IN THE UNITED STATES DISTRICT COURT FOR THE
EASTERN DISTRICT OF LOUISIANA

IN RE: OIL SPILL BY THE OIL RIG MDL NO. 2179
"DEEPWATER HORIZON" IN THE
GULF OF MEXICO, ON APRIL 20, 2010

EVALUATION OF THE CEMENTING ON THE 9 7/8 x 7" PRODUCTION STRING ON THE MACONDO WELL

EXPERT REPORT OF
GLEN BENGE

ON BEHALF OF
THE UNITED STATES OF AMERICA

August 26, 2011

DATED: August 26, 2011

Signature: Glen Benge

TREX-05990

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ABBREVIATIONS

ANSI	American National Standards Institute
API	American Petroleum Institute
API RP	API Recommended Practice
bbls	Barrels - equivalent to 42 US gallons
bpm	Barrels per minute
BHCT	Bottom Hole Circulating Temperature - the temperature at the bottom of the well while fluids are circulating in the well, expressed in degrees Fahrenheit
BHST	Bottom Hole Static Temperature - the undisturbed temperature at the bottom of the well, expressed in degrees Fahrenheit
ECD	Equivalent Circulating Density
° F	Temperature in degrees Fahrenheit
gal/sk	Gallons per sack - the volume, in gallons, of a liquid additive added to one sack of cement
gal/100 sk	Gallons per 100 sacks of cement - the volume, in gallons, of a liquid additive added to 100 sacks of cement
HPHT	High Pressure High Temperature
ISO	International Standards Organization
lb/gal	Pounds per gallon - the weight of one gallon of fluid expressed in pounds
MMS	Minerals Management Service
N2	Nitrogen gas
OT&C	Oilfield Testing and Consulting
psi	Pounds per square inch
SOBM	Synthetic Oil-Based Mud
SPE	Society of Petroleum Engineers

UCA	Ultrasonic Cement Analyzer
WH	Wellhead
WOC	Wait on Cement

Information Required by the Federal Rules of Civil Procedure

The following is a list of the items required by the Federal Rules of Civil Procedure:

1. This report contains my opinions, conclusions and the reasons therefore;

2. A statement of my qualifications is contained in Appendix A;

3. My compensation for the preparation of this report is included in Appendix B;

4. The data or other information I considered in forming my opinions is listed in the Documents Reviewed and References sections of Appendix C;

5. In the last four years I have not been a witness in any case.

I understand that fact discovery in this case is ongoing. In light of that, or should relevant information otherwise become available to me, I reserve the right to revise or supplement these conclusions.

1. Summary of Conclusions

This review is an evaluation of the available information regarding the production casing cementing job on the 9 7/8 x 7" production string on the Macondo well, and a determination of the key factors related to the failure of the cement to provide isolation in the well. Included in the report are discussions of the key decision points and their impact on the cementing results.

In my review of the data from the Macondo well, based on personal experience and industry practice, I have concluded the following with respect to the production casing primary cement job:

Cement did not isolate the formations in the Macondo well. The failure of the cement to provide wellbore isolation or act as a barrier can be summarized as: 1) inadequate design of the cementing slurry or job to address the requirements of the well; 2) failure of the cement slurry to perform as expected; and 3) failure of the cement slurry to be properly placed in the well.

For the cement to fail to provide a barrier in the Macondo well, it was either not present across from a producing formation or it was not set and able to act as a barrier to flow, or both. Channeling allowed for a flow path in the annulus for formation fluids. Even with a flow path in the annulus to the casing shoe, the cement left inside the casing had the potential to provide a wellbore seal inside the casing. For it to not have provided a seal, the cement was most likely not set because of contamination, temperature effects or both.

The BP wells team was well versed in cementing. These BP personnel were the final decision makers and were empowered to accept or reject the advice of both the BP internal cementing expert and Halliburton. The BP engineers chose to accept additional risks when designing the cement job with the awareness that remedial cementing work could be done at a later date. Those additional risks included using a leftover cement blend not appropriate for foamed cementing, using a foamed cement in a synthetic oil-based mud (SOBM) environment, limiting cement volume and selecting a reduced number of centralizers.

BP's slurry design for the Macondo well was inappropriate and not suited for a foamed cement application. BP compromised the quality of the slurry design by utilizing a dry blend leftover from the Kodiak #2 well. The dry blend leftover from the Kodiak #2 well contained additives that were not suitable for foamed cement. This resulted in a suboptimal foamed cement design.

A conventional (unfoamed) slurry could have been used to cement the Macondo well, which would have eliminated the significant risks associated with the use of a foamed cement on the production string.

The laboratory testing performed by Halliburton was incomplete and did not adequately evaluate the slurry. Because the cement was not originally developed as a foamed cement system, BP should have required more testing to confirm the appropriateness of the slurry design for the well. Free water, settling and unset foamed stability testing should have been part of the testing program. BP started the cement job without these key laboratory test results and without a complete set of tests on the slurry actually pumped on the Macondo well – the slurry containing 0.09 gal/sk SCR-100 retarder.

BP also did not follow its internal guidelines for testing cement slurries for deepwater wells. BP's recommended practices specifically identify temperature as a major risk factor that can lead to cementing failures. Use of its internal guidance could have helped BP identify weaknesses inherent in the suboptimal cement design.

Laboratory testing of a slurry design is dependent upon using the correct temperature of the well. Failure to use a correct temperature can lead to a slurry that sets too quickly, or one that will be over retarded for well conditions and does not gain strength when needed. Halliburton performed lab testing of the Macondo well's base slurry's strength at 210° F, and that temperature was reached four hours after the tests were initiated. The testing for foamed compressive strength was performed at 180° F and showed no strength development for at least 24 hours.

It takes time for a well, especially a deepwater well, to recover to near bottom hole static temperature (BHST). Based on the available temperature data reviewed, the Macondo well took significantly longer than four hours to reach 210° F after completion of the production casing cement job. In the case of the Macondo well, the negative pressure test was performed less than 18 hours after the cement was in place. Based on all of the information I reviewed, it is my opinion that, at the time of the Macondo well negative pressure test, the cement was not set. If the cement was not set by the time of the negative test, it would not have been possible for the cement to provide isolation in the well. Once the flow began during the negative pressure test, if the cement was not set, any potential isolation from the cement was permanently destroyed.

Foamed cement should not have been used in the SOBM environment that was present at the Macondo well. The destabilizing effects on foamed cement by SOBM are severe and can lead to a job failure. The risks of failure are so severe that I have not, nor will I, recommend using foamed cement in an oil-based mud environment.

The job design was inadequate for the cement to be placed properly in the well. Poor centralization, use of the base oil pre-flush, limited pre-job circulation and low pump rates virtually assured the cement integrity would be compromised. Lack of proper centralization of the production string increased the potential for channeling, thus leaving an un-cemented area in the annulus.

The production casing used six centralizers spaced throughout the bottom portion of the cemented interval. A pre-job OptiCem run by Halliburton recommended the use of 21 centralizers[1] and indicated an increased chance for channeling if that number was reduced.[2]

Inadequate pre-job circulation did not allow for breaking up of gels in the mud or circulation out of any formation fluids that may have entered the mud while the casing was being run. Coupled with poor centralization, this lack of circulation eliminated opportunities to maximize the circulatable volume of mud in the wellbore.

Finally, the use of base oil, particularly in a weighted mud system, can enhance channeling and is not recommended. BP's use of base oil increased the chance for channeling due to its very low density and viscosity. The base oil's low density also reduced the total hydrostatic pressure in the annulus.

2. Background and Credentials

In April 2011, I retired from ExxonMobil and began consulting in oil field cementing. Over my 34 year career, I have worked in every aspect of oil field cementing from shallow onshore wells to deepwater applications globally. I served on the client advisory boards for Schlumberger and Halliburton. I have worked extensively with foamed cementing. I designed and managed the initial offshore application of foamed cement in Mobile Bay in 1995 and published a paper on the well in 1996.

I received a B.S. degree in chemistry from Southwestern Oklahoma State University in 1976. I also completed one year of graduate school coursework in Analytical Chemistry at Oklahoma State University.

In 1977, I began working for Dowell, a division of Dow Chemical, in the technical services lab in Tulsa, Oklahoma. In this position, I analyzed the composition of field

[1] HAL_0010699
[2] BP-HZN-MBI00128722

samples of cement blends and was a liaison between the research lab and field operations. I later moved to the technical engineering and development group in Tulsa. In 1981, I transferred to Houston and worked as a regional cementing specialist. In 1986, I moved to New Orleans to become a division marketing specialist. In that position, I was in charge of the division laboratory and all cementing technical operations for the Gulf of Mexico.

In 1988, I moved to Mobil Oil in New Orleans and was part of the fluids team that managed drilling fluids, cementing, NPDES compliance and toxicity testing for the Gulf of Mexico drilling organization. I transferred to the Mobil E & P Technical Center group in Dallas in 1992 and served as a global cementing advisor. While at Mobil, I introduced foamed cementing technology to projects in Qatar, Angola, Germany and the east coast of Canada.

With the merger of Exxon and Mobil, I moved to Houston in 2000 to become the Senior Technical Advisor for cementing for ExxonMobil's global drilling operations. In 2009, I became the Drilling Training Manager for ExxonMobil and served in that position until my retirement in 2011.

Throughout my career I have attended over 30 industry schools covering cementing, drilling fluids, lost circulation, drilling practices and well control. I have authored over 20 technical papers, several of which have appeared in peer reviewed journals. While in New Orleans, I was on the board of directors of the American Association of Drilling Engineers (AADE) from 1989 until 1992 and served as AADE President from 1991 until 1992.

I have been a member of API Subcommittee 10 on Oil Well Cements since 1980 and served as its chairman from 2002 until 2005. I have served on and chaired numerous task groups on centralizers and completion fluids testing. I received the API Citation for Service in 2005. I chaired the task group on foamed cement for the ISO Technical Committee 67, Work Group 2 on cementing. ISO 10426-4 and its companion document, API RP 10B-4, are the results of this work.

I have been a member of the Society of Petroleum Engineers since 1977, and served as program and session chair for the SDPE/IADC International Drilling Conference from 1995 through 2004. I served as technical editor for the Journal of Petroleum Engineering for three years and have served as a technical editor for Drilling and Completion Journal since 2005. I received the SPE Outstanding Technical Editor Award for four years from 2007-2010.

I served as a technical advisor for the Department of Energy, National Energy Testing Laboratory for evaluations of cement systems for CO_2 sequestration. I am also a charter member of the Wellbore Integrity Work Group for the International Energy Association, Greenhouse Gas R & D Program (IEAGHG). I have presented papers at the Greenhouse Gas Technology Conferences in Washington, D.C. and Amsterdam.

3. Cement Job Design Process

3.1 Overview

Designing and executing a quality cement job is a multi-stepped, iterative process which can be summarized as follows: establish the objectives of the job, determine the variables, design to meet the job objectives and evaluate the job against the objectives. Without well-defined objectives, an optimized cement job cannot be designed or executed. **At the end of the design process, the cement slurry should be designed to have the greatest chance of meeting the stated objectives for the well.**

The reasons for cementing can include a need for formation isolation, casing support, corrosion protection, or any combination of these or many other factors. Within each general objective, more specific objectives may be identified. For example, a desire to obtain formation isolation can be limited to only isolating the bottom section of a well to obtain a shoe test or a need to isolate multiple zones in a single wellbore. The designs for each of these jobs, even though both involve formation isolation, could be very different.

