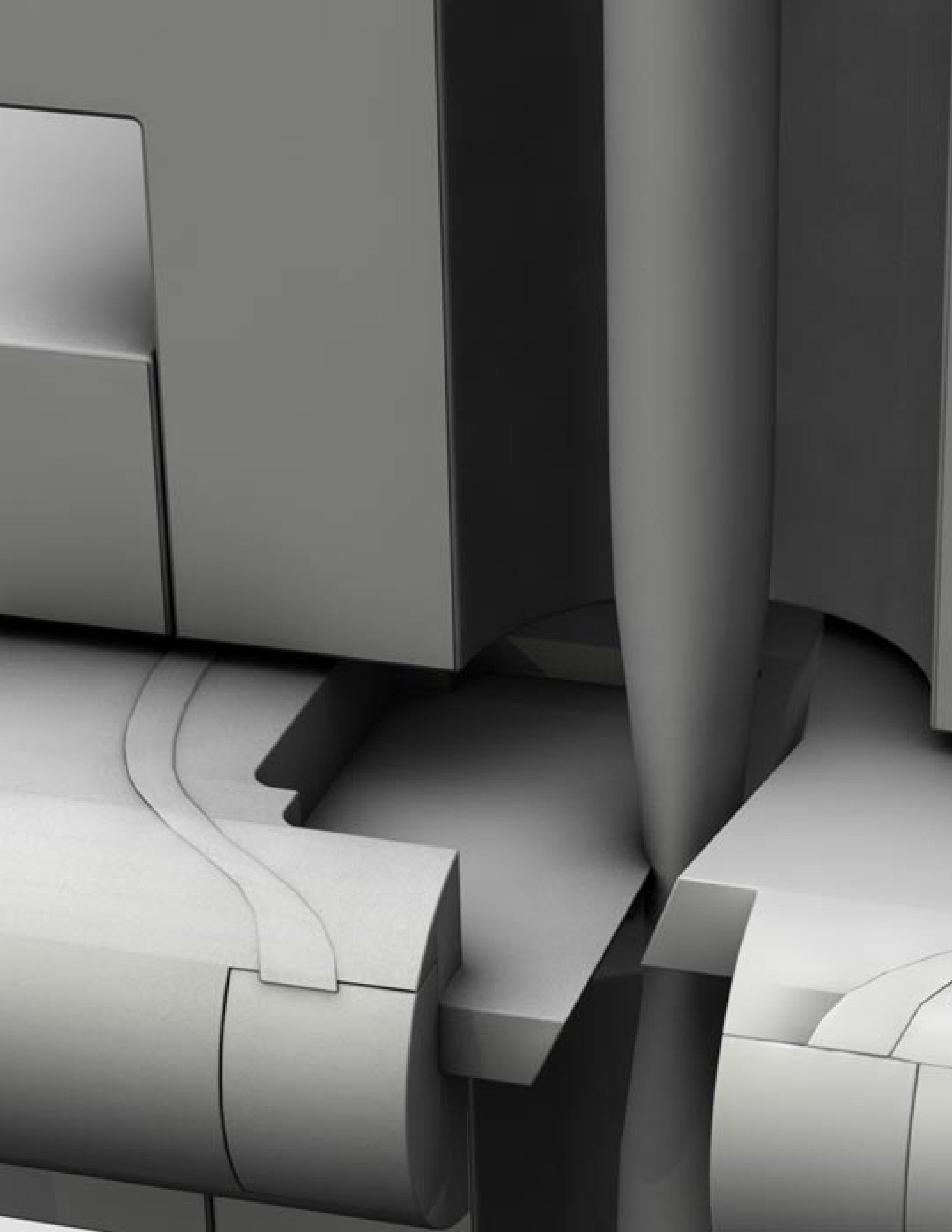


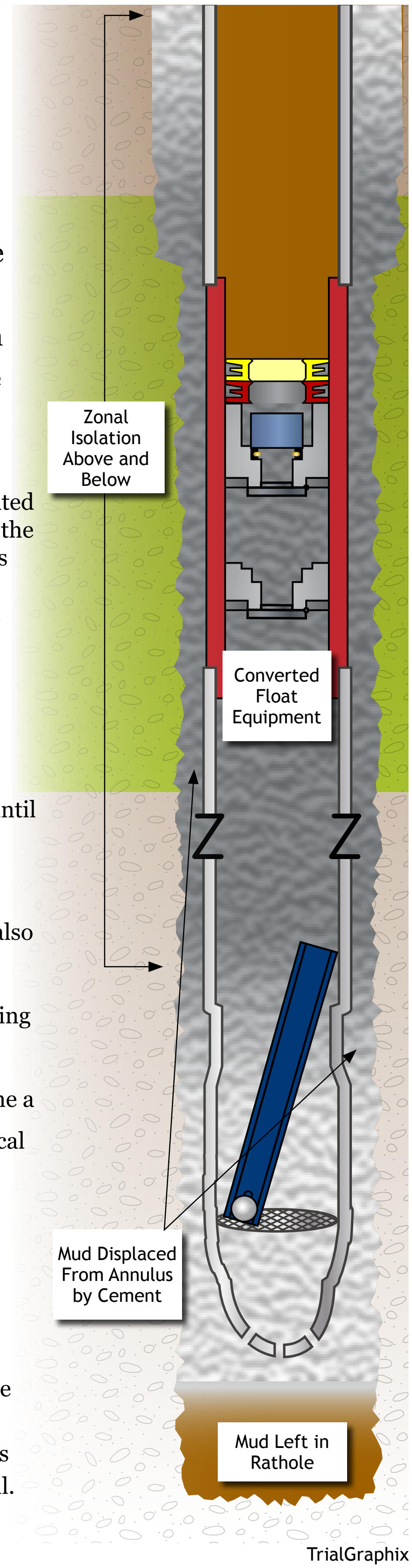
Chapter 4.3 | Cement

Well Cementing

Cement performs several important functions in an oil well. It fills the annular space between the outside of the casing and the formation. In doing so, it structurally reinforces the casing, protects the casing against corrosion, and seals off the annular space, preventing gases or liquids from flowing up or down through that space. A cement job that properly seals the annular space around the casing is said to have achieved **zonal isolation**.

The cementing process is procedurally and technically complex. This chapter first describes the steps in the cementing process, the ways in which cement can be evaluated and remediated, and methods for laboratory cement slurry testing. It then describes the Macondo cementing operation in detail. Finally, it sets out the Chief Counsel's team's technical and management findings regarding the Macondo cementing process. The Chief Counsel's team finds that the Macondo cement failed to achieve zonal isolation. While the Chief Counsel's team cannot be sure why the cement failed, the team has identified several risk and other factors that may have contributed to cement failure, either alone or together.

Figure 4.3.1. Typical completed cement job.



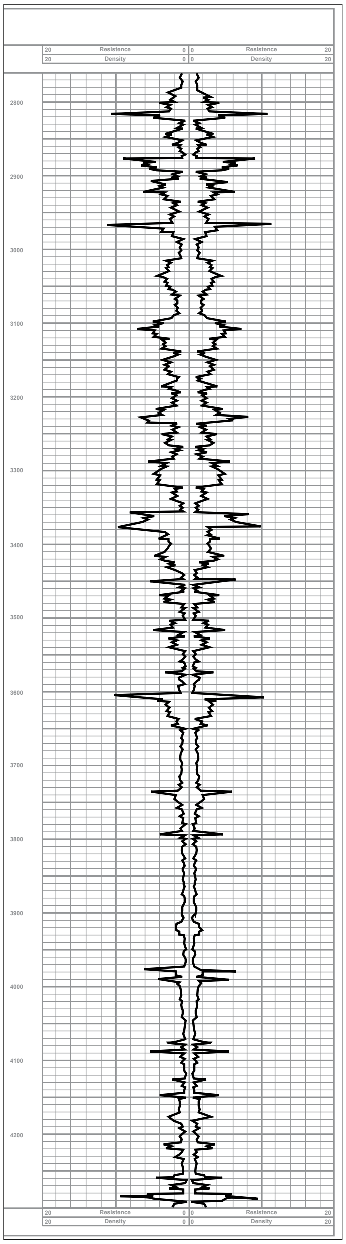
The Cementing Process

The cementing process involves pumping cement down the inside of a casing string until it flows out the bottom and back up into the annular space around the casing string. Achieving zonal isolation requires several things.

- First, the cement should fill the annular space in the zone to be isolated and also a specified space above and below that zone.
- Second, cement flowing into the annular space should displace all of the drilling mud from that space so that no gaps or uncleared **channels** of mud remain behind. If mud channels remain after the cement is pumped, they can become a flow path for gases or liquids from the formation. Good mud removal is critical for a successful cement job.[1]
- Third, the cement should be formulated so that it sets properly under wellbore conditions.

Although each cement job presents unique challenges, the principal steps involved in pumping cement at Macondo were the same as those for most deepwater wells. The following subsections describe the process in simplified form. These sections describe the process for running and cementing a production casing—the last casing string to be run in the well once a hydrocarbon-bearing zone has been penetrated. The process generally applies to running and cementing shallower casing strings and liners as well.

Figure 4.3.2. Sample caliper log data showing open hole diameter by depth.



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Primary Cementing. Primary cementing refers to an operator's initial attempt to seal a casing with cement. By contrast, **remedial cementing** refers to subsequent cementing efforts undertaken if the primary cement does not achieve zonal isolation.

Logging and Mud Conditioning

After rig personnel finish drilling a well that will be completed as a production well, they typically **condition** the mud in the wellbore and then log the wellbore itself before lowering the final production casing and performing the final cement job.

During drilling operations, mud engineers manipulate the characteristics of drilling mud in the wellbore to optimize the removal of cuttings and to maintain hydrostatic pressure in the well. At the end of drilling operations, the mud is normally circulated to homogenize its properties and modify those properties as necessary to facilitate wellbore logging and eventual mud removal. That circulation process is called mud conditioning. Drillers normally circulate the mud in order to remove cuttings from the mud and ensure that it displays uniform and appropriate density and viscosity characteristics.[2] American Petroleum Institute (API) recommendations state:

> Well preparation, particularly circulating and conditioning fluids in the wellbore, is essential for successful cementing. Many primary cementing failures are the result of fluids that are difficult to displace and/or of inadequate wellbore conditioning.[3]

Logging refers to the process of examining and recording the characteristics of the wellbore (first discussed in Chapter 2). Prior to running a production casing string, drillers typically examine the open section of the wellbore with an extensive suite of logging tools that use electric, sonic, and radiologic sensors to measure the physical characteristics of the formation and any fluids it might contain in order to learn as much as possible about the nature of the hydrocarbon-bearing formation.[4] One such tool, shown in Figure 4.3.2, is a **caliper log**, which measures the diameter of the wellbore. Because the wellbore diameter can vary significantly as a result of normal drilling variations, these data can be an important input in designing and modeling a primary cement job.

Lowering the Production Casing String in Place With Centralizers

After logging is complete, rig personnel lower the production casing into place. During this process, they may install **centralizers** , shown in Figure 4.3.3, which serve an important role in the cementing process.

When the cementing crew pumps cement (or any other fluid) down the production casing and back up the annular space around it, the cement tends to flow preferentially through paths of least resistance. When the casing is not centered in the wellbore, the wider annular space becomes the path of least resistance,[5] shown in Figure 4.3.4. Cement tends to flow up through those spaces. This can seriously compromise mud removal and leave channels of mud behind in the narrower annular spaces.[6] Because of this problem, cementing experts consistently emphasize the importance of keeping the casing centered in the wellbore.[7]

Figure 4.3.3. Centralizer.

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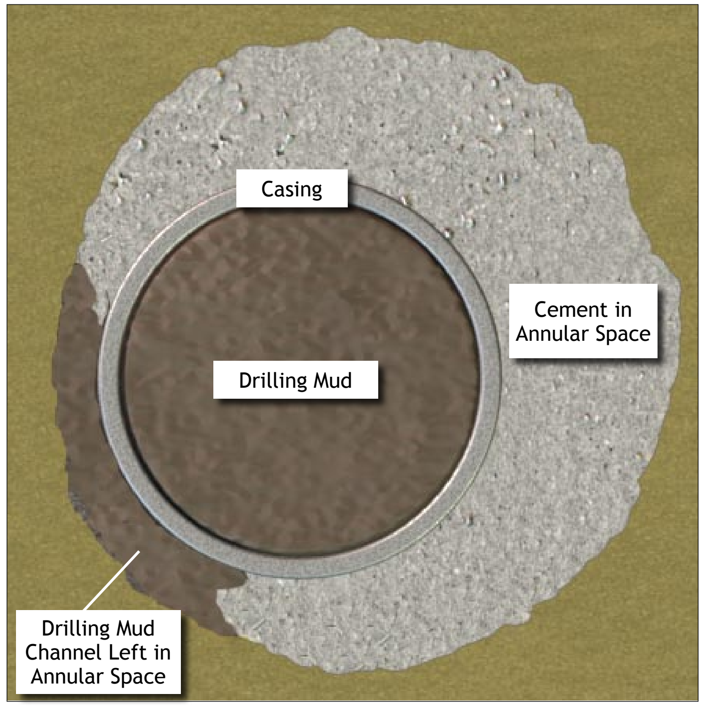
Centralizers help keep the casing as close to the center as possible. They come in a variety of designs. Centralizer **subs**, shown in Figure 4.3.5, may be screwed between casing sections while bow spring centralizer **slip-ons** are attached to the outside of existing casing using collars. Sometimes **stop collars** (so named because they stop the centralizer from sliding up or down the casing) are separate pieces from the centralizer; sometimes they are integrated into the centralizer itself.[8]

Engineers measure the degree to which a pipe is centralized in a wellbore by calculating the "pipe standoff ratio."[9] A perfectly centered casing has a standoff ratio of 100% while a casing that touches the walls of the wellbore has a standoff ratio of 0%. Although the industry rule of thumb is to achieve a standoff of 75%,[10] cementing experts state that operators should achieve the highest possible standoff in order to facilitate mud displacement from the annular space.[11] Engineers must calculate the standoff not only at each centralizer location, but also between the centralizers. Casing can bend and sag between centralizers, dramatically lowering the standoff in the intervals between them.[12]

Figure 4.3.4. Top view of off-centered casing.



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Float Valves and Float Valve Conversion

Illustrated in Figure 4.3.6, float valves are one-way valves (also called check valves) installed at or near the interior bottom end of a casing string. Once operational, float valves permit fluid (such as mud or cement) to flow down through the inside of the casing while preventing fluids from flowing in the reverse direction back up the inside of the casing. By doing so, float valves prevent cement that is pumped down through the casing, into the shoe track, and up into the annular space from flowing back up through the valves once the cement is in place, an occurrence known as "reverse flow" or "u-tubing."[13]

Shoe and Shoe Track. The **shoe** refers to the bottom of the casing. The **shoe track** is the section of the casing between the shoe and the float valves above it.

A **float check** examines whether the float valves are working properly—that is, preventing cement from flowing back up through the valves due to u-tube pressure. **U-tube pressure** is created by the differential hydrostatic pressure between the fluid column inside the casing and the fluid column in the annulus. In cases where the cement density is close to drilling mud density, the u-tube pressure may be very small—too small to induce backflow or to be detected at the rig. The smaller the density differential between the cement and mud, the smaller the u-tube pressure and its expected effects.[14]

Figure 4.3.5. Centralizer sub.

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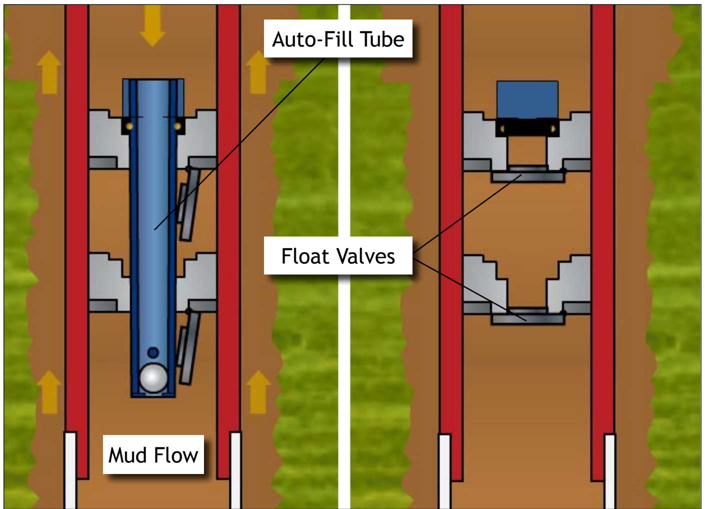
Float valves are important during the cementing process but can interfere with the process of lowering a casing string. As the casing string is lowered, it is generally preferable that mud be allowed to flow up the inside of the casing string. Otherwise, the casing will, as it descends, force mud down the well and back up through the annular space, greatly increasing the pressure that the casing string exerts on the formation as it is lowered.[15]

Figure 4.3.6. Float valve conversion.



