Chapter 4.2 | Well Design

EXHIBIT # 636
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BP's engineering team made a number of important well design decisions that influenced events at Macondo. Among other things, the engineers (1) decided to use a long string production casing, (2) installed rupture disks in the well, and (3) decided to avoid creating trapped annular spaces by omitting a protective casing and leaving annular spaces open to the surrounding formation. The Chief Counsel's team finds that these decisions complicated pre-blowout cementing operations and post-blowout containment efforts.

Deepwater Well Design

Wells are drilled for a reason: either to explore for oil and gas, appraise an earlier discovery, or create a development well in an existing oil field. By the time the well is designed, subsurface geologists and geophysicists will have identified subsurface objectives, usually using seismic reflection data. They will also have prepared—in as much detail as possible—a geologic prognosis describing lithology, pressure, and fluid content as a function of depth. If there are other wells nearby, the geologists and geophysicists will have used data from those wells to inform their prognosis.

The design team that plans the well must determine how best to achieve the well's objectives while managing potential drilling hazards. The hazards can include a variety of geologic features. For instance, porous gas-bearing intervals ("shallow gas")—sand layers containing pressurized gas or water, or unstable formations—may occur in the first few thousand feet below the seabed. Geologic faults and low-pressure hydrocarbon-bearing sands (depleted by nearby oil production) can also present hazards. Sudden variations in subsurface pore pressure can pose hazards as well. Operators must also consider man-made hazards such as nearby oil and gas development infrastructures (wells, platforms, pipelines) and ship traffic.

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Figure 4.2.1
Artist's rendering of the Macondo well from rig to rathole.

In many cases the design team can identify drilling hazards in advance and avoid them. But some geologic hazards, such as high pore pressures and hydrocarbon deposits, are impossible to avoid. Indeed, they are closely associated with the drilling objectives—oil companies often target high-pressure hydrocarbon reservoirs. High pore pressures are a common feature of the deepwater Gulf of Mexico environment, and often signal the presence of oil and gas.

Drilling engineers must therefore keep several key issues in mind as they design a deepwater well.

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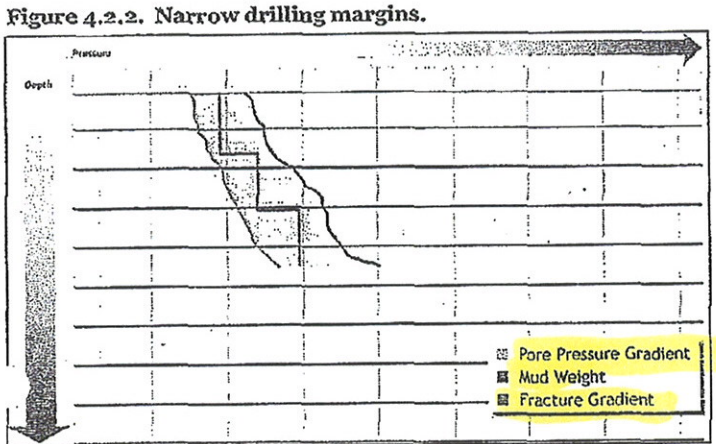
Pore Pressure and Fracture Gradients

Drilling engineers must design wells to manage intrinsic risks. Specifically, they must develop drilling programs that will manage and reflect the pore pressure and fracture gradients at a given drilling location as shown in Figure 4.2.2. (Chapter 2 describes these concepts in more detail.) The design team must specify the kinds of drilling fluids that will be used and the number and type of casing strings that will extend from the seafloor to the total depth of the well. The drilling fluids and casing strings must work together to balance and contain pore pressures in the rock formation without fracturing the rock.

Figure 4.2.2. Narrow drilling margins.



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Creating this plan can be difficult if engineers have limited information about subsurface geology and if actual pore pressures vary significantly from predictions.[1] This is often the case in exploration wells or in the first well in a new field. The problem frequently crops up in the Gulf of Mexico, which is prone to having a narrow window between the pore pressure and fracture gradients as well as zones of pore pressure repression (where the pore pressure gradient suddenly reverses and decreases with depth).[2]

Because drilling conditions often differ significantly from predictions, engineers often design and redesign a deepwater well as the well progresses. They work constantly to keep two factors within tolerable limits: **equivalent static density** (ESD) and **equivalent circulating density** (ECD). ESD refers to the pressure that a column of fluid in the wellbore exerts when it is static (that is, not circulating). ECD refers to the *total* pressure that the same fluid column exerts when it *is* circulating. When drillers circulate fluids through a well, ECD exceeds ESD because the force required to circulate the fluids exerts additional pressure on the wellbore.