There may be several objectives of a cement job, some of which may conflict with each other. For example, a job objective that requires a long pump time may conflict with a desire for rapid strength development. This conflict must be resolved, and once final objectives are established, designing of the job can begin.

The design of a cement slurry and its proper placement in a well must address all requirements of the well. The first step in cement design involves identifying the variables associated with the wellbore. These could be considered the "physics" of the cement job, or the requirements necessary to place the cement in the wellbore. Variables that impact design include: wellbore architecture, formation properties, hydraulics, fluid chemistries, fluid volumes, operational capabilities and mechanical robustness. Even a properly placed cement can fail if the slurry design does not adequately address the well parameters.

Each of these design variables carries with it an inherent uncertainty. Mitigating risks as much as possible is key to a proper job design. For example, uncertain wellbore size is a variable that can be mitigated by running a caliper log on the well to better determine hole size. Lacking a caliper log means more cement should be pumped on the well to assure the cement will cover the desired intervals.

The iterative process continues with confirmation that the slurry is properly designed to meet the requirements of the well. The objectives and "physics" of the cement job are used to design the cement slurry. In order to meet the job's objectives the necessary cement additives must be obtained for the job. This could be considered the "chemistry" portion of the design process. Many of the same variables that go into the "physics" portion of the design will also impact the "chemistry" portion of the process.

An understanding of down hole pressures and temperatures is critical for proper selection of slurry density and for the use of retarders or accelerators. Formation properties may dictate the need for fluid loss control. Wellbore architecture, pore pressures, fracture pressures and equipment capabilities will dictate how long the cement must remain in a fluid state, and thus impact the thickening time of the slurry.

The expectations for the performance of the cement slurry are based on laboratory test data, and the ability of that test data to simulate well conditions. The validity of the test data is influenced by proper selection of test temperatures and pressures. The temperature and pressure should as closely as possible simulate the conditions in the well. A failure to properly test at wellbore conditions can lead to a cementing failure.

Additionally, the cement slurry must be mixed properly at the rig with careful attention to density control and additive concentrations. Density control on location is essential to producing a cement slurry that performs as expected.

As with the identification of the job objectives, oftentimes some design requirements will conflict with other objectives on the well. As noted in the above example, if a very long thickening time is required, the design meeting that requirement may not build compressive strength quickly. In that instance, the risk associated with too short a thickening time on the well must be weighed against the risk of slow strength development.

Once the cementing objectives are established and the “physics” and “chemistry” of the design are complete, the cement must be placed properly in the well. Successful placement of the slurry in the annulus requires removal of the drilling fluid from the annulus and casing. This process includes proper casing centralization, wellbore preparation in the form of pre-job circulation volume and rates, spacer selection and use, proper mixing and pumping of the cement and full fluid returns during the job.

Failure of any portion of these processes may lead to a cementing failure. Insufficient data in preparing the design of the job can lead to the development of a slurry that does not have the performance characteristics necessary for well conditions. Improper testing or field mixing can yield a slurry that does not function as planned in the well. Finally, even with exacting design and an ideal cement slurry, failure to properly place the cement in the wellbore will result in a failure.

After the cementing operation is complete, there should be methods established to measure the success of the cement job. Those evaluation methods should determine whether the objectives of the job have been met.

The cement design process can be summarized as:

1. Establish the objectives of the job;

2. Determine the variables and design to meet the job objectives; and

3. Evaluate the job against the stated objectives.[3]

3.2 The Macondo Production Casing Design Process

BP had no expressed objective for the production string cement job beyond meeting the minimum MMS requirement that top of cement be 500 feet above the uppermost hydrocarbon bearing zone. BP's engineering design for the production string cement job was driven by the singular desire to minimize equivalent circulation density (ECD).[4]

Review of the available information shows the cement used on the Macondo well did not provide formation isolation nor act as a barrier inside the casing. BP's evaluation criteria was based on a single variable: maintain cement returns during the job. It appears this objective was to get a top of cement 500 feet above the highest hydrocarbon bearing zone to meet the MMS requirement.

The BP wells team was well versed in cementing. They were the final decision makers and were empowered to accept or reject the advice of both BP's internal cementing expert and Halliburton. Throughout the drilling of the Macondo well, the BP wells team demonstrated considerable control with respect to cementing design and operations. Evidence of this involvement is readily demonstrated in the design of a kick off plug.

In a series of March 11–12, 2010 communications, BP engineer Brian Morel questioned the use of a fluid loss additive in the cement system. In response to Morel's inquiry, Jesse Gagliano of Halliburton provided technical reasons for the use of the additive, and commented, "good luck explaining that to John [Guide], I've had no luck."[5]

Morel sent Gagliano's response to BP's internal cementing expert, Erick Cunningham, for comment. Cunningham noted BP company guidance in the use of fluid loss additives across certain zones, and endorsed the use of fluid loss in instances where there was high formation permeability.

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[3] For additional information on cementing basics and their application to the Macondo well, see Chapter 4.3 of the Chief Counsel's Report, pp. 67-78.

[4] ECD is the total pressure exerted in the well from the fluid hydrostatic pressure plus the friction pressure required to move the fluid. For example, for a drilling fluid that weighs 14.1 lb/gal, the static hydrostatic pressure would be 14.1 lb/gal. When the fluid is circulated in the well, the friction pressure will increase the pressure on the well, and the total pressure can be converted to an "equivalent mud weight."

[5] BP-HZN-MBI00110156 - 00110159

Morel's response on the fluid loss issue was the following comment:

> "Thanks for the response…Seems to be a constant argument in our team."

This statement indicates this was not the first time the BP wells team had discussed particular cement additives or slurry properties and points to a team that is well versed in cement slurry design.

An additional email conversation between BP and Halliburton occurred with respect to the spacer volumes on the same plug job. Halliburton's Gagliano recommended using 500 feet of spacer, noting the amount requested by BP (75 bbls) would be inadequate to properly remove the mud ahead of the plug. In his email, Gagliano stated:

> "I also ran some number for the spacer you want to run ahead. The volume you want to run is 75 bbls. Best practices recommend that we run minimum of 1,000 to 1,500 feet of spacer ahead. In the past I have historically only run 500' of spacer ahead when setting plugs because the volumes can get very large. The 75 bbls ahead is only equal to 90 foot of coverage (based on 29 ½" hole.) This footage ahead is not adequate to separate the mud and cement and to water wet the hole/casing. I recommend running the same amount of spacer that we ran on the last job (170 bbls). This will only be 204 feet of coverage based on the 29 ½" hole."[6]

Mark Hafle, a senior drilling engineer with BP, forwarded the email to Erick Cunningham requesting his comments or recommendations for spacer volumes. Cunningham provided the following response:

> "Have not had a chance to look at this in much detail, but I agree that running more spacer here is necessary due to the hole size. 90 feet of coverage is not sufficient and I would agree in theory with the 500 ft. target number sited by Jesse as a rule of thumb (even though I really dislike rules of thumb). With this hole size it would be difficult to achieve 500 ft."

Brian Morel of BP responded to Mark Hafle with the following comment:

> "Want to talk about the spacer volume? If so give me a call. Guide wants to stay with 75 bbls, and we reduced cement to 260 bbls (WSL worried about pressures being that high on the shoe). I agree about the spacer and don't believe spacer serve us any more than being a transition between the fluids, and make the mud turbulent for this situation…We don't need to water wet the hole, because we don't care about it sealing or stick to the

[6] BP-HZN-2179MDL00244182 - 00244183

> walls. Just need a hard core to push off. I know some people think I am crazy..."[7]

The above email communications point to a wells team that is knowledgeable in cementing, one that considers the merits of both cement additives as well as job designs, and one that would ask for guidance from their internal experts.

The communications also point to a team that is willing to dismiss the advice of both Halliburton and BP's internal cementing expert when that advice did not meet with what they, or in this case Mr. Guide, wanted to do. Brian Morel justified the decision to run less spacer recommended by both Halliburton and Cunningham by setting the goals of the job low.

The depth of BP's involvement in the cementing design is further exemplified in a series of emails from Brian Morel. In these emails, Mr. Morel is working with Halliburton and Erick Cunningham to select a lost circulation additive for the production cement job.[8]

In the email Mr. Morel stated:

> "I'm looking to find the most effective product for loss circulation during our production cement job."

This level of detail, in which BP engineers are selecting individual additives for use in the cement slurry, demonstrates the depth of BP's engineers' involvement in the cementing operation.

The BP engineers were personally involved in cement slurry design, additive selection and job design. These actions would be expected of an experienced team assigned to a deepwater well, a view that was shared by BP's internal cement expert, Erick Cunningham at his March 2011 deposition, where he stated:

> "In terms of looking at the way the job was being handled, it was, you know, it had a very bright young engineer, Brian Morel, working on the cement design. We had Mark Hafle, a senior deepwater drilling engineer working on the cement design, and we had a very experienced and a competent Halliburton engineer working on the cement design…. I had confidence in the capability of the well's team that was executing the cement design."[9]

4. Cement Job Design Decisions

The BP engineers chose to accept risks when designing the cement job based on their awareness that remedial cementing work could be done at a later date. Those additional

[7] BP-HZN-2179MDL00244182
[8] BP-HZN-2179MDL00248960
[9] Deposition of Erick Cunningham, March 23, 2011, p. 141, lines 4–11.

risks included using a leftover cement blend that was not appropriate for foamed cementing, using foamed cement in a SOBM environment, limiting cement volume and selecting a reduced number of centralizers.

4.1 The Macondo Slurry Design

4.1.1 Use of a Leftover Dry Blend

BP used a leftover cement dry blend from BP's Kodiak #2 well on the Macondo production string. This dry blend was not originally intended nor was it appropriate for foamed cementing applications. The base cement dry blend used for the production string on the Macondo well was not originally designed as a foamed cement system, and because of this, risks associated with slurry and foam stability were introduced to the job.

The base dry blend used for the cementing of the production string was a cement blend leftover from BP's Kodiak #2 well.[10] This dry blend consisted of:

LaFarge Class H Cement	
20%	SSA-1 Silica Flour
15%	SSA-2 Silica Sand
0.07%	EZ-Flo
0.25%	D-Air 3000
0.2%	SA-541
1.88 lb/sk	KCl[11]

For BP to use this particular cement dry blend on the Macondo production string, the blend had to be converted to a foamed cement to reduce its density. Converting this leftover cement blend to a foam slurry meant a new cement dry blend would not have to be sent to the rig.

The Kodiak #2 cement blend used on the Macondo production casing had additives that would not normally be used in a foamed cement design. The Macondo dry blend contained 0.25% D-Air 3000, a defoamer. While present in many conventional designs, the use of a defoamer is not recommended for use in foam designs.

The cement blend also contained SA-541, which is an additive that begins to work at 150° F to increase the viscosity of the cement. On the Macondo production casing, the stated circulating temperature used by BP and Halliburton was 135° F (or 15° F below the activation temperature for the additive). This means while the cement was being placed, the SA-541 was inactive.