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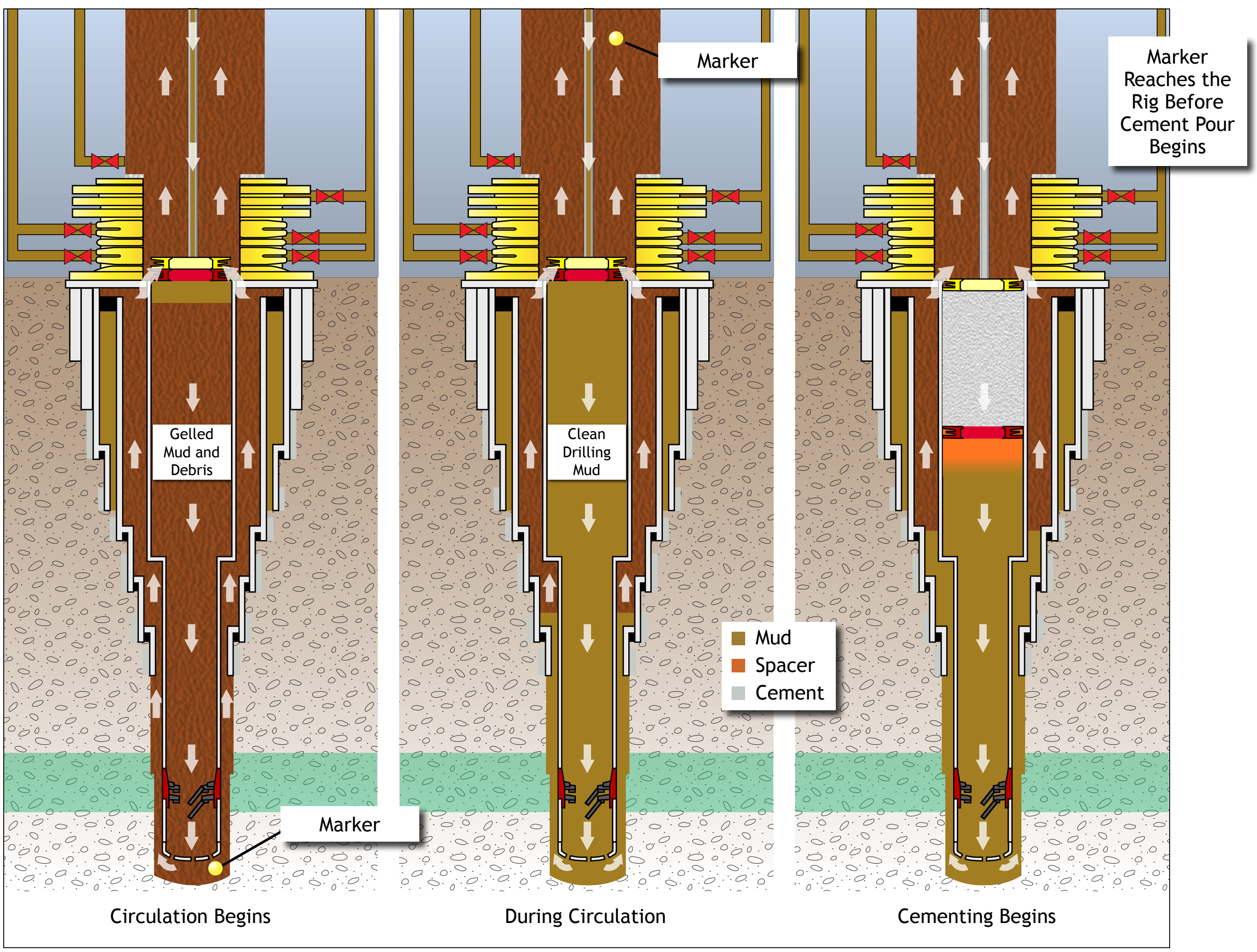
To allow mud to flow into the casing string while it is being lowered, operators typically use an **auto-fill tube**. An auto-fill tube is a hollow tube that extends through and props open the two float valves, allowing mud to flow up through the casing while the casing is being run into the well. Once rig personnel finish lowering the casing, they **convert** the float valve assembly by pushing the auto-fill tube down and out of the float valves. This allows the float valves to close, converting them into one-way valves before cementing begins.

Wellbore Conditioning

After converting the float valves, rig personnel normally circulate mud through the newly installed casing and wellbore again. Like the earlier mud circulation process, this has at least two benefits. First, it cleans the casing, drill pipe, and wellbore of cuttings, gelled mud, and other debris that can interfere with good cement placement and performance.[16] Second, the mud flow conditions the mud itself by breaking its gel strength, decreasing its viscosity, and increasing its mobility.[17]

Figure 4.3.7. Full bottoms up.



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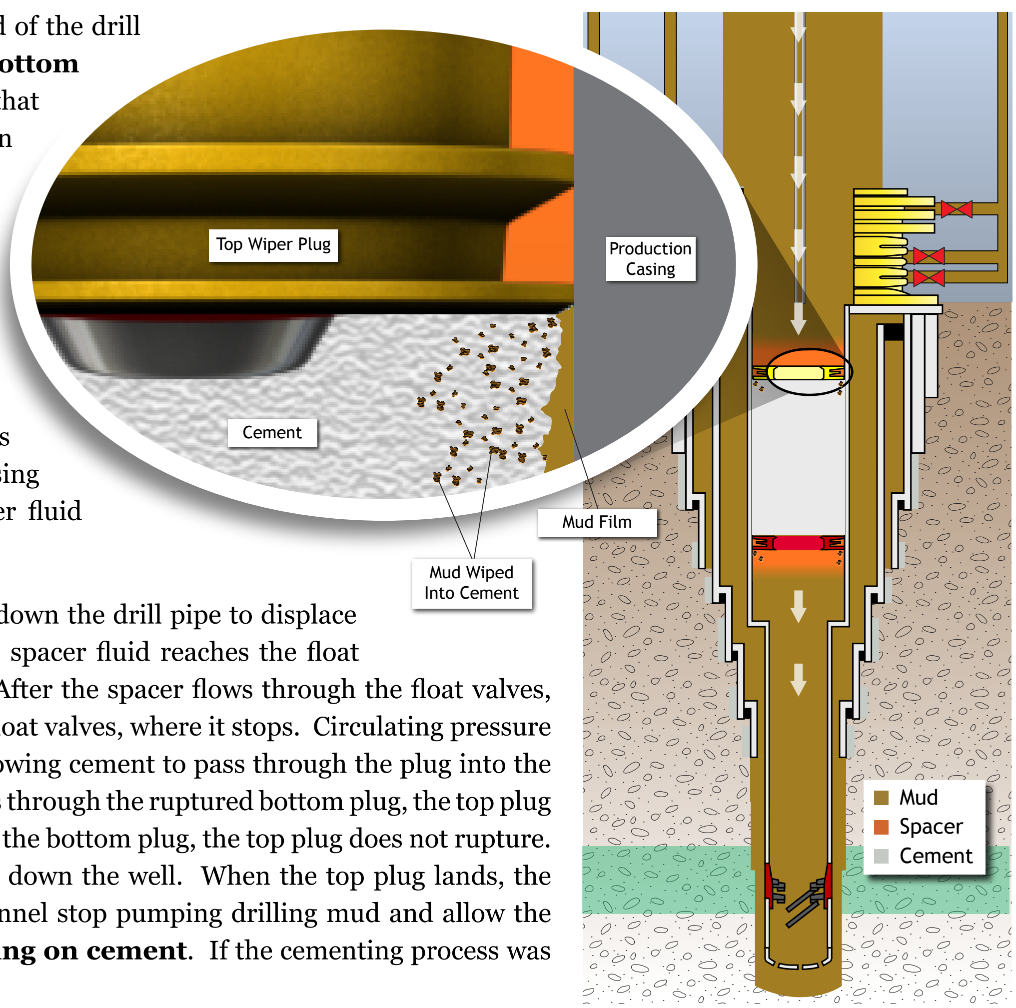
Under optimum conditions, operators prefer to circulate enough drilling mud through the casing after landing it to achieve what is known as a full **bottoms up**.[18] Circulating bottoms up means that the rig crew pumps enough mud down the well so that mud originally at the well bottom returns back to surface[19] as shown in Figure 4.3.7. The extended circulation required to do this confers a third benefit in addition to the two described above: It allows rig crews to physically inspect mud from the bottom of the well for the presence of hydrocarbons before cementing.

Pumping Cement

After completing the pre-cementing mud circulation, rig personnel pump cement down the well, then pump additional drilling mud behind the cement to push (or **displace**) the cement into the desired location at the bottom of the well. As they pump the cement, rig personnel must ensure that the oil-based drilling mud does not contaminate the water-based cement. The oil and gas industry has developed a variety of techniques to ensure that this does not occur. Rig personnel at Macondo used a common approach called the "two-plug method."[20] The two-plug method uses rubber **darts** and **wiper plugs** to separate the cement from the drilling mud as the cement travels down the well.

Rig personnel begin the cement pumping process by pumping water-based **spacer fluid** down the drill pipe. They then drop a **bottom dart** into the drill pipe, followed by the cement, then a **top dart** and more spacer fluid. After pumping the final spacer fluid down the drill pipe, rig personnel resume pumping drilling mud to push the spacer-dart-cement-dart-spacer train down the drill pipe.

Figure 4.3.8. Wiper plugs cause cement contamination.



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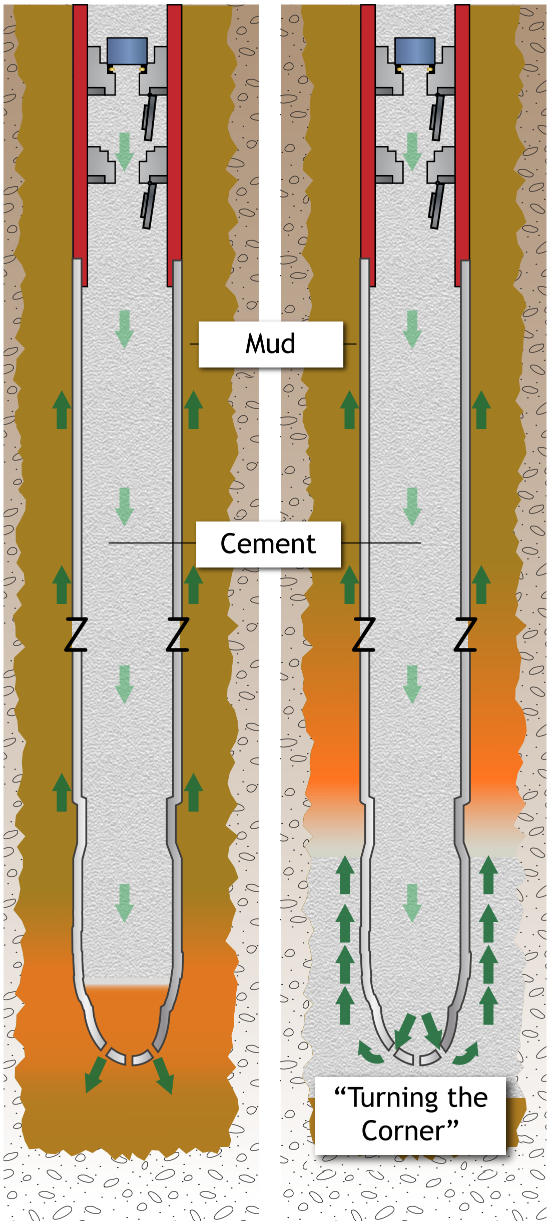
When the bottom dart reaches the end of the drill pipe, it fits into and launches a **bottom wiper plug** from the running tool that attaches the drill pipe to the production casing. The bottom plug then travels down inside of the production casing, separating the cement behind it from the spacer fluid and drilling mud ahead. Similarly, when the top dart reaches the end of the drill pipe, it launches a **top wiper plug** from the running tool. The top plug also travels down the inside of the production casing and separates the cement from spacer fluid and drilling mud behind.

The rig crew continues to pump mud down the drill pipe to displace the cement into position. Eventually, spacer fluid reaches the float valves and flows through the valves. After the spacer flows through the float valves, the **bottom plug** lands on top of the float valves, where it stops. Circulating pressure causes the bottom plug to rupture, allowing cement to pass through the plug into the shoe track. After all of the cement flows through the ruptured bottom plug, the top plug lands on top of the float valves. Unlike the bottom plug, the top plug does not rupture. It instead blocks further flow of fluids down the well. When the top plug lands, the cement should be in place. Rig personnel stop pumping drilling mud and allow the cement to set in a process called **waiting on cement**. If the cementing process was

Figure 4.3.9. Lift pressure.



Pressure increases to lift cement in the annulus.

designed and executed properly, the cement should at this point fill the shoe track and should cover the hydrocarbon zone in the annular space outside the production casing.

Even if rig personnel execute a two-plug cementing process precisely according to plan, cement can still be contaminated by drilling mud. As the wiper plugs travel down the casing, they wipe a film of mud away from the casing walls. The bottom plug removes most of the mud film but not all of it. The remaining mud film can contaminate the cement between the plugs as shown in Figure 4.3.8. The top plug also wipes the casing, but instead of wiping mud out of the way of the cement, it wipes that mud *into* the back portions of the cement flow.

The casing shoe track is designed to provide room for contaminated cement at the tail end of the pumping process. Absent a shoe track, that contaminated cement would travel into the annular space, potentially compromising zonal isolation.

Cement Evaluation

It is not easy for rig personnel to be sure about the progress or final result of a cement job at the bottom of a deepwater well. Cement does its work literally miles away from the rig floor, and there is no way to observe directly if the cement slurry arrives at its intended location, let alone whether it is contaminated or otherwise compromised. As a result, rig personnel cannot know whether the cement will isolate the well from the hydrocarbons in the reservoir as they pump the cement.

Because cementing is difficult to observe directly, the oil and gas industry has developed a number of methods for evaluating cement jobs indirectly. And because proper cementing is critical to well integrity, the API calls proper cement evaluation “indispensable.”[21] But each of the various methods of cement evaluation has limitations, and the API standard on cement evaluation therefore notes:

> Anyone who wants to competently evaluate the quality of a cement job must thoroughly understand all the variables, assemble and comprehend the relevant pieces of information, and reach the proper judgment.[22]

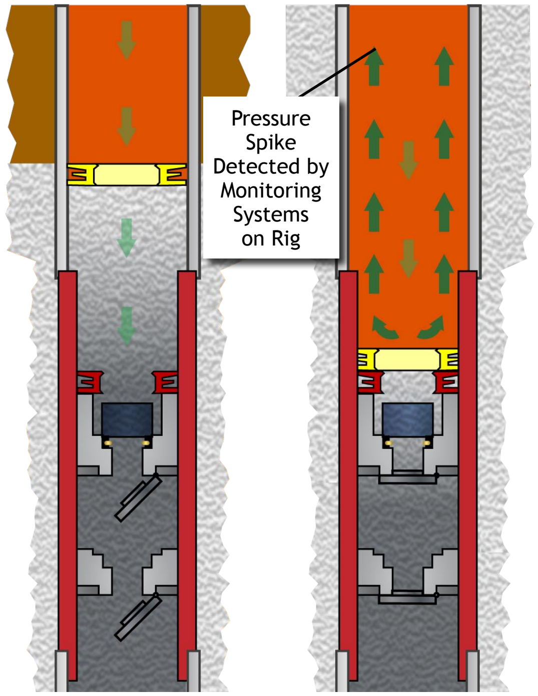
By understanding the full set of variables at play for a particular cement job, the right mix of tools can be employed to evaluate the cement.

Volume and Pressure Indicators

While pumping a cement job, a cementing crew knows only how much cement and mud they have sent down the well and how hard the pumps have been working to push it. Using these volume and pressure readings, the rig crew looks for three general indicators of success during the job: full returns, lift pressure, and on-time plug landing.

A cementing crew gets **full returns** when the volume of mud returning from the well during a cement job equals the volume of fluids (spacer, cement, and mud) pumped down into the well. To determine whether they are getting full returns, the cementing crew monitors mud tank volumes.

Figure 4.3.10. Bumping the plugs.



If the volume of fluid flow into the well equals the fluid flow out, the crew can infer that the well is behaving properly as a closed and leak-free container. If flow out is less than flow in, the crew has **lost returns** or **lost circulation**, and can infer that mud and/or cement has flowed into the formation.[23] The crew cannot tell *where* the rock fractured, however, and where the mud might have gone.[24]

Lift pressure, shown in Figure 4.3.9, is a steady increase in pump pressure that begins when the cement flows out the bottom of the well casing and "turns the corner" to flow upward against gravity. The pressure increases because cement is generally heavier than drilling mud (and has a different viscosity). If the cementing crew observes a steady pressure increase at the appropriate time after pumping cement down into a well, they can infer that the increase is lift pressure and that cement has arrived at the bottom of the well and has begun flowing upward into the annular space. Seeing the expected lift pressure also allows the crew to infer that cement is not being lost into the formation.

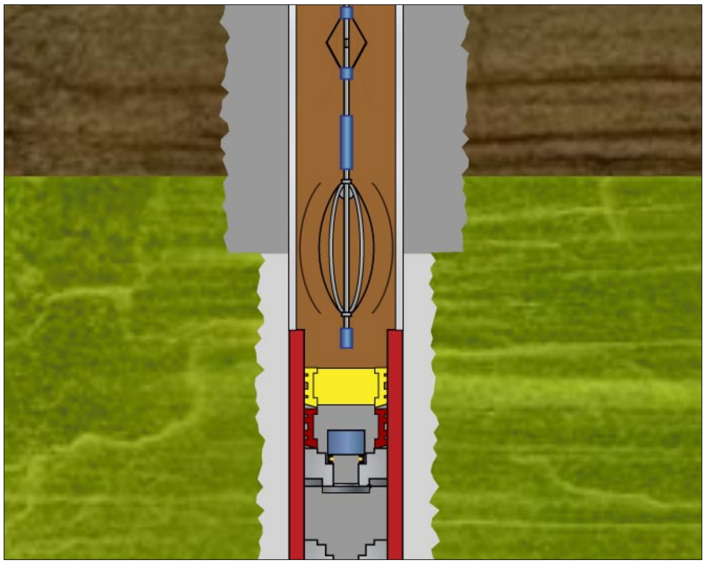
Finally, the rig crew can also watch pressure gauges to infer whether the wiper plugs used to separate the cement from surrounding drilling mud have **landed** or **bumped** on time at the bottom of the well as shown in Figure 4.3.10. By calculating the volume of the inside of the well and the rate at which they are pumping fluids into it, cementing crews can predict when the bottom plug and top plug should land. They then watch the rig's pressure gauges for telltale pressure spikes that indicate when the plugs actually land. If the pressure spikes show up when expected, the cementing crew can infer that the plugs landed properly, that cement arrived at the bottom of the well and flowed out of the shoe track into the annulus, and that substantial volumes of mud did not contaminate the cement as it moved down the well. If the pressure spikes do not appear on time, that suggests problems. For instance, large volumes of mud may have bypassed one or both of the wiper plugs. (Some volume of mud always bypasses the plugs; the plugs do not wipe the casing walls perfectly.) [25]

While pressure and volume indicators can suggest that a cement job has gone as planned, they do not give cementing crews any direct information about the location and quality of the cement at the bottom of the well. In particular, they do not indicate whether there has been channeling in the annulus or shoe track, or the location of the **top of cement** (TOC) in the annulus.[26] These indicators also are not sensitive to all of the issues that can cause cement to fail.