In planning the well, engineers will design a mud program to keep both ESD and ECD below the rock's fracture gradient. Drillers monitor these parameters carefully as they work.

Barriers to Flow

As discussed in Chapter 2, operators typically employ redundant **barriers** to prevent hydrocarbons from flowing out of the well before production operations. One important barrier in any well is the mud and drilling fluid system in the wellbore. When properly designed and operated, the drilling fluid system should balance the pressure of any hydrocarbons in the well formation. Engineers can also use other kinds of barriers during drilling and completion. Those barriers include cemented casing, mechanical and cement plugs, and the blowout preventer (BOP). Sound industry practice—and BP's own policy—generally requires an operator to maintain two verified barriers along any potential flow path.[3]

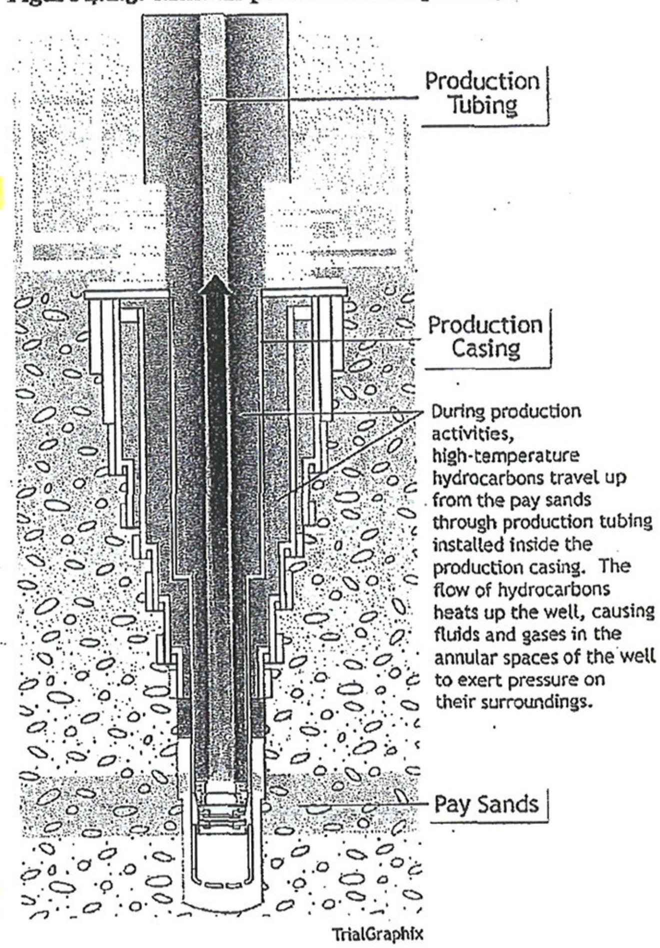
Annular Pressure Buildup

If an operator plans to use a given well to produce oil in the future (rather than merely to learn about subsurface geology), its design team must consider the environmental and mechanical stresses that the well will experience over its lifetime. The casing and completion program must ensure that these stresses do not compromise well integrity over the life of the well, which could be as long as several decades.

In deepwater production wells, engineers pay special attention to a phenomenon called **annular pressure buildup** (APB). Figure 4.2.3 illustrates that during production activities, high-temperature hydrocarbons travel up from the pay sands through production tubing installed inside the production casing. The flow of hydrocarbons heats up the well. As a result, fluids and gases in the annular spaces of the well expand. If the well design creates annular spaces that are enclosed, the fluids and gases trapped within those spaces will exert increasing pressure on the well components as they heat up. In some cases, the pressure can become high enough to collapse casing strings in the well and to force the operator to abandon the well.

Managing annular pressure buildup in a deepwater well requires careful planning and design. Engineers can use a number of design features to manage annular pressures or mitigate the risks of casing collapse. These include rupture disks, compressible fluids in the annular space, and insulated production tubing. Finally, they can design wells in ways that avoid creating trapped annular spaces at all.

Figure 4.2.3. Annular pressure buildup (APB).