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10 HAL_0562447 - 0562448

11 All percentages are By Weight of Cement (BWOC). A sack of cement weighs 94 pounds, therefore an additive added at 10% BWOC would mean there are 9.4 pounds of the additive per 94 pound sack of cement.

Of the last four foam cement jobs performed by BP, the Macondo design was the only one to incorporate these additives.[12]

4.1.2 Use of Foamed Cement

The use of foamed cement complicated the slurry design, and the risks associated with its application on the Macondo well went unrecognized by BP and Halliburton.

Foamed cement slurries are commonly used to aid in preventing annular flow after cementing, altering the mechanical properties of a cement and for reducing the density of a cement slurry. The technology has been in use for over 25 years, and was initially introduced on offshore rigs in approximately 1995.[13] Since that time, foamed cement has been used for the prevention of shallow water flows on wells drilled in deepwater in the Gulf of Mexico, as well as globally on various offshore projects.[14]

Foamed cement is defined as a **stable** mixture of a cement slurry and an introduced gas, typically nitrogen. The gas is held in place using surfactants and stabilizers that prevent the bubbles from coalescing prior to the cement setting.

A number of variables impact foamed cement stability. Among them are slurry composition, gas concentration, surfactant efficiency, temperature, pressure, shear and contamination. The stability of the foamed cement is essential to successful application of the system.

When evaluating a slurry for use in foamed cement, the base slurry density should be selected to give a final foam quality of between 15% and 35%. This range is based on laboratory work performed by a number of authors, with extensive work being performed by Goodwin and Crook in 1990.[15] This range of foam quality gives improved slurry performance while maintaining low permeability and good strength development.

When designing a foamed slurry, engineers should evaluate the base slurry, as well as the stability of the foamed cement at several foam qualities. Such an evaluation provides assurance that the slurry design can withstand changes in nitrogen rates during the job. Testing at 15% and 35% foam quality assures slurry stability at the extremes of the design range.

Additionally, slurry design testing should evaluate both the unset and set foamed cement. API RP 10B-4[16] provides guidance for both of these test series and also lists signs of instability for the tests.

[12] BP-HZN-BLY00174218
[13] Oil & Gas Journal, "Foamed cement job successful in deep HTHP offshore well," March 11, 1995.
[14] Benge, Glen and Poole, David: "Use of Foamed Cement in Deep Water Angola," SPE/IADC 91662, 2004.
[15] Goodwin, K. J. and Crook, R. J., "Cement Sheath Stress Failure," Paper SPE 20453, 1991.
[16] ANSI/API Recommended Practice 10B-4, First Edition, July 2004.

API RP 10B-4 is the API's recommended practice for testing of foamed cements at atmospheric pressure. The document contains a detailed protocol for performing foam stability testing of set samples. When the cement is set, the sample is to be cut into at least three sections and the density of each section is to be measured. Clause 9.3.4 of API RP 10B-4 lists some signs of instability. These signs include:

- More than a trace of free fluid
- Bubble breakout noted by large bubbles on the top of the sample
- Excessive gap at the top of the specimen
- Visual signs of density segregation
- Large variations in density from sample top to bottom.

The Halliburton laboratory report[17] and weigh up sheet,[18] which correspond to Halliburton's foam stability testing of the Macondo production string cement slurry, show only two sections of the sample were used for the foam stability test. There are no indications in any of the Halliburton lab reports as to the condition of the set cement sample, therefore it is not possible to determine if there were any signs of instability other than the density measurements reported by Halliburton.

The only successful set foamed stability test on the Macondo cement slurry reported by Halliburton showed a final density of 15.0 lb/gal for a slurry initially mixed at 14.496 lb/gal.[19]

API RP 10B-4 also contains a section for the determination of the stability of an unset foamed cement slurry. The purpose of the test is to check for settling and stability in the foamed cement slurry and record the visual appearance of the slurry noting such things as free fluid, settling or bubbles concentrating in a specific area.

Halliburton did not perform any testing for stability of the unset foamed cement.

Review of subsequent laboratory testing by Chevron for the National Oil Spill Commission indicated it was unable to generate a stable foam using the Halliburton slurry.[20] This was confirmed by work conducted by Oilfield Testing and Consulting.[21]

4.1.3 Combined Risks of Foaming the Leftover Kodiak #2 Dry Blend

As noted above, the base cement dry blend was not originally intended to be foamed, and was leftover from BP's Kodiak #2 well. Certain additives contained in the Kodiak #2 dry blend were either detrimental to or not necessary for foaming the cement slurry on the Macondo production string. These additives include D-Air 3000 and SA-541.

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[17] HAL_0028709
[18] HAL_DOJ_0000043
[19] HAL_0028709
[20] National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling, Cement Testing Results, Chevron, October 26, 2010.
[21] Oilfield Testing and Consulting report, August 1, 2011.

Use of the Kodiak #2 dry blend on the Macondo well is an example of a cement blend being converted to a foamed cement slurry rather than a slurry being designed and developed for use as a foamed cement system. A properly designed foamed cement system should be robust and account for variations in material concentrations, gas content and wellbore conditions.

Testing a leftover blend for use as a foamed cement slurry limits the laboratory and engineering designs to only the materials present in the cement blend, regardless of their efficacy to the slurry. Designing a slurry specifically as a foamed cement system gives the laboratory and engineering personnel the flexibility to develop an optimized foamed cement system.

Obtaining the lowest risk design involves mitigating known variables to the extent possible. For example, uncertainties in hole size are mitigated by running caliper logs, because more data is available to evaluate and mitigate the risk. Additionally, obtaining more laboratory data and complete testing results can mitigate the risk of using a dry blend that was not specifically designed as a foamed cement system.

BP had no previous experience using the Kodiak #2 dry blend in a foamed cement application on the Macondo well. Small changes in additive concentrations or the "ingredients" of the slurry requested by BP before the cement job began may have impacted several slurry properties. Because a full suite of tests was not performed by Halliburton on the Macondo slurry, those impacts remain unknown.

4.2 Additional Design Decisions

Regardless of the slurry design, the foamed cement job performed on the Macondo well contained a number of risks that jeopardized the cement job's potential for success including, but not limited to, using foamed cement in a SOBM environment, reducing the number of centralizers used on the production casing and pumping a low volume of cement.

4.2.1 Use of Foamed Cement in a SOBM Environment

The use of foamed cement in the Macondo well which contained SOBM and a base oil pre-flush added risks for destabilizing the foamed cement. Foams are formed by the addition of surface active agents known as surfactants along with gas to a fluid. Adding a hydrocarbon to a water-based foam will break or destabilize the foam.

The surfactants used for foamed cement are specialized surface active agents designed to work in a cement environment. While the surfactants are very effective at forming a stable foam, they will also interact strongly with hydrocarbons. Contaminating a foamed cement with hydrocarbons from either the SOBM or the base oil will tend to destabilize the foam, allowing the nitrogen to break out of the system.

The BP engineers were specifically warned by BP's internal cementing expert and Halliburton of the destabilizing effects of SOBM on foamed cement yet approved the use of foamed cement on the Macondo well.

This problem was recognized and communicated by Erick Cunningham to Brian Morel in a March 8, 2010 email in which Cunningham stated:

> "Foaming cement after swapping to SOBM presents some significant stability challenges for foam, as the base oil in the mud destabilizes most foaming surfactants and will result in N2 breakout if contamination occurs."[22]

To separate SOBM or oil contamination, a water-based spacer was used on the Macondo well. Halliburton ran tests to confirm the spacer's compatibility with SOBM and its ability to water wet the formation and pipe.[23] This testing demonstrated the spacer being run was chemically compatible with the SOBM. Halliburton laboratory testing did not evaluate the ability of the spacer to displace mud in the well; it only evaluated whether the fluids were compatible.

BP engineers were informed by Halliburton of the potential destabilizing effects of SOBM on foamed cement. In deciding whether to run spacer behind the top plug, Halliburton engineer Jesse Gagliano wrote in an email to BP personnel Hafle, Cocales and Walz on April 16, 2010:

> "Spacer behind cement -When we pump a foam job in a SOBM environment we usually pump a small volume of spacer behind the cement to prevent contact between the cement and SOBM. SOBM destabilizes the foamed system which could cause nitrogen breakout. There is a plug between the cement and mud but in the case that we might pump around the plug we put spacer as a buffer."[24]

Brian Morel of BP responded to Gagliano with the following comment:

> "Aren't we pumping non foamed cement behind the foamed job (7 bbls)? Brett is talking with Carl about effect on tools. We will give you an answer once he determines the effect."[25]

Gagliano responded to Morel stating:

> "We are pumping 7 bbls of un-foamed cement behind the job for the shoe track. The spacer is there as a precaution in case there is a problem or failure with the top plug and we pump around it. Depending on how much

[22] BP-HZN-2179MDL00282745
[23] HAL_0009699
[24] HAL_0010815
[25] HAL_0010815

> volume gets around the top plug the mud could still get to the foamed cement with intermixing of the fluid to that depth even with 7 bbls of un-foamed cement."[26]

Halliburton's Post Job Report notes 17 bbls of 14.3 lb/gal Tuned Spacer was pumped behind the top plug.[27] Even with a spacer that is completely compatible with the drilling fluid, the risk for contamination of the foamed cement with the SOBM would be eliminated only with 100% mud removal and no bypass of any fluids past the top plug.

Failure to properly centralize the casing in the Macondo well increased the potential for contamination of the foamed cement. Channeling in the eccentered annulus will increase the amount of cement exposed to the SOBM. **BP was aware of the potential destabilizing effects SOBM contamination could have on foamed cement.**[28]

BP was informed by Gagliano in an April 15, 2010 email that he had updated the OptiCem program which indicated cement channeling:

> "Attached is the updated OptiCem report & lab test. The items I updated in OptiCem are below; everything else is the same from the one we ran together yesterday.
>
> Imported caliper data
> Imported directional data
> Entered in centralizer info
> Updated Cement RPM data from lab test
>
> Updating the above info now shows the cement channeling and the ECD going up as a result of the channeling. I'm going to run a few scenarios to see if adding more centralizers will help us or not."[29]

In addition to using foamed cement in a SOBM environment, BP pumped base oil ahead of the spacer at the beginning of the cement job. Base oil ahead of spacer is not recommended in weighted mud systems like those found on the Macondo well.

The use of the base oil ahead of the spacer added yet another risk of contamination to the job design for the Macondo well. BP incorporated base oil into the job design in an effort to reduce ECDs.[30] Contamination by the base oil is more destabilizing than the SOBM

[26] BP-HZN-2179MDL00250637
[27] BP-HZN-MBI00170990
[28] BP-HZN-2179MDL00282745; HAL_0010815
[29] BP-HZN-2179MDL00249820
[30] BP-HZN-2179MDL00252452

itself. This is because base oil is 100% oil, and not an emulsion of oil, water and additives used to make the SOBM.[31]

4.2.2 Lack of Centralization of the Production Casing

Even with a perfectly designed and pumped cement slurry, if the cement slurry is not properly placed in the well, it cannot function as designed. **On the Macondo well production casing cement job, BP did not adequately centralize the production casing string to allow proper placement of the cement.**

Several key observations in this evaluation relate to centralization of the casing on the Macondo well:

- Better centralization would have resulted in improved displacement, a more controlled and reduced top of cement, lower ECDs during the cementing job and reduced gas flow potential calculations for all zones.