Cement Evaluation Logs

Because pressure and volume readings during the cement job are imperfect indicators of cementing success, the oil and gas industry has also developed tools for more directly examining a cement job after it is pumped. These cement evaluation tools generate data, or "logs," known as cement evaluation logs. Technicians commonly lower cement evaluation tools down inside the well on a **wire line.**[27] Once the tools reach an area that has been cemented, sensors in the tools probe the integrity of the new cement, measuring whether and to what extent the cement has

Figure 4.3.11. Cement bond log tool.



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filled the annular space between the cement and the formation.[28]

The most basic element in a cement evaluation system is the **cement bond log** tool.[29] The cement bond log tool works by measuring the well casing's response to acoustic signals. The tool includes an acoustic transmitter and receiver that are separated from each other by several feet of distance. The transmitters emit bursts of acoustic waves, and the receivers record the reverberations from those waves[30] as illustrated in Figure 4.3.11. Because steel casing, set cement, and fluids all respond differently to the waves, a technician can use the recordings to evaluate the quality of the cement job, just as one can discern a muffled bell from a free-swinging bell by ringing it.[31]

Modern cement evaluation systems combine the fairly straightforward cement bond log with variable-density logs,[32] ultrasonic imaging tools, and flexural attenuation logs.[33] By interpreting the combined data from these tools, a technician can assess the amount and quality of the cement in the annular space,[34] including the TOC and the location and severity of channels in that cement.[35]

Although modern cement evaluation logs have become increasingly sophisticated and reliable, they still have limits.[36] First, they are not easy to read; it takes an experienced technician to properly interpret the data. Second, very low-density cement, such as cement produced with nitrogen foam technology, can be difficult to evaluate with these tools.[37] (The density of the foamed cement at Macondo was not low enough to cause evaluation difficulties, however.[38]) Third, cement evaluation tools must be adjacent to annular cement in order to examine it. That means that the tools cannot evaluate cement in the shoe track or in the annular space below the float equipment. Float equipment and the shoe track cement block the tools from physically accessing those areas. Fourth and finally, cement evaluation logs work best after cement has completely hardened—a process that can take more than 48 hours.[39] Consequently, operators typically do not run cement evaluation logs until completion operations.

Additional Methods

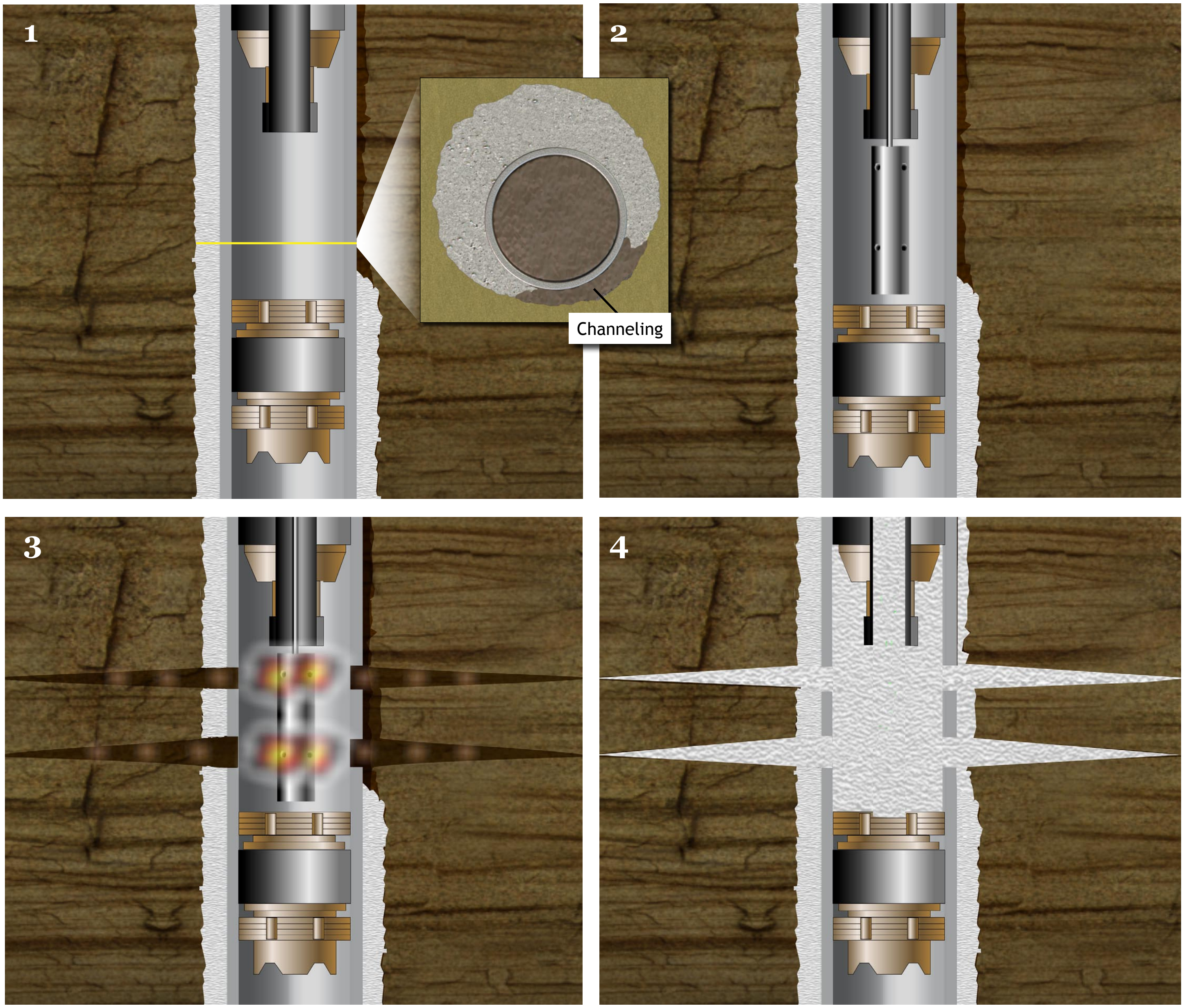
There are other methods to evaluate a cement job in addition to cement evaluation logs and pressure and volume indicators. In particular, a negative pressure test assesses whether a bottomhole cement job contains pressures outside the well and seals the well off from formation pressure. Chapter 4.6 of this report discusses negative pressure tests in detail.

Remedial Cementing

If cement evaluation reveals problems with the primary cement job, rig personnel can **remediate** the primary cement after pumping it. At a well like Macondo, the most common method for remediating the primary production casing cement is called **squeeze cementing**.

Figure 4.3.12 illustrates that squeeze cementing first involves perforating the production casing to provide access to the annular space around it. Rig personnel perforate the casing by lowering a tool that uses shaped explosive charges to punch holes through the casing and into the formation. Rig personnel then pump, or "squeeze," cement under pressure through the holes. In a properly

Figure 4.3.12. Remedial cementing—squeeze job.



From upper left: 1) Poor centralization has led to channeling; 2) a bridge plug is placed below the remediation area, and a packer is positioned above; 3) a perforation gun is lowered and fires shells through the casing and into the formation; 4) cement is pumped into the area, forced through the perforations, and into the formation, creating a seal.

executed squeeze job, the remedial cement then flows into the annular spaces where the primary cement has failed, filling in any channels and isolating zones as necessary.

Cement Slurry Testing

Cement hardens as a result of chemical reactions that depend on pressure and temperature. In the field, cement slurries are normally mixed at ambient temperature and pressure, then exposed to increasing temperatures and pressures as they are pumped down the well. These increasing temperatures and pressures can not only alter the chemical and physical properties of the liquid slurry and cured cement, but also can affect the cement curing process itself. Because every well presents a different combination of cementing conditions, it is critical for a cementing company to test a cement slurry design against expected conditions in the particular well before pumping it into that well.

Cement slurries consist of a number of ingredients, including dry Portland cement (which itself is a combination of several chemical compounds), water, and various dry and liquid chemical additives. Cementing personnel adjust the concentrations of these ingredients to suit the particular needs of a given well. Cement slurry designs thus vary from well to well. To complicate matters further, many of the ingredients used in a cement slurry are made from naturally occurring materials, and their precise chemical composition depends on their source.[40] The liquid chemical additives may vary from batch to batch, and the mix water composition can vary depending on its source. This means that each batch of cement slurry is different. Finally, the constituents of a given cement slurry also may degrade in storage upon exposure to heat, humidity, and atmospheric gases such as carbon dioxide. To address this variability, cementing companies usually perform their pre-job testing with representative samples of the actual ingredients that will be pumped into the well.

Pilot and Pre-Job Testing

A cementing company typically conducts at least two rounds of cement testing prior to pumping a challenging or uncertain cement job. First, it performs "pilot tests" substantially in advance of pumping the job in order to develop an appropriate cement slurry design (the recipe). At the time of the pilot tests, the operator gives the cementing company the best available information about the downhole conditions. That information may be incomplete, especially in the case of an exploratory well (such as Macondo). Sometime prior to pumping the cement, when the operator has learned the actual downhole job conditions, the cementing company typically performs pre-job tests using the actual cement ingredients that have been stored on the rig and will be pumped downhole. These pre-job tests are meant to confirm that the cement design will perform successfully during the upcoming job.

Laboratory Tests

To isolate hydrocarbons at the bottom of a well, the cement must display several attributes. First, as the cement is pumped into place at the bottom of the well, it must remain in a pumpable fluid state and not thicken prematurely. Second, once in place, it must set and develop strength within a reasonable time period. And third, the set cement must be sufficiently strong to provide casing support and zonal isolation. To check these things, cementing companies typically run a number of tests to evaluate a cement design during pilot and pre-job testing. The API has published recommended procedures for running these tests.[41]

Cement Test. Cement tests examine various properties of the cement slurry and the set cement, and investigate the curing process. **Thickening time** tests determine how long the cement slurry will remain pumpable (before starting to set up) under the temperature and pressure conditions in the wellbore. **Compressive strength** tests determine the length of time required for the cement slurry to develop sufficient strength to provide casing support and zonal isolation. **Rheology** tests examine various cement slurry flow properties. The slurry viscosity and yield point affect the pumping pressure required for slurry placement and the displacement efficiency by which drilling fluid is removed from the annular space. The yield point also provides information concerning slurry stability—the ability of the slurry to keep solids in suspension and prevent fluid-phase separation. **Static gel strength** is a measure of the degree to which an unset cement slurry develops resistance to flow when at rest. **Free-fluid** tests directly examine slurry stability.

As cement slurry travels down a well, it encounters increasing heat and pressure. Laboratory technicians sometimes stir the slurry at elevated temperatures (and sometimes at elevated pressures) to simulate these conditions in order to better understand how the cement will behave when it reaches its intended location. This practice is known as **cement conditioning** (not to be confused with mud conditioning, described above).

Modeling the Cementing Process

Before pumping cement, engineers can also model the cementing process using computer simulation programs. Engineers run these simulations using data about wellbore and casing geometry, mud conditioning, the number and placement of centralizers, and the volume, pumping rate, and characteristics of the various fluids pumped down the well. The simulations, in turn, predict various things about the cementing process such as the pressure that will be required to pump cement.

Engineers routinely use cement simulations to model the complex process of mud displacement from the annular space. Predicting mud displacement is important for at least two reasons. First, if the cement flow does not displace mud and spacer from the annular space, those materials may create a flow path for hydrocarbons. Second, and relatedly, poor mud displacement increases the potential for gas to flow into the cement column as it sets.[42] This gas flow can itself cause channeling and further compromise zonal isolation.

As the oil and gas industry develops deeper wells and more complicated well designs, engineers rely increasingly on computer modeling to predict mud removal. Operators and cementers can use these models to predict the impact of changing parameters such as cement flow rate and centralizer placement. By doing so, they can optimize these interrelated parameters for individual well conditions rather than relying on rules of thumb to guide their decisions. At the same time, the fluid mechanisms of mud displacement, gas flow, and other cementing phenomena are exceedingly complex. Computer simulations cannot model these phenomena precisely. In addition, even the best computer models depend entirely on their input data; if the input data are inaccurate, the modeling results will be inaccurate as well.

Preparing for the Macondo Cement Job

Lost Returns at Macondo

BP and Halliburton designed crucial features of the Macondo cement job in response to the April 9 lost returns event (when drilling mud flowed out of the wellbore and into the formation) described in Chapter 4.2. Although BP engineers successfully restored mud circulation by pumping 172 barrels of heavy, viscous "lost circulation" fluids down the drill pipe,[43] they also realized the situation had become delicate. Based on data from the lost circulation event, the engineers calculated that they had to maintain the weight of the mud in the wellbore at approximately 14.0 pounds per gallon (ppg) in order to maintain well control.[44] Drilling ahead with that mud weight would exert even more pressure on the formation, raising the equivalent circulating density (ECD). BP engineers calculated that drilling with 14.0 ppg mud in the wellbore would yield an ECD of nearly 14.5 ppg—an increase that the engineers believed could induce lost returns again.

The engineers concluded they had "run out of drilling margin" and that they could no longer drill to their planned total depth of 20,600 feet below sea level.[45] Instead, they cautiously drilled ahead from 18,193 to 18,360 feet in order to extend the wellbore beyond the pay zone. Optimally, engineers prefer to drill far enough beyond the pay zone to ensure that the float collar and shoe track will both be entirely below the pay zone. Among other things, this allows the operator eventually to use logging tools to evaluate all of the cement in the annular space in the pay zone. In March, before the April 9 lost circulation event, a BP engineer stated that BP planned an extended shoe track at Macondo.[46]

Wellbore Logging and Conditioning

After drilling, BP directed Schlumberger to run a series of logs to collect data from the well. Between April 10 and 15, 2010, Schlumberger technicians evaluated the formation to determine its porosity and permeability, and gathered fluid and core samples from the well. The logging data led BP to conclude that it had drilled into a hydrocarbon reservoir of sufficient size (at least 50 million barrels[47]) and pressure that it was economically worthwhile to install a production casing. Schlumberger also ran a caliper log to determine the exact diameter of the wellbore.[48]

On April 16, before running the final 9⅞-inch × 7-inch long string production casing, the rig crew circulated the open wellbore bottoms up.[49] They did not record any mud losses during this process.[50] The crew inspected mud from the bottom of the well and found that it contained 1,120 gas units on a 3,000-unit scale.[51] This was not an unusual amount of gas because the mud at the bottom had been sitting in place in the well for about a week at that point.[52] After circulating on April 16, gas eventually decreased to 20 to 30 units.[53]

Designing the Macondo Cement Job

BP's cement planning focused heavily on reducing the risks of further lost returns. BP recognized that if the formation fractured again during cementing, it could compromise the cement job and force the rig crew to conduct remedial cementing operations. BP engineers focused particular attention on ensuring that the ECD during cementing would not exceed the threshold that they believed would induce further losses. In order to minimize the ECD during cementing, BP: (1) reduced the volume of cement that would be pumped, (2) reduced the rate at which the cement would be pumped, and (3) used nitrogen foamed cement for reduced density.[54]

Cement Volume

Wellbore conditions are rarely optimal, and it is difficult to be sure precisely where cement has flowed during a cement job. Engineers can therefore improve the odds of achieving zonal isolation by increasing the volume of cement in the well design. Pumping more cement is a standard industry safeguard against uncertain cementing conditions. It reduces the risk of contamination by diluting the amount of contaminants in the cement. It also decreases the impact of errors in cement placement.

MMS Cement Volume Requirements

At the time of the Macondo blowout, MMS regulations included very few requirements that related to the cement design process at Macondo. One of those requirements concerned the volume of cement for a primary production casing cement job. According to 30 C.F.R. § 250.421: "As a minimum, you must cement the annular space at least 500 feet above the casing shoe and 500 feet above the uppermost hydrocarbon-bearing zone."

In other words, MMS required that the TOC in the annular space of the production casing be at least 500 feet above the "uppermost hydrocarbon-bearing zone."

BP's Internal Guidelines

BP's Engineering Technical Practice 10-60 (ETP 10-60), titled "Zonal Isolation Requirements during Drilling Operations and Well Abandonment and Suspension," lists the company's internal engineering design rules for cementing. ETP 10-60 states:

> **1.3** Zonal Isolation design criteria for cementing of primary casing strings to meet well integrity and future abandonment requirements, shall meet one of the following:
>
> - 30 m TVD [total vertical depth] (100 ft TVD) above the top of the distinct permeable zone where the top of cement (TOC) is to be determined by a proven cement evaluation technique (Section 5.3).
> - 300 m MD [measured depth] (1000 ft MD) above the distinct permeable zone where the hydraulic isolation is not proven except by estimates of TOC (Section 5.3). For each well the actual TOC shall be recorded along with the method used for this determination. Where the actual TOC is below the plan, the TOC shall be reviewed with stakeholders for its impact on future well integrity, operability, suspension and abandonment operations.[55]

Section 5.3 of ETP 10-60 distinguishes a "proven cement evaluation technique" from an "estimate" of TOC by stating that "to accurately assess TOC and zonal isolation cement sonic and ultrasonic logs should be used." By contrast, the ETP states that temperature logs (which can detect the heat exuded by cement) and cement column backpressure measurements can be used to "estimate" TOC. This means that unless a BP engineering team plans to run sonic and ultrasonic logs, it should design the cement job so that there is 1,000 feet of cement above the highest distinct permeable zone in the well.