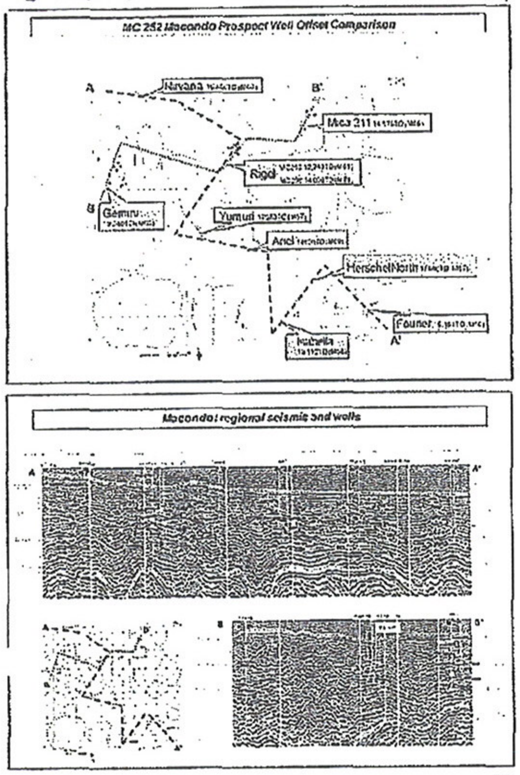


The Macondo Well Design

Even before it began drilling Macondo, BP believed that the well might encounter a substantial hydrocarbon reservoir.[4] But BP also recognized that it might also encounter a number of hazards, including shallow gas sands, overpressures, and depleted reservoir zones, as well as the expected oil and gas in the mid-Miocene objective reservoir. BP chose the particular drilling location for Macondo to penetrate the objective section while avoiding shallow gas sands that it had identified. BP identified potential minor drilling hazards beneath 8,000 feet below sea level: thin gas-charged sands and depleted (low-pressure) zones.[5]

Using seismic imagery, BP had a high degree of confidence that the formation below contained a significant accumulation of oil and gas.[6] BP therefore planned the Macondo well as an exploration well that it could later complete and turn into a production well.[7]

Figure 4.2.4. Offset wells and seismic data.



BP

The green star indicates Macondo's location.

BP drilling engineer Brian Morel and senior engineer Mark Hafle had the primary responsibility for the Macondo well design work.[8] They worked with a number of BP engineers and geoscientists to develop their plans.[9] Geologists and petrophysicists from BP's Totally Integrated Geological and Engineering Resource (TIGER) team helped develop a pore pressure profile for the well based on other wells in the vicinity ("offset wells") as shown in Figure 4.2.4.[10] A BP casing and tubular design team independently reviewed the well design.[11] Fluid experts and rock strength experts checked the geomechanical aspects of the well.[12] And because the well was being designed as a producer, BP completion engineers also provided input during the design process.[13] The completion engineers recommended, among other things, an analysis of the well's potential for annular pressure buildup and possible mitigation measures.[14]

In June 2009, the initial Macondo well design underwent peer review.[15] The reviewers concluded that the Macondo design team "did a lot of good work," that the initial design was "[r]obust" and "supported by good data and analysis," and that "all major risk[s] [were] addressed and mitigations developed."[16] Over the course of the next year, the Macondo engineering team would update its drilling program several times. But three key design features never changed.