- BP was in charge of the procurement, placement and running of the centralizers on the Macondo well.[32]

The centralization issues on the Macondo well highlight the key involvement and control practiced by BP on the well. While advised otherwise by Halliburton, the BP engineers chose to take on the additional risk of a poor cement job by not adequately centralizing the casing.

Centralizers are designed to move the casing away from the formation wall and center the pipe in the borehole. Several types of centralizers are available including bow spring, rigid and solid centralizers. To keep the centralizer at the desired location, stop collars are used either as separate pieces of equipment or as an integral part of the centralizer itself. The six centralizers purchased by BP for the Macondo well were bow spring

---

[31] Base oil also reduced the hydrostatic pressure in the well. The use of base oil was questioned in a March 8, 2010 email between BP engineers Mark Hafle and Brett Cocales.

In the email Hafle commented:

> "Not sure I like base oil use for this job. Any thoughts?
> Perhaps we can get Trent to take a look today too, since Brian and I are out of the office."

Brett Cocales responded to Hafle by stating:

> "I don't have a major issue with this as long as the dynamic pressures are well above the res pore pressure, it doesn't present a well control problem and helps lift the cement more. There should be no reason we cannot maintain circ at 5 bpm during this job with all the horsepower we have on location. We will just need to work thru a couple of contingency options if we lose a pump." BP-HZN-2179MDL00282833.

It is noted that on the actual job, the pump rate did not exceed 4 bpm.

[32] BP-HZN-CEC022433, BP-HZN-BLY00124205

centralizer subs. These bow spring centralizer subs are manufactured to be run as integral parts of the casing string by being screwed into the casing string itself. They are not clamped on or slipped onto the casing.

The following are examples of these integral centralizers.[33]

Figure 4-1. Examples of integral centralizers.

Additional bow spring centralizers were ultimately sent to the *Deepwater Horizon*, however, those centralizers did not have integral stop collars and were not used on the well. These centralizers are slipped onto the casing as it is being run and not screwed into the casing string as are the centralizer subs above. The following photographs depict a bow spring centralizer on the left, and one with an integral stop collar in the middle. (Note this photograph is for illustrative purposes only and does not represent the centralizers used on or sent to the Macondo well.[34]) An example of a separate stop collar is shown at the far right.

Bow Spring Centralizer | Bow Spring Centralizer with Integral Stop Collar | Stop Collar

Figure 4-2. Examples of bow spring centralizers.

[33] Photographs from Weatherford brochure available online.
[34] *Ibid*.

The following is a photograph[35] of the centralizers delivered to the *Deepwater Horizon*. As can be seen, the centralizers do not have integral stop collars.

Figure 4-3. Photograph of centralizers delivered to the *Deepwater Horizon*.

Wellbore centralization is a key factor in the proper placement of cement in the annulus. The degree of eccentricity, or lack of centralization in a casing string, has a direct relationship to the amount of channeling in the annulus. Centralizing the drill pipe allows the fluid to flow completely around the casing. If the pipe is not centered in the well, the wide side of the well will be the path of least resistance and more fluid will flow in that area. There can be areas in the well where no flow can occur. The following illustration is a cross section of fluid flow through an annulus with an eccentered casing:

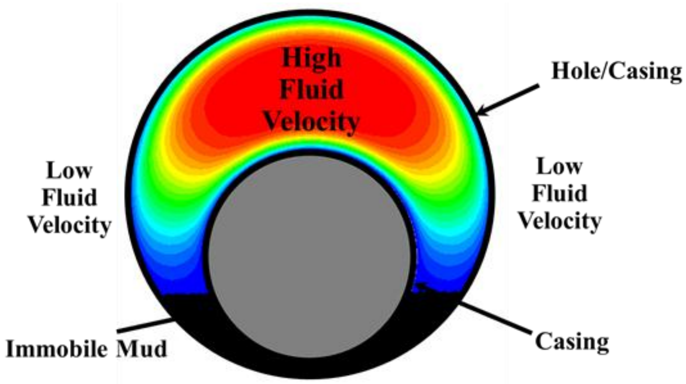
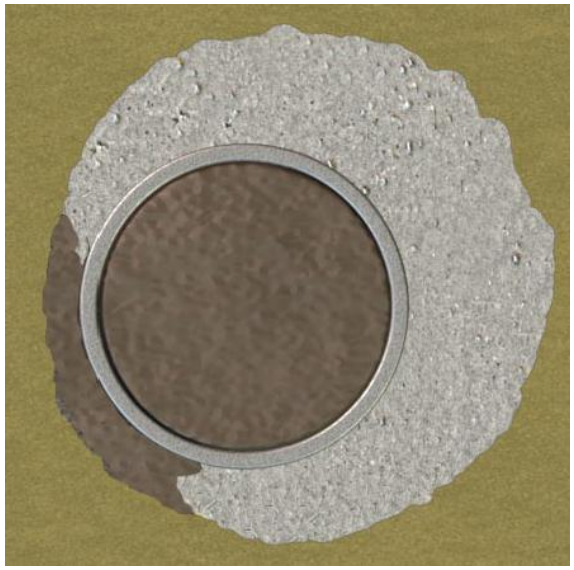


Figure 4-4. Illustration of fluid flow through annulus with eccentered casing.

[35] Macondo, The Gulf Oil Disaster, Chief Counsel's Report, National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling, 2011, p. 85.

The figure below illustrates the effects of eccentered casing on cement placement.



TrialGraphix[36]

Figure 4-5. Effects of eccentered casing on cement placement.

The simulation work performed by Cementing Solutions, Inc. (CSI) in support of BP's internal investigation of the Macondo blowout demonstrates that more centralizers improved displacement, lowered ECDs, decreased the gas flow potential and lowered the predicted top of cement.[37] The decisions by BP's engineers to proceed with the cement job without adequate centralization added more risk to the job than simply requiring a remedial cement job at a later date. The lack of adequate centralization increased channeling, increased the risk of contamination of the slurries, and increased the risk of a barrier failure in the well.

4.2.3 Low Cement Volume

The BP engineers mandated an exceptionally low volume of cement for the Macondo production string cement job. This design required an unrealistic level of displacement efficiency (100% displacement efficiency) leaving no room for error. The volume of cement on the production casing was very low compared to previous foamed cement jobs performed by BP. This further complicated the cementing job on the Macondo production string. The BP engineers recognized the small cement volume provided little or no margin of error.[38]

[36] Chief Counsel's Report, p. 69.
[37] BP-HZN-BLY00048343, BP-HZN-BLY00048345, BP-HZN-BLY00048347, BP-HZN-BLY00048348 and BP-HZN-BLY00048349
[38] BP-HZN-2179MDL00081650

The following table is a comparison of the cement volumes on the Macondo job[39] to those pumped on three previous BP wells. All volumes are in barrels.

Well Name	Macondo	Isabela	Nakika	King South
Vol. Base Oil	7	0	100	0
Vol. of Spacer	72	100	67	105
Vol. Lead Cement	8	10	14.3	10
Vol. of Foam	48	208.1	99.7	76
Vol. of Tail Cement	7	26	21.3	13.8
Total Cement	60	244.1	135.3	99.8

Table 4-1. Comparison of cement volumes pumped on BP wells.

The volume of cement was limited by BP's engineers in an attempt to prevent a trapped annulus by sealing the space between the production string and the previously run casing. This necessitated reducing the total amount of slurry to a very low volume.

Additionally, there was a very low volume of unfoamed tail cement (7 bbls) pumped on the Macondo production casing. This low volume of unfoamed tail cement was only sufficient to fill the casing from the float collar to the reamer shoe, and left no tail cement in the annulus.

5. Job Execution / Cement Placement

5.1 Start of the Cement Job

BP started the cement job without key laboratory test results for the retarder concentration used on the Macondo well. BP did not have a complete set of laboratory tests for the cement system that was pumped in the well that contained 0.09 gal/sk of SCR-100 retarder. Free water, settling and fluid loss tests were not available for any slurry tested, and the 0.09 gal/sk system also lacked rheology test data. Halliburton did not run complete laboratory testing on the slurry and BP did not follow up with Halliburton to ensure that this testing was performed.

BP had thickening time and strength development test results for both of the base slurries (0.08 and 0.09 gal/sk retarders). Cement jobs that are robustly designed for foamed cementing could proceed with only these two tests. However, because the Macondo well's dry blend was not originally designed for use as a foamed cement and contained additives that are not recommended for use in a foamed system, it was not appropriate for BP to initiate the cement job without complete test results.

[39] BP-HZN-BLY00174219

The decision to pump the slurry with 0.09 gal/sk retarder was confirmed by Brian Morel in an email response to Jesse Gagliano at 11:51 p.m. on April 18, 2010.[40]

Earlier that evening, Mr. Gagliano sent an email to Brian Morel at 6:50 p.m. asking:

> "Has a decision been made yet if you are going with the 8 gals or 9 gals of retarder?"

BP acknowledged the added risk brought on by the use of a higher retarder concentration in the slurry. This increase in retarder concentration was made as part of an effort by BP to support using a lower pump rate. The concentration of retarder for the slurry had been discussed between Brian Morel and John Guide the day before with Morel acknowledging the risk:

> "I would prefer the extra pump time with the added risk of having issues with the nitrogen. What are your thoughts? There isn't a compressive strength development yet, so it's hard to ensure we will get what we need until it's done."[41]

BP's last minute decision to increase the retarder content in the slurry, use a dry blend not specifically designed as a foamed cement system and reliance on limited laboratory testing of the slurry added risks to the cementing operation.

5.2 Pre-job Circulation

BP limited the pre-job circulation to much less than the planned volume prescribed in the April 15, 2010 BP drilling program.[42] Pre-job circulation removes cuttings and debris from the well, breaks up mud gel strengths, lowers mud viscosity, lowers ECD and prepares the wellbore for cementing. The purpose of pre-job circulation is to prepare the wellbore for cementing. The pre-job circulation serves to cool the well, remove any remaining drilling cuttings or debris from the annulus, break up any gelled mud, lower the mud viscosity, and indicates whether there are any entrained gas or other materials in the mud that may have entered the well while running casing.

Removing cuttings and debris from the well and breaking up gel strengths are important to reducing the ECDs on the well and preparing the well for cementing. Areas containing cuttings or gelled mud do not allow cement to be placed. Thinner fluids are more easily displaced from a well and lowering the mud viscosity through conditioning prior to the job can improve mud displacement.

Best practices call for circulating at least "bottoms up" prior to starting a cement job, which means the drilling mud at the very bottom of the well will be circulated to the top of the well. The mud that rests at the bottom of the well remains in a static condition in

[40] BP-HZN-2179MDL00250778
[41] BP-HZN-2179MDL00315248
[42] BP-HZN-2179MDL00249965

the well longer than any other fluid in the wellbore. This mud has also been subjected to the highest temperatures in the well for the longest period of time and is the mud across from the producing formations that is to be replaced by the cement.

The pre-job circulation volume on the Macondo well was very small and did not approach bottoms up. While there was concern over lost circulation on the well, no lost circulation was reported during the limited pre-job circulation, and it is not known why the pre-job circulation volume was reduced by BP.

5.3 Late Change on Centralizers

BP installed only six integral centralizers and did not use the additional 15 slip on centralizers and stop collars that it ordered and were present on the *Deepwater Horizon* when BP ran the production casing. This assured the casing was not adequately centralized to allow proper placement of the cement. BP recognized the challenge of centralizing the casing in the enlarged hole and chose to use the available six centralizers.

