are among the most severe in the world, an extensive scope of laboratory work was involved in qualifying the cementing systems used, especially with respect to the production liner. These systems, which included spacers, cement, additives, and an array of equipment designed for high-temperature operations had to be qualified to perform at the expected temperatures.

![Figure 3—Well schematic.](image)

**Problem Identification**

HPHT reservoirs generally exhibit the following characteristics:

- total vertical depth greater than 4500 m
- pressure greater than 1,000 bar
- temperatures from 160° to 260°C
**Table 1 - Well Casing Points**

<table>
<thead>
<tr>
<th>Well No.</th>
<th>29/6b-F1 (m)</th>
<th>29/6b-F2 (m)</th>
<th>29/6b-F3 (m)</th>
<th>29/6b-F4 (m)</th>
<th>29/6b-F5 (m)</th>
<th>29/4d-4 (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>30-in. MD</td>
<td>229</td>
<td>229</td>
<td>230</td>
<td>230</td>
<td>229</td>
<td>230</td>
</tr>
<tr>
<td>30-in. TVD</td>
<td>229</td>
<td>229</td>
<td>230</td>
<td>230</td>
<td>229</td>
<td>230</td>
</tr>
<tr>
<td>20-in. MD</td>
<td>905</td>
<td>905</td>
<td>899</td>
<td>909</td>
<td>905</td>
<td>904</td>
</tr>
<tr>
<td>20-in. TVD</td>
<td>905</td>
<td>903</td>
<td>898</td>
<td>909</td>
<td>904</td>
<td>904</td>
</tr>
<tr>
<td>13 3/8-in. MD</td>
<td>3640</td>
<td>3468</td>
<td>3464</td>
<td>3968</td>
<td>3532</td>
<td>3532*</td>
</tr>
<tr>
<td>13 3/8-in. TVD</td>
<td>3535</td>
<td>3466</td>
<td>3382</td>
<td>3518</td>
<td>3394</td>
<td>3530*</td>
</tr>
<tr>
<td>10 3/4-in. × 9 7/8-in. MD</td>
<td>5118</td>
<td>5002</td>
<td>5146</td>
<td>5425</td>
<td>5264</td>
<td>5175*</td>
</tr>
<tr>
<td>10 3/4-in. × 9 7/8-in. TVD</td>
<td>4904</td>
<td>5001</td>
<td>5063</td>
<td>4934</td>
<td>5086</td>
<td>5174*</td>
</tr>
<tr>
<td>7-in. MD</td>
<td>5926</td>
<td>5795</td>
<td>5806</td>
<td>5914</td>
<td>5914</td>
<td>5040*</td>
</tr>
<tr>
<td>7-in. TVD</td>
<td>5803</td>
<td>5764</td>
<td>5720</td>
<td>5960*</td>
<td>5729</td>
<td>6038*</td>
</tr>
<tr>
<td>Liner length</td>
<td>808</td>
<td>783</td>
<td>660</td>
<td>1027</td>
<td>828</td>
<td>865</td>
</tr>
</tbody>
</table>

*14 × 13 3/8-in. casing
*9 7/8-in. drilling liner run with 10 3/4-in. tie-back
*7 × 5 × 4.5-in. liner

**Table 2 - Computer Simulation vs. API BHCT Predictions**

<table>
<thead>
<tr>
<th>Casing Size (in.)</th>
<th>Simulated Maximum Temperature (°C)</th>
<th>API Standard (°C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>13 3/8</td>
<td>80</td>
<td>109</td>
</tr>
<tr>
<td>10 3/4 × 9 7/8</td>
<td>125</td>
<td>146</td>
</tr>
<tr>
<td>7-in. (liner)</td>
<td>180</td>
<td>176</td>
</tr>
</tbody>
</table>

**Bottomhole Static Temperature.** Designers should know the bottomhole static temperature (BHST) to design and assess long-term stability, or rate of compressive-strength development, for a cement slurry. Determining BHST is especially important in deep-well cementing, where the temperature differential...
that are designed for safe displacement times may be overretarded at TOC
temperatures, resulting in poor compressive-strength development. Generally, if the
BHST at the top of the cement column exceeds the BHCT, overretardation is not
expected.