In addition to zonal isolation, BP also considers annular pressure buildup (APB) in planning TOC.[56] The high temperatures caused by bringing hydrocarbons to the surface during later production can cause pressure buildup in the annular space. If trapped, the annular pressure will build up and can potentially collapse the inner casing string on itself and ruin the well. One way drillers avoid this is by allowing annular pressure to escape into the formation. By not cementing all the way up to the next liner—which necessarily means a lower TOC and lower volume of cement—the drillers allow a route for escape.[57] It is likely that APB concerns were a factor in determining TOC and cement volume at Macondo.[58]

Macondo Cement Volume

After the early April lost returns events, the BP Macondo team decided to limit the height of the cement column in the annulus. They had little room to maneuver: A higher cement column in the annulus would have exerted more pressure on the fragile formation below, increasing the ECD of the cement job and risking further lost returns.

Driven by ECD concerns, BP's engineering team focused its attention on determining where TOC should be. While the main hydrocarbon reservoir zone at Macondo began at 18,100 feet,[59] BP estimated that the "top HC [hydrocarbon] zone" began at 17,803 feet.[60] BP engineers decided to pump only as much cement above that zone as MMS required.[61] On or about April 14,[62] they determined that TOC should be 17,300 feet below the ocean surface—503 feet above the top hydrocarbon zone and 830 feet above the main hydrocarbon zone.[63]

On April 14, BP senior drilling engineer Mark Hafle initiated a formal management of change review of the plan to set the production casing.[64] He marked the document as a high priority and asked that its approval be completed by the next day.[65] Hafle incorporated the design decision regarding TOC in the management of change document. The document discussed the risk that the primary bottomhole cement would not act as a barrier: "If losses occur during the cement job, possible cement evaluation, remedial cement operations, dispensations and/or MMS approvals will be required prior to performing TA operations due to a lower than required Top of Cement in the annulus. Possible hydrocarbon zones could be left exposed in the annulus with only the casing hanger seal as the single barrier for the TA."[66] In the event that occurred, the document went on to note, "A perf[oration] and squeeze operation could be performed to add a second barrier in the annulus."[67] BP drilling and completions operations manager David Sims reviewed the management of change document and commented that the "[c]ontent looks fine."[68] BP drilling engineer team leader Gregg Walz, BP wells team leader John Guide, BP engineering manager John Sprague, and others also reviewed the document—all approved.[69]

Keeping TOC to a minimum necessarily reduced the total volume of cement that Halliburton pumped down the well. Several other features of the Macondo well also limited the total amount of cement that could be pumped:

- the relatively short distance the well had been drilled below the main pay sands;
- the relatively narrow annular space between the production casing and the formation; and
- BP's decision not to pump any cement behind the top plug.[70]

Halliburton calculated that it should pump approximately 51 barrels of cement (about 60 barrels after foaming) down the well in order to fill the shoe track and the annular space up to BP's specified TOC.[71] BP engineers recognized that this was a relatively small volume of cement that would provide little margin for error.[72]

Cement Flow Rate

Just as increased mud flow rate improves wellbore conditioning, higher cement flow rates tend to increase the efficiency with which cement displaces mud from the annular space. Cement must be pumped fast enough so that it will scour mud from the side of the wellbore instead of merely flowing past. The API notes that "[h]igher pump rates introduce more energy into the system allowing more efficient removal of gelled drilling fluid."[73] However, increased pump pressure required to move the cement quickly would mean more pressure on the formation (ECD) and an increased risk of lost returns.[74]

One way in which BP reduced the risk of lost returns at Macondo was by lowering the rate of cement flow. BP pumped cement down the well at the relatively low rate of four barrels or less per minute.[75] This was a lower rate than called for in earlier drilling plans,[76] but BP did inform Halliburton of the change and Halliburton's computer models accounted for the reduced flow rate.

Use of Nitrogen Foamed Cement

One very direct way to reduce the amount of pressure that a column of cement exerts on the formation below is to use lightweight cement. While there are several ways to generate lightweight cement, BP and Halliburton chose to use nitrogen foamed cement. Cementing personnel create nitrogen foamed cement by injecting inert nitrogen gas into a base cement slurry. This produces a slurry that contains fine nitrogen bubbles. Because nitrogen gas weighs so little compared to cement, the nitrogen bubbles make the overall cement mixture less dense than the base cement slurry.

BP and Halliburton jointly decided to use foamed cement technology at Macondo. (Chapter 4.4 discusses the choice in more detail.) This would reduce the weight of the middle portion of the Macondo cement slurry from the base slurry density of 16.74 ppg down to a foamed slurry density of 14.50 ppg.[77]

While using foamed cement slurry brought certain benefits, it brought risks as well. Chapter 4.4 explains in more detail how an unstable foamed cement slurry can fail to provide zonal isolation. A BP cementing expert specifically advised one of the Macondo engineers in March that cementing the production casing using foamed cement would "present[] some significant stability challenges for foam, as the base oil in the mud destabilizes most foaming surfactants and will result in N_2 [nitrogen] breakout if contamination occurs."[78] To guard against this possibility, the expert advised the team to pump non-foamed cement ahead of the foamed cement. This would create a "cap slurry" on top of the foamed slurry in the annular space that would mitigate the risk of foam instability.[79]

Planning for and Installing Centralizers at Macondo

BP procured only six centralizers for its production casing ahead of time, even though its plans had originally called for a greater number. Shortly before running the casing, however, Halliburton's modeling revealed that BP would need more centralizers to prevent channeling. In response, BP decided at the last minute to purchase 15 more centralizers and send them out to the rig. But unlike the six centralizer subs that BP had purchased earlier, these additional centralizers were slip-on centralizers with separate stop collars. Once BP realized this, it reversed itself and decided not to use them, reasoning that the risks of using them outweighed the risks of channeling.

API's Centralization Guidance

While the API recognizes the importance of centralization, it has no recommended specific standoff ratio for casing. Rather, the API encourages drillers to determine the appropriate standoff ratio based on individual well conditions. Nor does the API have any recommendation or standard for how far above the pay zone casing should be centralized. [80]

BP's Centralization Guidance

BP's official technical guidance instructs engineers to design centralization programs to ensure there is at least 100 feet of "centrali[z]ed pipe" above the "permeable zone" in the event a cement bond log is not run.[81] The technical guidance does not provide any further detail on the number or type of centralizers that should be used or the overall standoff that should result. BP in-house cementing expert Erick Cunningham explained that the guidance does not provide specific instruction on the number of centralizers that must be used to create a "centralized pipe." A casing could have centralizers on every joint or every three joints; both could be considered "centralized pipe" depending on the particular well. Cunningham stated that the only way to predict the effect of centralizer placement on mud displacement is through computer modeling.[82]

Macondo Team's Early Centralizer Plans

The Macondo team's September 2009 well plan included enough centralizers to likely satisfy BP's internal technical guidance. That plan's formula would have required the team to install at least 16 production casing centralizers given the then-planned total depth of 20,200 feet.[83] BP then produced another well plan in January 2010. Its formula would have called for at least 11 centralizers on the production casing.[84] Given the ambiguity of BP's technical guidance, it is unclear whether the January 2010 plan would have satisfied BP's internal requirements.[85] Both of these plans were based on a deeper well depth and larger casing diameter than BP eventually used at Macondo.

The Macondo Team Procured Six Centralizers for the Production Casing

On March 31, BP drilling engineer Brian Morel emailed a Weatherford sales representative, Bryan Clawson, and asked for "7-10" centralizer subs.[86] Clawson emailed Morel to say that Weatherford could only supply six centralizers immediately, explaining that it would take up to 10 days to manufacture more. Though it is common for Weatherford to manufacture centralizers to order, Morel did not ask Clawson to do so, even though Weatherford could at that point have made additional subs in time.[87] Instead, the BP team decided that six centralizers would be sufficient.[88] These six centralizer subs that Morel ordered were ultimately the only centralizers that the Macondo team used.

The Macondo Team Decided to Increase the Number of Centralizers to Address Potential Channeling Problem

During the long string decision-making process, Halliburton cementing engineer Jesse Gagliano had run a cementing model that predicted that the long string could be cemented successfully. Though Gagliano was a Halliburton employee, he worked at BP's Houston campus, and his office was on the same floor as those of BP's Macondo team.[89] Gagliano's April 14 model assumed proper centralization (by assuming a 70% standoff ratio) instead of calculating standoff based on centralizer placement plans.[90] It also assumed optimal wellbore size and geometry because BP did not yet have caliper log data from the well.[91] The April 14 model report did not predict significant channeling.[92]

On April 15, BP provided additional data to Gagliano from the Schlumberger logs, including caliper data, that could improve the accuracy of his cementing predictions. Based on the new data, Gagliano modeled the cementing process again, this time without assuming optimal centralization.[93] His new model predicted that using only six centralizers would result in lower standoff ratios and that this would be inadequate to ensure good mud removal and avoid mud channeling.[94] It also predicted that the mud channeling would increase the height of the cement column in the annulus (measured as TOC). That, in turn, would increase the effective pressure that the cement column would exert on the well formation below (ECD).[95]

That afternoon, Gagliano alerted Walz and BP operations engineer Brett Cocales to his predictions. Although Guide was out of the office, BP's engineering team acted on the information. The team was already concerned that the ECD during cementing operations could lead to lost returns during cementing and viewed lost returns as the biggest risk they faced during the cement job.[96] Based on Gagliano's predictions of increased ECD, Walz sought and obtained agreement from Guide's superior, Sims, to procure more centralizers and fly them to the rig immediately.[97] It appears that Walz and the BP team were concerned at this point about

Figure 4.3.13. Centralizer sub (top) and slip-on centralizer with stop collars (bottom).

Weatherford

the impact that channeling might have on ECD and were not directly concerned about the impact channeling might have on zonal isolation. [98]

Gagliano ran and distributed two additional cementing models from the afternoon into the evening of April 15 to evaluate the impact of adding additional centralizers.[99] His first model predicted that there would be reduced channeling with 10 centralizers, but still a significant amount. He emailed the model to the team, writing what he had already warned them about in earlier conversation: "Updating [the model with caliper and other data] 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."[100] Morel, who was on the rig and unaware that the team had made the unusual decision to fly centralizers to the *Deepwater Horizon*, responded that it was "too late" to get any more centralizers to the rig.[101] Gagliano's second model showed even less channeling with 21 centralizers. Both models showed that increasing the number of centralizers at Macondo would reduce the potential for gas migration in the annular space, though the centralizers' effect on gas flow was apparently of minor concern to the team compared with its effect on ECD.[102]

Sitting in the Houston conference room with Gagliano, Cocales carried out Walz's instructions to secure additional centralizers. Cocales called Clawson and ordered 15 additional Weatherford centralizers, the most that could be sent on a single helicopter.[103] BP also arranged for a Weatherford technician to accompany the centralizers and oversee the installation.[104] These 15 centralizers were leftovers from another BP project called Thunder Horse. Unlike the six centralizer subs already on the *Deepwater Horizon*, however, the Thunder Horse centralizers were slip-on centralizers as shown in Figure 4.3.13. BP's engineering team assumed that the Thunder Horse centralizers had integrated stop collars.[105] But the centralizer schematics that Clawson sent to Cocales on April 15 (and that Cocales forwarded to the rest of the BP engineering team) showed that the stop collars would be separate from the centralizers.[106]

Figure 4.3.14. Gregg Walz April 16, 2010 email to John Guide about centralizers.

From: Walz, Gregory S
To: Guide, John
Sent: Fri Apr 16 00:50:27 2010
Subject: Additional Centralizers

John,
Halliburton came back to us this afternoon with additional modeling after they loaded the final directional surveys, caliper log information, and the planned 6 centralizers. What it showed, is that the ECD at the base of sand jumped up to 15.06 ppg . This is being driven by channeling of the cement higher than the planned TOC.
We have located 15 Weatherford centralizers with stop collars (Thunder Horse design) in Houston and worked things out with the rig to be able to fly them out in the morning. My understanding is that there is no incremental cost with the flight because they are combining the planned flights they already had. The maximum they could fly is 15.
The model runs for 20 centralizers (6 on hand + 14 new ones) reduce the ECD to 14.65 ppg, which is back below the 14.7+ ECD we had when we lost circulation earlier.
There has been a lot of discussion about this and there are differing opinions on the model accuracy. However, the issue, is that we need to honor the modeling to be consistent with our previous decisions to go with the long string.
Brett and I tried to reach you twice to discuss things. David was still here in the office and I discussed this with him and he agreed that we needed to be consistent with honoring the model.
To be able to have this option we needed to kick things off at 6:00 pm tonight, so I went ahead and gave Brett the go ahead. We also lined up a Weatherford hand for installing them to go out on the same flight. I wanted to make sure that we did not have a repeat of the last Atlantis job with questionable centralizers going into the hole.
John, I do not like or want to disrupt your operations and I am a full believer that the rig needs only one Team Leader. I know the planning has been lagging behind the operations and I have to turn that around. I apologize if I have over step my bounds.
I would like to discuss how we want to handle these type of issues in the future.
Please call me tonight if you want to discuss this in more detail.

Gregg

Drilling Engineering Team Leader
GoM Drilling & Completions
Office: 281-366-0281
Cell: 281-543-8634
E-Mail: Gregory.Walz@bp.com

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Walz later explained his decision, as shown in Figure 4.3.14, to order the additional 15 centralizers to Guide in the following email, sent that night.[107]

Walz justified the decision to order additional centralizers because "we needed to be consistent with honoring the model." That model had convinced the team that a long string could be successfully cemented, so long as ECDs were kept in a low, narrow range. That model had also assumed that the centralizers would achieve a 70% standoff ratio.

The Macondo Team Decided Not to Install the Additional Centralizers

Sometime after 5 a.m. on April 16, a helicopter arrived at the *Deepwater Horizon*, carrying the 15 additional centralizers and Weatherford service technician Daniel Oldfather.[108] The helicopter did not, however, carry the stop collars and accessories that would be needed to secure the centralizers on the casing. Those had been shipped by boat and were scheduled to arrive by 4 p.m. (before the casing would be run).[109] Oldfather explained this to the rig crew when he landed.[110]

Figure 4.3.15. Centralizers delivered to the *Deepwater Horizon* on April 16, 2010.

BP

Morel was still visiting the rig at the time the helicopter landed. He examined the centralizers when they arrived. Like the other BP engineers, he had expected that the centralizers would have integrated stop collars. He now recognized that this was not the case.[111] Morel called Guide and told him that these were not the "one-piece" centralizers that he was expecting. Guide agreed they were not what he had planned on using either.[112] Morel took digital pictures of the centralizers and emailed them to Guide, telling him that "the centralizers do not have the stop [collars] on them."[113] However, Morel also told Guide that the centralizers could still be used because the boat carrying the collars would arrive in "plenty of time before needing them."[114]

After learning that the new centralizers had separate stop collars, Guide reversed Walz's decision to install them on the production casing in an email to him midday on April 16,[115] shown here in Figure 4.3.16.

Guide's email explained to Walz that the separate stop collars were prone to coming off the casing as it was being run into the well. Not only did this mean that the centralizers could slip away from their predetermined positions on the casing, but the centralizers could also get "hung up" against other parts of the well as the casing was being run. This could prevent the casing from being

Figure 4.3.16. John Guide April 16, 2010 email to Gregg Walz about centralizers.

From: Guide, John
Sent: Fri Apr 16 17:48:11 2010
To: Walz, Gregory S
Subject: Re: Additional Centralizers
Importance: Normal
Attachments: David Sims.vcf

I just found out the stop collars are not part of the centralizer as you stated. Also it will take 10 hrs to install them. We are adding 45 pieces that can come off as a last minute addition. I do not like this and as David approved in my absence I did not question but now I very concerned about using them

BP

lowered all the way to the bottom of the wellbore—a serious problem that would take significant time to fix.[116] Guide also noted that installing this type of centralizer would alone take 10 hours.[117] In a phone call with Walz, Guide weighed the risks of losses that fewer centralizers presented against the risk of a "last minute" addition of unfamiliar centralizers. There was no discussion at that point of stopping the job in order to procure the "correct" style of centralizers.[118] Instead, Guide told Walz and Sims he was reverting to the original plan. Sims agreed. Walz also accepted the reversal, saying, "I agree. This is not what I was envisioning," and apologized to the rest of the drilling team for the "miss-step" of ordering centralizers.[119]

During the same time period, Morel was attempting to position BP's six centralizers where they would be most effective, rather than place them at fixed intervals. As early as April 14, he had emailed Gagliano his suggested placement.[120] On April 15, when he mistakenly told Gagliano that it was "too late" to get more centralizers to the rig, he changed his recommendation, switching the position of two centralizers.[121] The next afternoon, the day BP reverted to the six centralizer plan, Morel changed the position of two other centralizers on his own "casing tally."[122] Morel supposedly based his recommendation on the caliper data and a wellbore image, though it is unclear precisely how he used them.[123]

Morel's placement of the centralizer subs was different than Gagliano's. Gagliano had assumed the centralizer subs would be evenly spaced apart while Morel placed them at irregular intervals.[124] It appeared that Morel expected Halliburton to run a new model based on his casing tally and centralizer placement. Morel's discussion with Cocales regarding the placement concluded, "We can argue this one out after we get the actual vs model data and see how it reacts."[125] As it turned out, BP never requested a model that reflected the actual centralizer placement, and Halliburton never ran one.

Neither Halliburton nor the BP engineering team appears to have considered that inadequate centralization might increase the chance of a blowout. Rather, they concluded that the worst-case result of using only six centralizers would be the need to conduct a remedial cement squeeze job.[126] As Cocales emailed Morel, "I would rather have to squeeze than get stuck above the WH [wellhead]. So Guide is right on the risk/reward equation."[127] In other words, Cocales preferred the increased risk of having to perform a remedial squeeze job to the increased risk of one or more of the 15 slip-on centralizers getting stuck in the well while the crew was running the production casing.