In an April 16, 2010 email exchange between Brett Cocales and Brian Morel regarding centralizer use, Cocales stated:

> "Even if the hole is perfectly straight, a straight piece of pipe even in tension will not seek the perfect center of the hole unless it has something to centralize it.
>
> But, who cares, it's done, end of story, will probably be fine and we'll get a good cement job. I would rather have to squeeze than get stuck above the WH. So Guide is right on the risk/reward equation."[43]

The conversation shifted to a discussion about the placement/location of centralizers with Morel responding:

> "See diagram below for centralizer placement. Tried to keep them in hole under 10.75" which is the max OD for bow spring subs (blue line.)"

Cocales provided Morel with the following comments:

> "If we think the hole is relatively straight, what if you placed them every 3 joints from the shoe which almost gets you to top of cement and should maintain the pipe standoff between centralizers. With the exception if the hole is too washed out or move it up or down a joint.
> Just my thoughts on the physics of it."

[43] BP-HZN-MBI00128383

Morel responded stating:

> "Hole is washed out if you do that, tried it before. This is all I could do to get in a none (sic) washed out interval, unless you really spread them out."

Cocales responded stating:

> "That's good. If we go back to the premis (sic) that we want the best centralization across the sands and above the sand for 200 ft., that is what you have and gives the completion folks the best chance to have good cement in this area. I'm good with this basis of design. Do you agree with that logic?"

In his final response Morel commented:

> "I agree. We can argue this one out after we get the actual vs. model data and see how it reads."[44]

As discussed in the email exchange, the following graph is the caliper log which indicates BP's placement of five of the integral casing centralizers.[45] (The location of the sixth and final centralizer is not shown on the graph).

[44] BP-HZN-CEC022670
[45] BP-HZN-MDL00033083

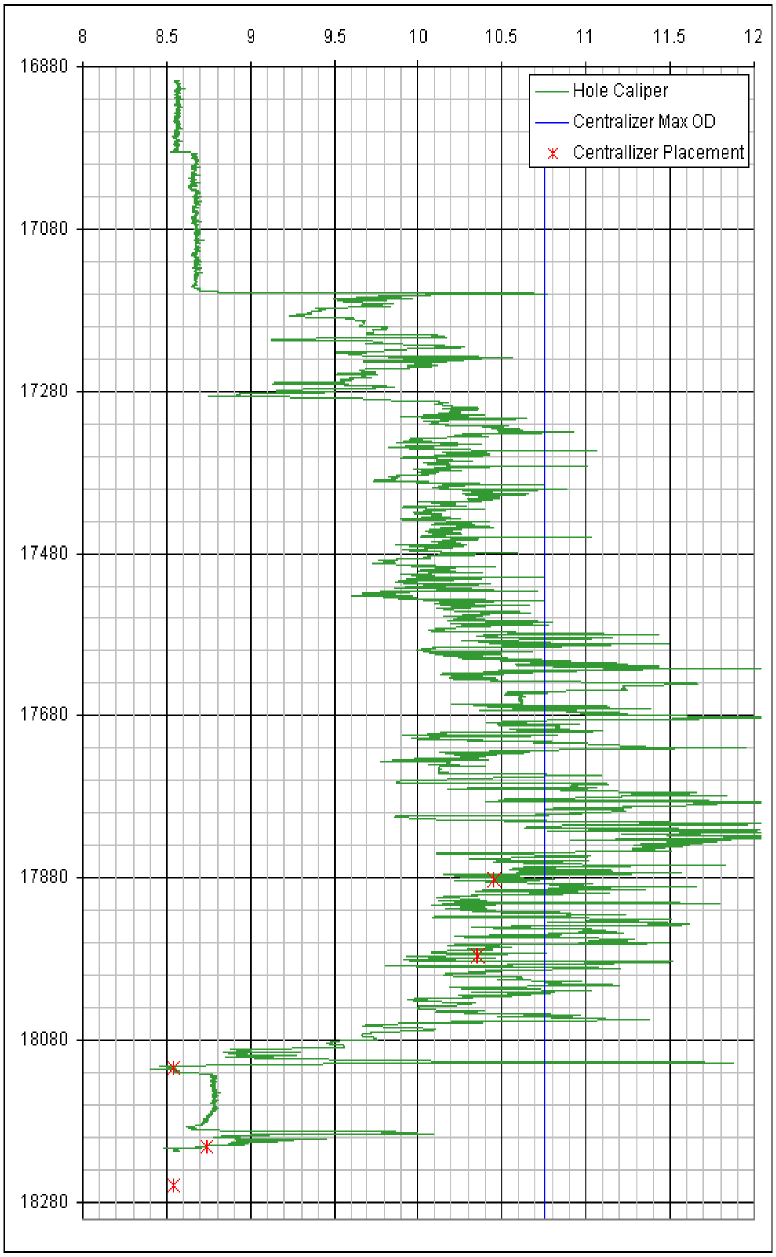


Figure 5-1. April 16, 2010 caliper log with centralizer placement on the Macondo well.[46]

While recognizing the limitations of the centralizers in an enlarged borehole, BP engineers Morel and Cocales did attempt to centralize as best they could across the sands. However, they did not acknowledge the increased potential for channeling and cement contamination by reducing the number of centralizers to six. Running the additional centralizers that were present on the rig would have reduced channeling and cement contamination in the enlarged hole.

46 BP-HZN-MDL00250606

5.4 Limited Pump Rates

BP limited the pre-job cementing and displacement pump rates in an attempt to reduce ECDs.

Wellbore isolation can only be achieved by placing cement completely around the casing. When one factor, such as centralization, is compromised, other practices should be improved. Putting energy into the wellbore will assist in cement placement, and this energy can be put into the well by pipe movement and fluid movement. For this subsea well, pipe movement was not possible which leaves only fluid movement as a way to put energy into the well. Fluid movement is achieved through pump rate. Higher rates equate to more fluid energy in the well.

Fluid rates for the Macondo cement job were limited by BP engineers due to a fear of losing circulation during the job. As noted in section 4.2.3 of this report, the cement volumes were very low, and any lost circulation would mean the top of cement would likely be below that required by MMS. This would require BP to perform cement evaluation logging and probable remedial work on the cement before leaving location.

5.5 Halliburton Job Performance on Location

In review of the graphical data presented in the Halliburton Post Job Report, the Halliburton cement crew on the *Deepwater Horizon* performed the cement job in accordance with the job design.[47] The Post Job Report presents a written record of the events prior to and during the cement job as well as graphical data from the cement, nitrogen and liquid additive skids.

Based on a review of Halliburton's Post Job Report data, there were no issues related to density or rate control of the cement, additives or nitrogen. Good density control of the cement system is critical to cementing success. The chart presented on page nine of the report shows good density control at 14.3 lb/gal for the spacer.

The cement density control from the Post Job Report, page 10, was excellent during the job. The density control on this job was within +/- 0.2 lb/gal throughout the foamed cement portion of the job. This is an acceptable variance for a continuously mixed slurry.

Nitrogen injection rates are keyed to cement rates, and based on the pre-job OptiCem runs, the nitrogen addition rates from the Post Job Report, page 14, were appropriate for the job.[48]

Finally, the surfactant additions must be accurate or slurry stability can be compromised. Based on the data reviewed in the Post Job Report, page 13, the ZoneSeal 2000 surfactant was added to the slurry as per the design.

[47] HAL_0028665
[48] BP-HZN-MBI00128722

5.6 Float Equipment Test

The float check test did not confirm the floats were holding because the differential pressure at the float collar was less than the pressure required to unseat the top plug.

The float equipment is a barrier to cement flow up to the rating of the float equipment. API RP 10F[49] provides testing methods and performance categories for float equipment. However, there are no industry tests where the float equipment is tested with wellbore fluids.

While not a specification, the performance requirements in the recommended practice serve as guidance for the selection of float equipment. Float equipment is categorized by its durability to flow (and reverse flow for auto-fill equipment) and the temperature rating of the equipment. The highest rating for float equipment is III-C, meaning the equipment can withstand 24 hours of forward flow, 400° F and a back pressure of 5,000 psi. The auto-fill float equipment used on the Macondo well was classified as III-C equipment.

Conversion of the auto-fill float equipment on the Macondo well was complicated by apparent blockage of the reamer shoe, float collar or a combination of both, and required higher pressures to establish circulation in the well. After circulation was established, the circulating pressures were much lower than predicted for the job.

It is not known if the initial circulating pressure predictions performed by BP and M-I Swaco accounted for the restrictions in the float equipment, or if subsequent calculations by M-I Swaco were performed with the assumption the restriction had been removed, which should yield a lower circulating pressure.[50] BP engineers decided the lower circulating pressure resulted from a failure of two separate pressure gauges on the mud pumps, and proceeded with the cement job assuming the float equipment had converted and was functioning properly.

In the pumping sequence of a primary cement job, a top rubber plug is often used to separate the cement from the displacement fluid. This solid rubber plug is pumped behind the cement and stops when it reaches the float equipment. The end of a cement job is typically signaled by a pressure increase seen when the plug lands on the float equipment. This is commonly referred to as bumping the plug, and signals the displacement of the cement is complete.

BP performed several "checks" on the float equipment. The first check occurred when the plugs bumped on the float equipment. This is an indication the landing profile on the float equipment was still in place and functioning as designed.

[49] API RP 10F, Third Edition, April 2002.
[50] Deep Water, The Gulf Oil Disaster and the Future of Offshore Drilling, Report to the President, National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling, p. 98.

After the plug is bumped, typically the pressure is increased by 500 - 1,000 psi over the final displacement pressure to assure the plug has landed on the float equipment. On the Macondo well, once the top plug was bumped, the pressure was increased to 1,000 psi above the bump pressure, again assuring the float collar was still in place and functioning.

After the plug has bumped, the pressure is bled to zero and the flow of fluid from the well is monitored for a period of time. If the valves in the float equipment are functioning properly, the flow from the well will stop. If the flow does not stop, it is an indication the valves in the float equipment are not closed, and the heavier fluids in the annulus are flowing back into the casing.

The following illustration depicts the process. In figure A, the cement is displaced into the well with the top plug behind the cement. Figure B shows the plug landed on the float equipment and the valve is keeping the fluids in the annulus from flowing back up the well. Figure C shows a situation where the valve did not function properly and the fluids in the annulus are free to flow back up the casing.

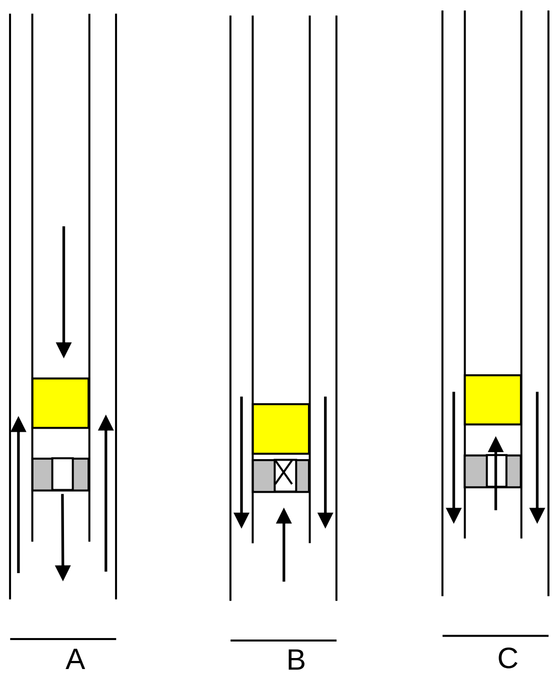


Figure 5-2. Float check process.

