An Integrated Approach to Cement Evaluation

Cement sheath evaluation is enhanced when engineers consider cement evaluation logs in the context of events that took place during drilling and subsequent cement slurry placement. Such an integrated approach helps engineers confirm the presence of zonal isolation or determine why isolation has not been achieved. In the latter case, a complete well history analysis offers operators valuable guidance for improving future cementing operations.

Primary cementing operations rank among the more important events that occur during a well’s lifetime. The cement sheath plays a critical role in establishing and maintaining zonal isolation in the well, supporting the casing and preventing external casing corrosion.

Well cementing involves a myriad of geologic, chemical and mechanical parameters. The operation may be divided into several principal activities—drilling the wellbore, casing the wellbore, placing the cement slurry in the casing to wellbore annulus, allowing the cement to set and then evaluating the quality of the resulting cement sheath. Secondary considerations may include remedial treatments to correct cementing problems and the long-term effects of production on cement sheath integrity.

Primary cementing requires the wellbore to be in a condition that is conducive to successful cement slurry placement. For example, the borehole should be free of washout, out-of-gauge zones. Caused either by soft or unconsolidated formations or as a result of drilling practices, washouts create irregular and enlarged boreholes that are difficult to clean up and tend to hold gelled or dehydrated drilling fluid that can contaminate the cement slurry. Because they also create voids in the borehole wall that must be filled with cement, washouts must be factored into cement volume calculations. To determine the location and volume of washouts, engineers usually perform openhole caliper measurements prior to running casing. In the absence of a caliper measurement, the cement volume must be estimated. When designing the cement job, engineers may also be guided by other formation considerations, including bore pressures, fracture gradients and the locations of potential lost circulation zones.

As the casing is run in the hole, centralizers installed on the outside of the pipe establish a standoff between the casing and the wellbore that provides open flow paths in an annulus. The general guideline for centralization is to maintain a casing standoff sufficient for effective mud removal and cement sheath coverage. When the casing is poorly centralized, annular constrictions can trap drilling fluid between the casing and the wellbore, preventing complete cement coverage. This problem is exacerbated as a well’s deviation angle increases.

For many years, the industry has employed strategies to promote optimal cement placement results. These strategies, collectively known in the industry as good cementing practices, dictate that drilling fluid be conditioned prior to a cement job. Conditioning is a process of homogenization, cuttings removal, gelled mud dispersal and adjustment of rheological properties to facilitate cementing. Many cement placement simulators provide recommendations that address drilling fluid conditioning. In the absence of cement placement simulators, cementing personnel commonly circulate at least one annular

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volume of drilling fluid before pumping the cement slurry. This precaution is carried out after casing is run to remove entrained gas and cuttings, break the fluid’s gel strength and lower the fluid’s yield stress and plastic viscosity. However, such broad measures may be questionable in light of the highly diverse and increasingly complex wells being drilled today.

Chemical washes and spacer fluids are pumped ahead of the cement slurry to facilitate removal of drilling fluid and prevent commuting of the drilling fluid and the cement slurry. The types and volumes of washes and spacers are selected on the basis of the drilling fluid properties and hole geometry as well as the physical and chemical environment downhole.

When feasible, casing movement—in the form of reciprocation, rotation or both—is performed while circulating drilling fluid and while pumping preflushes and cement slurries. Casing movement helps reduce drilling fluid viscosity and dislodge gelled drilling fluid from annular constrictions, thereby providing an improved environment for cement placement.

The cement slurry is designed to perform within the parameters of the anticipated wellbore environment. Accurate temperature and pressure data are essential inputs to the design process. Cement parameters that must be optimized include rheological properties, thickening time, strength development, permeability, free fluid and long-term durability.

During job execution, care must be taken to prepare the preflushes and cement slurries according to the design and to pump these fluids at the planned rates to ensure successful cement placement. The wellhead pressure must also be examined throughout the operation to verify that the fluids are being placed properly and that the well is under control. Modern cement mixing and pumping equipment is fitted with sensors that allow engineers to closely monitor and record these parameters.

After the cement sheath has set and hardened, logging helps engineers ascertain the quality of zonal isolation. Log interpretation can be improved if logging personnel are informed of previous drilling and cementing activities as well as the physical properties of the cement. Information about hole geometry, potential lost circulation zones, mud type, spacer fluid and cement properties, pressure testing and unusual events that occurred during drilling and cementing may help logging engineers properly calibrate tools and ensure that sufficient logging data are obtained for cement sheath evaluation. Building on established cementing practices, a system for rendering all relevant information into a compatible format allows a more efficient and thorough analysis of the principal parameters influencing primary cementing and zonal isolation.

