InTuition Energy Associates Pte Ltd

Deepwater Horizon Macondo Blowout

A Review of Cement Designs and Procedures

Final Report – Draft Copy Only

Phil Rae

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Exhibit No.

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Executive Summary

- The Macondo blowout was almost certainly initiated by failure of the primary cement job in the 9 7/8" x 7" annulus which allowed gaseous hydrocarbon to enter the well. Gas migration probably began shortly after cement placement due to rapid decay of the overbalance pressure on the hydrocarbon-bearing zone, a situation that may have been inadvertently exacerbated by operational procedures.

- The cement design, in terms of composition, volume, performance and, arguably, density, was inappropriate for this casing string in this particular well. Better designs with superior properties could easily have been formulated and proposed for this critical cementing operation.

- Laboratory data presented for the cement slurry were inaccurate or misleading and misrepresented the properties and characteristics of the cement. Failure to identify the significance of these inaccuracies and inconsistencies, or to advise of their potential importance, almost certainly contributed to the subsequent disaster.

- Important additional laboratory tests that would have verified the performance characteristics of the cement and spacer systems proposed, and their suitability or otherwise for this application, were not carried out, or not reported.

- Based on this analysis, the cement failure allowed gas to invade the annulus and to make its way either upwards to the casing hanger or downwards to the casing shoe. In the former scenario, pressure on the unsecured (no lock down) casing hanger could have lifted the assembly and compromised the seal, allowing, initially, mud to enter the well and ultimately allowing gas to reach the marine riser and/or drill pipe.

- The replacement of mud with seawater in the marine riser was probably a critical event, sufficiently reducing the pressure above the casing hanger and making it vulnerable to upward displacement by gas pressure beneath it, possibly compromising the BOP while simultaneously opening the flow path from the reservoir. An alternative flow path via the casing shoe and float equipment cannot be ruled out at this time without access to additional data.

- Undertaking certain operations in the well (pressure testing and, in particular the negative test) at very early time, post-cementing, while cement was not guaranteed to be set and mechanically competent was dangerous, given the configuration of the well.

- The use of a single production longstring in this well, with an incompletely cemented annulus and an inadequate second barrier, was inappropriate. At the very least, cement should have been brought into the previous liner to ensure coverage of all open formations and additional mechanical barriers should have been deployed e.g. swell packers. Ideally, the well should have been completed with a liner/tieback configuration which would have provided additional safeguards.

- Hanging off the casing string in the well immediately after cementing and setting the seal would have exacerbated significantly the risk of gas invasion in the production annulus by isolating it from the hydrostatic pressure of the fluid in the marine riser. Subsequent volumetric reductions in this annulus, resulting from leakoff and cement hydration, would have been uncompensated by riser fluid from very soon after cement placement. The net effect would have been even more rapid annular pressure decline and/or volumetric expansion of nitrogen in the foamed cement. The latter, if it occurred, may have further compromised the quality of what was, undoubtedly, an already questionable cement system. Either phenomenon could have caused loss of annular integrity due to gas influx and migration.

- Apart from the fundamental cement job design issues, several other factors probably contributed to failure of the primary cement. Individually, these factors may not have been catastrophic but in combination they could probably have influenced the outcome.

- Insufficient mud circulation time, prior to the cement job, probably resulted in further, but very minor, loss of hydrostatic overbalance during, and immediately after, cementing, due to gas in the mud being circulated back only to the riser.

- Poor centralization of the casing string, due to the use of an insufficient number of centralizers, may have compromised mud displacement and favored the creation of mud channels. While the deployment of less than the recommended number of centralizers would have decreased casing standoff and probably increased the risk of inter-zonal communication and possibly gas flow, it would not necessarily have precipitated it.

- It should be noted that the Halliburton Gas Flow Potential calculation is based on a very simple, but largely unproven, concept. Exactly how that has been applied in the Opticem software and, more to the point, the scientific validity of that implementation is unclear. Coupling the already-questionable GFP calculation with a mud displacement model to provide an adjusted GFP value has no scientific basis, to the best of my knowledge.

- The fact that no viscous pill was spotted in the rathole under the casing shoe may have increased the risk of cement contamination due to fluid density differentials. However, the significance of this is unclear. As far as I am aware, there is still no incontrovertible evidence to suggest that the casing shoe/double flapper valve was definitely the entry point for gas into the well. However, other circumstantial evidence suggests that it played a critical role in the initiation of the blowout by allowing mud to escape from the well.to the production casing annulus, indicating a lack of competent cement there.

A Review of Cement Designs and Procedures on Macondo

Introduction

This work was undertaken on behalf of, and at the request of, Transocean. The workscope involved a review of technical/commercial proposals and job designs prepared for the cementing of the 9 7/8" x 7" tapered longstring on the ill-fated BP Macondo-1 (MC 252 #1) exploration well in the Gulf of Mexico.

Also examined were laboratory results from a series of reports on cement tests undertaken by the cementing contractor, Halliburton. Laboratory procedures were assessed and compared with industry standard procedures used for cement testing and slurry composition was reviewed on the basis of its composition and characteristics.

In addition, various pieces of correspondence, including e-mails, daily drilling reports, post-job reports were examined for information, relating to preparations for the cement job, operational procedures followed and post-cementing procedures.

Finally, the findings of this review, based on the documents provided and interpretation of sometimes incomplete information , were considered within the context of the events aboard the Deepwater Horizon in the days leading up to 20th April, 2010.

The conclusions drawn are mine alone but they are supported by many individual pieces of information. However, they are, of necessity, still speculative insofar as the exact causes of the disaster are concerned. Hopefully, additional information will emerge in the coming weeks and months to confirm or refute these preliminary findings.

Specific Workscope Requested By Transocean

(as per e-mail from Perrin Roller on 2nd June, 2010)

- Forensic look back at the cement design utilized
- Review and comment on the lab test results for the slurries
- Design application fit for purpose?
- Recommendations for future cementing operations in similar situations
- Wellbore preparation prior to cementing (evaluation of what was done and recommended best practices)
- Mechanical considerations for float eq and plugs.
- Any other areas that we have not addressed

Background

Macondo is a deepwater oil and gas field located at a water depth of around 5000 feet in the Gulf of Mexico. The Macondo-1 exploration well was drilled to a measured depth of 18,360 ft (18,349 TVD) and cased and cemented with 9 pipe strings. The conductor casing was driven while the cemented strings consisted of 2 primary casings and 5 liners plus the final casing, the ill-fated 9 7/8" x 7" casing tapered longstring. This review considers only the latter since only cursory information was provided for the previous cementing operations.

Bottom hole static temperature, even at a depth of 18000 ft, is relatively low, being in the range of 210 deg. F but this is not uncommon in deepwater scenarios. Circulating temperature is also a relatively cool 135 deg. F.

Deepwater wells usually exhibit rather narrow pore pressure/fracture pressure envelopes, complicating the drilling and cementing process and the Macondo well was no exception. This problem can be managed in most wells but it requires careful planning and attention to detail. It may also dictate variations in the original drilling plan and requires numerous contingencies in response to actual well conditions encountered during drilling. Finally, deepwater well construction often requires non-standard approaches to cementing including, for example, the use of lightweight cement slurries in what could be regarded as unconventional circumstances.

Review of Cement Job Designs

Cement has multiple functions in an oil and gas well. The most important objective of any primary cement job is to provide a competent annular seal, ensuring that formation fluids are contained at their respective depths until deliberately produced, if required, by perforating. Cement is used to cover and isolate each individual producing interval, maintaining zonal isolation between each and providing a competent barrier between these zones and the surface This zonal isolation and pressure integrity should be maintained over the entire life of the well. No fluid movement, either gas or liquid should be possible at any time through the cemented annulus. In fact, the cemented annulus should, at a minimum, present a barrier to vertical fluid movement equivalent to the original barrier presented by the layers of rock that were removed in the process of wellbore construction. This is particularly important when the cemented annulus provides direct communication between a hydrocarbon reservoir and the surface.

