Abstract

Operators involved in the recovery of hydrocarbons from heavy-oil reservoirs often face the problem of maintaining well integrity in steam-injection wells. A significant portion of these wells suffer various forms of leaks and in the most severe case complete steam breakthrough to surface. Throughout the life of heavy-oil wells, cement material degradation and stresses in the cement sheath induced by extreme temperature cycling result in severe mechanical damage and ultimate failure of the cement sheath. These problems motivate different operators to explore new cementing technologies that are capable of achieving reliable long-term zonal isolation in these extreme conditions.

The main challenge for operators is to design thermally stable cement with mechanical properties sufficient to withstand stresses induced by the large temperature changes. This paper describes the development of a new cement system, which is stable, strong, impermeable and flexible up to a temperature of at least 350°C (650°F), corresponding to the maximum steam injection temperature. Depending on the curing temperature this new cement system provides low Young’s modulus of 1,800 to 4,000 MPa while maintaining excellent compressive and tensile strengths compared to cements currently used in the oilfield industry. Aging the cement system for 6 months at steam temperatures demonstrates the stability of the set material properties, including maintaining a low permeability.

Field trials in North America show that this new cement system can be easily implemented into standard cementing operations using conventional equipment. Cement evaluation logs after cement operations confirm that excellent zonal isolation and wellbore integrity are readily achieved.

By keeping adequate strength and flexibility, this new cement system reduces the risk of cement sheath failure and steam migration throughout the life of these steam-injection wells. It provides a long-term well integrity solution for any well exposed to very large temperature increase after the cement initial set, such as in fields exposed to steam temperatures.

Introduction

Heavy-oil reserves are estimated at 15% of the total oil reserves around the world. To satisfy global future oil demands, fields containing heavy oil represent an increased share of the world’s total oil production. There is a variety of heavy-oil production processes, particularly thermal methods; this is because the key fluid property (viscosity) is highly temperature dependant. When heated, heavy oils become less viscous and can therefore flow through the reservoir rock and production tubulars. Heavy-oil recovery methods include cyclic steam stimulation (CSS), otherwise known as “huff and puff”, steam assisted gravity drainage (SAGD), also known as “steam soak”, continuous steam injection and vapor assisted petroleum extraction (VAPEX) (with exposure temperatures up to ~350°C (650°F) at pressures up to 16.5 MPa (2,393 psi).

Extreme conditions of these stimulation processes impose stringent requirements on the performance of the cement sheath to maintain the wellbore integrity. Cement mechanical properties play one of the key roles in providing reliable and durable zonal isolation through the life of the well.
First, the cement should set at the relatively low placement temperatures (Bour 2005) and acquire compressive and tensile strengths sufficiently high to withstand the first heating cycle. Second, the cement should possess sufficient flexibility (low Young’s modulus) to adequately respond to the expansion of the metal casing during heating and cooling steps of the process. Finally, it is important to maintain stability of the mechanical properties during the whole process of heavy oil recovery.

However, the task to design strong, flexible and durable zonal isolation is somewhat ambiguous. Cement is an inorganic material and usually for this class of materials, the increase of its strength is accompanied by an increase in Young’s modulus (Bour 2005).

This challenge to simultaneously achieve the desired mechanical properties is solved by the addition of special fillers that have a Young’s modulus lower than that of the matrix. When selecting a filler, one must consider its stability over the entire range of steam-injection temperatures.

This paper describes a new system that allows for achieving an excellent combination of mechanical properties with durable performance of the cement sheath and one that adapts to conditions of steam-injection practices employed in heavy-oil recovery processes in Canada.

Material and methods used

Cement system description.

The cement system is designed by starting with standard design practices required for thermally stable cement systems. A novel material is added to attain desired mechanical properties, and the density of the cement system is verified to be within the requirements to maintain well control.

The novel cement system is designed to be thermally stable. Based on the recommendations given by Nelson and Guillot (2006) crystalline silica is added to cement matrix to obtain the CaO/SiO2 ratio of approximately 1 and prevent cement strength retrogression at high temperatures. Then, novel high-temperature-resistant filler having a low Young’s modulus was used in conjunction to increase flexibility of the inorganic matrix.