Precise temperature readings are essential for cementing, especially at high
temperatures, because an error as small as 3° to 5°C can significantly affect
results, even when slurry materials are chosen to minimize the effect of slurry
sensitivity. Generally, cement sensitivity increases as BHCT increases;
consequently, all laboratory tests performed to improve slurry properties should be
run with samples of the same batch of cement, mixing water, and chemical
cementing additives that will be used for the job. Downhole conditions must be
duplicated as closely as possible. Calculated values for the pressure and time-to-
bottom should be used for testing instead of the tabular values presented in the API
RP10B®. The best method for estimating the bottomhole temperatures in HPHT,
horizontal, or deviated wells is to use a computer-based simulator.

Organization

Because HPHT operations heighten the critical nature of every well-completion
event, Elf has developed, and is improving, a drilling management system (DMS)
that allows wells to be planned and drilled, and allows performances to be analyzed
so that lessons learned can be applied to subsequent well jobs (Figure 5). This
philosophy was applied to the six HPHT wells discussed in this paper. Both land and
offshore personnel were involved in planning and drilling the well, in monitoring and
recording operational performance, and in evaluating and analyzing the results.
Programs and prespud meetings provided the link from planning to cementing, the
final well report, and debriefing meetings from drilling to evaluation. An HPHT best
practices book that will bridge any gap in the HPHT drilling schedule is being
developed for inclusion in the DMS.
The preplanning phase involved the Elf Fluids Team in Aberdeen, Elf Research Centre in France, and the Halliburton European Research Centre in Liederdorp, Holland.

This procedure resulted in a comprehensive offshore program being provided before each cement job. Such programs contain the following:

- well data
- centralization program
- detailed prejob preparation
- circulation-pressure data from previous wells
- procedures for preparing spacer and cement slurry
- mixing and pumping parameters, including rheology checks for cement and spacer, conditioned mud ahead of cement, and addition order for slurry additives
- predicted ECD at displacement volumes
- details of predicted circulating, previous pressure while drilling (PWD) temperature data, predicted flowline temperatures, and detailed cement slurry testing reports
- contingency planning for possible squeezes, plugs, etc., planned and tested in advance of any requirement

The cementing success achieved in this demanding environment was a direct result of the rigorous and comprehensive prejob fluids testing, correct execution in the field, documentation of results, postjob reporting, and analysis of results.
**Fluids Team**

The fluids team should have the following characteristics and skill sets:

- A consistent staff of competent personnel capable of team building
- A clear understanding of roles and responsibilities
- Dedicated personnel for each specialization
- Awareness of the rig
- A dedicated team offshore and on land
- Good communication between offshore and onshore crews
- An offshore crew of up to six people for critical jobs: two senior service operators, an onshore engineer, a laboratory technician, a service supervisor, and a mechanic
- An awareness of critical nature of operations

HPHT training and team-building exercises were provided for all onshore and offshore personnel to build a cohesive team. The cementing and mud contractor were within the same company group and shared the same office, easing communications and helping build a team environment with key service contractors.

**Laboratory Testing**

**Cement Slurry Testing.** The objective of the fluids team was to design a slurry that:

- had well-known characteristics.
- was relatively insensitive to changes in temperature and retarder concentration.
- showed good stability.
- exhibited low fluid loss.
- could be used with a tuneable cement-spacer fluid to provide maximum displacement efficiency in a narrow ECD window.
- was gas tight to resist potential gas migration.
- achieved long-term zonal isolation.

The liner slurry was formulated with dry-blended API Class G cement and 35% silica flour. The following liquid additives were used as the mix fluid:

- Combined fluid-loss transition time control agent
- Dispersant
- Synthetic retarder
- Retarder intensifier
- Stability/early strength agent
The following dry additives were added during mixing:

- Weighting agent
- Cement expansion agent
- High-temperature stability polymer

**Environmental Issues**

The UK sector of the North Sea has government regulations that require materials to meet environmental compliance regulations\(^5\). Materials are characterized by the volumes that may be discharged into the sea. For cementing material, the categories range from A to E. For Category A, discharges are strictly limited, while Category E materials may be discharged much more freely. On this project, excluding the cement and cement blends, 19 cement and spacer additives were used. Of these 19, 68% met the Category E classification. Of the remaining 32%, 16% were Category D, and the remaining 16% were Category C. The use of these materials, most of which carried Category E classification, did not hamper the technical performance of the slurries and demonstrated that high performance can be achieved while complying with environmental regulations.