In the annulus there are three possible paths for fluid movement; the interfaces between cement/rock and cement/casing and the cement matrix. Poor mud removal is normally identified as the major source of communication problems, although poor bonding at the interface can occur even when mud cake or oil films have been completely removed.

Cement bonding can also be affected by slurry properties like fluid loss and free water. However, cement adherence to the formation and casing is primarily affected by cement shrinkage and by stress changes induced by downhole variations of pressure and temperature. These occur mainly inside the casing but can also originate in the formation.

Early strength development and rapid permeability decline are important to ensure structural support to the casing and hydraulic/mechanical isolation of downhole intervals, respectively. Delays in strength development cause significant amounts of lost time due to the need to Wait-On-Cement. Thus, drilling and other well completion operations cannot proceed and the rig must sit idle until the cement is deemed strong enough to continue. In deep water operations, where rig costs are high, this is viewed as particularly significant.

The actual development of strength in cement systems is dependent on a number of factors. The type of cementitious material (i.e. the cement type or Class – A, C, G, H, as defined by API) is important due in part to chemistry and in part to granulometry. Slurry density is considered critical - lower density has, traditionally, been associated with lower strength due to dilution effects and replacement of cementitious material with additional water or inert solids. Temperature is a key parameter and, to a lesser extent, the pressure. Less appreciated, is the influence of the many types of additives that are included in slurry formulations. Correct selection of cement and additives allows slurry tailoring to achieve a "strong cement" that will support the mechanical stresses that occur during ongoing drilling operations and throughout the well's productive life. Since cement is normally the primary means of isolation, its integrity as a sealing material should be paramount.

Actual Cement Design

The cement slurry system proposed for this casing was a foamed cement design. This was based on the use of a 16.74 ppg (lbm/gal) Class H cement base slurry foamed to around 14.5 ppg using nitrogen gas. A small volume (~4 bbls) of unfoamed base slurry was to precede the foamed cement and the program also specified the use of 7 bbls of the same unfoamed base slurry to complete the job. The latter was certainly intended to fill the shoe track and provide higher density, stronger cement at the bottom of the well.

Foamed cements are not new and have been used on literally thousands of oil and gas well cement jobs around the world over the past 30 years. They are particularly popular in deepwater cementing applications because of several desirable characteristics. These include their relatively favorable setting behavior and early strength development at the low temperatures typically seen in deepwater wells, particularly in the shallower casing strings. They are also relatively flexible, less prone to tensile failure, provide good thermal insulation and, prior to setting, they are somewhat compressible. This latter property is generally accepted to provide some protection against gas migration, a phenomenon associated with the undesirable movement of hydrocarbon gas through the cement, during the actual cement setting process – the so-called liquid:solid transition.

So, while it is relatively unusual to use foamed cement for a production casing scenario, it is not unprecedented and there are several factors in this well that may, superficially at least, have supported the proposal to use it. The perceived need to use a lightweight slurry due to a narrow pore/frac pressure window is one reason. So, too, is the risk of gas migration and the desire to have a lightweight cement with good mechanical properties. However, it should be noted that these factors do not make the use of foamed cement mandatory. Even if a lightweight cement system was considered essential (which it was not, given the decision to pump such a small volume of cement), there are several alternative types of lightweight cement system that could be employed here in place of foamed cement. The fact that the Deepwater Horizon already had the necessary equipment onboard to perform foamed cementing may have played a role in the decision, as much as anything else. In such situations, with experienced crew who are well-versed in the technology, foamed cementing is relatively easy to perform and can offer certain advantages, particularly in terms of logistics, over other competing lightweight cementing technologies.

Having said all of the above, however, laboratory testing of the cement system for the intended application was inadequate, given the critical nature of the cement job. Laboratory results were inconsistent and should, at the very least, have called for repeat testing. Compressive strength tests on the Foamed Cement (14.5 ppg) suggested that it remained unset until sometime in excess of 24 hours, a key consideration given that the well was subjected to both positive and negative pressure tests after only 16 hours. Ultrasonic Cement Analyzer (UCA) data was presented for the base slurry (16.74 ppg) showing reasonable strength of 500 psi after only 6 hours. The test methodologies and temperatures employed are different but such a vast discrepancy in the appearance of set characteristics should have raised some concerns. Were all additives included in both designs? Was the foaming agent actually used in the base slurry tests? This is actually a very critical point, given the discrepancies between the onset of strength development in the slurry used for the crush test (the foamed slurry) and that used for the UCA test (the base slurry).

While the absolute values of strength for each of these slurries would be different (due to the inclusion of gas in the foamed slurry), the onset of strength development should be similar since the gas (whether nitrogen or air) is essentially inert and does not greatly affect either the thickening time or development of mechanical strength. Based on the results, this was not the case for these slurries although, as noted below, the test temperatures and pressures used were different, for operational reasons. However, as an alternative explanation, it is also conceivable that the foaming agent was not included in the slurry used for UCA testing since it makes the base slurry much more difficult to handle and prone to foaming (obviously). Without knowing the exact composition of the foaming agent used, it is difficult to be sure but there is every possibility that the foaming agent might act as an additional non-specific cement retarder, extending the thickening time and impairing the strength development of this cement system. Certainly, this could explain the huge discrepancy in the evolution of compressive strength between the base and foamed cement slurries. If this had been the case (and there is no evidence available at present to confirm or refute such an hypothesis), the cement test in the water bath would provide a more realistic assessment of the cement's genuine mechanical properties under field conditions than the UCA test.

1) It is safe to assume that, because of equipment limitations, it was rather difficult (although it is not impossible) to check the compressive strength of foamed cement under anything approaching downhole conditions. This is because of pressure limitations (6000 psi max for a UCA, normally) and the need to inject nitrogen under pressure to have the correct foam density under the specific test conditions. So, in conclusion, Halliburton have provided UCA strength results for the base (unfoamed) slurry at 16.7 ppg which, of course, are totally irrelevant from the perspective of the actual strength of the foamed slurry.

2) The crush test on the foamed slurry is indeed done with a slurry at 14.5 ppg, apparently. However, while it gives an indication of the foamed slurry mechanical properties, it is only an approximation. This is because:

a) the slurry is foamed with air rather than nitrogen

b) the test is done only at atmospheric pressure and, consequently, the temperature is limited to about 90 deg.C. - in this case they have run it at 180 deg.F

c) the crush test has poor reproducibility under the best of circumstances and even worse when the test slurry is foamed.

3) Despite the fact that the crush test is supposedly a 14.5 ppg foamed slurry, the report wrongly identifies it as having a foam quality of 0. This is almost certainly an error. The foam quality should be approximately 18%.

4) The two tests 73909/1 and 73909/2 are actually on slightly different slurries. The retarder SCR-100 has been increased from 0.08 gal/sk to 0.09 gal/sk to extend the thickening time slightly. As a result, TT increased from ~5hrs 30mins to ~7hrs 30mins. The incremental retarder concentration probably makes little difference to some test results (e.g. rheology) but it does affect both thickening time and compressive strength results so, by rights, these sets of results should not be combined as if they were based on identical slurries when, in fact, they were not..

5) The UCA test result was achieved after circulating the slurry for 3 hours at 135 deg.F (BHCT). This involves shearing the slurry for the prescribed time (to better simulate pumping) and then pouring the slurry into the UCA cell. This usually gives better (i.e. more favorable) results than would be obtained with an unsheared slurry but can be justified on the basis that the slurry is indeed pumped for several hours.

6) Similar questions can be raised on the thickening time tests which again were performed on the base slurry and showed reasonable setting times. Testing the base slurry for thickening time is an accepted practice yet, despite the addition of some extra retarder to further lengthen the thickening time, no additional new data were generated for compressive strength or slurry rheologies.

7) The rheology showed hallmarks of an unstable slurry – one that may be prone to settling or Free Water, based on the Fann data presented for both mixing and bottom hole rheologies. This is indicated by slurries that exhibit non-API rheologies where the 600RPM Fann reading is more than twice the 300RPM reading. By definition, for Bingham Plastic fluids (which simplistically describes the behavior of many muds), the 300RPM reading = Plastic Viscosity (PV) + Yield Point (Ty), and the 600RPM reading = 2xPV+ Ty and, hence, PV = 600RPM - 300RPM. Thus, when the 600RPM reading > 2x 300RPM reading, it implies a physically impossible negative Ty value. Under most all circumstances, this suggests that the slurry is unstable and may suffer particle segregation.