The BP team did not explicitly communicate its decision to use only the six centralizer subs on the rig to Halliburton or Weatherford.[128] When Gagliano eventually learned of the decision (from a Halliburton cementer aboard the rig), he asked BP to confirm it, and when he received no reply, he ran a new model on April 18.[129] It predicted poor centralization, "SEVERE" gas flow potential, and mud channeling. When Gagliano emailed the latest cement job procedures to the BP team at 9 p.m. that night, he attached this report.[130] He spoke with Walz the next morning (April 19) about the potential for channeling.[131] Walz in turn spoke with Guide about the issue.[132] BP nevertheless proceeded with its plan to run only six centralizers.

As BP has pointed out, Gagliano's April 18 model was based on several imperfect inputs. Notably, Gagliano assumed that BP would use seven centralizers, not six, and again, that BP would space them evenly along the casing, not place them in sections of the borehole where they might be especially effective.[133] Gagliano also utilized an incorrect pore pressure in the reservoir zone, which could influence the model's prediction of gas flow into the cement column.[134] It is unclear, however, whether eliminating these inaccuracies could have eliminated the channeling and gas flow predicted by the model. The use of fewer centralizers would decrease centralization, and the actual placement of two-thirds of the centralized joints was within 15 feet of the placement of the centralizers in the model.[135] In any case, the April 18 model was the most accurate model of the cementing process that existed before the blowout,[136] and it predicted that channeling would occur.[137] (As of 10 months after the blowout, Halliburton had still not produced modeling results that more accurately reflect Macondo conditions.)

BP began installing the casing at 3:30 a.m. on April 18 and finished at 1:30 p.m. on April 19.[138]

Float Collar Installation and Conversion at Macondo

Once the production casing string had been run, the crew turned to converting the valves in the float collar. Until this time, the float valves had been propped open by an auto-fill tube. Rig personnel needed to push the auto-fill tube down and out of place, thereby converting the float valves and allowing them to close (Figure 4.3.1). Once closed, the float valves would become one-way valves that would permit drilling mud and cement to flow down through the inside of the casing but would prevent "reverse flow" or "u-tubing."[139]

Shoe Track Length and Placement

The shoe track is the space between the float collar and the reamer shoe at the bottom of the casing. (A **reamer shoe** is a bullet-nosed, perforated piece of equipment that guides the casing toward the center of the hole as it is lowered into the well). At the end of the cement job, this space is filled with the "tail" portion of the cement that was pumped down the well. That tail cement may be contaminated by mud scraped from the casing by the top wiper plug. Indeed, one purpose of the shoe track is to contain contaminated tail cement.

A longer shoe track increases the volume for capturing contaminated tail cement, which in turn reduces the likelihood that such cement will flow into the annular space. A larger shoe track also dilutes the impact of any contamination in the tail cement. Morel suggested the shoe track at Macondo may not have been long enough but ultimately left the decision whether to extend the length up to the well site leaders on the rig.[140] According to Guide, BP also wanted to set the shoe track deeper in the well so that it was entirely below the hydrocarbon-bearing zone.[141] Ultimately, the shoe track was not below all of the hydrocarbon-bearing zones because the total depth of the well was shallower than planned due to problems of losing returns into the formation.[142]

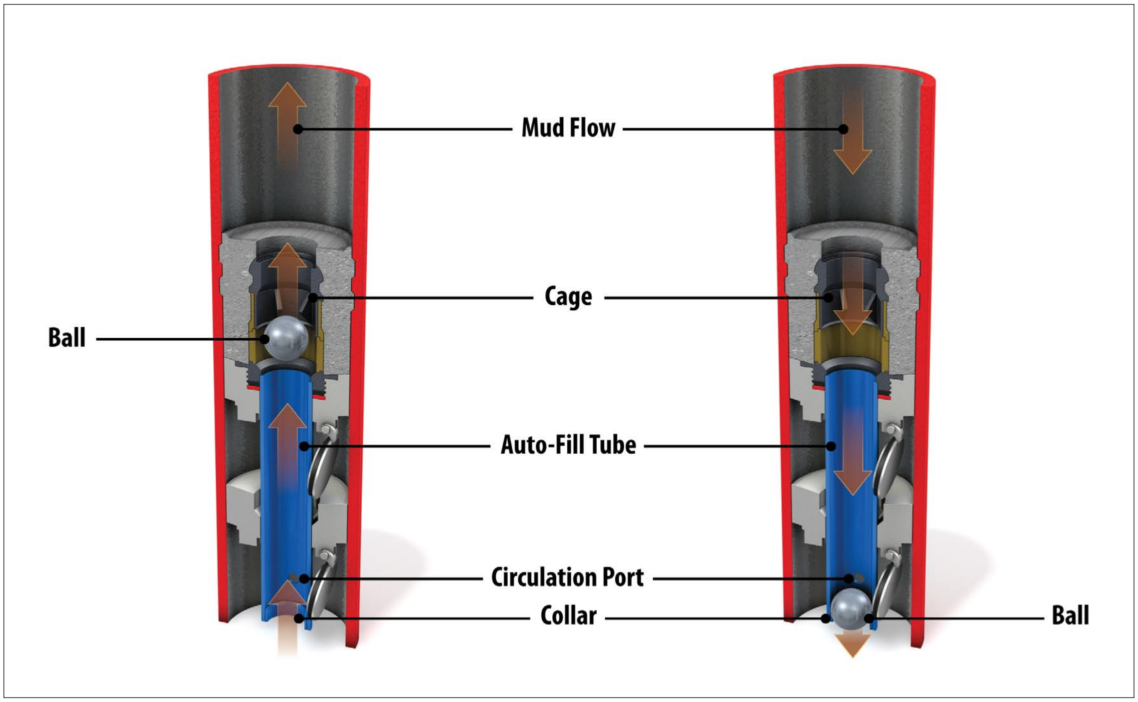
Macondo Float Collar

The production casing at Macondo contained a Weatherford Flow-Activated Mid-Bore Auto-Fill Float Collar, which rig personnel had installed just above the 180-foot shoe track at the bottom of the casing string.[143]

The Weatherford float collar held two aluminum float valves set approximately 6 inches apart and propped open by an approximately 14-inch-long auto-fill tube (made out of phenolic resin).[144] As shown in Figure 4.3.17, the auto-fill tube allowed mud to flow up through the float valves while the casing string was run. Once the production casing had landed, however, the crew needed to push the tube out of the way to allow the float valves to close.

The float collar's auto-fill tube contains a 2-inch weighted ball, which is free to move within the tube but not out of it. At the top of the float assembly is a plastic cage that prevents the ball from escaping but allows mud to flow through. At the bottom is a phenolic resin collar that is less than 2 inches in diameter, which also allows mud, but not the ball, to flow through. When casing is being run, mud flowing up through the tube pushes the ball against the inside of the cage. When the casing lands, the ball falls to and plugs the bottom of the tube, leaving two small holes on the side of the tube as the only path through the tube for mud circulated down through the well.[145]

Figure 4.3.17. Auto-fill float collar.



TrialGraphix

Flow while casing is being lowered (left) and flow during conversion (right).

The crew converts the float valves by pumping mud down through the tube, against the ball, and out the two holes in the side. As rig personnel increase the flow rate of mud, the constricted flow path creates a differential pressure against the auto-fill tube. Once the flow rate exceeds a certain threshold, the differential pressure should break four shear pins that hold the auto-fill tube in position and force the tube downward and out of the float collar assembly. With the auto-fill tube removed, the float valves spring shut, "converting" the float collar into a one-way valve system.[146]

According to calculations based on Weatherford's specifications, the Macondo float collar assembly would have converted at a flow rate of approximately 6 barrels per minute (bpm), which would have created a 500 to 700 pounds per square inch (psi) differential pressure across the auto-fill tube.[147] Achieving the requisite flow rate through the two small holes is the only way to convert the collar. Significantly, increasing pump pressure above 500 to 700 psi would not push the auto-fill tube through and convert the valves unless the flow through the two side holes exceeds the flow rate recommended by Weatherford.

Attempted Float Conversion at Macondo

Rig personnel prepared to convert the float collar at approximately 2:30 p.m. on April 19.[148] The crew turned on the pumps and began pumping mud down the well in an effort to establish circulation to convert the float equipment. Morel and BP well site leader Bob Kaluza oversaw the operation.

The crew ran into a problem. They could not establish circulation (and hence had a zero flow rate), suggesting that the float collar or shoe track was somehow plugged. The crew increased pump pressure nine times before finally establishing mud circulation. They increased pump pressure to 1,800 psi, then to 1,900 psi, but could not establish circulation.[149] Rig personnel then pressured up to 2,000 psi four times but still could not circulate. The crew then pressured up to 2,250 and then 2,500 psi and again failed to establish circulation.[150] The crew then made a ninth attempt to establish circulation, pressuring up to 2,750 psi, then 3,000 psi. At 3,142 psi, the pressure finally dropped and mud began circulating down through the float collar assembly.[151] Significantly, however, the crew never thereafter achieved sustained flow rates of 6 bpm, which were required for conversion of the float valves based on calculations using Weatherford specifications.

The rig crew sought advice from shore during these attempts to establish circulation. At 3:28 p.m., Hafle emailed a representative from Allamon, another equipment supplier, and asked for the specifications of the auto-fill float equipment. The Allamon representative responded and suggested "rocking the casing in 1000 psi increments up to 5,000 psi."[152] Morel called Clawson at Weatherford, reported that they could not break circulation, and asked how much pressure could be applied.[153] After checking with the Weatherford engineering department, Clawson called back Morel and told him they could increase pressure up to 6,800 psi.[154] However, he also told Morel that at 1,300 psi the ball would pass through the bottom of the auto-fill tube without converting the floats.[155] Morel called Guide onshore and received permission to increase pressure to 2,200 psi.[156] The crew pressured up to 2,250 and then 2,500 psi but still failed to establish circulation.[157] Guide later gave permission to increase pressure to 5,000 psi.[158]

Questions remained after establishing circulation. At 5:30 p.m. on April 19, Clawson of Weatherford emailed BP's Morel inquiring about progress.[159] Morel responded, "[W]e blew it at 3140, still not sure what we blew yet," indicating the rig crew did not know what they had dislodged with the amount of pressure applied.[160] Kaluza said, "I'm afraid we've blown something higher up in the casing string."[161] Hafle said, "Shifted at 3140 psi. Or we hope so."[162] Despite these uncertainties, the rig crew proceeded onward.

Low Pressure After Circulation Established

After establishing circulation, BP observed another anomaly. The pump pressure required to circulate mud through the well was significantly lower than expected.[163] As shown in Table 4.3.1, mud engineers from M-I SWACO had calculated that 370 psi would be required to circulate at 1 bpm and 570 psi at 4 bpm post-conversion. However, after the crew established circulation, it took only 137 psi to circulate at 1 bpm, which made Kaluza uncomfortable.[164] The crew increased circulation to 4 bpm, which required only 340 psi of pressure—230 psi less than M-I SWACO had predicted.

The low circulating pressure raised concern among personnel on the rig floor.[165] Kaluza spoke to Morel, who was on the rig.[166] Morel called Guide onshore, who agreed the pressures appeared low.[167] Cocales asked M-I SWACO to rerun its model to confirm that the original calculations had not been mistaken; M-I SWACO's models continued to predict substantially higher circulating pressures than actually observed.[168]

Guide and Kaluza instructed the crew to switch from pump 4 to pump 3 to see if changing pumps might change the circulation pressure.[169] They observed a slightly higher circulation pressure (396 psi at 4 bpm) after switching pumps, but this was still significantly lower than the expected pressure.[170]

Table 4.3.1. Low pressure observed after circulation established.

Circulation Rate	1 bpm	4 bpm
Pressures Observed	137 psi[171]	340 psi (on pump 4)[172] 396 psi (on pump 3)[173]
Pressures Modeled	370 psi[174]	570 psi[175]

At Guide's suggestion, the crew checked whether the Allamon **diverter** in the drill pipe might be leaking. The diverter is a valve opened during casing installation to allow drilling fluid flowing up inside the casing to flow into the annulus and back to the surface. At Macondo, the diverter was located in the drill pipe, above the wellhead at a final depth of 4,424 feet.[176] The test confirmed the diverter was closed.[177] Morel and Kaluza considered the possibility of a breach somewhere in the casing string.[178] However, they determined that a leak in the casing could not be fixed at the moment and, if present, would be revealed by later pressure tests (such as the positive pressure test).[179]

BP never resolved the low circulation pressure issue, concluding instead based on discussions with the rig crew that the pressure gauge was likely broken.[180] Morel and others felt comfortable proceeding because of the fact that the cement would be pressure tested later.[181] According to BP interview notes, Kaluza later described the low circulation pressure as an anomaly and said that after he had discussed it with Guide and well operations advisor Keith Daigle, Guide instructed Kaluza to begin pumping cement.[182]

Pre-Cementing Wellbore Conditioning at Macondo

Circulation After Landing the Long String

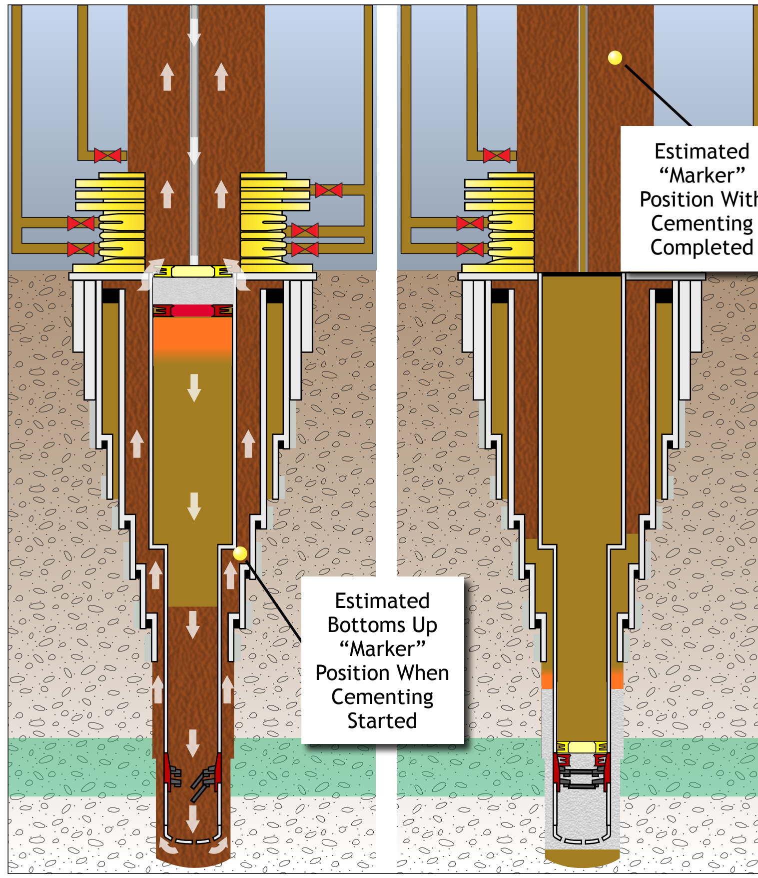
After converting the float valves, BP circulated mud again to clean the inside of the production casing string, remove any debris and cuttings dislodged by the casing installation, and condition the mud in the wellbore for cementing.

Planned Pre-Cement Circulation Volumes and Rates

An API recommendation from May 2010 was to circulate a minimum of 1.5 annular volumes or one casing volume after casing installation, whichever is greater.[183] Had this recommendation been in place at Macondo, this would have meant circulating 4,140 barrels (bbl) of drilling fluid. Halliburton recommends performing at least one full bottoms up circulation on a well before pumping a cement job.[184] This standard would have required BP to circulate 2,760 bbl of drilling fluid through the wellbore.[185]

Early BP drilling plans discussed pre-cementing circulation but did not call for a full bottoms up circulation. Omitting a full bottoms up is not unusual at deepwater wells because of the large mud volumes involved—circulating bottoms up could have taken as long as 12 hours at Macondo.[186] BP's September 2009 and January 2010 drilling programs called for circulating and conditioning 1.5 × pipe volume of drilling fluid "unless loss returns are experienced."[187] Although the plan did not specify which "pipe" volume it was referring to, circulation volumes are typically based on the volume of the casing used. The total long string casing and drill pipe volume at Macondo was 884 bbl, so it appears the plan called for the rig crew to circulate 1,326 bbl of mud before cementing.[188]

Figure 4.3.18. BP's pre-cementing mud circulation.



TrialGraphix

BP changed its plans in response to the April 9 lost circulation event, decreasing both the pre-cementing circulation volume and rate in order to reduce ECD. BP's April 12 plan thus called for circulating volume equal to one casing plus drill pipe capacity if hole conditions allowed, at a reduced rate of 8 bpm.[189] In its subsequent April 15 plan, BP further lowered the pump rate to "reduced rates (3 bpm) based on MI-SWACO models to keep ECD below 14.5 ppg."[190]

Even after receiving full returns during circulation on April 16, BP engineers remained concerned about lost returns during pre-cementing circulation.[191] They feared that circulating too extensively could damage the inside of the wellbore or instigate another lost returns event.[192] Onshore, Walz discussed whether to circulate full bottoms up with Gagliano late in the morning on April 19.[193] Afterward, Walz also spoke with Guide about circulation.[194] Ultimately, Guide recommended against circulating bottoms up because of concern over lost returns and gave approval to begin cementing.[195] On the rig, Halliburton cementing engineer Nathaniel Chaisson brought up the idea of circulating a full bottoms up but was told by a BP well site leader that a lower volume would be pumped.[196] Halliburton's April 18 cementing proposal lists reduced volumes, calling for 111 barrels at 1 bpm, followed by 150 barrels at 4 bpm for a total of 261 bbl.[197] Chaisson noted in the April 18 plan that the volumes and pump rates listed were "as per co. man,"[198] indicating that one of the BP well site leaders had provided it.