**Temperature**

Temperature has a profound effect on the safe placement of the cement slurry\(^2\). Under normal cementing conditions for vertical wells, API tables and calculations have been used successfully for many years. However, for HPHT wells, the high temperatures cause the slurries to be sensitive to temperature and, therefore, the accuracy of the predicted cementing temperature is more critical. Also, because of the depth of the casing string, cementing volumes and displacement times are greater than normal. This increases the acceptable thickening time required for safe placement. Therefore, more retarder is required for HPHT wells. If the cement is overretarded, compressive-strength development may take longer than required. For example, the compressive-strength development at the top of the slurry, at the top of a long liner, can be adversely affected by an increase in retarder. This overretardation may also be a detriment to other properties, such as the slurry's resistance to gas migration.

For these reasons, computerized, well-fluid temperature simulation was used to determine cementing temperature predictions\(^7-9\) (Figures 6 and 7).
This temperature simulation program was used extensively for all the casings. The accuracy of the software has been tested over many years, and was previously verified by downhole measurement. Actual downhole temperatures were measured on one of these wells with a PWD and logging tools for correlation with the computer simulation program. The data showed good correlation between the computer-predicted simulations and the measured downhole temperatures (Figure 8).

The temperature values for maximum BHCT and lowest postcement placement thermal recovery are interpreted to allow for safe placement and reliable setting of the slurry within the likely parameters measured. Maximum BHCT for slurry thickening-time testing is determined from a worst-case scenario of low flow rate and shortest prejob circulation (Figure 7). The worst-case scenario for thermal recovery is based on the longest prejob circulation at the highest achievable rates. This temperature is applied to the slurry compressive-strength development at the top of liner (Figure 6).

![Figure 6—Cement temperature curve.](image)

Compressive-strength testing is simulated in an ultrasonic cement analyzer (UCA)\(^\text{10}\). This instrument has been modified to allow the application of actual downhole pressure, rather than the minimum 207 bar recommended by the API. Under certain HPHT conditions, applying actual downhole pressure has resulted in a set time of one-half that achieved with the more commonly applied minimum API pressure.
The type of retarder and the cement properties that are imparted on the slurry also allow the slurry to perform under the required temperature parameters. This is explained further in the following section.

Retarder Sensitivity

To determine if the slurry could be used at these extreme temperatures, tests were performed to evaluate the slurry system's sensitivity. The thickening time was measured initially with ±10% of the recommended retarder concentration. As mentioned previously, cement slurries can be highly sensitive to temperature variation. The slurry was tested ±10°C from the targeted BHCT. Variations in density were also investigated. All of these factors contribute to the suitability of the slurry for HPHT operations. Testing parameters were altered during the project, and the ± limits were
reduced after the temperature range of the well and slurry parameters were identified. These tests showed that the liner slurry was relatively insensitive to temperature or retarder concentration variation (Figures 9 and 10).

Retarders selected for the liner were (1) a nonlignosulfate (NLS) retarder that could help simplify the design of the slurries, and (2) a high-temperature retarder/intensifier (RI). The NLS is effective in freshwater slurries at BHCTs up to 250°F (121°C). In saturated salt slurries, this retarder can be used at BHCTs between 250° and 350°F (121° and 177°C). When combined with certain retarder-enhancing agents, NLS retarder can be used in freshwater cement systems at BHCTs as high as 430°F (221°C). The RI was primarily designed for intensifying common retarders, such as NLS retarder. The RI is highly soluble in water. Consequently, it exhibits more uniform thickening times and has less effect than other retarders on cement compressive-strength development, especially at the top of a long cement column.