Well control is a primary responsibility during all operations in the wellbore, including cementing operations. Slurry densities are typically designed to be less than 1900 kg/m3 to minimize the risk of fracturing the heavy-oil formations during cementing operations. Lower slurry densities are desired to minimize this risk even further. The density of the novel cement systems is varied between 1,640 kg/m3 (102 lbm/ft3) and 1,710 kg/m3 (107 lbm/ft3).

Sample preparation and aging.

Cement slurries were prepared using standard industry practices. Samples were cured at room temperature for several weeks, and then subjected to high temperature simulating steam injection conditions.

Cement slurries were mixed at the selected density according to ISO 10426-2 guidelines. For measuring the initial mechanical properties developed by the cement, slurries were placed into metallic molds and set in a water-curing chamber for one week at 35°C [95°F] and 13.8 MPa [2,000 psi]. The samples were then cored into cylinders having 2.5-cm (1-in.) diameter and a 5.1-cm (2-in.) length, and discs having a 5.1-cm (2-in.) diameter and a 2.5-cm (1-in.) length.

At such low-placement temperatures, cement hydration can continue over an extended period of time. Thus, cores obtained from the slurry with a density of 1,660 kg/m3 (104 lbm/ft3) were placed into the water and left on the bench for 3 weeks to monitor the development of the compressive strength and Young’s modulus.

To investigate the durability of the mechanical properties at high temperatures, the cores were then placed back in a water-curing chamber at temperature of 344°C [650°F] and pressure of 20.7 MPa [3,000 psi] for a period of from 1 to 6 months. The curing temperature was increased from ambient temperature to curing temperature over a 6 hr period, and after each month of curing, the curing chamber was allowed to cool down for approximately 14 hr. To decrease the impact of the pressure fluctuation, the pressurization and the depressurization steps were each performed in 1 hr. Therefore, the samples cured for more than 1 month were subjected to the consequent cycles of heating and cooling to simulate actual operating conditions.
Set cement composition and properties characterization.

The mechanical properties measurement methodology is detailed by James and Boukhelifa (2006). The cylindrical cores were used to determine the unconfined compressive strength (UCS) and Young’s modulus. The disc cores were used to measure the splitting tensile strength (also known as the Brazilian compression testing method) using a steel apparatus described in reference 5.

Investigations of the cement mineral phase composition and structure were performed by X-ray diffraction (XRD) analysis (Siemens D5000) and scanning electron microscopy (SEM) (Hitachi S3400N instrument under an accelerating voltage of 3kV).

Results and discussion

Thermal stability of high-temperature-resistant cement matrix.

Any cement system that is proposed for steam injection wells must be thermally stable. Mechanical properties of the novel cement system are investigated at placement temperatures, and after curing at high temperatures.

Study of the cement compressive strength and Young’s modulus development kinetics at placement temperature is presented in Table 1. It shows that even at low temperatures, mechanical properties reach almost maximum values in 1 week and then remain stable over longer period of time (taking into account measurement errors). This observation allowed for selecting a 1-week duration for the low-temperature curing procedure as being sufficient to acquire the initial mechanical properties of cement. Based on those observations, a 1-week duration can be recommended as the minimum time between cementing and steam-injection jobs.

Stiles (2006) demonstrated that when cement systems used by oilfield industry for steam-injection process are subjected to the high temperatures, their mechanical properties evolve and age with time. However, cements stabilize after the first month of high-temperature curing and don’t significantly change even after a 2-yr period. The evolution of the UCS of new flexible-cement systems having a density between 1640 kg/m3 and 1710 kg/m3 with aging time at 344°C (651°F) and 20.7 MPa (3,002 psi) is shown in Fig. 1. The UCS values at “0” time on the plots correspond to the initial mechanical properties of the cement samples obtained after 1 week of the low-temperature curing. After one month of curing at high temperature there is an expected change in material strength, but then UCS stays stable during 3 months of high-temperature curing. Such behavior of the UCS can be explained by the difference between mineral phase compositions of cement samples obtained after the low- and high-temperature curing. Crystalline silica, being inert at low temperatures, reacts with cement hydrates at temperatures 150°C (302°F) and a new phase—Xonotlite—is formed (Taylor 1964). XRD analysis confirms that after 1 month of aging at 344°C (651°F), all crystalline silica has been consumed and Xonotlite was formed. With an aging time increase from 1 to 3 months, no phase changes occur and Xonotlite remains the only phase identified in the samples. This observation explains why a plateau of the mechanical properties is obtained after 1 month of high-temperature curing.