8) Surprisingly, no Fluid Loss Control data were presented for this slurry, perhaps because it contained no specific additives to control fluid loss. This is surprising. Fluid loss control is absolutely essential in any slurry that is used to control gas migration and while foamed cement has better leak-off characteristics (and higher compressibility) than normal cement, fluid loss must still be minimized to prevent premature depressurization. In fact, it is widely accepted that fluid loss control in slurries for gas migration prevention should be <50 mL/30 mins (or even lower, at <30mL/30mins).

9) Even more surprisingly, under the circumstances, the cement design contained a defoamer. This is unusual to say the least. Defoamers, in my experience and, as far as I am aware, according to the norms used by the major service companies, are never run in a Foamed Cement system since their main action is to affect surface tension in such a manner as to cause phase separation (or break-out) of the gas-in-liquid dispersion (i.e. the foam). Thus, their effect can be to destabilize foams and, while a defoamer would certainly help improve mixability of the

base slurry by minimizing unwanted air entrainment, its use in a foamed cement design should not have been considered without appropriate supporting laboratory tests. Such tests would have examined the foamed cement slurry stability versus time at temperature to assess whether there was any increased risk of nitrogen gas separation from the foam.

10) An additional factor in this well that would make the use of a foamed cement design questionable was the concurrent use of a synthetic oil-based mud (SOBM) system in the well. Foams, in general, do not like oil and, in the case of SOBM, surfactants are used to stabilize the invert emulsion and control rheological properties. These surfactants can compromise an aqueous foam's stability. This is important since, although the mud and cement are not meant to contact one another (they are separated by spacers), residual oil left on casing/formation, or in mud channels due to poor displacement, could potentially result in localized (or even general) foam collapse. Such an outcome would obviously be serious and this possibility should have been examined during compatibility testing. However, no compatibility testing data were provided, leaving me to conclude that such testing was not, in fact, carried out prior to the cement job.

11) No free water data were provided for the slurries (either base slurry or foamed cement slurry). To be fair, these tests are probably not relevant for a foamed cement system since, normally, any free water would be secondary to foam stability. Thus, if any slurry stability test should have been performed, it should rather have been a foam stability test. This is a simple test to perform and merely looks at whether the foam remains dimensionally stable during a water bath test (volumetrically as well as bubble size distribution).

12) Finally, no data are presented for gel strength development of this cement which, again, is surprising since Halliburton largely championed the idea of using gel strength to counteract gas migration. Indeed, they introduced a special testing device (the MACS Analyzer) specifically to assess gel strength development in cement systems and this device has been a major sales tool for the company's expertise in deep water cementing. In fact, the lack of gel strength data are surprising only until one looks at the conditions immediately after cement placement. The time to develop so-called Critical Static Gel Strength, which is defined as the gel strength value at which the cement slurry becomes sufficiently self-supporting that it nullifies overbalance pressure on the active zones, can probably be measured in minutes for this well, with this slurry, under these conditions. However, that is not completely the fault of the cement slurry. Operational procedures certainly did nothing to help the situation, either (see later discussion).

Cement Distribution in the Annulus

Assuming the wellbore geometry is known within reasonable limits, it is normally relatively easy to calculate cement fill in the annulus, on the basis of simple volumetric calculation. Exceptions may arise, however, in cases where losses have occurred or large percentages of mud are bypassed during the cement placement. The former occurs when circulating pressures exceed formation fracture pressure; the latter when cement fails to displace mud from washouts or where substantial channels remain in the cement due to poor mud displacement.

In the specific case of the 9 7/8" x 7" casing cementation, a 4-arm caliper was available to provide a fairly accurate assessment of wellbore geometry and, by extension, a good estimate of hole volume. Normally, this is a prerequisite for foamed cementing, especially in a small annulus, since foam volume is dependent on pressure. Thus, a foam that is raised in the annulus higher than planned is subjected to less hydrostatic pressure and expands, reducing its own density and exerting less pressure on foamed cement beneath it, which also expands, and so on. It must be noted, however, that in the Macondo well, this is not quite so critical due to the already high pressure at such depths. Thus, the slurry density change caused by bringing foam cement 200 ft higher than expected at this depth (unlikely) would only be about 1 percent.

Thus, based on the job design employed and assuming perfect displacement, the top of cement (TOC) was calculated to be at a depth of 17300 ft. The MI-Swaco report records no incidence of either losses or flow, immediately prior to, during, or subsequent to the cementing operation. This suggests that operational aspects of the job were within acceptable limits and there were no obvious incidents that may have predicted anything other than a normal cement job.

However, this begs the question: Why was it decided to leave a part of the open hole uncemented, especially since this annulus was in direct communication with surface? The answer to that probably involves two separate considerations that, in this case, conspired to further compromise the outcome of an already questionable cement job. These are respectively:

a) the so-called Gas Flow Potential (GFP), a rather arbitrary predictive index to assess the susceptibility of a well to post-placement gas flow, and
b) concerns about thermally-induced pressure build-up, a phenomenon that hs been noted in some other deepwater wells.

Further discussion on this issue can be found below.

Coverage of All Active Zones

Clearly, to ensure adequate isolation, it is imperative that competent cement covers all active zones, particularly if such zones have higher pore pressures, exhibit moderate to high permeability or may be prone to losses. The primary reservoir intervals in this well (as far as I can ascertain) were at a depth of approximately 18,200 ft. These were ostensibly at a pressure equivalent to 12.5-12.6 ppg. However, it should also be noted, as commented elsewhere in this report, that there are other active zones exposed during this cement job. These include a gas-bearing interval around 17830 ft with a pore pressure of 13.01 ppg and an even shallower zone (pore fluid composition unknown) with a much higher pore pressure (14.1 ppg equivalent) at 17730 ft.

In my opinion, all of these zones should have been considered potentially active in a well that had exhibited unpredictable behavior during its construction. Both kicks and losses had been features of this well throughout and both phenomena had, apparently, occurred during the drilling of the reservoir section that was to be cemented. Thus, the design process should have considered all of these zones with a focus on the uppermost interval with highest pressure. This was not, in fact, what Halliburton did and I believe their approach was incorrect. The fact that they used a deeper zone as the critical interval in their Opticem simulations and ascribed it a pore pressure that was inaccurate also suggests that there was insufficient dialogue between Halliburton and BP on this critical aspect of well design. The uppermost zone, with a pore pressure only slightly below mud weight, was clearly worthy of consideration, especially when it was unclear what the zone contained. Even if it had been confirmed that the zone contained only water, inflow from it would surely have compromised a foamed cement. In my opinion, the OBP on this zone was unacceptably low, especially when its contents were unknown, there was only a bare minimum of cement above it, that cement itself was a foam of questionable quality and the next line of defense was the casing hanger seal assembly.

For further information on this aspect of cement job design, I would refer the reader to the chapter Cement Job Design in the textbook Well Cementing (Edited by Erik Nelson 1990).

Vertical Height of Cement Above Uppermost Active Zone

While cement is generally regarded as a reliable and cost-effective sealant, it is also recognized that it is not perfect for such applications and that its placement cannot be guaranteed with absolute accuracy. Accordingly, rules-of-thumb have evolved over the years to account for such imperfect material properties and uncertain displacement mechanics, especially for critical cement jobs and for those where problems like gas migration are anticipated. These rules-of-thumb mostly specify the minimum length of cement that should be placed above the uppermost active zone in a given well segment. Some cementing service companies use values of 500 linear feet of cement while others may specify 200 linear meters, underlining the empirical nature of such guidelines.

If we consider the zones at 17730 ft and 17830 ft to be active (which I do), the originally designed TOC was barely adequate, at best.