Figure 9—Retarder temperature sensitivity at 182°C.
Slurry Testing

Slurry testing procedures were selected based on these properties:

- **Temperature**: Highest simulated BHCT and variation of retarder and temperature
- **Pressure**: Actual bottomhole pressure for thickening time
- **Compressive strength**: At the following top-of-liner (TOL) conditions:
  - Simulated temperature and pressure
  - Lowest simulated BHCT used with longest thermal recovery
  - Ultrasonic cement analyzers set for simulated temperature and actual BHP [not API minimum (207 bar, 3,000 psi)]
- **Mixing effects**: Investigated and standardized
  - Order of addition
  - Time taken to add
  - Holding of mix water
  - Time to mix at surface
  - Surface mixing temperature/shear effects
- **Slurry stability**
  - Sedimentation test
  - HPHT rheology (Figure 11)
- **Low fluid loss**
  - Reduces chances of dehydration
  - Synergistically shortens the transition time for improved resistance of gas migration
Spacer Testing

Spacer tests were based on these properties:

- Compatibility with mud and cement slurry
- Water-wetting ability, with appropriate use of surfactants
- Stability at high temperatures
- Variable rheology to allow efficient mud removal\(^\text{1}\) without raising ECD to high levels
- Water-based system with addition of surfactants
- HPHT conditions

Gas Migration Control Testing

Because of the high pressures, long liner intervals covered by cement, and narrow margins between fracture and pore pressure, the potential for gas migration in the critical zone was high. To help reduce this risk, the slurries placed in these zones were designed to resist gas influx, and a combination of additives was provided to ensure a short transition time\(^\text{11,12}\). The transition times for the liners varied from 10 to 16 minutes, with an average of 12 minutes (Table 3). The zero-gel times, which indicate how long hydrostatic pressure is applied, averaged just more than 2 hours. This allows the available hydrostatic pressure to be applied over a long period, and then transitioning from a low-gel strength to a high-gel strength, minimized the potential for gas migration.

Figure 11—Cement slurry PV/YP at downhole conditions.
### Table 3 - Liner Gas Migration Transition Times

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Transition Time</th>
<th>Zero Gel</th>
</tr>
</thead>
<tbody>
<tr>
<td>F1</td>
<td>10</td>
<td>192</td>
</tr>
<tr>
<td>F2</td>
<td>6</td>
<td>48</td>
</tr>
<tr>
<td>F3</td>
<td>16</td>
<td>118</td>
</tr>
<tr>
<td>F4</td>
<td>14</td>
<td>135</td>
</tr>
<tr>
<td>F5</td>
<td>15</td>
<td>124</td>
</tr>
<tr>
<td>5-well average</td>
<td>12.2</td>
<td>123.4</td>
</tr>
</tbody>
</table>

**HPHT Rheometer**

The HPHT rheometer developed for use in North Sea cementing operations is based on the Fann 35 principle of bob-and-sleeve (Figure 12). An impeller circulates the fluid while downhole conditions are reached. This circulation can be stopped while readings are obtained. The operational limits of this instrument are 205°C and 1,030 bar. The special electronics package is unaffected by the magnetic particles that affect other types of HPHT rheometers.

![Figure 12—HPHT rheometer adapted for use in North Sea cementing.](image)

The rheometer measures the rheological properties of fluids under HTHP conditions. From the shear stress data obtained at various shear rates (or
rotational speeds) with this rheometer, calculations can be performed to
determine n’ and K’, apparent viscosity, plastic viscosity, and yield point.
These parameters are critical to calculating fluid velocity and frictional
pressure to predict flow behavior of cement slurries and other pumped
fluids.

**Offshore Confirmation of Thickening Time**

The thickening time for the slurry pumped offshore for the 7-in. liner was verified in
a portable API-approved consistometer.

Generally, the thickening time offshore compared favorably with the onshore
laboratory test results (Table 4). In cases where an appreciable variation occurred,
physical factors were identified as the cause. In Well F1, mix water was lost before
retarders were added, resulting in slightly overretarded slurry. On Well F5, mix
water was kept at the surface for more than 8 hours, and the slurry was recirculated
in the batch mixer for an extended time, because of operational constraints.

Comparing offshore and onshore thickening time and rheology in laboratory tests
provided additional quality-control checks and ensured that onshore fluid mixing and
testing was representative of wellsite-mixed fluids. Rheology checks were also
performed on the spacer and slurry at particular stages of their mixing to ensure
fluid quality (Table 5).