For some selected samples, the curing time at high temperature was extended to 6 months. XRD spectra obtained for samples of various densities aged during one month and six months are very similar. An example of the typical mineral phase composition of the new system is presented in Fig. 2 where the main phase of the cement matrix is still Xonotlite.

SEM analysis performed with these samples also confirmed an absence of the degradation of the flexible filler. Its presence in the cement matrix is observed over the entire course of curing up to 6 months (Fig. 3). Thus, it was concluded that the material composition is stable up to a temperature of 344°C (651°F).

Analysis of the novel cement system mechanical performance in simulated application conditions

After determining that the novel cement system was thermally stable, it was necessary to confirm that the novel cement system would maintain mechanical integrity during steam injection conditions. A suitable cement system was chosen for an intermediate casing string in a SAGD injector well. A numerical model was used to calculate the stresses in the cement sheath when the novel cement system was exposed to simulated well conditions.

Novel cement composition having the density of ~1660±400 kg/m3 (104±25 lbm/ft3) was selected for the field test to cement intermediate casings of SAGD injector wells operated by StatOil Hydro in Canada. First, long-term stability of compressive and tensile strength and Young’s modulus was confirmed after a 6-month exposure to a temperature of 344°C (651°F) (Fig. 4). While considering measurement errors, plateau values were reached for all principal mechanical properties. Low Young’s modulus values between 1,800 and 4,000 MPa (261,068 and 580,151 psi) in determining high-material flexibility are achieved, both before and after aging at high temperatures.

System performance assessment under stresses in the cement sheath subjected to steam injection was performed by numerical modeling described by Thiercelin et al. (1998). This model predicts microannulus, cement failure in compression or in tension, using 2D analysis. Geometry details for intermediate casing of injector wells and formation properties where achieving a reliable
Zonal isolation is a must are given in Table 2 and Table 3, respectively. The maximum temperature achieved during the steam-injection process is 250°C (482°F).

The approach described by DeBruijn et al. (2009) was used to determine the fastest possible heating rate to achieve the maximum steam-injection temperature; i.e., a basic heating schedule consisting of a linear temperature increase between 10 and 250°C (50 and 482°F) was applied. Mechanical properties developed by the novel cementing system after curing for 1 week at 35°C were analyzed in relation to the sheath stresses induced by the thermal expansion of the casing and confinement from formation. In these simulations, the shortest time to heat the well without simulated cement sheath failure was 2 days compared with 6 days for the conventional thixotropic system used in the majority of the heavy-oil wells in Canada (DeBruijn et al. 2009).

Analysis of the stresses exerted on the cement sheath when applying this schedule showed that it still has to be adjusted to prevent cement from failing in the tension mode. This conclusion is in agreement with the previous observations that the ideal cement properties for a steam-injection well include a low Young’s modulus and a high-tensile strength (Myers et al. 2005).

Following the recommendations given in previous work by DeBruijn et al. (2009), a conservative heating schedule comprising the steps of the linear temperature increase with the intermediate steps of exposure to constant temperature to steam-heat a well consists of:

1. Heat to 100°C (212°F) for 1 hr or longer
2. Operate the well at 100°C (212°F) for 1 day
3. Increase the well temperature an additional 25°C (77°F) per day for each of the next 6 days
4. Minimize pressure increases as much as possible

For the novel cementing system, it is possible to increase the heating rate from 25°C/d (77°F/d) to 75°C/d (167°F/d) (see Fig. 5). Long-term performance of cement against stresses developed during steam injection according to the schedule shown in Fig. 5 is presented in Fig. 6. The area above the red lines represents the ratio between compressive strength and Young’s modulus (Fig. 6a) and tensile strength and Young’s modulus (Fig. 6b) required for the cement to maintain the well’s integrity during the entire life of the well. Analyzing cement mechanical properties measured after initial low-temperature curing and after 6-month aging, even at 344°C (651°F), and plotted versus these requirements allows for drawing safe conclusions on the durability of the new solution under stresses developed in the sheath during steam injection.

Thus, these mechanical property measurements before and after exposure to steam and these stress-analysis simulations validated this new cement for these field conditions. Field tests were started to verify in-situ that the novel cement system maintains wellbore integrity and develop good bonding across the cemented zones.

**Case study**

This case history is from Alberta’s heavy-oil fields where the SAGD process is used to produce reserves. A novel high-temperature-resistant cement was pumped in the intermediate casings of injector and producer wells of SAGD pairs (Injector and Producer).