Overbalance Pressure (OBP) and Gas Flow Potential (GFP)

With very few exceptions, wells are drilled with muds that exert hydrostatic pressures in excess of formation pore pressures, to ensure well security and control. The excess is referred to as "overbalance pressure" (OBP, as officially defined in API-65). In addition, under circulating conditions, while drilling or cementing, for example, fluid friction pressures exert additional backpressure on the well and the total pressure acting on active formations may be expressed as the sum of both, converted to an equivalent pseudo-hydrostatic fluid density. This is referred to as the Equivalent Circulating Density, or ECD. Generally, absolute hydrostatic density of the fluid column (when static) must always exceed formation pore pressure, providing a safe OBP of 200-300 psi (or greater). ECD, on the other hand must not exceed the formation breakdown pressure (frac pressure), as determined by fluid leak-off tests or other techniques. Exceeding frac pressure can induce mud losses that can, in turn, compromise well security if the losses are left unchecked.

In general, the cementing operation increases the risk of losses because cement spacer density and cement slurry density are traditionally greater than original mud density and friction pressures may also be higher, resulting in both elevated hydrostatic pressure and elevated ECD. While this may make job execution more difficult when weak formations are present, the additional OBP afforded by the heavier spacer and cement (compared to mud) provides additional protection from fluid invasion and gas migration once the cement is in place (assuming no losses, of course). Unfortunately, in the Macondo well, the choice of cement design left the well extremely vulnerable to gas invasion and very poorly protected once the cement sheath had been compromised. The OBP on the active zones at 17230 ft, 17330 ft and 18200 ft, immediately post-placement was ~62 psi, 1075 psi and 1492 psi, although it should be noted that these were not, in fact, the values used by Halliburton in their Opticem simulations. The low OBP on the uppermost zone was partly due to the use of a lightweight foamed cement and the problem was exacerbated by placing the TOC in the open hole. The latter action was taken, presumably, to mitigate long term annular pressure build-up in the flowing well. However, it may also have been designed like this in the dubious belief that placing the TOC several hundred feet inside the previous casing, would lead to a greater risk of gas migration (i.e. high Gas Flow Potential or GFP).

Gas Flow Potential is a dimensionless number based on a very simple theorized post placement pressure ratio – nothing more, nothing less. Strictly speaking, it takes no account of a whole host of other critical factors involved in the phenomenon of gas migration, despite what some people may believe. Thus, in its simplest form, no consideration is given to fluid rheologies, mud displacement, centralization, cement fluid loss, setting behavior or, most significantly, the potential inflow performance of the zone from which the gas may flow. GFP considers only the post placement overbalance (OBP) on the zone and the so-called Maximum Pressure Restriction (MPR) that might arise from a cement slurry exhibiting thixotropic behavior during the early stage of liquid:solid transition. This thixotropic parameter (Static Gel Strength or SGS) is set at a value of 500 lbf/100ft^2 (~240 Pa) based on simple (and, quite frankly, questionable) experiments (performed around 25 years ago) that measured the ability of gas bubbles to percolate, at macroscopic scale, through fluids with different levels of SGS. The MPR is based on a simple calculation that considers annular geometry (OD minus ID) and cement column length (i.e. height). The calculation is based on a standard driller's "pressure to break circulation" equation, substituting the 500 lbf/100ft^2 SGS for the normal mud gel strength.

Thus, the equation reduces to:

Maximum Pressure Restriction (MPR) = 1.67 x Cement Column Length/(OD-ID).......(1)

Length is in feet, annular geometry in inches.

The GFP is the ratio of the MPR/OBP:

Gas Flow Potential (GFP) = MPR/OBP...(2)

Negative values of GFP represent extreme risk since the well is actually flowing (i.e. negative OBP or underbalanced) immediately after cement placement, clearly an undesirable scenario. Values ranging from 0 to 1 represent insignificant problems since the theorized pressure loss due to cement gelation is insignificant (at GFP=0, of course, by definition, we would have no cement at all and therefore no risk of gas flow since there would be no pressure loss in the cement column). As the GFP rises from 1 (MPR=OBP), the risk increases, although it is still considered MINOR up to GFP of 3-4. Above this, the risk is considered MODERATE and a GFP>8 is considered SEVERE.

Much has been reported about the fact that the Macondo well was identified as representing a SEVERE risk of gas flow, with a GFP of slightly >10. This was tied to the fact that less than the recommended number of centralizers was deployed. According to Halliburton, using more centralizers would have avoided this problem by enhancing mud removal but this advice was not followed by BP. Thus, prophetically apparently, the Opticem software predicted disaster and the outcome was, by most accounts, a foregone conclusion. This is both disingenuous and incorrect.

While I fully agree that poor mud removal would have been problematic and needed addressing, I do not accept that Opticem predicted anything substantive, other than by chance, and think that far too much credence has been given to a very questionable piece of software. It is far more likely that the fundamental problem lay with the cement design itself, rather than the use of more or less centralizers.

Before commenting further, it should be noted that the SEVERE GFP risk assessment using less centralizers was based on apparently erroneous input data. The Halliburton simulation used the lower zone (at 18200 ft) and ascribed it a much higher pore which does not agree with the data from Geotap measurements. The combination of a low calculated OBP (due to the high input pore pressure) and the longer cement column height (using the deeper zone) would have resulted in a higher than normal value for GFP. Using an even greater cement column height (due to channeling and poor mud displacement) would have resulted in a much higher value of MPR (which is dependent here strictly on cement column length) and consequently an even higher, but still incorrect, GFP. The validity of this computation, however, is not particularly credible in an annulus with more than one fluid (i.e. a mud channel), but that is beyond the scope of this discussion and suffice it to say that the GFP is fundamentally flawed and over-simplistic.

I would like to comment here that the Halliburton design approach of using the lower gas zone in assessing risk for cementing this well was incorrect, in any case. Well design criteria for flow conditions should be based on the shallower active zones and on those with the highest pore pressures, as noted previously, in this review. I would have certainly scrutinized and considered the uppermost zone (at ~17730 ft), whose pore contents were unknown but which had the highest pore pressure at the shallowest depth of all. Thus, for safety's sake, it might be considered as the shallowest active zone with clearly the highest pore pressure (14.1 ppg) and, even more significant, with almost no cement coverage above it.

Of further very great, and so far unremarked upon, significance was the procedure of setting down the casing, complete with its hanger and seal assembly, in the subsea wellhead immediately after cementing. This appears to have attracted little scrutiny. Yet, this procedure serves to effectively hydraulically isolate the fluid in the production casing annulus, from the hydrostatic column in the marine riser above it. While this has little significance, from a well security perspective under many circumstances - in a sealed annulus (for example in the case of a tieback string where permeable formations are not exposed) or in situations with no active gas zones or in a shelfwell with limited water depth - it has serious implications in a deep water, potential gas migration well scenario, like Macondo. This procedure may be normal operating procedure in many wells but it should be examined carefully for future applications of this nature to ensure that it does not compromise safety.

Upon sealing the annulus, the initial full hydrostatic pressure, including that of the fluid above the seal, is locked under the seal. However, fluid loss (leak-off) to permeable strata causes this initial additional pressure to decline rather quickly, since the system is now isolated hydraulically from the column above. There is a tendency, therefore, for the fluid column to equilibrate with the pore pressure of the active zones. This is already an undesirable situation when we are dealing with a cement slurry that is still far from being set, since it increases the risk of invasion of the cement by pore fluids. It is for this reason that specifications for fluid loss control on cement slurries used in gas migration situations are particularly strict – to reduce the rate of depressurization of the cement slurry. Thus, it beggars belief that the slurry used on the Macondo well included no fluid loss control additive and that values for API Fluid Loss were neither provided by Halliburton nor apparently requested by BP. This is a serious failing and should have raised flags at several levels, as should the lack of any data on cement slurry gel strength evolution.

Even with the incorporation of fluid loss control additives, the situation becomes increasingly critical from a well security perspective as the cement begins to build gel strength and, ultimately, to transition from liquid to solid. During this time, the cement becomes more self-supporting and loses its ability to transmit hydrostatic pressure. Then, internal shrinkage, induced by chemical hydration, causes further pressure reduction while, simultaneously, creating new (secondary) porosity within the setting cement paste. The combination of these effects is widely accepted to be the primary drive mechanism for the initiation of gas invasion and migration in the setting cement.