**Table 4-Laboratory vs. Offshore Thickening-Time Tests**

<table>
<thead>
<tr>
<th>Well</th>
<th>Laboratory TT (hr:min)</th>
<th>Offshore TT (hr:min)</th>
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</thead>
<tbody>
<tr>
<td>F1</td>
<td>7:18</td>
<td>9:35</td>
</tr>
<tr>
<td>F2</td>
<td>7:26</td>
<td>7:40</td>
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<tr>
<td>F3</td>
<td>7:25</td>
<td>6:50</td>
</tr>
<tr>
<td>F4</td>
<td>8:20</td>
<td>8:23</td>
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<tr>
<td>F5</td>
<td>7:27</td>
<td>6:06</td>
</tr>
<tr>
<td>4d-4</td>
<td>7:33</td>
<td>7:28</td>
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</table>
Table 5-Laboratory vs. Offshore Rheology

<table>
<thead>
<tr>
<th>Fluids</th>
<th>Temp. (°C)</th>
<th>SG</th>
<th>F300</th>
<th>F200</th>
<th>F100</th>
<th>F60</th>
<th>F30</th>
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<th>F3</th>
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<tbody>
<tr>
<td><strong>Laboratory</strong></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Conditioned Mud</td>
<td>50</td>
<td>2.15</td>
<td>71</td>
<td>49</td>
<td>30</td>
<td>-</td>
<td>-</td>
<td>9</td>
<td>7</td>
</tr>
<tr>
<td>Spacer</td>
<td>82</td>
<td>2.25</td>
<td>114</td>
<td>93</td>
<td>69</td>
<td>-</td>
<td>-</td>
<td>38</td>
<td>36</td>
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<td>Slurry</td>
<td>88</td>
<td>2.3</td>
<td>275</td>
<td>208</td>
<td>112</td>
<td>69</td>
<td>38</td>
<td>10</td>
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<tr>
<td><strong>Offshore</strong></td>
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<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Conditioned Mud</td>
<td>50</td>
<td>2.15</td>
<td>87</td>
<td>48</td>
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<td>20</td>
<td>13</td>
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<tr>
<td>Spacer</td>
<td>82</td>
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<tr>
<td>Slurry</td>
<td>82</td>
<td>2.3</td>
<td>270</td>
<td>182</td>
<td>106</td>
<td>61</td>
<td>35</td>
<td>10</td>
<td>5</td>
</tr>
</tbody>
</table>

**Displacement**

Initial mud characteristics appeared to be favorable. They included a low PV/YP, but without barite sag (Table 6) and a minimal gel-strength development.

The following processes and procedures were used for displacing the mud:

- A mixture of solid and bow-spring centralizers was used for all critical sections with an 80% standoff.
- An erodibility process helped optimize mud removal.
- A new cementing simulator was used for designing fluids and rates to ensure mud removal in the eccentric annuli within the fracture gradient.
- For the liner, approximately 50 m3 of treated thinned mud with a lower YP than the original formulation was used for conditioning the hole ahead of the cement spacer.
- The rheology of the cement slurry and the spacer were measured at downhole conditions, and the stability of the slurry was confirmed with the HPHT rheometer.
- A tester to determine static gel strengths was used for measuring the erodibility of the mud at actual downhole static times, temperatures, and pressures.

**Quality Control**

**General Procedures.** Procedures used to ensure quality control and assurances included:

- Starting with a good quality API Class G base cement with a known HPHT response to ensure good job performance
- Documenting the batch number for each additive to ensure tracking
- Qualifying all materials for the extreme-temperature range
- Obtaining samples from the rig
- Checking the mix water for chloride content
• Using only the rig samples for testing (materials must be on board well in advance).

**Table 6-Fann 70 Data for N-Alkane Synthetic-Based Mud at 2.15 S.G.**

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
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</thead>
<tbody>
<tr>
<td>Pressure</td>
<td>1,205 bar</td>
</tr>
<tr>
<td>Temperature</td>
<td>180°C</td>
</tr>
<tr>
<td>PV</td>
<td>22 cp</td>
</tr>
<tr>
<td>YP</td>
<td>26 lbf/100 ft²</td>
</tr>
</tbody>
</table>

**Offshore Procedures.** In addition to the general procedures, the team used the following procedures to ensure quality control during offshore work:

• Adhered to detailed job procedures
• Had adequate stocks of cementing materials, batch-numbered and tested
• Used a calibrated pressurized mud balance to check all fluids at every stage during mixing

**Cement Evaluation**

**Cement Bond Logging.** Cement bond logging (CBL) and variable density logging (VDL) were used for evaluation. Prejob procedures included using a detailed checklist, which included checking tool calibration, tool centralization, and compensating for thicker pipe (e.g., heavyweight liner, 7-in., 42.7 lb/ft).