Schlumberger engineers have developed a technique by which logging personnel and operators may easily view and analyze previous well events, thereby improving log interpretation. This article presents case histories from Alaska, Colorado and Texas, USA, and from the Gulf of Mexico. These cases illustrate how performing a comprehensive examination of the entire well construction process can help engineers verify primary cementing success or diagnose why cementing objectives have not been met. In the latter case, the lessons learned can provide guidance for remediation and improving results in future wells with similar parameters.

**Integrated Cement Evaluation**

In the context of well cementing, the concept of following a cementing operation from the design stage through the execution stage and to the evaluation stage has existed for some time. Accordingly, Schlumberger has organized dedicated teams of drilling, geomechanical, logging and cementing engineers that perform multidisciplinary analyses of virtually all parameters relevant to the lifetime of a well. A community of these engineers is located at Schlumberger PetroTechnical Engineering Centers (PTECs) around the world. Their principal objective is to provide operators with information to safely and efficiently construct wells and maximize well productivity. The engineers gather the data and arrange the information in a workflow that allows offset well histories to be used during well planning.

Within the PTECs, multidisciplinary teams of well integrity engineers (WIEs) collaboratively analyze many well parameters and arrange the information in a workflow that allows straightforward visualization of the history and current status of a well. At key junctures, the WIE teams are also able to remotely monitor and analyze the current status of a well. Because the datasets frequently come from various sources in a variety of formats, they must be normalized to allow a coherent examination. Engineers accomplish this task by entering the data into the Techlog wellbore software platform.

The platform consists of a comprehensive set of modules that accommodates the myriad types of data acquired during a well’s lifetime. An interactive graphical user interface allows engineers to evaluate details throughout the entire well construction process.

The WIEs use the software platform to collaboratively examine formation geology and petrophysics, well geometry, drilling events, drilling and cementing fluids, cement placement events and cement sheath evaluation logs (Figure 1). The information is arranged into a chronological account of well events that is used in the newly developed Invizion Evaluation well integrity service. Ancillary data such as laboratory test results and modeling predictions may be displayed in separate windows on the presentation.
The system’s capability to visualize and evaluate all of the available well data allows the WIEs to perform improved interpretations and determine why zonal isolation has or has not been achieved. Using the Invizion Evaluation service, holistic assessments have been performed on more than 100 casing strings worldwide.

**Cementing Depleted Sands in Alaska**

An operator in Alaska is producing from a reservoir characterized by depleted sands, potential lost circulation zones and a narrow fracture pressure window. The wells have deviation angles up to 60° and the producing interval lies between 9,800 and 10,060 ft [2,990 and 3,070 m]. The bottomhole static temperature (BHST) is approximately 150°F [66°C]; the temperature at the anticipated top of cement (TOC)—about 4,000 ft [1,200 m]—is 75°F [24°C]. A retarder was added to the cement slurry to prevent premature setting at the TD; however, the retarder also presented risk of slurry overretardation at the TOC depth.

Because of the narrow fracture pressure window, a low fluid density contrast was necessary to avoid well failure.

The densities of the drilling fluid, spacer fluid and cement slurry were 10.4, 11, and 11.5 lbm/galUS [1,250, 1,320 and 1,380 kg/m³], respectively. State regulations require that, before continuing operations, engineers must confirm the location of the top of cement and verify the presence of competent cement around the circumference of the casing. Because of the small density contrast between the wellbore fluids, the operator typically had to wait several days after the cement job for the set cement to develop an acoustic signature that would be discernable by most wireline logging tools. The delay was expensive in terms of rig time.

To determine whether cementing and logging could proceed more efficiently while reducing the waiting-on-cement (WOC) time, the operator elected to use the Invizion Evaluation service. The engineers were provided with data gathered during drilling and cementing along with the compositions and rheological properties of the wellbore fluids.