It is for the above reasons that slurries for use in scenarios where the risk of gas invasion and migration are high must be specifically designed with this risk in mind. The incorporation of anti-gas migration additives (latex, micro-silica, etc) is common and, while foamed cement is recognized as a suitable technology to address this problem under certain circumstances, its use on the Macondo well should have been questioned, scrutinized and justified technically, or dismissed in favor of another, more proven approach.

Barriers to Flow

Given the nature of the hydrocarbon fluids produced by the oil and gas industry, it makes sense not to rely on a single barrier between active formations and surface to prevent flow or uncontrolled escape of hydrocarbons. Thus, it is a requirement to ensure that at least two competent barriers must lie between a hydrocarbon zone and the surface. During drilling the mud column and the BOP stack constitute two barriers although, in deep water, the use of a marine riser makes this situation less secure than normal, in the event of an emergency disconnect, for example.

In the case of the Macondo 9 7/8" x 7" production casing, the planned annular barriers consisted of the cement and the casing hanger seal at the wellhead. However, as elaborated above, these barriers proved to be inadequate, due to design deficiencies, mechanical failure or because they were compromised by procedural errors. Pre-job design tests indicated that the cement slurry was potentially unstable and exhibited unsuitable setting characteristics and poor mechanical properties for such a critical application. The conflicting compressive strength values for a foamed versus unfoamed base cement may be regarded as normal but the huge discrepancy in the time for the onset of any mechanical strength between the two is certainly not. Since nitrogen is inert, both base slurry and foamed cement slurry should begin to set at around the same time, although the foam will have lower absolute values of initial (and ultimate) strength. The fact that the foamed system did not exhibit strength until almost 2 days had elapsed while the base slurry was apparently set within a few hours suggests that the slurries tested were not the same. This certainly requires explanation.

The volume of cement slurry appears to have been unusually small for such a critical application. It may have been reduced on the basis of an initially high calculated Gas Flow Potential (GFP), or to place the TOC into open hole, something that both BP and Halliburton have claimed was desirable for long term well integrity (to avoid annular pressure buildup due to thermal effects). However, such considerations must always be secondary to the need to ensure primary isolation.

Regardless of the cement design, it is always a bad idea to isolate it prematurely, from an hydraulic and hydrostatic perspective, when there is a risk of gas migration. It is especially serious if that isolation procedure ultimately removes several thousand psi of OBP and where the isolation point (i.e. the casing hanger seal, in this case) is many thousands of feet above the TOC. Unfortunately, this was exactly the situation on the Macondo well when the casing hanger seal was engaged in the wellhead, significantly increasing the risk of gas invasion. Obviously, the use of a single longstring versus a liner/tieback arrangement is a critical factor here. The latter would have presented less risk, although it should be noted that, with a liner top packer, there would still have been a high probability of gas invasion of the liner annulus with this cement slurry. However, with the sealing element (liner top packer) much deeper in the well in this case, the risks of creating an annular flow path are generally accepted to be lower, Shoe failure, of the type that may have compromised the Macondo well, would still potentially create a problem, however, even with a liner, but its occurrence would have been unlikely to result in the same outcome.

Pressure testing of the casing so soon after the cement job was not wise. It was particularly unwise given the conflicting cement test data, noted above, that was never explained adequately nor rechecked/retested to eliminate any doubts about its veracity. Based on the only test result provided, for something that was ostensibly representative of the foamed cement formulation at its downhole density, the cement slurry was nowhere near set after 16 hours. To pressure the casing positively and negatively, thereby causing casing expansion and contraction, when the cement was not conclusively proven to be set and mechanically competent and under conditions where other barriers may have been compromised, was dangerous. The float equipment had caused concerns in conversion and while the plug had bumped and the flappers reportedly held on backflow, the differential pressure was so low that little flow would have occurred in any case. The positive and negative tests were much more demanding. This was especially the case in the Macondo well with the proposed configuration for the latter which put some 1000 psi of additional drawdown than was considered normal for a negative test. As a result of this high drawdown, the hanger seal too would be subjected to forces that could unseat it under the negative test scenario. Neither of these dangers appears to have been adequately considered in evaluating the risks of performing these pressure tests at this time.

Mud Displacement

Where cement is the primary sealant (as in most oil and gas wells), effective zonal isolation requires complete mud displacement. Unlike cement, drilling mud does not normally set and channels of mud remaining in the cemented annulus can act as conduits for reservoir fluids, compromising the cement seal. Furthermore, mud and cement are often incompatible and contact between the two may produce undesirable effects. Both mud and cement may gel to produce a viscous, unpumpable mixture or additives in the mud may contaminate the cement and either delay setting and reduce compressive strength or, perhaps, cause a premature set. In the case of a foamed cement, contamination with an oil-based mud, in particular, may cause destabilization of the foam due to incompatibilities between the mud's oil phase and its oil-wetting surfactants and those used to constitute the foamed cement.

In order to avoid such problems and provide a high probability of achieving competent zonal isolation, a variety of measures are usually undertaken prior to, and during, the cementing operation. These include:

- Pipe Centralization
- Mud Circulation and Conditioning
- Use of Spacers/Flushes
- Ensuring Fluid Compatibilities
- Optimizing Placement Rates

Each of these is discussed in greater detail, below.

Pipe Centralization

Casing centralizers have been in use for many years but they are still regarded by many as unnecessary pieces of casing jewelry. They have been criticized for causing problems in getting casing to bottom and stories abound in the industry of more centralizers ending up on the sea bed than on the casing string.

In reality, centralizers are an important part of any primary cement job and, in some cases, they are absolutely essential, defining the difference between success and failure of the operation. While it has long been recognized that poorly centered pipe may compromise full cement coverage in the annulus, it is still generally not appreciated just how critical is the effect of eccentricity on the cementing process. By definition, a perfectly centered pipe in a perfectly gauge hole is referred to as having 100% stand-off. A pipe that lies against one side of the borehole, in contact with the formation (or the inside of another casing), is referred to as having 0% stand-off. Intermediate conditions, expressed as percentages, lie between these two extremes.

In the case of 7" pipe in 8 ½" open hole, movement of the pipe by a mere ¼" from the center line of the well axis, reduces the stand-off from 100% to a mere 67%. The net effect of this apparently minor deviation of the casing towards one side of the wellbore has profound effects on fluid velocities in the annular space around the pipe. Fluid being circulated through the well will now favor flowing on the wider side of the annulus and the fluid velocity on that side will also be faster. This leads to a separation of the leading fluid interfaces with the fluid on the narrow side trailing behind that on the wide side. The effect can be very significant, extending tens or even hundreds of feet. In the case of non-Newtonian fluids, especially those like muds that possess gel strength, it may be impossible to get them to flow on the narrow side of the annulus at all. In such a scenario, a portion of the annulus may be left with a long gelled stringer of mud on the narrow side. Thus, poor centralization sets up conditions for poor mud displacement and predisposes towards channeling in the annulus.

Pumping the displacing fluid in turbulent flow can reduce this effect somewhat but it is important to note that the geometry of an eccentric annulus requires much higher pump rates to achieve turbulence compared to the fully-centered case. In order to achieve turbulent flow in an annulus with 67% stand-off, we would need to pump at twice the rate that we would require in the 100% stand-off case. Such rates are normally impractical to achieve or would increase the risk of causing other problems, like lost circulation. In such circumstances, the best solution is to physically move the casing throughout the cementing operation, either by reciprocating or rotating the pipe. Moving the casing acts to break-up gelled mud and improve the flow distribution in the annulus.