For a 7-in. liner, the approximate values for free pipe were ± 61 mv, and the transition time was 280 msec. Transition time in the UCA was used to give the value of acoustic impedance for the calibration of logging equipment. The acoustic impedance of cement taken from the UCA was 6.4 to 6.9 Mrayls. Best practices were used, including not changing downhole pressures after placement to eliminate potential microannuli.

The UCA indicates the relative compressive strength development in a cement sample, cured under downhole temperature and pressure conditions. Strength is determined by measuring the change in velocity of an ultrasonic signal transmitted through a cement specimen as it hardens.
(As the strength of the cement specimen increases, the ultrasonic signal's transit time through the sample decreases.) Therefore the UCA can be used to determine the acoustic impedance of the cement.

**Top Hole Cementing.** On the first two wells, top-up jobs were performed because of cement fallback. On subsequent wells, a special lightweight cement blend (SLCB) was used as a lead slurry. The SLCB was composed of blended cements, ceramic hollow spheres, and other additives that enhance slurry performance and synergistically form a low-density slurry with excellent compressive-strength development and thixotropic properties.

The basic SLCB slurry is mixed at 1.52 SG. The physical properties of this light slurry, especially the compressive-strength development, are better than those of a 1.92-SG slurry prepared with Class G or rapid hardening cement (RHC) (Table 7). In addition, the slurry provides thixotropic properties and quick gel-strength development, making it ideal for eliminating cement fallback, and top-up jobs. This SLCB slurry is also classified as gas-tight. The use of this blend eliminated the need for top-up jobs to be included in the program.

### Table 7-Compressive Strength (Bar at 9°C)\(^a\)

<table>
<thead>
<tr>
<th>Material</th>
<th>SG</th>
<th>6 hr.</th>
<th>8 hr.</th>
<th>10 hr.</th>
<th>16 hr.</th>
<th>24 hr.</th>
<th>36 hr.</th>
<th>48 hr.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Lightweight special blend</strong></td>
<td>1.52</td>
<td>1</td>
<td>5</td>
<td>11</td>
<td>28</td>
<td>52</td>
<td>86</td>
<td>98</td>
</tr>
<tr>
<td><strong>API Class G</strong></td>
<td>1.92</td>
<td>0</td>
<td>2</td>
<td>5</td>
<td>17</td>
<td>33</td>
<td>80</td>
<td>97</td>
</tr>
<tr>
<td><strong>RHC with ceramic spheres</strong></td>
<td>1.61</td>
<td>2</td>
<td>3</td>
<td>5</td>
<td>8</td>
<td>15</td>
<td>31</td>
<td>37</td>
</tr>
</tbody>
</table>

\(^a\)All cement was mixed with seawater and 3% CaCl\(_2\) by weight of cement (BWOC).

**Equipment and Hardware**

**Mixing Equipment.** Because of the special requirements of this project, the cementing and bulk equipment was reviewed during drilling of the first well. To allow the cement unit to be able to mix barite plugs, an additional line was installed to route barite directly to the unit. During the first few
jobs with the 24-m³, two-compartment batch tank, dusting was a problem during cement mixing. Consequently, the cement was rerouted through the surge tank, which helped remove some of the air before it was transferred to the batch tank. These adaptations proved successful, and much less dust was observed in later jobs.

Bulk cement was standardized on the rig by using a blend of API Class G and 35% silica flour to eliminate high-temperature strength retrogression. This standardization eased logistics because special blends were not required for each cement job. Cement additives were either prehydrated or added as liquids. A number of dry additives were initially used in the liner slurry, but adding them through the hopper resulted in clogging, and the amounts were difficult to meter accurately. Although the use of dry additives did not cause any significant problems, liquid additives were preferred, and almost all of the cement additives, except the weighting agent and high-temperature polymer, were added as liquids. This reduced the initial mixing time and increased the accuracy of field mixing. Because of the increase in the total amount of liquid additives, the cement slurry, which had little freshwater content initially, was formulated with no additional freshwater, so there was no need to check the quality of water used for the slurry. The weighting agent chosen was manganese tetraoxide, which provides excellent weighting and high-temperature suspension properties and can be added directly to the mix water before the cement is added, reducing the time that the mixed slurry has to be held on surface. If a hematite ore is used, it is normally added after the cement has been mixed, thus the mixed slurry must be kept on surface for a longer period. This can adversely affect the required slurry properties by lengthening the required thickening time, leading to overretardation of the slurry. Initially, the amount of time required for adding the weighting agent created problems because the fineness of this material blocked the mixing hopper. The original hopper had a 10-in. ID, but also had a restriction of 6 in. This restriction was later enlarged to 10 in. The flow of the material from the hopper increased, but the material still clogged in the chute. The chute arrangement was then modified by moving the deck entry point to allow the angle of the chute to change from approximately 30° from the vertical to within 5° of vertical. The result of this more direct chute arrangement was that the time required for adding the weighting agent dropped from more than 5 hours to less than 1 hour.