In this illustration, it is important to understand there is a force required to move the plug up the casing in figure C. The top plug is not free floating and must be pushed up the well. The force available to push the plug is the differential pressure at the end of the cement job. This pressure, sometimes called the lift pressure, is the difference in the pressure in the annulus and that in the casing. On the Macondo well, that differential, or lift pressure, was less than 60 psi.

The pressure required to move the top plug up the well shown in figure C is 165 psi at ambient temperature.[51] At less than 60 psi, the differential pressure at the end of the cement job was not sufficient to unseat the top plug and move it up the casing. Because of the low differential pressure at the end of the Macondo production casing job, there was no way to determine if the float valves were in fact functioning.

The final float equipment check occurred with the positive pressure test. This tested the integrity of the casing and the top cement plug as it was sitting on the float collar. The successful positive test on the casing again confirmed the top plug and float equipment were in place and able to hold pressure from above.

The positive pressure test does not evaluate any fluids below the top plug. The top plug provides a pressure seal against the float collar, and no pressure is transmitted below the plug. A casing test only tests the casing down to the plug. **Set cement below the plug is not required for a successful positive pressure test**.

It is apparent from the positive pressure test on the well that the float equipment was capable of holding the top plug in place. This test does not evaluate if the equipment was capable of holding pressure from below the collar. If flow was coming through the float collar and up the casing, then the float equipment valve system did not prevent that flow.

6. Laboratory Testing and Reporting

6.1 Overview

There are no established minimum testing requirements for cement designs by Halliburton. Halliburton's engineer selects the tests to run. In evaluating the Halliburton laboratory testing and the reporting of lab results, it is apparent the Halliburton in-house engineer is responsible for selecting the tests that will be performed on the cement slurry. There also does not appear to be a standard suite of tests performed for each cement design.

The most common lab tests performed on cement slurries are thickening time,[52] rheology, strength development, free water and fluid loss. Additional testing such as settling or slurry stability, gel strength, gas migration and compatibility tests for spacers are also performed to a lesser extent.

The Halliburton laboratory testing for the base slurry used on the Macondo well production string focused on the following tests:

Thickening Time
Rheology
Strength Development

[51] Deposition of Brent Lirette, June 11, 2011, p. 88, lines 8-11.
[52] Thickening time may also be referred to as pump time. These terms are used interchangeably.

Additional tests were performed on the foamed cement sample and included FYSA viscosity, foam crush compressive strength and foam stability. Halliburton did not perform tests for free water, settling or fluid loss.

Halliburton also did not perform the complete suite of tests required in the Offshore Wells Services Contract between BP and Halliburton. Based on review of the testing requirements found in Table 2.3 of the contract, the only test required that was not performed by Halliburton was the operating free water test.[53]

BP's Drilling and Completions Cementing Manual's recommended practices for cement testing identifies fundamentals, risks and test procedures for cement testing.[54] Section 4.1 of the manual lists laboratory testing requirements for BP cementing operations and outlines the testing to be performed by job type. In the case of the Macondo production string, the required testing from this section includes:

Pump Time	Compressive Strength
Operating Free Water	Rheology

API fluid loss is required when the slurry contains a fluid loss additive. BP settlement testing is mandated when the hole angle exceeds 70°, the temperature exceeds 250° F or weighting agents or low density particles are used.

The only references to foamed cement within BP's recommended practices are found under Section 5.1 - Gas Migration, where it is noted that foam slurries cannot be tested in the gas migration equipment being described, and in the Appendix, where ISO 10426-4 is referenced.[55]

A complete test series was not performed for the slurry containing 0.09 gal/sk SCR-100 retarder that was actually pumped on the Macondo well.

As discussed in the Job Execution section of this report, BP initiated the cement job without a complete set of lab data for the slurry that was pumped on the Macondo well. The degree of uncertainty associated with pumping a cement job with incomplete lab data is dependent upon well conditions. On the Macondo well, the risks associated with pumping the cement job without complete lab results were too great given the well conditions and slurry design.

BP's use of a system originally designed for the Kodiak #2 well, and not one specifically designed as a foamed slurry, added risks that could have been mitigated by more complete laboratory data.

[53] BP-HZN-MBI00022401
[54] BP-HZN-2179MDL02136569 - BP Drilling and Completions Cementing Manual, Cement Laboratory Testing Section, SRP 4.1-0003, November 2009.
[55] ISO 10426-4 is equivalent to API RP 10B-4.

Furthermore, BP's last minute selections of the cement's additive concentrations altered the cement slurry's properties. This is clearly evident in the thickening time and strength test results reported for the slurries containing 0.08 and 0.09 gal/sk of the SCR-100 retarder. Had this slurry design been used previously by BP and Halliburton, familiarity with the system may have reduced the risk of pumping a slurry with less than complete lab test data.

Halliburton's laboratory reporting is inconsistent and confusing. Without direct input from a Halliburton engineer, it is not possible for the reader of the report to determine the date on which the report was generated, whether it represents a complete set of data or the actual composition of the slurries tested.

The Halliburton lab reports for the Macondo well contain data for slurries tested with two different retarder concentrations, 0.08 and 0.09 gal/sk SCR-100.[56] It is not readily apparent from the test results that some of the results are for a slurry with the lower retarder concentration.[57] A review of the available "final" lab reports shows at least five reports, each containing varying lab test results. On each of these Halliburton reports, there is no indication other than a laboratory generated request ID number that the data corresponds to a slurry containing 0.08 gal/sk SCR-100 retarder or 0.09 gal/sk SCR-100 retarder.

Thickening Time Testing

The thickening time, or pump time, of a cement slurry is a determination of the amount of time the slurry will remain pumpable at well temperatures and pressures.[58] (The thickening time of the Macondo slurry with 0.08 gal/sk of retarder was reported as 5:30 and the 0.09 gal/sk retarder was 7:37.)

These thickening times were reported in an April 17, 2010 email to BP by Jesse Gagliano. Gagliano noted the job time was 4:08 and stated he would feel comfortable with the 5:30 results.[59] Gagliano also reported the Ultrasonic Cement Analyzer (UCA) and foamed crush strengths were available for the 8 gallon slurry system but not for the 9 gallon slurry system.

Brian Morel forwarded this note to John Guide with the statement:

> "I would prefer the extra pump time with the added risk of having issues with the nitrogen. What are your thoughts? There isn't a compressive strength development yet, so it's hard to ensure we will get what we need until its done."

[56] *See* HAL_0028709 - 0028712, HAL_0044651 - 0044652, BP-HZN-2179MDL00250688 - 00250689, HAL_0010641 - 0010642 and HAL_0010868 - 0010870. In this case 0.08 gal/sk = 8 gal/100 sk and 0.09 gal/sk = 9 gal/100 sk. Retarder concentration may be referred to as either gal/sk or gal/100 sk.
[57] Deposition of Thomas Roth, July 26, 2011, p. 488, lines 5-12.
[58] The "viscosity" of the slurry is measured in Bearden units of consistency (B_c), and values above 70 B_c are considered unpumpable.
[59] BP-HZN-2179MDL00315248

The selection by BP of the higher retarder concentration (9 gallons of retarder) was confirmed by Brian Morel in an April 18, 2010 email exchange between Morel and Gagliano.[60]

Strength Testing

The UCA is a laboratory test device used for determining the strength of a cement slurry. The slurry is placed in the UCA cell which is then heated to the test temperature and pressure. The UCA uses an ultrasonic signal that is passed through the sample of cement. As the cement sets, the time it takes for the signal to travel through the sample changes and is correlated back to a compressive strength result. The UCA does not directly measure strength development but uses a mathematical correlation to determine strength.

Halliburton conducted the UCA sonic strength testing on the slurry using a four hour heat up rate from the initial circulating temperature of 135° F to 210° F for all strength tests. This heat up rate is counter to the recommendations found in BP's recommended practices,[61] though it does follow API recommended practices.[62]

Section 4.2 of the BP recommended practice for cement testing requires the UCA test to be ramped to BHCT in one hour then to 95% of the static temperature over 12 hours. The document also recommends in deepwater and HPHT wells, such as Macondo, WellCat be used to predict the heat up rate and to use that rate for strength testing. (WellCat is an industry available temperature predictive computer program.)

The UCA strength of the production string cement system with 0.08 gal/sk SCR-100 retarder showed 50 psi in 5:54 and 500 psi in 6:19. The 12 hour strength was reported as 2,143 psi and the 24 and 48 hour results were 2,526 psi and 2,641 psi respectively.[63]

In the UCA testing at 210° F, the same sample of cement containing 0.09 gal/sk SCR-100 retarder showed 50 psi in 8:12 and 500 psi in 8:40. At the end of 12 hours, the sample tested showed a strength of 2,301 psi. This sample was preconditioned for three hours before being placed in the UCA for testing.[64]

Comparing these two test results indicates the additional retarder delayed the onset of strength by slightly more than two hours.

The only data available for the foamed cement was crush strength data for the system containing 0.08 gal/sk retarder.[65] The slurry was conditioned for one and one half hours prior to starting the test, and the data showed no strength development until 48 hours, at

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[60] BP-HZN-2179MDL00250778
[61] BP-HZN-2179MDL02136569 - BP Drilling and Completions Cementing Manual, Cement Laboratory Testing Section, SRP 4.1-0003, November 2009, p. 8.
[62] ANSI/API Recommended Practice 10B-2, First Edition, July 2005, Clause 8.7, p. 26.
[63] HAL_0010869
[64] HAL_0028709-0028710
[65] A crush compressive strength test of the 0.09 gal/sk retarder cement slurry was cancelled by Jesse Gagliano. *See* HAL_DOJ_0000049 – 0000050.

which time the strength was reported as 1,590 psi. The strength testing for the foamed cement sample was performed at 180° F and atmospheric pressure. The test procedure is outlined in API RP 10B-4.[66] Because the foamed cement is generated at atmospheric pressure in the lab, it cannot be cured under high pressure, thus the test is limited to 180° F to prevent boiling the water in the sample. No data is available for crush strength testing of the slurry with 0.09 gal/sk retarder, however as seen with the UCA testing above, the addition of more retarder would also have delayed the strength development of the slurry.

Free Fluid[67] Testing

Halliburton did not perform free fluid tests of the Macondo slurry. This testing was later performed for the National Oil Spill Commission[68] and by Oilfield Testing and Consulting.[69] Results from both labs show varying degrees of free water and also noted settling of the sample, with higher free water and settling noted when the test was performed at a 45 degree angle. (Having no free fluid is recommended for a production casing cement system.) The results from this testing indicate a base slurry that is not stable and should be redesigned.

Fluid Loss Testing

As with the free fluid testing, fluid loss tests were not performed by Halliburton. The results of tests performed for both the National Oil Spill Commission and by Oilfield Testing and Consulting show high fluid loss results, which would be expected for a system that did not contain a fluid loss additive in its design. BP guidelines do not require a fluid loss test be performed on slurries that do not contain a fluid loss additive. BP did not identify any objectives that would have required fluid loss in the base slurry.