Mud Circulation and Conditioning

After drilling a section of hole through the reservoir section, it may be some considerable time before the well is cemented. Retrieval of the drill-string and BHA, open hole logging operations and the time needed to run casing, especially in a deep well, can mean that the mud in the well remains quiescent (or at least not actively circulated) for a prolonged period of time. Drilling mud is naturally thixotropic and tends to build gel strength if left undisturbed for a time. It is quite common in such circumstances for hydrocarbon gas to invade the mud column adjacent to the reservoir and it is normal recommended practice to circulate the mud in the well when the casing string has been run to TD and the well is being prepared for cementing. This procedure breaks the mud gel strength and ensures that the mud in the well is mobile while also bringing any small volumes of gas that may have invaded back to surface. If large volumes of gas are detected, this may be an indication that the margin between mud hydrostatic pressure and reservoir pore pressure is insufficient or that the mud exhibits excessive thixotropy.

As with many oilfield procedures, the amount of time spent circulating the mud in the well prior to cementing is not hard-and-fast and depends on many factors. General guidelines, as provided in documents like API-65, are often followed unless there are specific reasons to deviate from such procedures. Typical practices include circulating the mud from the bottom of the well back to surface (bottoms-up), circulating one and a half annular volumes or one casing volume (whichever is greater) or circulating the entire contents of the well. Additional procedures may involve running so-called fluid calipers to establish what proportion of the mud is actually mobile and being circulated. A fluid caliper uses a marker of some type in the mud and involves the pumping of at least one entire well volume. The time taken to recover the marker multiplied by the pump rate provides an indication of the volume of mobile mud and this is compared with the theoretical hole volume. The procedure may be carried out more than once or at more than one rate to gauge the impact of rate on circulation efficiency.

Mud has many functions in an oil and gas well. Apart from providing hydrostatic overbalance to prevent unwanted flow from subsurface strata, it also acts as a connection between those strata and surface. Pit losses or gains indicate changes in well stability and they alert personnel of the need to make adjustments to fluid densities or circulation rates, etc. The mud also acts as a lubricant, helping to cool the bit, and as a transport medium, carrying rock cuttings from the bottom of the hole to surface. This capacity to lift cuttings is no longer necessary when cementing operations commence, particularly on a production string, and, in fact, this property of the mud makes it more difficult to remove from the well. As a consequence, it is routinely recommended by industry guidelines, in general, and cementing service companies, in particular, that mud should be thinned or "conditioned" prior to cementing. It should be noted, however, that while this is widely recognized as beneficial it is not consistently done, at the level of field operations, due to the perception that it represents unnecessary time and expense.

Use of Spacers/Flushes

As noted above, mud and cement are usually incompatible, often combining to form viscous mixtures that are difficult to displace from the annulus and that do not provide an adequate wellbore seal. For this reason, fluids called "spacers" are typically pumped ahead of the cement slurry (and sometimes behind it, too), to provide a buffer between the mud and cement. Spacers, therefore, may be considered as specially designed, weighted fluids that are pumped to remove the mud while maintaining hydrostatic pressure control in the well. Spacers must be compatible, rheologically, with both mud and cement so that intermixing does not cause any unpredictable viscosity changes during the displacement process. Ideally, the spacer should completely displace all mud from the annulus in the section to be cemented, ahead of the cement slurry's arrival, thereby ensuring that mud and cement never contact one another. It goes without saying that the spacer itself (and any mixtures of spacer with mud) should remain fluid and very easy to displace from the annulus by the cement slurry, if we are to ensure good zonal isolation.

In wells drilled with oil-based muds, or synthetic oil-based muds as in the Macondo case, there are additional challenges. Such muds have oil as the external phase and they tend to oil-wet surfaces that they contact, including both the wellbore and the casing. Unfortunately, cement does not bond well to such oil-wet surfaces so, in order to ensure good adhesion and bonding between the cement and these surfaces, it is necessary to water-wet them. This is normally accomplished by incorporating a water-wetting surfactant in the spacer. The surfactant removes the oil film ahead of the cement slurry's arrival and leaves all contacted surfaces water-wet.

With heavier oil-based muds, the high concentration of fine oil-wet solids in the mud (organophilic clay, barite, calcium carbonate, drill solids), increases the risk of incompatibility between even the mud and the spacer. This problem can generally be solved by pumping a "flush" which consists of a small volume of solids-free "base oil" (ie. the oil component of the mud), ahead of the spacer. This acts to dilute the mud, reducing its viscosity by reducing the solids concentration at the critical interface between mud and spacer. It is, of course, important to minimize the volume of flush, particularly in a small annulus. Otherwise, well security may be compromised by the reduction in hydrostatic pressure that the solids-free, low-density flush causes in the well.

The volumes of spacer/flush that must be pumped to ensure complete mud removal vary from well to well. They are dependent on many factors, including mud/spacer/cement rheology, fluid densities, hole geometry, casing standoff and pump rate. However, a general rule-of-thumb, based on experiment and many years of field cases, calls for the pumping of sufficient wash/spacer to provide 10 minutes of contact time. Thus, at a displacement rate of 4 BPM, the minimum volume of flush/spacer required would be 40 barrels; at 6 BPM it would be 60 barrels. This should be viewed as a minimum criterion and, where possible, it would generally be beneficial to pump more spacer than this simple calculation suggests.

Ensuring Fluid Compatibilities

As noted above, it is important that spacer fluids be compatible with both mud and cement. Test methods are described by API/ISO in API Recommended Practice 10B-2 specifically for the testing of mud/spacer/cement compatibility and these are widely used. Unfortunately, no laboratory data were provided by Halliburton on fluid compatibilities, suggesting that these tests were not performed. It must be said that these tests are time consuming and do not always provide useful information, especially when the operation is offshore. The results are only strictly applicable if representative samples of the drilling fluid (containing all the drill solids, etc) are used and the latter may not be available in a timely manner. As a result, they are not used consistently by every service company for every cement job. However, given the particularly critical nature of this cement job with gas migration flagged as a risk, foamed cement in use as the primary barrier material and oil-based mud present as the drilling fluid, it is difficult to imagine a more deserving case for fluid compatibility testing. Even in the absence of any customer requests for such testing, the cementing company, who are purportedly experts in their field, should have conducted a full suite of tests to ensure that the fluids were compatible and the foamed cement, in particular, remained stable. As noted above, to date, no data have been presented to support the claim that compatibility testing was actually carried out ahead of the cement job.

Optimizing Placement Rates

It has long been recognized that pump rate is important in the mud displacement process. Higher rates generally favor mud displacement by providing energy in the form of pressure drop and it is this pressure drop that drives the displacement process. Particularly when displacing thixotropic muds, the shear stress developed by the displacing fluid must exceed the yield point of the mud if it is to put the mud in motion and displace it. This is only one of several criteria that must be met to guarantee effective displacement in the absence of pipe movement. The latter, incidentally, greatly assists the displacement process but is disliked by many industry veterans for fear of sticking pipe or having other mechanical problems.

Industry guidelines support the use of turbulent flow for cementing operations since it provides higher pressure drops and a flatter average velocity profile, reducing channeling and improving displacement. Unfortunately, it is difficult to achieve turbulent flow in many circumstances due to higher circulating pressures and the risk of formation breakdown (losses) while circulating at high rates. Also, as mentioned above, even slight eccentricity of the annulus, due to casing being poorly centralized in the borehole, can require unrealistic pump rates to achieve turbulence. The rate used for displacement on Macondo was only 4 BPM, certainly a laminar flow displacement regime for the mud, spacer and cement slurries. The diesel flush, of all fluids, would have been the only one with any chance of being in turbulent flow in the annulus. However, from a practical perspective, there was no real possibility to exceed this low displacement rate without running the risk of losing circulation due to increased wellbore friction and, hence, ECD. So, again, the real world conspired to limit the pump rates that could be employed to cement this well.

Mud Displacement – Summary and Conclusions

Displacing all the mud from an interval in a deep well and replacing it with cement to ensure zonal isolation is not a simple task, given the constraints mentioned above. In general, however, using a combination of the techniques mentioned and following widely accepted industry practices provides good results in the vast majority of cement jobs. This has been verified by numerous studies over many years.