Pre-Cement Circulation Volumes and Rates

At approximately 4:18 p.m. on April 19, the rig crew re-established mud circulation after running the long string.[199] The rig crew then circulated a total of approximately 350 barrels of mud at rates up to 4 bpm before beginning the cementing process.[200] This figure exceeds the 261 bbl called for in the April 18 Halliburton cement job procedure[201] but is significantly lower than the 2,760 bbl required for a full bottoms up.[202]

Additional Circulation During Course of Cementing

BP has argued that the Chief Counsel's team must also take into account the additional mud volume circulated up the annulus from the bottom during the cement job itself in determining the total volume of mud circulated prior to the conclusion of the cement job. During the cement job, rig personnel pumped approximately 1,020 bbl of base oil, spacer, cement, and mud down into the well, which would have displaced an equal volume of mud.[203]

When combined with the pre-cementing circulation, this means that rig personnel pumped a total of 1,370 bbl of fluids (mud, spacer, and cement) down the well by the time cementing was complete.[204] This would have brought the bottomhole mud up into the riser to a depth of 4,250 feet below the ocean surface by the end of the cement job as shown in Figure 4.3.18. It would have taken a total of 2,760 bbl of circulation to bring the bottom mud all the way back to the rig.[205]

Table 4.3.2. Plans reduce pre-cement circulation volumes and rates.

Plan	Recommended Volume	Volume in Barrels	Recommended Circulation Rate
API RP 65, Part 2[206] (First edition)	1.5 annular volumes or one casing volume, whichever is greater	4,140 bbl (1.5 annular volumes)	
Full Bottoms Up		2,760 bbl[207]	
BP September 2009 Plan[208] and January 2010 Plan[209]	1.5 x pipe volume	1,325.73 bbl[210]	—
BP April 12 Plan[211]	1 casing and drill pipe capacity, if hole conditions allow	883.82 bbl[212]	~ 8 bpm
BP April 15 Plan[213]	1 casing and drill pipe capacity, if hole conditions allow	883.82 bbl[214]	3 bpm, based on M-I SWACO models to keep ECD below 14.5 ppg
April 18 Halliburton Cement Proposal[215]	—	111 bbl 150 bbl per company man	1 bpm 4 bpm
April 19 Actual Circulation		350 bbl	1-4 bpm

Cementing Process at Macondo

Halliburton's cementing team began pumping cement for the production casing on April 19.[216] In all, they pumped the following fluids down the well:

Table 4.3.3. Cementing volumes.

Material Pumped	Volume
Base oil	7 bbl[217]
Spacer fluid	72 bbl[218]
Unfoamed lead cement	5 bbl[219]
Foamed cement	39 bbl (Foamed to 48)[220]
Unfoamed tail cement	7 bbl[221]
Spacer	20 bbl[222]

After pumping these fluids, the cementing crew pumped mud into the drill pipe to push the cement down the well into position.[223]

Over the next three-and-a-half hours, the cement traveled down the drill pipe and into the well. During that time, rig personnel watched pump pressures at the rig for signs of cementing progress. Morel saw small pressure spikes suggesting that the top and bottom plugs had passed through the crossover joint in the long string.[224] Personnel on the rig agreed that the plugs bumped.[225] At 12:38 a.m. on April 20, Chaisson marked in his tally book that the plugs bumped at a pressure of 1,175 psi.[226]

Morel noted that the bottom plug landed 9 bbl ahead of plan.[227] This meant that the rig crew had to pump 9 bbl less fluid down the well than they planned before the bottom plug reached the float collar, potentially suggesting that the bottom plug had bypassed mud on its way down the well, and that the bypassed mud had contaminated the cement.

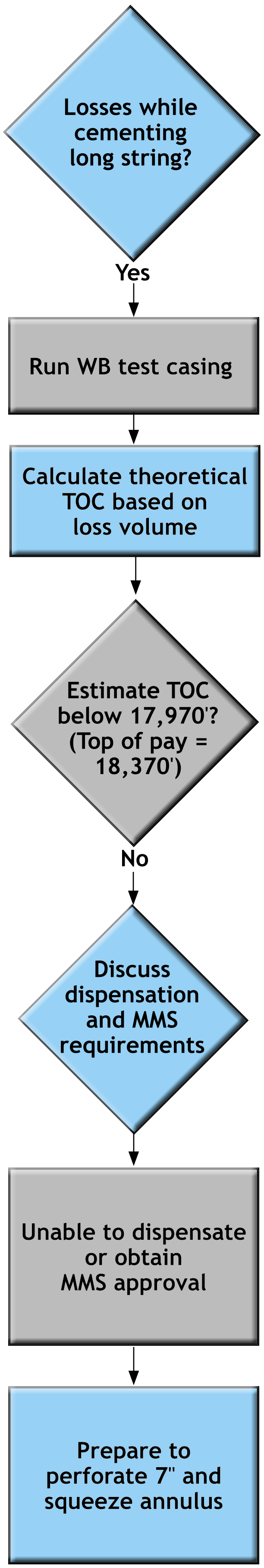
The top plug landed according to plan.[228] Chaisson watched the Sperry-Sun data[229] and estimated 100 psi of lift pressure before the top plug bumped.[230] Guide looked at the data from shore and thought it "easy" to see lift pressure.[231] Throughout cementing, the rig crew saw "full returns."[232]

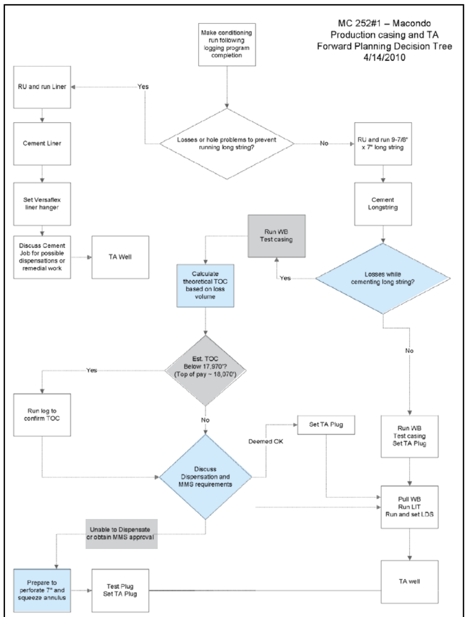
BP and Halliburton declared the job a success based on the indirect indicators—lift pressure, bumping the plugs on time, and full returns. Chaisson sent an email to Gagliano at 5:45 a.m. saying, "We have completed the job and it went well."[233] He attached a detailed report stating that the job had been "pumped as planned" and that "full returns were observed throughout."[234] Just before leaving the rig, Morel emailed the rest of the BP team: "Just wanted to let everyone know the cement job went well. Pressures stayed low, but we had full returns the entire job, saw 80 psi lift pressure and landed out right on the calculated volume.... We should be coming out of the hole shortly."[235] Later, Morel followed up with an email saying "the Halliburton cement team...did a great job."[236] Sims congratulated Morel and the BP team, writing, "Great job guys!"[237]

The Float Check at Macondo

After cementing was complete, rig personnel conducted a **float check** to ensure the float valves had closed properly. Rig personnel began by pressuring up the system after bumping the top wiper plug.[238] They then released the pressure and monitored the system for pressure differentials and flow back from the well.[239] BP well site leader trainee Lee Lambert and Halliburton cementer Vincent Tabler opened a valve at the cementing unit to see how much mud flowed out of the well when they released the pressure. [240] (Some modest flow back is expected due to the compressibility of fluids during the pumping of the cement job.) Models had predicted 5 or 6 bbl of flow back.[241] The two men observed 5.5 bbl of flow, which tapered off to a "finger

Figure 4.3.19. Decision tree.





BP/TrialGraphix

tip" trickle.[242] Tabler testified they watched flow "until it was probably what we call a pencil stream," which stopped, started up again, and then stopped altogether.[243] The total flow at that point was close to the predicted flow,[244] and the two men concluded the float valves were holding.[245]

Cement Evaluation at Macondo

BP's Decision Tree for Cement Evaluation

BP's decision process for determining whether to run evaluation tools after the cement job focused on lost circulation concerns as shown in Figure 4.3.19. On April 15, Hafle developed a cementing decision tree that effectively reduced the decision process to a single question: "Losses while cementing long string?"[246] If the cementing crew reported losses while pumping the cement job, the decision tree stated that BP engineers would "Calculate theoretical [top of cement] based on loss volume." If that calculation estimated that TOC was *below* 17,970 feet that would mean that there was less than 100 feet of cement above the top of the pay zone—400 feet less than MMS requires.[247] In that situation, the decision tree required a "log to confirm" the TOC.

If the theoretical calculation predicted that TOC was *above* 17,970 feet, the decision tree stated that the Macondo team would discuss MMS requirements and consider seeking a dispensation. If unable to get dispensation or "obtain MMS approval," then BP would "perforate" the casing and "squeeze" the annulus to remediate the cement job. An operator would not normally run a cement evaluation log and plan to remediate cement before temporary abandonment operations; the Macondo team's explicit discussion of these contingencies illustrates how concerned they were about the possibility of cement losses.[248]

On April 15, Morel distributed a full plan for the temporary abandonment procedures at Macondo. The plan summarized the cement evaluation decision tree and provided further detail on the criteria for how to evaluate the cement job:[249]

1. If cement job **is not** successful: (no returns or lift pressure seen): set wear bushing / Run IBC-CBL log / Wait on decision to do remedial work (MMS and BP).
2. If cement job **is** successful (partial returns or lift pressure seen) **or** IBC-CBL log and required remedial work is completed.

The plan thus stated that the BP team would declare the cement job "successful" if it saw "partial returns" or "lift pressure." It anticipated that the team might need to run cement evaluation tools ("IBC-CBL log") but required doing so only if "no returns or lift pressure seen." Steps one and two were the only steps in the BP plan that contemplated cement evaluation: In step three, the crew would move on to the temporary abandonment phase of the well and begin to displace mud in the wellbore with seawater.

BP Ordered Cement Evaluation Services From Schlumberger

On the same day that Morel distributed the temporary abandonment procedures, BP well site leader Ronnie Sepulvado placed an order with Schlumberger for cement evaluation services.[250] Sepulvado did so to ensure that a cement evaluation team would be available on the rig if the cement job did not go as planned. The order included a "full suite of logs,"[251] including a cement bond log, isolation scanner, variable density log, and inclinometer survey.[252] Schlumberger planned to evaluate the annular cement from the float collar to about 500 feet above the expected TOC.[253] The total cost for the services would be about $128,000.[254]

On April 18 and 19, a team of technicians from Schlumberger flew out to the rig.[255] BP told the team that the cement evaluation log would be run only if there were lost returns.[256] The Schlumberger team waited for more than a day on the rig to see if BP needed their services.

BP Sent Schlumberger Home

At 7:30 a.m. on April 20, the Macondo team discussed the cement job during its daily morning phone call with its contractors. BP concluded during the call that the cement job had gone well enough that it could send home the Schlumberger technicians. According to Guide, "everyone involved with the job on the rig site was completely satisfied with the job."[257] Having seen lift pressure and no lost returns during the cement job, BP sent the Schlumberger team home and moved on to prepare the well for temporary abandonment. At approximately 11:15 a.m., the Schlumberger crew left the rig on a regularly scheduled BP helicopter flight.[258] Not running the cement log probably saved BP about eight hours of rig time.[259]

Technical Findings

The Primary Cement at Macondo Failed to Isolate Hydrocarbons

It is undisputed that the primary cement at Macondo failed to isolate hydrocarbons in the formation from the wellbore—that is, it did not accomplish zonal isolation.[260] If the cement had set properly in its intended location, the cement would have prevented hydrocarbons from flowing out of the formation and into the well. The cement would have been a stand-alone barrier that would have prevented a blowout even in the absence of any other barriers (such as closed blowout preventer rams, drilling mud, and cement plugs).

Although the Chief Counsel's team is certain that the Macondo cement failed, data currently available do not allow the team to determine precisely why. It may never be possible to make such a determination. Government investigators recovered samples of debris from the blowout that may be cement, but they have not currently determined whether it came from the well and, if so, from where within the well.[261] There are no plans to directly examine the annular cement currently remaining at Macondo for clues. Even if someone were to plan such an examination, the blowout and subsequent remedial efforts may have obscured or erased any clues that might otherwise have been discovered.

BP, Halliburton, and Transocean have each speculated about potential failure mechanisms. Based on information currently available, the Chief Counsel's team can conclude that most (if not all) of the cement pumped at Macondo flowed through the float valves and that most of the cement that rig personnel intended to place in the annular space around the production casing did in fact reach that location. (Chapter 4.1 discusses the remote possibility of a casing breach that would have affected cement placement.) Several events may have contributed to cement failure, either alone or in combination:

- cement in the annular space may have flowed back into the production casing due to u-tube pressure and failure to convert the float valves;
- drilling mud may have contaminated the cement in the shoe track and/or annular space badly enough to significantly slow cement setting time;
- cement in the annular space may not have displaced mud from the annular space properly, leaving channels of mud behind;
- cement in the shoe track may have flowed down into the rathole (the open section of wellbore below the reamer shoe), "swapping" places with drilling mud and increasing the potential for flow through the shoe track;
- cement slurry characteristics (such as retarder concentration, base slurry stability/ rheology, or foam instability) may have compromised the sealing characteristics of the cement (discussed in Chapter 4.4); and
- severe foam instability may have allowed nitrogen bubbles to break out of the slurry, with unpredictable consequences (also discussed in Chapter 4.4).

Any theory regarding the precise mechanisms of the Macondo cement failure must account for several issues that the Chief Counsel's team has identified. Most importantly, if our team is correct that hydrocarbon flow came through the shoe track and up the production casing, then the tail cement in the shoe track must have failed to block that flow. It would have taken only a relatively small amount of properly set cement in the shoe track to block that flow. This suggests one of three nonexclusive possibilities to the Chief Counsel's team.

Drilling mud contamination. The first is that enough drilling mud contaminated the shoe track to delay cement setting time so that the shoe track cement did not provide a competent flow barrier at the time of the blowout. This probably would have taken a significant amount of mud; testing by Chevron indicated that even with 25% mud contamination, the Macondo cement formulation would develop adequate compressive strength without serious delay.[262]

The mud in question could have been entrained in the cement flow during cement placement by, for instance, the wiping action of the plugs. If the plugs landed off-schedule (as post-blowout statements by Morel suggest), that would support this theory. Cementing experts emphasize that the shoe track is designed to prevent cement contaminated by plug bypass from entering the annular space. Shoe track cement should therefore properly be treated as one part of the overall cement barrier system and may not bar hydrocarbon flow on its own.

Drilling mud could also have "swapped" into the shoe track from the open hole section below the casing (sometimes called the rathole). The rathole volume was similar to the shoe track volume. Mud contamination could also have come from the annular space around the production casing if channeling or other phenomena caused contamination of that area and float equipment malfunctions allowed this material to flow back into the shoe track under u-tube pressure.

Gross nitrogen breakout. The second possibility is that the foamed middle section of the cement slurry was so unstable (as discussed in Chapter 4.4) that nitrogen gas bubbles in it "broke out" of suspension while the cement was flowing down the drill pipe and production casing. This could have left large gas-filled voids not only in the middle section of cement that was injected with nitrogen, but also in the tail cement (which became the shoe track cement). That tail cement should not otherwise have had nitrogen in it. A problem with this theory is that pumping data from the cement job do not show the sorts of gross anomalies that one would expect if cement and nitrogen flowed through the float collar separately.

Nitrogen breakout could also have occurred after the cement arrived at the bottom of the well. This might not have produced anomalies in the pumping job data but still could have compromised the quality of the set cement. As described in Chapter 4.4, unstable nitrogen foamed cement can be excessively porous and permeable once set. Hydrocarbons can flow through such cement.

Gross cement slurry failure. A final possibility is that the Macondo cement slurry was unstable even before being foamed with nitrogen. As Chapter 4.4 explains in greater detail, pre-blowout testing shows that the Macondo slurry had a very low yield point, and post-blowout testing shows that a cement slurry produced using the Macondo recipe had a tendency to settle as it set. It is possible that these problems compromised the quality of the Macondo cement job so that cement in the shoe track could not have prevented hydrocarbon flow. A problem with this theory is that it appears, based on available information, that the cap cement in the annulus above the pay zone set up properly and created a barrier to flow up the annulus.

Using Six Centralizers Increased the Risk of Cement Failure

Reduced pipe centralization increases the risk of poor mud displacement, the risk that mud channels will compromise zonal isolation, and the risk that hydrocarbons will migrate into and through the annular cement as it sets. Without a direct examination of the Macondo cement, the Chief Counsel's team cannot determine whether any of these things occurred, let alone whether they caused or contributed to the blowout. The team can only conclude that BP's engineering decision increased the risk of cementing failure.

The Chief Counsel's team cannot at this time accept Halliburton's conclusory assertion that the limited number of centralizers at Macondo caused inadequate mud displacement, channeling, and cement failure.[263] To support its view, Halliburton relies heavily on the results of the model that Gagliano produced on April 18.[264] But Gagliano produced the April 18 report using several assumptions that did not match the eventual Macondo conditions. Halliburton points out that Gagliano received these assumed figures from BP, but that it is irrelevant; because the April 18 modeling inputs were inaccurate, the modeling output was unreliable even if one were to assume that those models accurately predicted problems with a cement job.[265] (Halliburton personnel have argued that their model would still have predicted channeling even with corrected inputs. However, Halliburton has yet to provide the results of a corrected model to the Chief Counsel's team or the public. This leads the Chief Counsel's team to infer that the results are not favorable to Halliburton.)

The Chief Counsel's team also cannot accept BP's equally conclusory assertion that the decision to use only six centralizers "likely did not contribute to the cement's failure to isolate the main hydrocarbon zones...."[266] Chapter 4.1 explains that the Chief Counsel's team finds it likely that hydrocarbon flow came up the production casing through the shoe track. But even though insufficient centralization may not have directly affected the integrity of the cement in the shoe track, it very well could have damaged the integrity of the cement in the annular space around the pay zone. If that cement had worked properly, shoe track cement failure would have been irrelevant.