6.2 The Importance of Temperature

Temperature is of critical importance to cement slurry design. The temperatures used in laboratory testing should simulate those found in the wellbore, and failure to properly account for the temperatures can lead to a cementing failure. The setting of cement is a chemical reaction that is highly dependent on temperature. As temperature in a wellbore increases, the reaction rate increases and the cement gains strength faster. Lower temperatures will delay the setting of the cement. API recognizes the importance of temperature and specifically addresses it in API RP 10B-3.[70]

API RP 10B-3 - Recommended Practice on Testing of Deepwater Well Cement Formulations, states in Clause 6 - Strength tests for deepwater well cements:

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[66] ANSI/API Recommended Practice 10B-4, First Edition, July 2004.
[67] Also called "free water."
[68] National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling, Cement Testing Results, Chevron, October 26, 2010.
[69] Oilfield Testing and Consulting report, August 1, 2011.
[70] API/ANSI Recommended Practice 10B-3, First Edition, July 2004.

> "The strength development of cement used in a deepwater cementation can be influenced by many factors, including heat of hydration, casing/wellbore size, final slurry location (annulus or shoe track), and initial slurry temperature**. Given the number of variables contributing to the rate of strength development in a deepwater well, the temperature and pressure schedule should be determined by means of numerical heat transfer simulation or by field measurement from an offset well(s).** In this way, the test schedule can reflect as closely as possible the actual temperature and pressure profiles found after placement." (Emphasis added.)

BP's recommended practice mimics the API and contains a table of risks and mitigating actions.[71] This table specifically states that testing at the wrong temperature creates a risk that the primary cementing operations will fail. Measures to be taken to mitigate this risk include:

> "Not relying on API schedules for temperature selection for deviated wells, HPHT and deep water wells. Do not rely on API ramping schedules and use a ramping schedule simulating the expected field cementing operations."

The same table identifies "test procedures and conditions [that] do not model actual field practice and conditions" as a risk. The recommended mitigation of this risk is:

> "Communications between WSL, BP engineer, cement company engineer and laboratory. Documenting procedure and conditions on the laboratory test request sheet, the laboratory report and the rig cement program."

All of the UCA strength testing of the base cement for the Macondo production casing conducted by Halliburton was performed at 210° F, and Halliburton used a heat up rate of four hours. The samples were preconditioned at 135° F prior to starting the strength testing, meaning the time used to heat the samples from 135° F to 210° F was four hours for the UCA strength tests.

For the UCA heat up rate to be representative of the conditions in the Macondo well, the temperature of the well would need to reach 210° F within four hours of the end of the cement job. There is no down hole temperature data available for well temperatures following the cement job, however there is temperature information available from logging runs made prior to the cement job contained in wireline logging diaries within BP's documents. These runs were made after the well had reached total depth, the drill pipe pulled out, and logging began. The wireline log data provides a close approximation of well conditions prior to cementing The well had been circulated prior to pulling the drill pipe out of the hole, and remained static during the logging runs. This static period during logging would allow the well to heat up.

[71] BP-HZN-2179MDL02136569 - BP Drilling and Completions Cementing Manual, Cement Laboratory Testing Section, SRP 4.1-0003, November 2009, p. 5.

Review of the open hole temperature information shows the well static temperature to be 228° F after 32 hours and 232° F after 48 hours.[72] This data indicates the heat up rate corresponding to a 93° F increase in 32 hours would average approximately three degrees per hour. (This calculation assumes an initial circulating temperature of 135° F.)

For the well to have reached 210° F in four hours, the average heat up rate would have been in excess of 18° F per hour. This very high heat up rate is unrealistic for a deepwater well.

The wireline log temperature data becomes significant when the results of the Halliburton foamed cement compressive strength tests are reviewed. As previously noted, the tests were performed at 180° F and atmospheric pressure. These test results show zero strength development for over 24 hours at 180° F.

Foamed cement testing is restricted to atmospheric conditions, while UCA testing is performed at higher temperatures and pressures. Because the results of the foamed crush strength tests indicated no strength at 24 hours, an investigation was warranted to determine the reason for the slow strength development. The air used to foam the sample in the lab would have no effect on when the cement sets.

The 30° F difference in the test temperatures reflected in Halliburton's laboratory results for the foam crush tests (180° F) and the UCA testing (210° F) is significant. This temperature difference, as well as the rate at which the sample was heated to the temperature, will definitely impact the rate of strength development.

The Oilfield Testing and Consulting report (OT&C report) contained results from the testing of a series of laboratory prepared cement slurries.[73] All testing was performed with cement and cement additives representative of those used on the job for the Macondo well in April 2010.

Section 9 of the OT&C report provides the results of a series of strength tests performed on the slurry containing both 0.08 and 0.09 gal/sk SCR-100 retarder. Additional testing is also reported for two slurries contaminated with various amounts of spacer or base oil.

The strength testing in section 9 utilized a modified ramp for heating the samples from BHCT to 210° F. The ramp schedule is noted as:

> Pre-condition all samples for 3 hours at 135° F
> Ramp from 135° F to 165° F in 4 hours
> Ramp from 165° F to 185° F in 4 hours
> Ramp from 185° F to 195° F in 4 hours
> Ramp from 195° F to 210° F in 4 hours
> Maintain 210° F for the remainder of the test period

[72] BP-HZN-BLY00189102
[73] Oilfield Testing and Consulting report, August 1, 2011.

The test results (reflecting two different conditioning ramps) reported on page 30 of the OT&C report for the slurry containing 0.09 gal/sk SCR-100 retarder are as follows:

Slurry UCA-2 Conditioning ramp[74] - 83 min to 135		Slurry UCA-2B Conditioning ramp - 230 min to 135	
50 psi	15:22	50 psi	16:32
500 psi	16:33	500 psi	17:42
12 hr. psi	0	12 hr. psi	0
24 hr. psi	2,762	24 hr. psi	2,794
48 hr. psi	3,459	48 hr. psi	3,958

Again, the Halliburton UCA testing performed at 210° F with the sample of cement containing 0.09 gallons per sack of SCR-100 retarder showed:[75]

50 psi	8:12
500 psi	8:40
12 hr. psi	2,301

Comparing the OT&C report data to the Halliburton results shows the sensitivity of the Macondo slurry to the temperature ramp. The modified heat up rate delayed the onset of strength (defined by the time to reach 50 psi) by seven to eight hours, and at 12 hours, no strength was shown in any of the samples tested by Oilfield Testing and Consulting.

This data, indicating the sensitivity of the slurry, confirms the BP statement in their recommended practices:

> "Do not rely on API ramping schedules and use a ramping schedule simulating the expected field cementing operations."[76]

Based on the available data, strength development of the Macondo production casing slurry is very sensitive to temperature and determining when the cement set is critical for determining when it is safe to continue wellbore operations.

As demonstrated by the OT&C report and the Halliburton data, and based on the sensitivity of the Macondo cement design to temperature, it is apparent that:

[74] The conditioning ramp used for the testing took the prepared slurry from room temperature to 135° F in either 83 or 230 minutes, then held the sample at that temperature for an additional three hours. This means the sample ramped to temperature in 83 minutes would have a total of 293 minutes or 4:53 of total conditioning time before being placed in the UCA. Likewise, the sample using the 230 minute heat up ramp would have a total of 450 minutes or 6:30 of total conditioning time prior to being placed in the UCA.

[75] HAL_0028709 - 0028710

[76] BP-HZN-2179MDL02136569 - BP Drilling and Completions Cementing Manual, Cement Laboratory Testing Section, SRP 4.1-0003, November 2009, p. 5.

- **When the positive pressure test was performed 12 hours after the cement was in place, the cement was not set in the well.**

- **When BP performed the negative test on the Macondo well less than 18 hours after the cement was in place, the Halliburton foam crush data indicated the cement was not set.**

7. Post Cement Job Evaluation

Lowering the expectations of the cement job is echoed in the production casing job on the Macondo well. According to the following BP prepared flow chart, the production cement job was to be judged only by the ability to maintain returns.[77] Only the loss of returns while cementing the long string job was used as a benchmark for the success or failure of the production cement job on the Macondo well. If there were no losses on the job, the next step was to set the wear bushing (WB), test the casing and temporarily abandon the well.

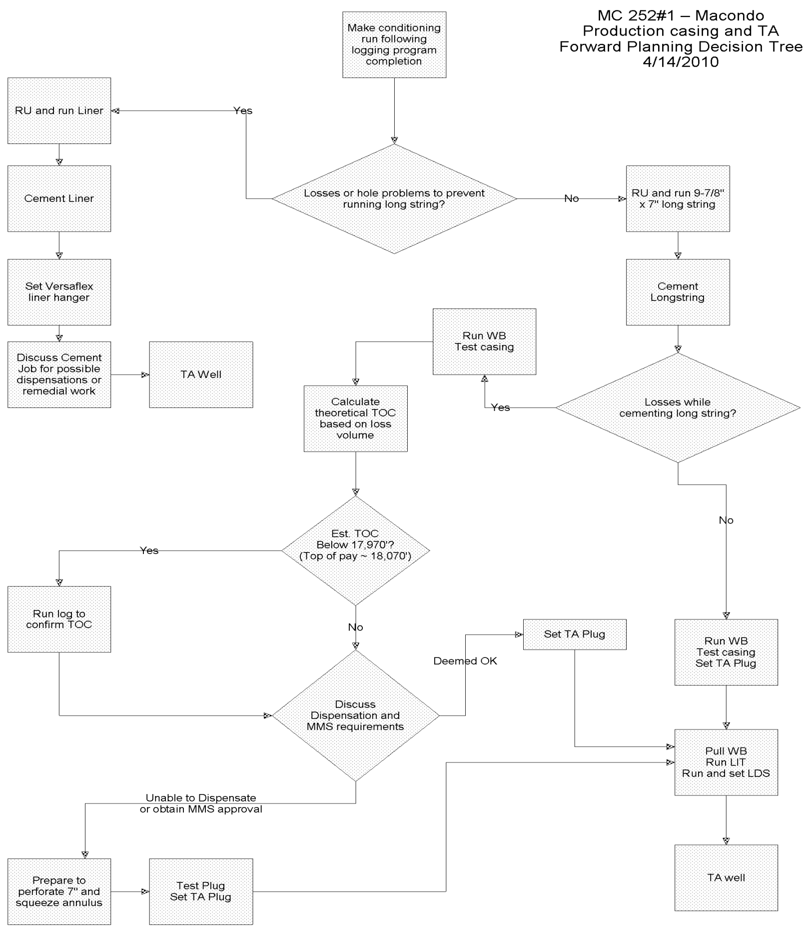

Figure 7-1. BP's April 14, 2010 MC 252#1- Macondo Production casing and TA Forward Planning Decision Tree.