The injection well consists of surface casing set at 185 m (607 ft) measured depth (MD). A 375-mm (15-in.) bit is then used to drill the intermediate hole section to casing setting depth at a true vertical depth (TVD) at around 400 m (1,312 ft). The wells have a kick-off point (KOP) at approximately 230-m (755-ft) MD and turned horizontally with approximately 25 m (82 ft) of horizontal hole prior to casing depth. Intermediate casing size is 298 mm (11.7 in.). No caliper log was run and the openhole annular excess was estimated up to 110%.

The producing well consists of surface casing set at 185 m (607 ft) measured depth (MD). A 375-mm (15-in.) bit is then used to drill the intermediate hole section to casing setting depth at a true vertical depth (TVD) at around 480 m (1,575 ft). The wells have a kick-off point (KOP) at approximately 260-m (853-ft) MD and turned horizontally with approximately 100 m (328 ft) of horizontal hole prior to casing depth. Intermediate casing size is 298 mm (11.7 in.). No caliper log was run and the openhole annular excess was estimated up to 200%.

The new cement system met all the regulatory requirements and it exhibited properties accepted by industry as best practices for horizontal wells. Placement properties of the slurry, shown in the Table 4: they are compliant with all Canadian regulatory requirements, achieving 3500 KPa compressive strength within 48 hours. Rheological properties of the slurries are satisfactory and allow casing rotation throughout intermediate cement jobs. Free-water was zero, consistent with industry accepted best practices for horizontal wells.
Cement evaluation was performed several days after the cement jobs. The cement bond evaluation was done with a segmented bond log tool, deployed on tractor through the horizontal section. Both unpressured and 7-MPa (1,015-psi) pressure passes were run on two wells to identify the possible microannulus, which can result in a pessimistic bond evaluation.

Cement evaluation log interpretation can be performed to determine the quality of the cement bond to the casing, and the effectiveness of the cement placement techniques can be inferred. Nelson and Guillot (2006) provide guidance for interpreting cement evaluation logs in Chapter 15.

The log insert data shown in Fig. 7 includes the top of each cement evaluation log that is presented.

Cement evaluation logs for Injector and Producer that compare unpressured and 7-MPa (1,015-psi) pressurized passes are presented in Fig. 8 and Fig. 9 respectively. Though the improvement of the bond interpretation with pressure indicates the presence of a microannulus, bond evaluation for the wells cemented with the new system can be described as very good. As noticed by DeBruijn et al. (2009) microannulus that may be observed in the heavy-oil wells may be mitigated with the improvement of the drilling and cementing practices that will be implemented for the next jobs.

Conclusions

1. A new high-temperature-resistant cement system was developed to provide reliable zonal isolation during stimulation of heavy-oil wells.
2. The new cement system is thermally stable at temperatures up to 344 C (650 F)
3. Excellent material performance is achieved by combining high-mechanical strength and high-flexibility. Unique composition of the new solution allows for applying this system in the wells where steam-injection temperatures reach 350°C (662°F).
4. Performance and durability of the new solution were confirmed by simulations under the conditions of the heavy-oil wells in Canada.
5. The new solution allows for a more rapid heat-up schedule and longer resistance to the extreme conditions of the heavy-oil wells compared to the conventional solution.
6. This new solution was successfully deployed in SAGD wells in Alberta, Canada where cement bond logs show that zonal isolation is achieved.

Acknowledgement

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References


TABLE 1 – DEVELOPMENT OF THE CEMENT MECHANICAL PROPERTIES WITH TIME AT 35°C (95°F) (CEMENT SLURRY DENSITY OF 1,660 kg/m³ (104 lbm/ft³))

<table>
<thead>
<tr>
<th>Curing Time, week</th>
<th>Unconfined Compressive Strength</th>
<th>Young’s Modulus</th>
<th>Poisson ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MPa</td>
<td>psi</td>
<td>MPa</td>
</tr>
<tr>
<td>1</td>
<td>16 ± 1</td>
<td>2300 ± 150</td>
<td>4,000 ± 300</td>
</tr>
<tr>
<td>2</td>
<td>18 ± 1</td>
<td>2600 ± 150</td>
<td>4,500 ± 500</td>
</tr>
<tr>
<td>3</td>
<td>18 ± 1</td>
<td>2600 ± 150</td>
<td>4,600 ± 400</td>
</tr>
</tbody>
</table>