BP's technical guidance and early Macondo well plans called for more centralizers than were actually run and for centralizers to be used over a larger casing interval.[267] If BP believed that its engineers could reliably reduce the number of centralizers (and hence cost) by scrutinizing caliper logs and pinpointing the placement of centralizers, one would expect its guidance documents and well plans to describe this practice. And while BP has repeatedly questioned the accuracy of the Macondo cementing models and the value of Halliburton's model in general,[268] it offers little affirmative technical analysis of its own to support its claim that centralization was not an issue at Macondo. Moreover, *before* the Macondo blowout, BP engineers thought the model's predictions of channeling were sufficiently credible that they flew 15 more centralizers to the rig in response.

Limited Pre-Cementing Mud Circulation Increased the Risk of Cement Failure

BP's decision to circulate a limited volume of mud at a relatively low rate before cementing may have led to inadequate mud conditioning and wellbore preparation. BP's decision was perhaps an understandable response to its concerns about formation integrity and lost returns, but it also increased the risks of cementing failure.

BP has defended its decision not to circulate bottoms up before cementing. It has argued, among other things, that modern technologies can identify wellbore cleanliness problems without full mud circulation and that the Macondo team took other measures to prepare the wellbore for cementing. For instance, the team circulated bottoms up *before* running the production casing[269] and pumped additional spacer during the cementing process to remove debris from the well.[270] At the same time, BP cannot dispute that circulating bottoms up is a "best practice" specified by Halliburton and other cementing experts,[271] and that its team did not do so. Although circulating less mud may have reduced the particular risk of lost returns, it nevertheless increased other aspects of the risk for cement failure, as compared to completing a full bottoms up.

Low Cement Volume Increased the Risk of Cement Failure

The limited volume of cement used at Macondo increased the risk of cement failure. BP pumped only about 60 barrels of cement (after nitrogen foaming) at Macondo. While BP may have thought it necessary to pump a small amount of cement to reduce the risk of lost returns, this approach magnified three other risks.

First, it meant there would be less cement in the annular space above the hydrocarbon zones—less even than BP's technical guidance recommends.[272] Second, it increased the risk that placement errors would leave insufficient cement in the shoe track or in the annular space corresponding to the hydrocarbon zone. And third, it increased the detrimental effects of any mud contamination. Mud contamination may have been a particular problem at Macondo because the design called for a tapered long string casing. That casing design called for the top and bottom wiper plugs both to wipe mud from a relatively long length of casing and to wipe two different casing diameters.[273]

Before the blowout, BP's engineering team recognized that their design called for a low cement volume that would provide little room for error. [274] And since the blowout, BP has recognized that "small cement slurry volume" increased cementing difficulties at Macondo.[275]

Cementing Pump Rate Increased the Risk of Cement Failure

In concert with Halliburton, BP chose to pump the primary cement at a relatively low rate.[276] This low rate would have decreased the efficiency with which the cement would have displaced mud from the annular space, especially given Halliburton's predictions regarding the impact of a reduced number of centralizers.[277] This, in turn, would have increased the risk of mud-related cementing failures such as channeling, contamination, and gas flow.

Using a Reamer Shoe Instead of a Float Shoe May Have Increased the Risk of Cement Failure

BP could have decreased cementing risks using a float shoe. Like a reamer shoe, a float shoe is a rounded piece of equipment that attaches to the bottom of a casing string and helps to guide the string down. But unlike the reamer shoe, the float shoe includes a check valve that functions much like the valves in the float collar. That extra check valve serves as an extra line of defense against cement contamination and helps keep debris and contaminants away from the float collar's valves. The existence of the extra check valve also helps to ensure proper cement placement by preventing cement from flowing back up the casing. Industry engineers often install float shoes where they are concerned about cement contamination.[278] While cement contamination was (or should have been) a concern at Macondo, BP chose not to install a float shoe on its production casing.

Rathole Issues Could Potentially Have Increased the Risk of Cement Failure

BP chose not to take precautions against **rathole** swapping. The rathole, again, is the open section of wellbore below the end of the production casing. As described above, mud in this portion of the wellbore can swap places with cement in the shoe track if the mud is less dense than the tail cement. This can contaminate the cement in the shoe track or potentially create a flow path through the cement in the shoe track.

One common precaution to guard against this phenomenon is to pump a small volume of dense mud into the rathole. If this mud is more dense than the cement, it will tend to stay in place rather than swap places with the cement. Although early BP plans called for this procedure,[279] the engineers eventually chose not to do it because the volume was small and improper placement could cause ECD concerns.[280] They reasoned that this created relatively small risks: the density differential between the mud and tail cement was not large, and the rathole volume was relatively low.[281] Halliburton personnel admitted after the blowout that rathole swapping could create a problem, but they had not considered the issue before pumping the job.[282]

Rig Personnel May Not Have Converted the Float Valves

Although rig personnel and BP concluded that they successfully converted the float valves, the Chief Counsel's team finds that the float valves at Macondo may not have actually converted.[283] Unconverted float valves could have compromised the bottomhole cement job at Macondo.

Rig Personnel Never Pumped Mud at the Rates Weatherford Specified to Convert the Float Collar

Planning documents and pumping data show that rig personnel never pumped mud down the well at sustained rates high enough to ensure float valve conversion. While well plans specified mud circulation rates that would have converted the float valves, actual rates never exceeded 4.3 bpm—significantly less than the 6 bpm required to convert the equipment:

Table 4.3.4

	Flow Rate Needed to Convert	Differential Pressure Needed to Convert
BP September 2009 Plan[284] and BP January 27, 2010 Final Drilling Program[285]	12 bpm maximum	~ 600 psi
BP April 12, 2010 Drilling Plan[286] and BP April 15,2010 Drilling Plan[287]	8 bpm minimum	~ 500 to 700 psi per Weatherford recommendation
Weatherford Manufacturer Recommendation[288] Adjusted for 14.1 ppg Mud Weight[289]	6 bpm[290]	600 psi[291]
April 19 actual[292] steady flow rate never exceeds 4.3 bpm,[293] which would result in a differential pressure of approximately 328 psi[294]		

BP contracted Stress Engineering Services, a third-party engineering firm, to conduct post-blowout testing on float collars similar to those used at Macondo.[295] On the basis of this testing, BP asserts that temporary surge flow rates caused by sudden pressure changes in the well would have converted the float equipment.[296] BP contends that there were two potential surge-inducing events. The first was the sudden drop in pressure from 3,142 psi once mud circulation began.[297] The second was during the cement job when the bottom plug burst at 2,392 psi.[298]
The Stress Engineering analysis shows that the Macondo float valves may have converted because of pressure-induced surge flows. But if this in fact happened, it was by happenstance, not design. More importantly, without having pumped mud consistently through the float collar at Weatherford-prescribed rates, BP personnel had no sound basis for concluding that the float valves had converted. And the later float check that they performed was not a reliable indicator that the float collar had sealed.[299] BP's own report agrees.[300]

Although rig personnel deemed the Macondo float check to be a success, the check was actually inconclusive because of the small density differential between the cement and drilling mud in the well. Halliburton's April 18 model predicted 38 psi of differential pressure.[301] (The Chief Counsel's team's calculations based on actual volumes pumped indicate a u-tube pressure of about 56 psi—an inconsequential difference.[302]) A Weatherford representative confirmed that 38 psi of differential pressure is "pretty tiny,"[303] and other experts agree that it would be hard to detect.[304] The small u-tube pressure would also have meant that any cement backflow may have been too small and gradual for rig personnel to detect in the time that they monitored for flow.

The Drop From 3,142 psi May Have Been Due to a Clogged Reamer Shoe or a Failure of the Float Collar System

Rig personnel assumed that the sudden drop in pump pressure from 3,142 psi indicated that they had converted the float collar. If the float collar did not actually convert, then something else must have caused this pressure drop. The Chief Counsel's team has identified two possible explanations.

The Reamer Shoe May Have Been Clogged

The first possibility is that the unexpected pressure increases and sudden pressure drop may have been caused by a clog in the reamer shoe that eventually cleared in response to elevated pump pressure.

Drilling mud pumped down the Macondo production casing and through the float collar assembly had to exit the bottom of the casing through three 1⅝-inch holes ("circulation ports") at the

Figure 4.3.20. Clogged reamer shoe.

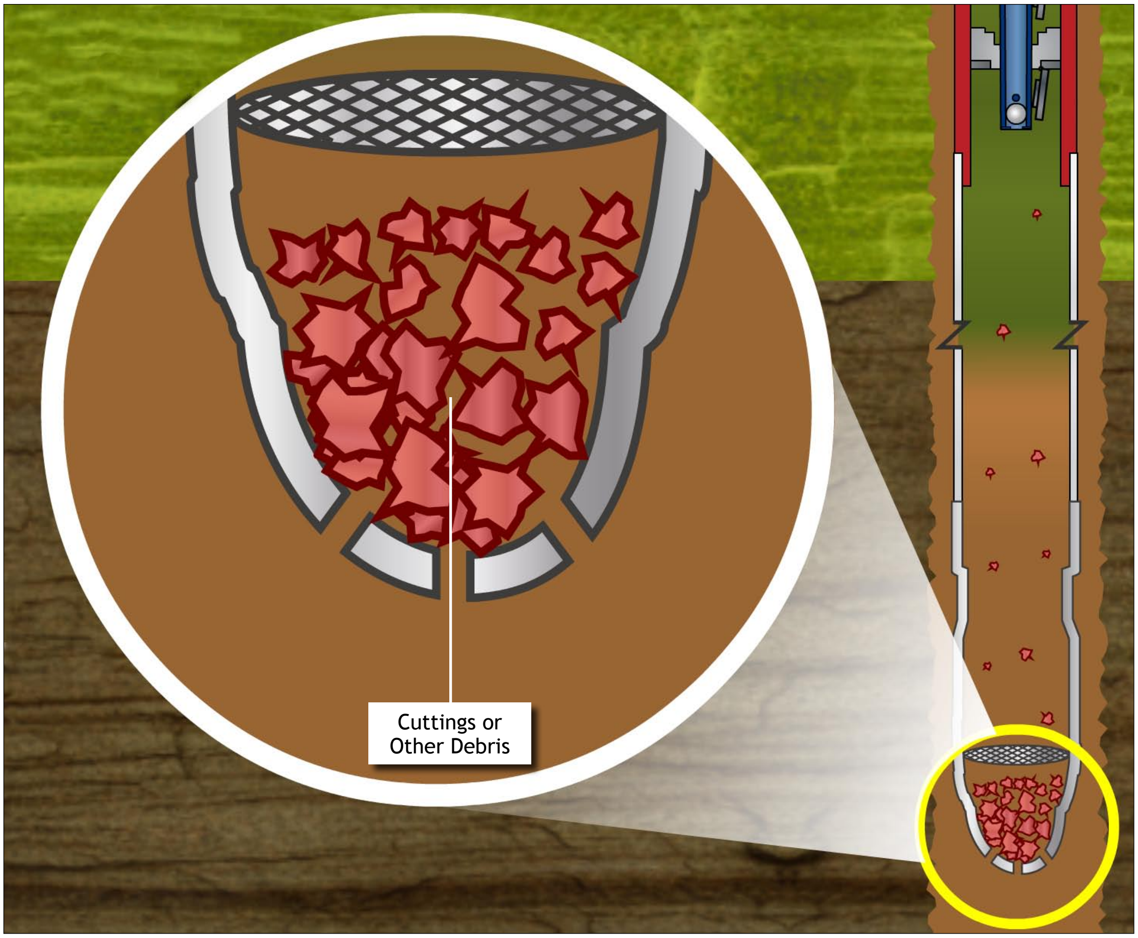
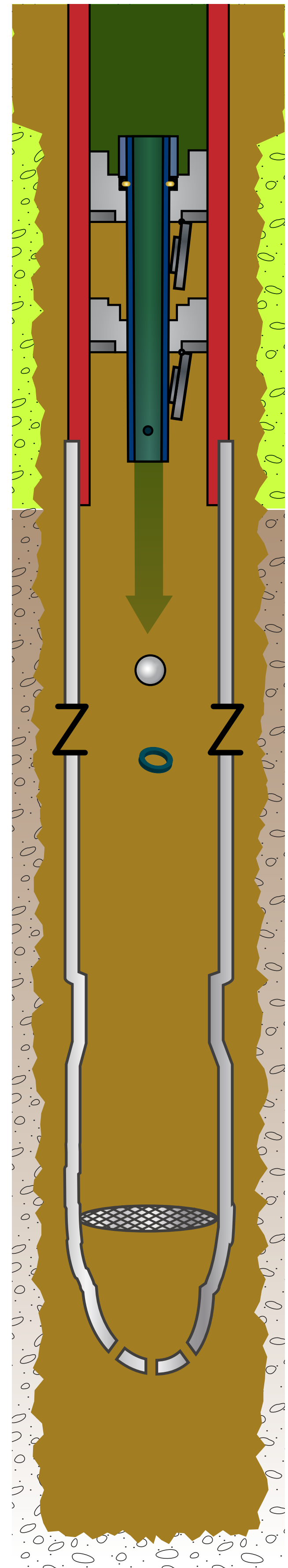


Figure 4.3.21. Ball forced through tube.



bottom of the reamer shoe.[305] Debris and/or cuttings may have plugged these holes during the course of casing installation as shown in Figure 4.3.20. This could explain why the rig crew was unable initially to establish mud circulation after landing the production casing. It could also explain why the pressure dropped suddenly from 3,142 psi—that pressure may have been sufficient to clear a clog in the reamer shoe to allow mud to flow again.

After the blowout, at least two BP personnel identified a clogged reamer shoe as a factor that may have complicated the float conversion process. Morel told BP investigators soon after the blowout that he believed the reamer shoe may have been plugged.[306] Sepulvado, who was onshore at the time of the blowout, similarly told the Chief Counsel's team that the only reason such high pressures would have been needed was because differential pressure was not getting to the ball,[307] which may have been caused by a clogged reamer shoe.[308] Besides interfering with float conversion, a clogged reamer shoe could have complicated cementing by altering cement flow out of the reamer shoe.

The Ball May Have Been Forced Through the Auto-Fill Tube

A second possibility, shown in Figure 4.3.21, is that the sudden pressure drop may have been caused when pump pressure forced the ball inside the auto-fill tube through the end of the auto-fill tube. The collar that would normally have retained the ball within the auto-fill tube was held in place with brass pins. It is possible those pins and the collar failed, allowing the ball to pass through.[309] This would have left the auto-fill tube in place between the float valves and created a path for flow in either direction.

If the ports in the bottom of the auto-fill tube were clogged, the rig pumps may have placed enough force on the collar to shear the brass pins instead of the pins holding the auto-fill tube in place. Clawson informed Morel on April 19 that it would only take 1,300 psi of pressure to force the ball through the collar without converting the float valves.[310] It is not apparent whether Morel considered or informed others of this possibility.[311]

Unconverted Float Valves Would Have Increased the Risk of Cement Failure

If rig personnel never converted the float valves at Macondo, it would have left an open flow path through the float collar assembly. That flow path may have allowed cement to flow back into the casing from the annular space outside the casing, which would in turn have left less cement in the annular space. This flow would also have: (1) increased the potential for contamination of the shoe track cement with mud; (2) brought foamed cement from the annulus into the shoe track (which should have contained only unfoamed tail cement); and (3) allowed any nitrogen that broke out of the foamed cement to compromise the shoe track cement. The open flow path would also have made it easier for any hydrocarbons that bypassed the cement to flow through the float collar assembly.[312]

Properly Converted Float Equipment Is Not a Reliable Barrier to Hydrocarbon Flow

The Chief Counsel's team does not believe that even properly converted float valves would have constituted a reliable physical barrier to hydrocarbon flow. While BP's internal investigation report appears to state that float valves could be a barrier,[313] several senior BP personnel disagreed with that statement.[314] Weatherford does not consider float equipment a barrier to hydrocarbon flow and instead provides the equipment only to prevent backflow of cement.[315] The API similarly states only that "float equipment is used to prevent the cement from flowing back into the casing when pumping is stopped"[316] and does not include float equipment among its list of subsurface mechanical barriers.[317]

Management Findings

BP's Management Processes Did Not Force the Macondo Team to Identify and Evaluate All Cementing Risks and Then Consider Their Combined Impact

BP engineers failed to fully appreciate the cementing challenge they faced at Macondo. Every deepwater cement job presents a technical challenge, but the Macondo cement job involved an unusual number of risk factors. Several were inherent in the conditions at the well. BP and Halliburton created several others during the course of the design and execution of the primary cement job. The list includes:

- narrow pore pressure/fracture gradient;
- use of nitrogen foamed cement;
- use of long string casing design;
- short shoe track;
- limited number of centralizers;
- uncertainty regarding float conversion;

- limited pre-cementing mud circulation;
- decision not to spot heavy mud in rathole;
- low cement volume;
- low cement flow rate;
- no cement evaluation log before temporary abandonment; and
- temporary abandonment procedures that would severely underbalance the well and place greater stress than normal on the cement job.