The well deviation created a narrow side of the annulus, where cement contamination by mud would be more likely. Knowing the rheological properties of the drilling fluid, spacer fluid and cement slurry, the engineers performed cement placement simulations to obtain guidance for preventing such cement slurry contami-

![Figure 2. Alaska well presentation. Tracks 1 through 5 display well information and measurements obtained before cement placement. Tracks 6 through 9 present cementing execution information. Track 9 predicted that some mud contamination (red) could be expected in the lead cement slurry to a depth of 9,200 ft. However, no contamination was predicted across the tail slurry below 9,150 ft (Track 9, dark gray). Tracks 10 through 14 show cement evaluation results. Acoustic and ultrasonic logs that were run 27 hrs after cement placement confirmed adequate cement coverage and zonal isolation across both the lead and tail portions of the cement sheath below 4,000 ft (Track 14, predominantly brown).](image-url)
presentation (of sustained casing pressure at the surface after cementing. The second red). The acoustic impedance map also showed regions of poor cement displacement simulation predicted areas of poor mud displacement (Track 2, numerous areas of poor casing standoff (Track 1, red). The cement
left ) indicates
9. For a description of the Isolation Scanner tool operation:
6. A narrow fracture pressure window describes a condition in which the mud weight required to drill an interval without fluid influx is close to that which would cause the formation to fracture or fail.
8. The unit of acoustic impedance is the rayl, normally given in Mrayl. One rayl = 1 kg/s/m².
that, despite the contamination, the cement slurry would set within 10 hours; however, the acoustic impedance differential was only 0.3 Mrayl—too small to be detected by conventional logging tools.8 Three days of curing would be necessary for the cement to develop a sufficiently high acoustic impedance contrast to permit evaluation by conventional logging methods—confirming the operator’s previous experience.
The WIEs recommended the use of the Isolation Scanner cement evaluation service because of its ability to acquire more sensitive acoustic impedance measurements.9 The tool combines the classic pulse-echo techniques of ultrasonic bond logging tools with a flexural imaging technique that provides more effective imaging of the annular fill, including reflection echoes at the cement-formation interface—the third interface echo (TIE). The TIE also allows engineers to determine whether material behind the casing is solid, liquid or gas. Correlating data from the UCA to the capabilities of the Isolation Scanner technology, the WIEs determined that logging could commence as early as 27 hours after cement placement. The cement execution data and laboratory data, combined with the log information, illustrated the presence of good cement across all sections of the cement sheath. The operator has continued to employ this evaluation technique, lowering the WOC time and reducing completion costs.
Solving Sustained Casing Pressure in Colorado
The Niobrara play in the Denver-Julesburg basin is located in a highly populated region along the Front Range in Colorado, USA. This field produces approximately 250,000 bbl/d [39,700 m³/d] of oil from the Niobrara formation. One of the principal operators has more than 8,400 active wells in the region. Effective zonal isolation is of particular importance because some wells are located immediately adjacent to residential areas. Sustained casing pressure caused by gas migration through inadequate tail cement is a cause for concern and has been confirmed by cement bond log (CBL) and USI ultrasonic imager logs in certain cases. To mitigate gas migration, the operator elected to try the Invizion Evaluation service. The operator provided the WIEs with pertinent well data, which were loaded into the Techlog platform to produce a comprehensive presentation (Figure 3).
The analysis indicated that previous wells had poor casing centralization, resulting in poor mud removal that allowed channels to form in the cement sheath and serve as conduits for annular gas migration to the surface. Based on these findings, the operator increased the centralizer density by 50%, which led to better cement slurry displacement and mud removal. Sustained casing pressure was no longer observed.

The investigation also included using the CemSTRESS cement sheath stress analysis software to estimate the radial and tangential stresses imposed on casing strings, cement sheaths and formations during the life of a well. The input parameters included Young's modulus, Poisson's ratio and cement compressive strength. The software evaluates cement sheath performance in compression, tension or both; it can also identify both inner and outer microannuli and predict their size and development over time. In wells that experienced gas leakage, CemSTRESS analysis showed that the Young's modulus of the formation surrounding the tail section of the cement sheath was too low to support the mechanical properties of the cement compositions that had been pumped. As a result, the cement sheath simulation indicated failure under traction, a possible explanation for the poor casing-cement bonding across that interval. Engineers altered the cement slurry composition to improve cement sheath flexibility. In addition, the cement slurry contained an additive to cause slight cement sheath expansion after setting, thereby improving the bond. The operator has successfully applied the revised cementing strategy in wells in the region.

**Mitigating Gas Migration in South Texas**

An operator producing from the Eagle Ford Shale in South Texas, encountered difficulties while cementing surface casing.

The 10 3/4-in. surface casing was set inside 80 ft (24 m) of 16-in. conductor pipe. The casing string extended vertically from the surface through the conductor pipe and inside a 13 1/2-in. open hole to 4,525 ft (1,379 m).