TABLE 2 – GEOMETRY OF THE INTERMEDIATE CASING OF INJECTOR WELL

| Casing Configuration                      | Intermediate hole, mm (in.) | 375 (15) |
| Casing diameter, mm (in.)                | 298.5 (11.7) |
| Casing weight, kg/m (lbm/ft)             | 80.4 (177) |
| Young’s modulus, MPa (psi)               | 200,000 () |
| Poisson ratio                            | 0.27 |
| Thermal conductivity, W/(m·K) (?)        | 15 |
| Specific heat capacity, J/(kg·K) (?)     | 500 |
| Coefficient of linear thermal expansion, /°C (/°F) | 13·10⁻⁶ (7.2 ·10⁻⁶) |

TABLE 3 – PROPERTIES OF FORMATION ACROSS INTERMEDIATE CASING OF THE INJECTOR WELL

| Depth, m (ft) | 395 (1,296) |
| Density, kg/m³ (lbm/ft³) | 2,300 (5,071) |
| Young’s modulus, MPa (psi) | 4,500 (652,670) |
| Poisson ratio | 0.425 |
| Thermal conductivity, W/(m·K) (?) | 1.83 |
| Specific heat capacity, J/(kg·K) (?) | 710 |
| Coefficient of linear thermal expansion, /°C (/°F) | 13·10⁻⁶ (7.2 ·10⁻⁶) |

TABLE 4 – PLACEMENT PROPERTIES OF THE NOVEL HIGH-TEMPERATURE RESISTANT CEMENT SLURRIES; COMPLIANCE WITH CANADIAN REGULATORY REQUIREMENTS (ALBERTA EUB STATE REGULATION)

<table>
<thead>
<tr>
<th>Slurry Property</th>
<th>Case A</th>
<th>Case B</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zero Free Water (horizontal wells)</td>
<td>Achieved</td>
<td>Achieved</td>
</tr>
<tr>
<td>Fluid Loss Control - Approximately 100 mL</td>
<td>64</td>
<td>26</td>
</tr>
<tr>
<td>Thickening Time at 20°C (68°F)</td>
<td>3: 59 hr:mn</td>
<td>02:53 hr:mn</td>
</tr>
<tr>
<td>40 Bc</td>
<td>6:38 hr:mn</td>
<td>04:13 hr:mn</td>
</tr>
<tr>
<td>70 Bc</td>
<td>7:11 hr:mn</td>
<td>04:42 hr:mn</td>
</tr>
<tr>
<td>Compressive Strength at 3,500 kPa (500 psi) in 48 hours at 20°C (68°F)</td>
<td>21:50 hr:mn</td>
<td>17:50 hr:mn</td>
</tr>
</tbody>
</table>
Figure 1: Evolution of the unconfined compressive strength with high-temperature curing time (344°C (650°F) and 20.7-MPa (3,000-psi)) pressure.

Figure 2: Material phase composition of cement samples obtained after high-temperature curing (344°C (650°F) and 20.7-MPa (3,000-psi)) pressure. black -1 month ; red – 6 months
Figure 3: SEM observations of flexible particles after: a - 1 week of curing at 35°C (95°F) and 13.8-MPa (2,000-psi) pressure; b - 1 month of high-temperature curing at 344°C (650°F) and 20.7-MPa (3,000-psi) pressure; c - 6 months of high-temperature curing at 344°C (650°F) and 20.7-MPa (3,000-psi) pressure

a.

![Graph 1: UCS vs Aging time at 344°C (650 °F)]

b.

![Graph 2: TS vs Aging time at 344°C (650 °F)]
Figure 4: Long-term evolution of the principal mechanical properties of the novel high-temperature-resistant cement composition selected for the field trial in the SAGD injector well at 344°C (650°F) and 20.7 MPa (3,000 psi): a – unconfined compressive strength; b – tensile strength; c – Young’s modulus

Figure 5: Heating schedule for the novel high-temperature resistant cement
Figure 6: Analysis of long-term performance of novel system under the recommended steam schedule: a = under compression stresses; b = under tensile stresses
Figure 7: CBL-VDL cement bond log inserts

Figure 8: Injector: SBT Composite Cement bond log
Figure 9: Producer: SBT Composite Cement bond log