BP engineers certainly recognized some of these risk factors and even tried to address some of them. For instance, the team asked Halliburton to use additional spacer during the cement job to compensate for the limited pre-cementing circulation.[318] But it does not appear that any one person on BP's team—whether in Houston or on the rig—ever identified all of the risk factors. Nor does it appear that BP ever communicated the above risks to its other contractors, primarily the Transocean rig crew. For instance, Transocean was never aware that Halliburton had recommended more than the six centralizers that were used.[319]

More importantly, there is no indication that BP's team ever reviewed the *combined impact* of these risk factors or tried to assess the overall likelihood that the cement job would succeed, either on their own or in consultation with Halliburton. Rather, BP appeared to treat risk factors as surmountable and then forgettable. For instance, after Guide had decided to use only six centralizers despite the risk of channeling, one BP engineer wrote to another team member, "But who cares, it's done, end of story, [we] will probably be fine and we'll get a good cement job."[320] Reviewing the aggregate effect of risk factors may not even have led BP to change any of its design decisions. But if done properly, it may have led BP engineers to mitigate the overall risk in ways that could have prevented the blowout. Indeed, a major oil company representative stated that the risk factors at Macondo were so significant that his organization would not have counted the Macondo cement job as a barrier to annular flow outside the production casing even after a successful negative pressure test.[321]

A closely related issue is that once BP's engineering team properly identified a risk, it often examined and addressed the risk without a full appreciation of other risks its *response* might create. For instance, BP's team focused almost exclusively on the risk of lost returns in designing its cementing program. BP engineers may well have been right to view this as the largest individual risk they faced. But they failed to consider the secondary impacts of their numerous responses to that risk, which included reducing pre-cementing circulation, cement volume, and cement flow rate. Those responses may have increased the overall likelihood of cement failure even as they decreased the potential for lost returns.[322]

BP Did Not Properly Manage Design Changes and Procedural Modifications

Impact of Changes to Its Mud Circulation Plan

BP's engineering team does not seem to have recognized that late-stage changes to mud circulation plans might impact float collar conversion. Before the early April lost circulation event, the team intended to circulate fluids at 8 bpm—a rate that would have converted the float valves. But the BP team later reduced the planned circulation rate to 4 bpm because of ECD concerns—a rate that would not have converted the float valves according to the manufacturer's specifications. The April 15 drilling plan highlights the disjoint: It simultaneously calls for circulation rates of *at least* 8 bpm to convert the float equipment but recommends circulating mud at 3 bpm "to keep ECD below 14.5 ppg."[323] Circulating at 8 bpm would clearly exceed that ECD threshold, and an independent expert found this inconsistency irreconcilable.[324]

If BP had recognized that lowering planned circulation rates could impact float collar conversion, it could have solved the problem easily. Weatherford can readily produce float collars that convert at different flow rates—changing the conversion flow rate can be as simple as changing the number of shear pins or the size of the holes in the bottom of the auto-fill tube. BP could therefore have used a different float collar assembly that would have converted at the lower flow rates it planned. Its engineering team does not appear to have considered this possibility or the internal inconsistency in its drilling plan.

Centralizer Sub Procurement

By January 2010, BP's well plan had called for at least 11 centralizers for its final production casing string. Weatherford, BP's centralizer supplier, recommends that its clients notify it of equipment needs four to six weeks in advance.[325] But BP engineers waited until the last day of March to begin the process of ordering centralizers, leaving themselves less than three weeks of lead time. If BP had ordered centralizers earlier, Weatherford personnel would have had ample lead time to manufacture more centralizer "subs" to meet BP's request,[326] and BP's team would not have been forced to decide whether to use slip-on centralizers.

When BP eventually ordered centralizers from Weatherford, the engineer who made the request only asked for a range of "7-10" centralizers rather than the 11 centralizers that BP's January 2010 plan specified. It appears that BP engineers relied on their own estimates of centralizer needs given well conditions, but it is unclear why those conditions would have been any different than when the original well plan was designed.[327] When Weatherford responded that it had only six centralizers in stock, BP's team viewed this as sufficient even though it was less than the number the engineer requested and about half the number called for in the well plan. There is no indication that BP's team even asked whether additional centralizer subs could be manufactured in time, nor is there any evidence that BP attempted to secure acceptable equipment from other suppliers besides Weatherford.[328]

Managing equipment procurement is a key part of safe and efficient offshore drilling. By failing to plan centralizer procurement properly, BP's engineering team forced itself to choose between using only a few centralizer subs, adding slip-on centralizers that its team believed posed mechanical risks, or incurring costs by waiting for Weatherford to manufacture additional subs at the last minute.

Decision Not to Run Additional Slip-On Centralizers

BP also mismanaged its engineering response to Halliburton's advice to add centralizers. First, BP and Halliburton could have considered centralizer availability during the mid-April design review that led them to determine they could cement a long string without exceeding ECD thresholds. Instead, they simply assumed optimal centralization without examining whether they had the materials on hand to achieve it.

Once Gagliano advised BP's team that additional centralizers would be needed to avoid channeling, the team responded by procuring 15 additional centralizers immediately. The immediate response reflects appropriate levels of concern, but also highlights the problems with making complex design changes at the last minute. The engineering team believed that it was ordering slip-on centralizers with integrated stop collars even though a Weatherford representative sent the team specifications that showed otherwise. It appears that BP's team did not review these specifications carefully, perhaps because of time pressure. Careful review here would have avoided last-minute decision making on April 16.[329] The decision to send these additional centralizers prompted Guide to complain to his supervisor Sims the next day:

> David, over the past four days there has been so many last minute changes to the operation that the WSL's have finally come to their wits end. The quote is "flying by the seat of our pants." More over we have made a special boat or helicopter run everyday. Everybody wants to do the right thing, but this huge level of paranoia from engineering leadership is driving chaos.... The operation is not going to succeed if we continue in this manner.[330]

After the centralizers were delivered, BP made its final decision not to use them without careful engineering review. After Guide found out the type of centralizers Weatherford had provided, he argued that they should not be used because of recent problems that BP had experienced with the design.[331] (Guide mentioned time and cost concerns as well.) But Guide and the rest of the BP team appear to have been motivated by personal experience rather than any disciplined analysis. Notably, they did not consult the Weatherford centralizer technician that they had flown to the rig, who could have provided valuable input on the relative risks of centralizer hang-up.[332] It is not even clear whether BP believes *now* that its Macondo team should or should not have used the centralizers; the Bly report states that the team "erroneously believed that they had received the wrong centralizers."[333]

BP also did not examine whether the mechanical risks of running additional centralizers outweighed the cementing risks of *not* using them. BP's team could easily have asked Gagliano to run a new model to predict the impact of using only six centralizers and could have provided up-to-date wellbore and well design data to improve the accuracy of those predictions. The team also could have consulted its in-house cementing expert Cunningham.[334] BP could have asked Halliburton to incorporate Morel's irregular placement of centralizers into its model, rather than simply relying on Morel's apparent ad hoc analysis to determine their placement. It did none of these things.[335] BP's engineering team may have been motivated by skepticism of Halliburton's modeling,[336] but this was the only analytical tool the team had at the time.

Having made a last-minute decision to use fewer centralizers than planned, BP's team should have recognized that decision would increase the risks, first, of lost returns (by increasing ECD), and second, of overall cementing failure. Instead, the team appears to have viewed its centralizer decision-making process as a "miss-step"[337] that had little significance after it occurred. Had BP at least noted the risks of using fewer centralizers than it had planned, its rig personnel and contractors might have been better prepared for the events that followed.

Communication of Centralizer Decisions Hampered Risk Identification and Management

Once BP decided not to run the additional centralizers, it made no effort to inform its contractors of its decision. Weatherford's technician only learned that the centralizers would not be used by asking about the issue hours after the installation should have occurred.[338] When he did learn of it, the technician was concerned enough to call his supervisor—he had never been on an installation job that had been canceled.[339] But neither he nor anyone else at Weatherford expressed concerns to BP. Instead, the technician's supervisor instructed him to defer completely, stating: "Third party, we do what the company man requests."[340]

Gagliano only learned about the decision from Tabler, who in turn learned it from Chaisson, who in turn learned of the decision by happenstance.[341] Gagliano stated that he was "frustrated,"[342] and emailed BP's team to confirm the decision and to ask if he should rerun his models, but nobody ever responded to him.[343] Gagliano eventually updated the cement model on his own, but his model lacked up-to-date information from BP, and he sent it only after the casing run had begun. A prompt response from BP to Gagliano might have improved the Macondo team's appreciation of the risks they faced.

Use and Management of Modeling Results

BP engineers mismanaged their use of Halliburton's computer cementing models.

It is unclear why BP did not review Halliburton's modeling results more carefully and continually update Halliburton's data after April 14. Industry experts say that it is not uncommon for operators to depart from cementing rules of thumb (such as full bottoms up) in reliance on favorable modeling predictions. But operators who do so should continually update such models to ensure that their departures do not cause cementing problems. At Macondo, BP appears to have done little after April 14 to ensure that Halliburton was using up-to-the-minute data. BP provided Halliburton a caliper log but not updated information about reservoir pressure and centralizer placement. Instead, it appears that BP's engineering leadership paid little attention to refining the model once it produced results they found favorable.

BP's willingness to disregard Halliburton's April 18 modeling predictions is especially questionable given the degree to which BP relied on the model's earlier predictions. On April 14, BP relied almost exclusively on a Halliburton model to conclude that it could successfully cement a long string casing. At this time, BP engineers knew that the model was based on incomplete data. BP then disregarded the April 18 predictions even though the concerns it identified were similar to those that motivated more serious analysis on April 14. BP's apparent skepticism of the value of the April 18 results is hard to square with its near-total reliance on the April 14 results.

BP Did Not Adequately Evaluate the Significance of Float Conversion Difficulties

BP's management and review of the float collar conversion process were inadequate. As explained above, BP should have secured different float equipment once it modified its planned circulation rates. BP also mismanaged its evaluation of the float conversion process on the rig. BP rig personnel properly consulted their shore-based engineering team after encountering difficulties when converting the float collar. But after reinitiating circulation at much higher pressures than expected, BP's team appears to have assumed the float valves converted. If the team had instead reviewed the data carefully, it would have recognized that it had not yet circulated mud in excess of 4.3 bpm and might have increased circulation to ensure conversion.

Making matters worse, BP and Transocean personnel then tried to explain away concerns about lower-than-predicted circulation pressures by blaming a faulty pressure gauge. BP has since pointed out that the circulating pressures predicted by M-I SWACO were erroneous and that the circulation pressure observed was actually what should have been expected. But rig personnel believed at the time that M-I SWACO's predictions were accurate, and yet there is no evidence that they took steps to confirm the gauge was actually faulty or tried to replace it.[344]

If BP or Transocean had adequately considered the possibility that the float valves did not convert, they could have undertaken efforts to mitigate the potential risks. For instance, one standard industry tactic to address float valve failure is to add pressure inside the casing system after pumping cement and to thereby counterbalance any u-tube pressure that might otherwise induce flow back through open float valves.[345]

BP Focused Excessively on Full Returns as an Indicator of Cementing Success

The Macondo team's approach to cement evaluation at Macondo was flawed. Because the team focused its attention so heavily on the risk of lost returns, it overemphasized the significance of full returns as an indicator of cementing success.

Receiving full returns showed that cement had not flowed into the weakened formation but provided little or no information about: (1) the precise location where the cement had ended up; (2) whether channeling had occurred; (3) whether the cement had been contaminated;[346] or (4) whether the foamed cement had remained stable. Similarly, reports of on-time top plug arrival indicated, at most, only one thing for certain: The cement flowed through the float collar. (Morel's report that the bottom plug bumped early may suggest that mud contaminated the cement during job placement.) Accordingly, BP's technical guidance documents do not list reports of full returns or on-time plug bumping as indicators of zonal isolation.[347]

BP engineers also considered lift pressure a positive indication. Company technical guidance documents state that lift pressure can provide a coarse indication of TOC (if not zonal isolation) but that it "is unlikely to provide a sufficiently accurate estimate" of TOC when "cement and mud weights are very similar,"[348] as they were at Macondo. While one BP engineer stated that lift pressure was "easy" to see at Macondo,[349] another admitted after the blowout that it was not a valid confirmation of good cement placement.[350] Industry experts who reviewed the data after the fact were also skeptical. The Chief Counsel's team spoke with several experts who agreed that the roughly 100 psi pressure increase that rig personnel observed at Macondo after the bottom plug landed was too low to be a reliable indication that cement had turned the corner and flowed up into the annulus.[351] One described 100 psi of lift pressure as "nearly unreadable."[352] That relatively small pressure increase might have been caused by cement "turning the corner" into the annulus, but it might also have been caused by friction from cement flow.[353]

Better management would have encouraged the BP team to question the overall value of its pressure and volume indicators. BP's own report appears to agree. It states:

> A formal risk assessment might have enabled the BP Macondo well team to identify further mitigation options to address risks such as the possibility of channeling; this may have included the running of a cement evaluation log.... Improved technical assurance, risk management and management of change by the BP Macondo well team could have raised awareness of the challenges of achieving zonal isolation and led to additional mitigation steps.[354]

Rather than aiding decision making, the Macondo team's cementing decision tree reinforced the flaws in its analytic approach. Proper risk management in a complex engineering project requires a constant awareness of risks and potential risks. The decision tree instead encourages a simplified linear approach in which complex risks (such as the risk of failed cementing) can be forgotten or ignored on the basis of simple and incomplete indicators (such as partial returns or lift pressure).

Most Operators Would Not Have Run a Cement Evaluation Log in This Situation, but BP Should Have Run One Here, in Part Because of Its Chosen Temporary Abandonment Procedures

At least some personnel appear to have believed that the Macondo team was planning to run a cement bond log no matter what. On April 20, a BP completions engineer emailed Morel to ask for cement bond log data. When Morel responded "No CBL," the completions engineer wrote "Can you explain why? I thought y'all were planning to run one."[355]

A cement evaluation log would have provided more direct and reliable information about the cement job than pressure and volume indicators on which BP relied. While most operators would not have run a cement evaluation log until the completion phase, BP should have run one here[356] for at least two reasons. First, BP engineers recognized or should have recognized that this was a "finesse" cement job that presented higher-than-average risks.[357] Full returns would not identify if channeling had occurred; a cement bond log could.[358] Second, BP's temporary abandonment procedures would force the rig crew to rely on this finesse cement job as the sole hydrocarbon barrier in the Macondo wellbore. Alternatively, BP should have sought other means for addressing the risk of unsuccessful cementing.

Halliburton Did Not Adequately Inform BP of Cementing Risks or Suggest Design Alternatives

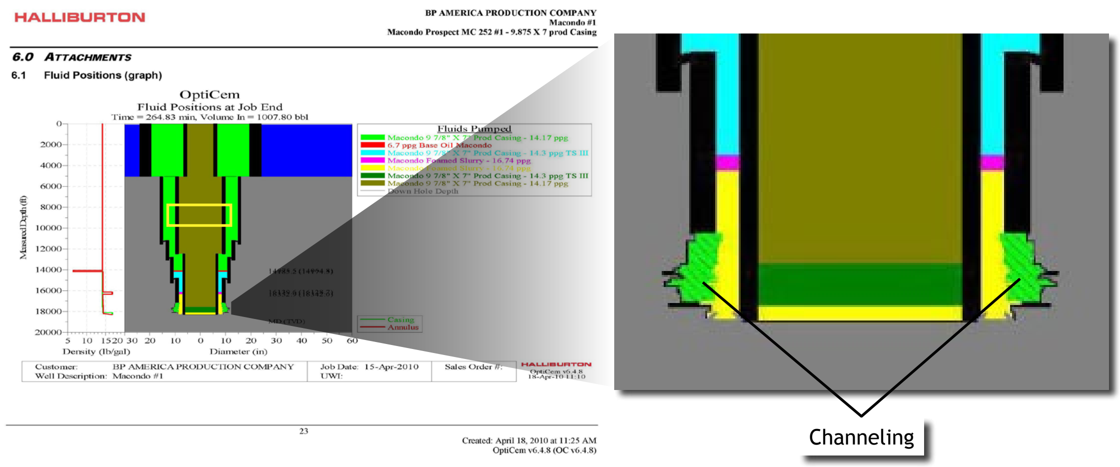
Halliburton did not provide BP the full benefit of its corporate cementing expertise. Since the blowout, senior Halliburton personnel have repeatedly and forcefully emphasized the complexity and difficulty of the Macondo cement job and the limitations of indicators such as full returns.[359] But Halliburton's personnel did not raise all of these concerns before the blowout, let alone emphasize them with the same force.

It appears that Gagliano mentioned the possibility of cement channeling to individual BP engineers on April 15 and then again later on April 19.[360] But he did not flag the concern in his emails or express serious reservations. Gagliano told Congressional investigators that he "recommended to BP that they use 21 centralizers" but admitted that he "did not think there would be a well control issue."[361]

Gagliano also testified that he would have recommended that BP perform a cement bond log given the reduction in the number of centralizers but did not do so because "we do not recommend running a [cement] bond log"[362] and, anyway, he "was never asked."[363] Although Gagliano was present when BP discussed criteria for the cement bond log, he never told anyone full returns alone could not identify channeling.[364] Moreover, the only risk factor that Halliburton identified during the design process was the relatively low number of centralizers. Halliburton did not discuss any other risk factors or recommend other design changes that might have mitigated those risks. Halliburton personnel were aware that BP's design called for a low cement volume and a low cement flow rate. They also knew of the decision not to circulate bottoms up, the float valve conversion difficulties, and the low post-conversion circulating pressures. [365] But they never raised concerns about these risk factors, let alone offered BP an independent assessment of the overall likelihood of success of the cement job.

The format of Halliburton's modeling reports exacerbated communication difficulties. After the blowout, Halliburton personnel argued that the reports included predictions of channeling and gas flow that BP engineers should have heeded.[366] Halliburton could have highlighted these warnings—along with overall assessments of cementing success—in a simple summary early in

Figure 4.3.22. Page 23 of Halliburton's April 18, 2010 OptiCem™ report.



Halliburton

Halliburton personnel explained the green areas as predicted channeling.

the report. Instead, the reports presented information in an obscure and unnecessarily technical manner. (For instance, as shown in Figure 4.3.22, the reports present channeling predictions only as unexplained jagged lines in a well diagram).[367] As a result, BP engineers reviewed the predictions in a cursory fashion, if at all.[368]

Halliburton missed another opportunity to communicate its concerns when it reported the overall success of its cement job. Chaisson expressed complete satisfaction with the cement job in his post-job report but later clarified that "[cementing] was successful on the surface. As far as being successful downhole, actually if it were successful at getting zonal isolation, I cannot be sure of that."[369] Halliburton explains the difference between its pre-blowout reports and its post-blowout skepticism by suggesting that it is BP's responsibility as the operator to evaluate the significance of cementing indicators and BP's responsibility to mitigate risks at the well. Whether that turns out to be true as a legal matter, Halliburton could have helped avoid the blowout if it had highlighted the risks of the cement job and the limitations of the few cementing indicators it had reviewed.