[77] BP-HZN-MBI00010575

On the production cementing job, BP's wells team knew the shortcomings of their cement job could be repaired through remedial cement work. This is evidenced in an April 16, 2010 email from Brett Cocales to Brian Morel regarding centralizer use:

> "Even if the hole is perfectly straight, a straight piece of pipe even in tension will not seek the perfect center of the hole unless it has something to centralize it.
>
> But, who cares, it's done, end of story, will probably be fine and we'll get a good cement job. I would rather have to squeeze than get stuck above the WH. So Guide is right on the risk/reward equation."[78]

This note demonstrates the BP personnel were aware of the poor centralization on the well and had weighed the potential risks of becoming stuck above the wellhead by running additional centralizers. The BP engineers appeared to believe that sacrificing centralization was a lower risk option because the well could later be squeezed to make up for the deficiency in design.

BP's evaluation criteria were not suitable to evaluate the integrity of the cement. As discussed in section 5.6 of this report, the lift pressure observed on the cement job was not sufficient to adequately estimate the top of cement.

8. Post Cement Job Well Operations - Wait on Cement (WOC) Time

When BP performed the positive pressure test 12 hours after the cement was in place on the Macondo well, the OT&C data[79] indicates the cement was not set, with the Halliburton data showing the foamed samples also were not set. When BP performed the negative test on the Macondo well less than 18 hours after the cement was in place, the Halliburton lab data showed the foamed cement was not set.

After the cement is placed in a well, it must be allowed to set. This is commonly referred to as wait on cement, or WOC, time. The WOC time is determined by evaluating the strength development data from the lab reports. Industry practice calls for waiting until the cement has 500 psi strength before continuing well operations.

When cement is relied upon as a barrier for well control, the same requirements placed on any other piece of well control equipment should also be placed on the cement. A barrier must be tested to be relied upon in the well. In the deposition of Thomas Roth of Halliburton, he stated:

> "[O]nce cement is placed in a well, before it can be depended upon to be an effective barrier as part of a well control program, it must be confirmed."[80]

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[78] BP-HZN-MBI00128383

[79] Oilfield Testing and Consulting report, August 1, 2011, p. 30.

[80] Deposition of Thomas Roth, July 26, 2011, p. 505, lines 10-14.

BP selected lost returns as the sole evaluation criteria for the cement job on the well and performed no other testing to assure the cement was acting as a barrier in the well.

APPENDIX A

CURRICULUM VITAE OF GLEN BENGE

GLEN BENGE

Employment Overview:

- Involved with all aspects of the development, coordination and implementation of oil field cementing services for global drilling operations for ExxonMobil.
- Subject matter expert in all facets of oil field cementing including laboratory and job design, equipment and field operations, and cement logging evaluation.
- Authored numerous technical papers on oil field cementing.

Employment Experience:

April 2011 - Present Consultant - Oil Field Cementing

January 2009 - March 2011 Drilling Training Manager, ExxonMobil – Houston, TX

- Manage training curriculum and schools for global drilling organization.
- Coordinate and develop schools to address current and future business needs, assuring sufficient personnel are trained for specific future operations. Identify and mentor future technical trainers.
- Develop competency framework to assimilate new hire personnel into drilling throughout the global organization, including partner affiliates (UAE, Qatar, Angola and others).
- Serve as ExxonMobil Drilling representative for CO_2 – Carbon Capture and Sequestration issues.

January 2000 - January 2009 Senior Technical Advisor, ExxonMobil – Houston, TX

- Subject matter expert for ExxonMobil's global drilling operations in cementing. Responsibilities included global operations support, and the development of internal technical standards, reference documents and training materials.
- Senior Technical Advisor for cementing to Drilling Management. Served as client advisor to the three major cementing Service Companies. Set ExxonMobil expectations for cementing Service Providers, provided direction for procurement of cementing services and materials, and evaluated tenders for drilling and production.
- Served as corporate contact for cementing related issues on industry and government committees. Acted as technical advisor to the industry and government groups.

July 1992 - January 2000 Engineering Advisor - Fluids Team Lead, Mobil – Dallas, TX

- Coordinated fluids group in Well Construction and Completions for Mobil Exploration & Production Technical Center.
- Provided technical expertise in fluids for Mobil worldwide drilling operations.
- Managed internal and external cementing research and development projects.
- Coordinated cement system design and evaluation, equipment selection and cement job performance for Mobil drilling.
- Functioned as a liaison between cementing Service Companies and Mobil.
- Designed and executed first offshore foamed cement job for Mobil in Gulf of Mexico, Mobile Bay operations.
- Introduced foamed cement use on wells in Germany and HTHP (high temperature high pressure) wells for offshore operations in Qatar and Nova Scotia.

February 1988 - July 1992 Senior Drilling Fluids Specialist, Mobil - New Orleans, LA.

- Managed the cementing business for Mobil, Gulf of Mexico Drilling.
- Developed Mobil operational and laboratory guidelines and cementing policies.
- Monitored EPA requirements for NPDES discharges and mud toxicity compliance testing. Coordinated efforts with environmental groups internal and external to Mobil.

1977 - 1988 Dowell Schlumberger, New Orleans, Houston and Tulsa

- Division Technical Specialist for offshore Gulf of Mexico and inland water cementing operations.
- Manager of the offshore division testing laboratory. Coordinated research and marketing plans to address the technical needs of the offshore and inland marine cementing operations.
- Developed cementing marketing plans for Southern Region of Dowell Schlumberger, which covered the Gulf Coast and all offshore operations. Responsibilities included trend analysis, equipment and personnel deployment and market share evaluation.
- Worked in laboratory and engineering functions with Dowell in Tulsa. Managed introduction of new cementing materials and services to field operations. Coordinated efforts in technical writing of internal and client training schools and sales literature. Evaluated equipment and technical requirements for new services and developed ultra lightweight cementing capabilities for Dowell.

Education:

BS, Chemistry, Cum Laude, Southwestern Oklahoma State University, Weatherford, OK

Course work toward Masters, Analytical Chemistry, Oklahoma State University

Continuing education through industry, Mobil and ExxonMobil. (25 + schools)

Professional Activities:

President, New Orleans Chapter, American Association of Drilling Engineers, 1991 - 1992,
Board of Directors, 1989 - 1992

Member, American Petroleum Institute (API) Committees 10 & 13 - 1980 to present

Chairman, API Sub-Committee 10 on Oil Well Cements - 2002 - 2005

Chairman, Task Group on Centralizers - API Spec 10 B

Chairman, Work Group on Completion Fluids - API RP 13J

API Citation for Service - 2005

Member, ISO Subcommittee 3, Technical Committee 67, Work Group 2

Member, Society of Petroleum Engineers (SPE) – 1978 to present

Member, Program Committee and Session Chairman, SPE/IADC Drilling Conferences, 1995-2004

Technical Editor - Journal of Petroleum Technology - 2003 - 2005

Technical Editor - SPE Drilling and Completion - 2003 to present

SPE Outstanding Technical Editor Award - 2007, 2008, 2009 and 2010

Publications: *** Denotes Peer Reviewed Journal**

Bannister, C. E. and Benge, O.G.: "Pipe Flow Rheometry: Rheological Analysis of a Turbulent Flow System for Cement Placement," SPE 10216, 1981.

Benge, O. G., Jones, R. R. , Dresher, T. D., and Dolan, R. T., : "A New Low Cost Permafrost Cementing System," SPE 10757, 1982.

Benge, O. G., Spangle, L. B. and Sauer, C. W. : "Foamed Cement - Solving Old Problems with a New Technique," SPE 11204, 1982.

Abbott, R., Benge, G., Elbel, J., Jeffrey, R., Klarfeld, D. and Naylor, J. : "Deep Well Evaluation and Completion," Drilling, July 1983.

Edmondson, T. D. and Benge, O. G. : "A Case Study of Ultralightweight Cementing Practices in the Northeastern United States," SPE 12318, 1983.

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Benge, O. G. and Webster, W.W., "Evaluation of Blast Furnace Slag Slurries for Oil Field Application," IADC/SPE 27449, 1994.

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Benge, Glen, McDermott, Jim R., Langlinais, Joey C. and Griffith, James E., "Foamed cement job successful in deep HTHP offshore well," Oil & Gas Journal, March 11, 1996.

Judge, Robert A, and Benge, Glen, "Advances in Metering and Control Technology Improves Design and Execution of Foamed Cement Jobs," IADC / SPE 47831, 1998.

Deeg, Wolfgang, Griffin, James, Crook, Ron and Benge, Glen, "How foamed cement advantages extend to hydraulic fracturing operations," World Oil, November 1999.

Ron Crook, Ronnie Faul, Glen Benge, and Richard Jones, "Eight Ways to Help Ensure a Successful Cement Job," World Oil, July, 2001.

Benge, Glen and Dew, Ed, "Meeting the Challenges in Design and Execution of Two High Rate Acid Gas Injection Wells," SPE / IADC 91861, 2004. Published in **SPE Drilling & Completion***, Sept. 2006.

Benge, Glen and Poole, David, "Use of Foamed Cement in Deep Water Angola," SPE/IADC 91662, 2004.

Benge, Glen, Carruthers, Bill, Gardner, Craig, "New program enhances API monogram," Oil & Gas Journal, September 2004.

Benge, G., Darby, J., Peroyea, M., Aguilar. T, Mueller, D and Doherty, D., “Deep Gas-Well Cementation: A Review of Risks and Design Basis for Use of a Liquid Cement Premix for Large Offshore Cementing Operations” SPE/IADC 98970, 2006.

Benge, Glen, "Improving Wellbore Seal Integrity in CO_2 Injection Wells," Greenhouse Gas Technology Conference - 9, Washington D.C., 2008.

Benge, Glen, "Improving Wellbore Seal Integrity in CO_2 Injection Wells," SPE / IADC 119267, 2009.

APPENDIX B

STATEMENT OF COMPENSATION

I have been compensated at a rate of $225 per hour for my services to the United States Department of Justice (USDOJ) in this matter. For any deposition or trial testimony the USDOJ will compensate me at a rate of $375 per hour.

APPENDIX C

DOCUMENTS CONSIDERED

I. DOCUMENTS REVIEWED

The information reviewed for the development of this report includes:

Halliburton OptiCem computer runs

Halliburton laboratory test data sheets, charts, weigh up sheets and reports

Halliburton design reports

Halliburton Post Job Report, April 20, 2010

Halliburton Foam Cementing Operations Manual, Part No 254.00022, 1998

Halliburton Global Laboratory Best Practices, 2003

Computer model work performed by Cementing Solutions, Inc. (CSI)

Email communications related to cementing of the Macondo well

BP's Drilling and Completions Cementing Manual - Cement Laboratory Testing Section

Engineering Report on Testing of Weatherford M45AP Float Collar, Stress Engineering Services Inc., November 22, 2010

National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling, Cement Testing Results, Chevron, October 26, 2010

Report by Oilfield Testing and Consulting, August 1, 2011

Deposition transcripts and exhibits related to cementing

API Specifications and Recommended Practices

Industry technical papers, in particular those found through the Society of Petroleum Engineers

Industry available engineering handbooks

Deepwater Horizon Accident Investigation Report, BP, September 8, 2010

Deep Water, The Gulf Oil Disaster and the Future of Offshore Drilling, Report to the President, National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling, January 2011

Macondo, The Gulf Oil Disaster, Chief Counsel's Report, National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling, 2011

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Mueller, D. T., Franklin Jr., V. L. and Daulton, D. J., "The Determination Nitrified Cements of the Static and Dynamic Properties of Nitrified Cements" paper SPE 20116, 1990

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