In reviewing the batch-mixing process, the team decided to use a recirculating line with a larger ID to reduce the chances of blockage. The original recirculating line had a 1.5-in. ID at the densometer connection,
but was modified with a 3-in. special densometer and 3-in. ID lines. This change led to a general improvement in the mixing system on the batch tank.

In the case of these extreme HPHT operations, a correctly designed large-capacity batch-mixing tank provides greater control and consistency in the cementing of these long liner sections. This equipment was an asset in the success of the project.

**Pressure-Testing Casing.** The casing strings were tested at up to 900-bar applied pressure as required by the operator. To reduce rig time and limit the potential for a casing/cement microannuli to form, the pressure tests were performed as the top cementing plug landed on the float collar during the cementing process.

Because the actual quoted ID of the casing was often greater than the book value, the ID of the long casing strings was calipered before the casing strings were loaded offshore. This, along with the mud's compressibility factor, helped determine the volume required to bump the cementing plugs, allowing almost all the cementing plugs to be correctly displaced to the float collars and the casings to be pressure tested on bump.

**Results**

No remedial cementing work was required in the critical zone. Hard cement on the top of the liner on all wells was within a few meters of predicted theoretical top of cement. Good CBL was recorded across the production zones (Figure 13), and zonal isolation was achieved.

**Future Developments**

The future poses the following challenges for developing new and better technology to successfully cement HTHP wells:

- Drilling deeper at temperatures up to 225°C with smaller hole diameters and placing small slurry volumes effectively at great depths
- Successfully cementing more highly deviated HPHT wells
- Addressing problems caused by increased displacement volumes, and hence longer thickening times, while still maintaining desirable slurry properties
Conclusions

Success in cementing depends upon the rigorous application of best practices in the following areas:

- Planning at all levels should occur in parallel with initial well plans, since the equipment development and qualification process can take years.
- Rigorous testing and "what if" scenarios should be tested and evaluated for all fluids, with emphasis on robust slurry design and a clear knowledge of cementing temperature windows.
- Prejob simulation is vital for knowing the envelope of the environment. Rigorous laboratory testing and prejob computer simulations should be used to confirm envelope of performance of the cement and spacer systems.
- A team approach is a vital component of a successful cementing job. Personnel should agree on their roles and responsibilities, and backups should be in place in case of an emergency.
- An adequate offshore crew, including service operators, laboratory technicians, cement fluid engineer, services supervisor, etc., should be assembled.
- Sufficient time must be allowed for the complex slurry testing. Laboratory testing that is normally executed in a day for standard well designs may take a week to complete for an extreme HPHT well.
- When cement additives are not dry-blended with the bulk cement, liquid additives are preferable to allow for accurate addition and reduced mixing time.
- A postwell report and follow-through are required to build detailed procedures and to summarize historical information.
- Rig equipment performance is vital for delivering the best engineering practices.
- HPHT cementing involves large fluid volumes, which also require a large batch tank for critical jobs.
- There is no easy formula for successful cementing in HTHP conditions. It requires a combination of teamwork, effort, experience, discipline, equipment, and application of best practices.
References


6. The Offshore Chemical Notification Scheme (OCNS).


SI Metric Conversion Factors

\[ \text{ft} \times 3.048^* \]
\[ \text{E-01} = \text{m} \]

\[ \text{bar} \times 1.0^* \]
\[ \text{E+05} = \text{Pa} \]

\[ \text{in.} \times 2.54^* \]
\[ \text{E+00} = \text{cm} \]

*Conversion factor is exact.*