Having said that, we can identify the adoption of numerous less-than-ideal practices in the cementing of the Macondo well, suggesting the importance of the mud displacement process was not given the focus and attention it deserved. Inadequate mud conditioning and circulation prior to cementing may have left unreturned cuttings or gas and/or gelled mud in the flowpath of the cement. The use of fewer than the recommended number of centralizers would lend credence to the fact that this was just considered another unnecessary part of a simple operation in a vertical well. History may judge otherwise but it is fair to say that many, if not the majority, of oilfield operators would have had exactly the same opinion, prior to events on this well.

The spacer and diesel flush volumes used were adequate and I have no specific objection to the fluids used or the sequence in which they were pumped. Both spacer and flush were certainly necessary and probably performed as expected but, again, no verification of that performance was provided by Halliburton ahead of the cement job, or subsequent to it. No compatibility test data, showing the rheological properties of mixtures of mud/spacer/cement in various ratios, were proffered. The procedures specified in API Spec 10 should have been followed to ensure compatibility and provision of that data for scrutiny ahead of the cement job should have been a requirement of the cementing contractor.

The pump rates used during the job were what they were and, while they may not have been optimal for mud displacement there was little practical margin to modify these rates. Slight increases in rate would have little practical significance in terms of enhancing mud displacement while putting the well at risk from losses due to higher ECDs. Again, we should recognize that many wells are cemented at less than the ideal modeled displacement rates due to the practical limitations of pore/frac pressure constraints. While the above identified shortcomings in the testing of the spacers and less-than-adequate number of centralizers are certainly significant, I can find no substantive evidence that these were any more than minor contributors to the disaster.

Cement Wiper Plugs and Cement Float Equipment

Some concerns have been raised about the ability of cement wiper plugs to transit the tapered string and actually do the job they were intended to do – separate the cement from the spacer and mud and wipe the interior surface of the casing string. However, all indications from the actual job are that these plugs functioned, as planned. There were clear pressure indications as they passed through the 9 7/8" x 7" x-over and both plugs bumped at the float collar. Furthermore, proprietary data from tests conducted in the past, indicate that this should not be a cause for concern.

Questions were also raised regarding float equipment and the difficulties in converting the autofill equipment prior to cementing. Suspicion was cast on the fact that the double-flapper valve may not have been sealed or that it was somehow left partially open during pressure testing, perhaps at a time when cement may not have been completely set. However, it must be said that, despite difficulties and multiple attempts, the float conversion was apparently finally accomplished and indications were that the floats held for backflow, despite lower than normal differentials between the annulus and the inside of the casing. That being said, the calculated end-of-job pressure differentials were inordinately low so backflow would have been minimal and may have been mistaken as a good result. Also, the low differential may have been inadequate to close the flappers, in any case.

Whether these flapper valves sustained damage during the conversion process that left them vulnerable to leakage from the annulus later, under the rigors of the negative test, is unknown at this time. However, my analysis indicates that these valves played a critical part in the disaster by providing a flow path out of the well during well suspension operations. Primarily, this indicates that there was no competent cement beneath them. It is also possible, but by no means certain, that the shoe track provided not only an exit path for mud but also the flow path for hydrocarbons into the well. If so, that would mean that the flapper valves did not seal against backflow. However, this remains unclear. The flapper valves are designed to allow flow out of the well so the fact that did so and allowed mud to escape indicates only that there was no competent cement above and below them, not that they themselves failed. This is certainly something worthy of further investigation but it confirms that the cement job was a failure.

Cementing Operations

Cementing operations appear to have been carried out much as planned. Pump rates, pressures densities and nitrogen injection rates, as reported in written reports and recorded on Halliburton's data acquisition system, all fall within the normal margin of error that one would expect in such an operation. Questions remain as to the integrity of the foamed slurry mixing process given the very high nitrogen ratio required in such a deep well and certainly this merits further analysis. However, until such analysis emerges, the obvious conclusion would be to avoid the use of foamed cements at such well depths in future.

Cement Evaluation

Much has been written about the inadequate cement evaluation, post-placement, on Macondo. In particular, the fact that the decision was taken not to run a Cement Bond Log (CBL) has generated enormous public outcry and prompted ever more accusations of cutting corners and compromising safety. It is true that cement bond logging can identify the presence or absence of material in the annulus but, unfortunately, it is still not a surefire guarantee that isolation exists. If anything, this task is more difficult with foamed cement than any other type of cement system.

The conventional CBL relies on the interpretation of the acoustic response of the casing to a 20 kHz acoustic pulse fired at it. If the casing is unsupported by material in the annulus, it rings, rather like a bell. In the case of well cemented casing, the signal is attenuated quickly and the receiver picks up very little acoustic energy so the CBL shows low amplitude, implying good acoustic coupling with a solid material in the annular space. Unfortunately, because of the omnidirectional nature of the acoustic pulse, the CBL measurement is, in fact, a kind of circumferential average of the acoustic energy. So, the CBL is not particularly good at identifying channels in the cement, especially if these channels are not directly adjacent to the casing surface. Furthermore, the CBL relies on a physical property of the material in the annular space called acoustic impedance. This property, the product of the acoustic pulse velocity and the cement density, is expressed in units called Rayls, or more conventionally, in MegaRayls. and, unfortunately, foamed cement has a lower acoustic impedance than most slurries, making its characterization much more difficult than that of a normal cement. Finally, the acoustic properties of cements evolve with time. After only 16 hours, it may not have been possible to identify foamed cement in the annulus, regardless of its competence.

In conclusion, the CBL may not have been very effective as an evaluation tool in the Macondo well, even if it had been run. At a minimum, running a CBL in such a scenario should involve a certain prescribed WOC time – perhaps 24 – 30 hours, depending on the cement system used and the well conditions. Consideration should also be given to the use of more sophisticated tools than the simple acoustic CBL. Ultrasonic tools like, for example, the CET, PET or USIT are far better for cement evaluation than the CBL, although they may not all be applicable for use under the specific well conditions at Macondo, due to issues related to fluid densities and compositions. Where useable, however, these tools are capable of higher spacial resolution and can potentially identify channels in the cement sheath that could compromise isolation. Perhaps, even more relevant in the case of Macondo, ultrasonic tools are excruciatingly sensitive to the presence of gas in the annulus. Thus, they can identify the difference between normal cement, gasified cement (like foamed cement or gas-invaded cement) and free gas, providing a much more comprehensive analysis of the integrity of the cement as a wellbore barrier.

The wireline companies can provide best advice on which specific tools are applicable for use, and their limitations, under relevant circumstances.

Conclusions

The key to understanding what actually happened in this tragedy is to find a plausible explanation of why and how hydrocarbon gas entered the wellbore and then how it was able to move undetected from its entry point near the bottom of the well to a place where it could escape containment. As noted in numerous commentaries, it is mandatory to have at least two independent, competent barriers in an oil and gas well. In this case, those putative barriers consisted of the cement in the annulus, covering the pay zone, and the seal at the casing hanger.

We have established that the cement job design was probably inadequate and flawed in a number of ways. The selection of a foamed cement, in a deep well containing oil-based mud, was not a good idea, regardless of the well specifics. Its use in a deepwater well that had been subject to kicks and lost circulation during the drilling process was even more questionable. With minimal post-placement overbalance pressure (OBP) on active gas zones (and a casing hang-off procedure that exacerbated the problem), and only a partially cemented annulus, using foamed cement was certainly ill-considered but probably need not have been totally catastrophic had all the required cement slurry testing been performed. Such testing would have exposed weaknesses in the design and would almost certainly have prompted changes in slurry design or implementation of altemative procedures to mitigate those faults.

It is my firm belief that companies with the in-house technical knowledge and expertise that major international E&P and service companies possess, would not deliberately have cemented the Macondo well with a design that was known to be inadequate for the job. However, not every member of such organizations possesses the level of knowledge and expertise needed to make that assessment. A combination of inexperience, ignorance and complacency might ultimately have been responsible for allowing the flawed design to somehow escape the normal checks and balances and end up being used in this well. That is for others to decide. Certainly the use of this slurry, given the procedures that were followed in its testing and those that were to be followed in its placement, and immediately thereafter, should have raised serious questions about its suitability.