Figure 4. Overview of an Invizion Evaluation service for an Eagle Ford well. Engineers divided the Invizion Evaluation presentation into five zones (left). Key observations included that, although cement slurry had reached the surface during displacement, losses occurred thereafter and the top-of-solids depth was 240 ft (Track 13). Liquid channels existed between 240 and 550 ft. Washouts occurred between 500 and 1,200 ft (Track 4).
The operator faced three principal cementing risks: lost circulation, hole washouts and gas migration from shallow flow zones between 250 and 600 ft [76 and 183 m] measured depth. An offset well on the same pad developed gas migration outside the casing and required remedial cement squeezes and a casing patch to fix the problem. The casing patch reduced the inner diameter of the casing to an extent that interfered with further well development plans. The operator sought advice from Schlumberger to propose measures to improve cementing results in future wells.

Updated cementing practices were employed to prevent gas migration along the surface casing string. Both the lead and tail cement slurry incorporated a gas migration control additive. The tail slurry was also designed to set quickly to further minimize the risk of gas migration, the operator elected to install an external casing packer (ECP) within the casing-conductor pipe annulus.

The cementing operation successfully stopped gas migration; however, after the cement slurry reached the surface, lost circulation difficulties were encountered, and the TOC fell back into the well before the top plug reached the bottom of the casing string. The WIEs performed the Invizion Evaluation service to investigate these problems as well as verify annular zonal isolation.

The overall presentation indicated that the TOC was at 240 ft [73 m]. Washouts and liquid channels in the cement slurry were also observed. To more thoroughly examine the data, the WIEs divided the well into five analysis zones (Figure 4). In Zone 1, extending from TD to 4,060 ft [1,237 m], good cement bonding was present despite about 10% mud contamination. In Zone 2, between 4,060 and 2,006 ft [611 m], evidence of mud invasion and lost circulation was apparent; nevertheless, the interpretation indicated good bonding within the interval. A discrepancy between the predicted and measured location of the interface between the tail slurry and lead slurry provided evidence that the lead and tail slurries were mixed during displacement.

In Zone 3, between 2,006 and 1,250 ft [611 and 381 m], mud pockets were observed. Log interpretation indicated bonded solids around the casing and the development of liquid channels. Similar results were seen in Zone 4 between 1,250 and 560 ft [381 and 171 m] (Figure 5). Zone 5 extended from 560 ft to the...
surface, and liquid channels were observed in the cement sheath (Figure 6). The presence of the inflated ECP was evident at 75 ft [23 m]. The tortuosity of the channels and their position on the wide side of the annulus suggested fluid flow into the annulus after cement slurry placement. The overall analysis indicated that, despite the operational problems, the cementing operation achieved adequate zonal isolation. A possible explanation for the losses and lowered TOC is that during displacement, the pumping pressure may have initiated ECP inflation, thereby reducing the effective annular size inside the conductor pipe. The resulting pumping pressure increase at shallow depths may have caused formation breakdown. Furthermore, the formation of channels was a possible result of inadequate casing centralization below 1,000 ft [305 m]. Therefore, the recommendation for future offset wells is to eliminate the ECP from the well design and to install a centralizer on each casing joint.

Figure 7. Deepwater Gulf of Mexico exploration well log. Engineers relied mainly on the bond index (BI) data (Track 2) to estimate the TOC. The BI falls significantly at 18,640 ft (red line), and engineers chose that depth as the TOC. This finding is not as evident in the acoustic impedance map (Track 1) or the variable density log (Track 3).
Well Planning in the Deepwater Gulf of Mexico

An operator developing a deepwater prospect in the Mississippi Canyon in the Gulf of Mexico encountered difficulties while completing an exploration well drilled in about 4,059 ft [1,237 m] of water. Previously, the operator drilled to a depth exceeding 20,000 ft [6,100 m] and cemented a 14-in. casing string inside a 16-in. liner. The length of the overlap between the casing string and the liner was 8,940 ft [2,725 m], and the annular clearance within the liner lap was 0.425 in. [1.08 cm]. The casing string was designed to isolate a zone composed entirely of salt. Fluid losses during drilling and cementing indicated the presence of lost circulation zones.

After the cementing operation, a logging run was performed to locate the TOC (Figure 7). Relying mainly on CBL attenuation data and a computed bond index (BI), the logging engineers estimated the TOC was located at 18,640 ft [5,680 m]—3,960 ft [1,210 m] lower than expected—which meant that the upper portion of the salt zone was uncemented.

The operator, who plans to drill a similar offset well in the future, approached Schlumberger to provide an Invizion Evaluation service on the exploratory well and help formulate strategies to prevent difficulties that might impede successful zonal isolation in the offset well. The operator provided archival data from the earlier well. This information—including openhole logging-while-drilling (LWD) data; compositions and physical properties of the drilling fluid, spacer fluid and cement slurries; and analyses of well fluids that returned to the surface—was integrated into the Invizion Evaluation presentation. Engineers also discovered that, during the previous logging run, significantly more data were actually acquired but never examined. The additional data included flexural attenuation (FA), TIE and a solids, liquids and gas (SLG) map.