The well depth dictated that a large volume of nitrogen was required to be added to the slurry at surface to achieve the required density downhole. Thus, the slurry may better have been described as a mist rather than a foam and it may never have become a true foam cement, instead breaking out to its constituents, base slurry and nitrogen, during pumping and never reforming downhole. However, this can only be described as conjecture, at this time, based on mixing conditions and injection pressures and would require testing to confirm the condition and stability of the eventual slurry.

Immediately after the cement was placed, the operational procedure called for the setting of the seal at the casing hanger. The net effect of such a procedure is to prematurely isolate the longstring annulus from the hydrostatic pressure of the drilling fluid in the riser above it. From a gas migration risk perspective, this procedure should have raised red flags, with both the operator and the cementing service company, especially in a well that was already identified as being at risk from gas migration. The hydrostatic pressure of the fluid column is initially locked under the hanger seal but, this pressure would have decayed rather rapidly, especially in a cement with no fluid loss control, exposed to permeable strata. Thus, any volumetric changes occurring beneath the hanger would result in some pressure loss which would be compensated at least partially by gas expansion in the foamed cement. In other words, the foamed cement would expand to compensate for the inevitable volume reductions, caused by leakoff and cement hydration, increasing the likelihood that nitrogen would break out of the slurry and potentially create channels. We can assume that hydrocarbon gas entered the annulus sometime fairly soon after the cement was in place and may have already migrated at least to the cement/spacer interface. If the foamed cement had become completely destabilized, the gas may have also pushed its way down to the casing shoe.

Without having access to all the cement test data, it is difficult to be certain but it is fair to say that, given the slurry properties, as detailed in the Halliburton reports and widely reported in public, it was at the very least questionable to perform a series of pressure integrity tests on the well so soon after placement. The cement, in my opinion, had probably already been compromised by any one of the factors, or any combination of the factors, discussed above but, regardless, it was premature to pressure test the well. The positive pressure test would have caused some casing expansion and might have compromised an already-weak cement bond, assuming the cement had actually set. The negative test would have caused a similar effect but, in and of itself, would not have been disastrous in a well with sealed flow paths, at the shoe and at the wellhead.

In the Macondo, case, however, with no lockdown sleeve in place, pressure underneath the large surface area at the hanger could easily have rendered the casing temporarily buoyant, lifting it slightly and compromising the hanger seal. This could have occurred both during the negative test and later, when the riser was being circulated to seawater, on the wellsite team's presumption that the well was secure. A leak at the casing shoe, while a foamed cement of questionable quality was weak, perhaps unset or even absent altogether would also have seriously compromised well integrity. Finally, perhaps, the negative test could have invited gas into the casing shoe, assuming the double flapper valves were somehow no longer patent, thereby providing an internal flow path. Each scenario is feasible given what we have identified in this review of the cementing of the Macondo well. Design, testing and communication failures coupled with poor field practices, including, but not limited to, poor mud conditioning, inadequate pre-job circulation, inadequate casing centralization, premature annular hydraulic isolation, insufficient WOC time before pressure testing, excessive drawdown during the negative test and misinterpretation of its results, may all have played a part in the accident.

It is my sincere hope that the contents of this review will help contribute in some small way to a better understanding of some of the risks implicit in cementing operations and help prevent such disasters and loss of life in the future.

Appendices

Laboratory Testing Issues

1) Thickening Time testing was carried out on the base slurry which is normal. However, for the TT test to be valid, it must contain all additives, including the foaming agent. Special procedures for the preparation of such slurries must be followed in the laboratory (or the slurry foams uncontrollably and cannot be used for testing). Yet the test sheets indicate no special procedures. Coupled with the discrepancies between UCA compressive strength (on base slurry) and water bath compressive strength (on Foamed Cement slurry), this suggests (but does not confirm) that the foaming agent may not have been included in the TT and UCA compressive strength tests.
2) The slurry design was modified by the addition of extra retarder (SCR-100) to provide additional thickening time. Yet the data for rheologies were left unchanged implying that these tests were not repeated despite the modification i.e. the data do not reflect the actual slurry pumped. It is unclear whether the compressive strength data (both UCA and Water Bath) were based on the original or the modified slurry with extra retarder but my assumption would be that these tests were conducted at the lower retarder concentration..
3) Rheological data suggest that the base slurry was unstable both at surface and downhole conditions. The Plastic Viscosity (PV) = 600RPM reading – 300RPM reading. So, this implies a PV of (180-84)=96 centiPoise (cP) at surface and (130-56)=74 cP at BHCT. These values are OK but the problem lies with the calculated values of Ty (yield point). This is defined as:

   Ty = 300RPM reading – PV

   So this implies a Ty or (84-96)= minus 12 and (56-74)=minus 18, respectively, at surface and at BHCT. Negative yield points are a physical impossibility and are normally indicative of unstable slurries. The lab should have commented on slurry stability, at the very least.

4) The slurries contained no fluid loss control additives and no API Fluid Loss data are presented. This is almost inconceivable in a scenario where a slurry is being applied against gas migration. It is universally accepted that exceptional fluid loss control is a prerequisite for anti-gas migration properties and, normally, fluid loss control would have been specified for any cement system being used across the reservoir section. Why these issues were not immediately apparent to Halliburton personnel, in particular, is completely beyond my understanding.
5) The foamed cement slurry design incorporated defoamer, as noted in the main body text. Normally, cementing service company manuals advise that such additives should not be included in foamed cement. At the very least, foam stability tests should have been conducted on the slurry to check that it remained dimensionally stable. This involves simple testing using a 250 mL

glass cylinder filled with foamed cement. The volume of the foam is monitored from pouring until it sets, or some other arbitrary time.

6) The fact that SOBM was in the well should have made fluid compatibility testing mandatory when foamed cement was to be deployed. The testing procedures are clearly specified in API Spec 10 involving combinations of spacer/mud, spacer/cement and spacer/mud/cement and these would have prima facie been conducted on the base slurry. However, it would have been advisable, given the much-publicized concerns about poor centralization and imperfect mud removal, to check the stability of the foamed cement in the event of mud contamination. I would certainly have requested such a test.

7) Gel strength testing using a special device known as a MACS Analyzer, originally introduced into the industry by Halliburton specifically in relation to gas migration and shallow water flows in deepwater wells, should have been conducted. This device measures the gel strength development of cement slurries. The measurement is a continuous one so the test tracks gel strength evolution. Gel strength development is important because it is widely regarded as a key driver in the pressure loss experienced in the setting cement column. This, in turn, instigates the loss of OBP and subsequent invasion of the cement column by gas.

8) It goes without saying that anomalous test results, involving discrepancies between tests that should provide complementary or confirmatory results (e.g. UCA and water bath compressive strength tests) should have been investigated. At the very least, these tests should have been repeated to confirm or refute the initial discrepancies.

Documents Used In Well Analysis

Casing Sizes and Weights:	As per Macondo Schematic	BP HZN CEC017401
Fluid Densities:	Halliburton Pump Schedule	HAL 0010995
Job Designs	Halliburton	HAL 0010988-0011011
		HAL 0010699-0010720
		HAL 0010592-0010611
Macondo Well Production Casing Operations Program		BP HZN CEC017621-9
Pore Pressures	As per data	BP HZN CEC022125/6
Laboratory Test Data	As per Halliburton Lab Sheets	HAL_0010868 - 70

Hydrostatic Pressures at End of Job, Based on Fluids Interfaces At the Following Depths

Fluid	Fluid Density	Depth of Leading Edge	Pressure
Mud	14.17 ppg	Surface	Atmos.
Flush	6.7 ppg	14511 ft	10692 psi
Spacer	14.3 ppg	14621 ft	10730 psi
Lead Cement	16.74 ppg	17195 ft	12644 psi
Foamed Cement	14.5 ppg	17313 ft	12747 psi
Tail Cement	16.74 ppg	18304 ft	13494 psi

Fluid Interfaces calculated on the basis of fluid volumes, displacement volumes and estimates based on hole caliper. Note the Tail Cement slurry leading edge interface is at shoe depth and the tail slurry fills the shoe track.