The openhole data revealed the presence of three intervals along the salt zone that were contaminated by other minerals (Figure 8). Engineers had previously assumed that the salt
zone was continuous. The contaminated intervals were identified as possible sites where lost circulation took place, and their presence helped explain why the TOC was below the intended depth.

Equipped with the mud, spacer and cement slurry property data as well as pressure charts acquired during the cementing operation, the WIEs performed fluid placement simulations. The first simulations confirmed that the pressure charts were consistent with the occurrence of lost circulation when the float valves were converted on the casing prior to cement job execution. In addition, engineers noted that the fluid displacement pressure exceeded the fracture pressure in the interval. The elevated pressure likely resulted from the constricted annular clearance between the liner and the casing string.

The second set of simulations examined the capability of the spacer fluid and cement slurry to displace the drilling fluid (Figure 9). Engineers noted that centralizers had been installed only at the bottom of the casing string. Above the centralizers, the casing standoff was poor, and the simulations indicated poor mud removal and a sizeable channel above about 18,700 ft [5,700 m]—a depth consistent with what had been concluded to be the top of cement in the earlier interpretation.

Integration of the additional logging data with the previous findings was revelatory (Figure 10). The acoustic impedance map, coupled with the FA and SLG maps, showed the TOC to be much higher than previously thought—at about 16,000 ft [4,880 m]. Unfortunately, this depth was still below that required to cover the entire salt interval. Furthermore, WIEs confirmed that the cement sheath quality was good in the centralized portions of the annulus around the casing shoe, and the cement slurry that rose to 16,000 ft had a clear placement channel consistent with computer simulations performed after the job execution.

The new information resulting from the Invizion Evaluation service allowed the operator to adjust the completion plan for the future. The operator’s engineers formulated a plan to improve centralization of tubulars in regions

Figure 9. Cement placement simulations for an exploratory well in the Gulf of Mexico. Centralizers were installed only in the lower part of the casing string. Above about 19,300 ft [5,880 m], the casing standoff was poor (Track 1). The displacement simulations (Track 2) predicted that full cement coverage (gray) rose to a depth of about 18,700 ft [5,700 m]. Above, the annulus contained drilling fluid (brown). The mud contamination risk simulation concurred. Mud contamination (Track 3, red) began as the casing standoff decreased. Full cement coverage (Track 3, green) was predicted in the centralized region.

14. Float equipment, installed near the bottom of a casing string, comprises valves that allow drilling fluid to enter the casing interior as the string is lowered into the well. As a result, the casing is filled with drilling fluid before the cement slurry is pumped. Before the cement job commences, a ball or other activation device is pumped into the casing. When the ball reaches the float equipment, the valves are converted such that they permit only one-way flow out of the casing and into the annulus, thereby preventing reverse circulation, or U-tubing, of the cement slurry.
above the casing shoe. To reduce friction pressure during pumping and minimize lost circulation, the operator decided to eliminate the 14-in. casing string and extend the 16-in. liner through the salt zone. Care will also be taken to ensure that fluid placement pressures remain below formation fracture pressures, further reducing the probability of lost circulation while allowing the cement slurry to reach the intended depth.

Expanding the Scope of Holistic Cement Sheath Evaluations

Engineers and wellsite personnel have only one chance to achieve a successful primary cement job for each casing string. Remedial cementing to solve problems associated with a faulty cement sheath has a less than stellar success rate and may even reduce a well’s productivity.

Improved understanding of primary cementing operations can be gained by examining well histories while performing comprehensive interpretations of log data. Indeed, the added insight provided by the Invizion Evaluation service can further enhance the value of integrating all available information and allowing operators to make better informed decisions concerning drilling and cementing practices.

To date, the Invizion Evaluation service has been aimed at examining current cementing practices and the objective is to improve them and troubleshoot less than optimal outcomes. The longer-term value of the service will be enhanced as engineers and operators become more proactive during the well cementing process, making real-time cementing decisions that make use of all borehole measurements and data obtained during drilling. For example, the information may be entered into the Techlog platform as it is acquired, facilitating close collaboration among personnel involved in the drilling and cementing process. Ultimately, engineers may apply the Invizion Evaluation service at the planning stage, allowing geologists and geophysicists to collaborate with the drilling and cementing engineers to further ensure primary cementing success.—EBN