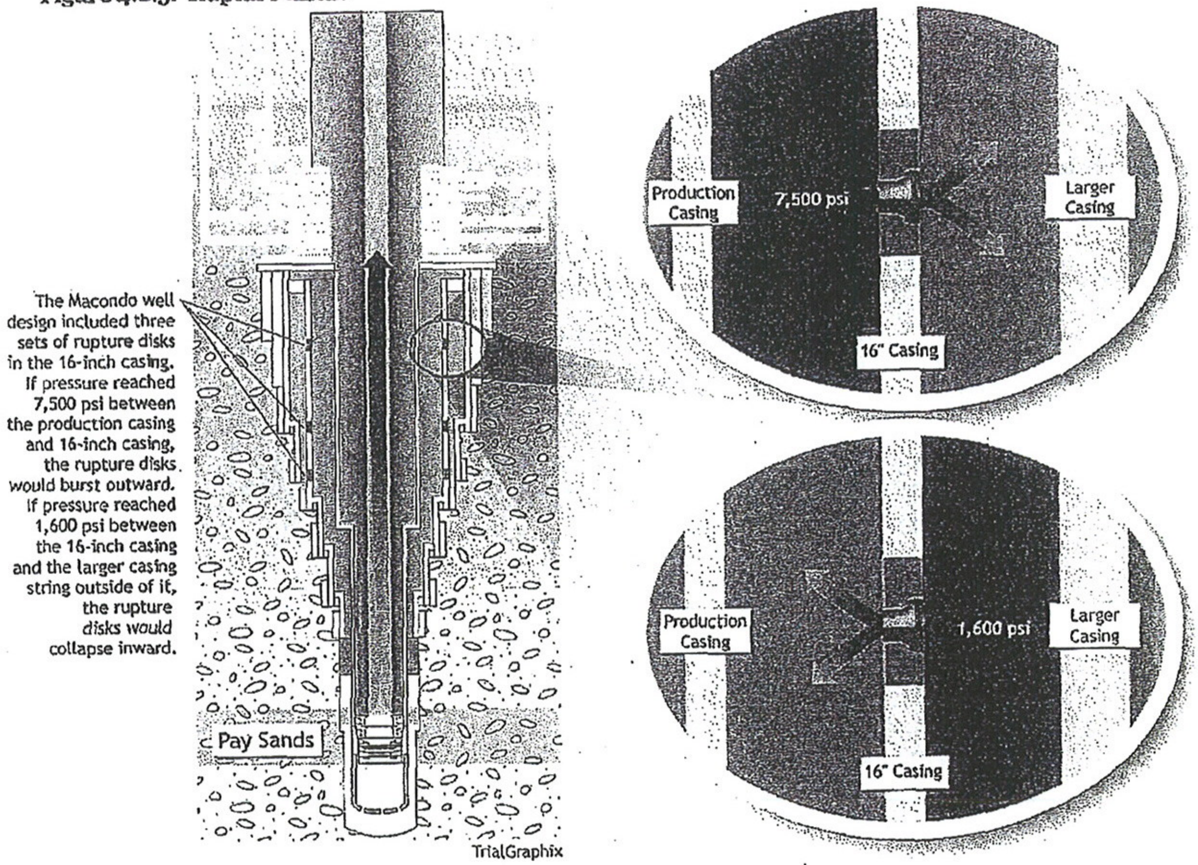
Rupture Disks

All of BP's Macondo well designs included three sets of rupture disks in the 16-inch casing.[17] The 16-inch casing was the longest piece of pipe outside of the production casing. The **rupture disks** (or burst disks) would relieve annular pressure before that pressure could build up high enough to cause a collapse of the production casing or the 16-inch casing.

The disks worked in two ways as shown in Figure 4.2.5. First, if pressure between the 16-inch casing and the production casing reached 7,500 pounds per square inch (psi), the rupture disks would *burst outward* and release that pressure.[18] Because the production casing was rated to withstand 11,140 psi of pressure, this would prevent annular pressure from rising to the point at which it could collapse the production casing.[19] Second, if pressure *outside* of the 16-inch casing (that is, between the 16-inch casing and the other larger casing strings outside it) exceeded 1,600 psi, the rupture disks would *collapse inward* to release that pressure.[20] Because the 16-inch casing was rated to withstand 2,340 psi of pressure, this would prevent pressure outside the 16-inch casing from rising to the point at which it could collapse the 16-inch casing.[21]

Once ruptured, the disks would leave small holes in the 16-inch casing through which pressure could bleed into the surrounding rock formation.[22]

Figure 4.2.5. Rupture disks.



Protective Casing

BP's well design consistently and deliberately omitted a **protective casing.** A protective casing is an intermediate casing string outside the production casing that runs from deep in the well all the way back to the wellhead.[23] A protective casing supplies a "continuous pressure rating" for the interval that it covers (as shown in Figure 4.2.6) and seals off potential leak paths at the tops of previous liner hangers.[24]

It is common industry practice to use a protective casing whenever running a long string production casing.[25] But the Macondo team never planned for a protective casing[26] because installing such a casing would also have negated their efforts to mitigate annular pressure buildup.[27] Specifically, it would have sealed off the rupture disks and the previously open annuli in the casing design.

Figure 4.2.6. Protective casing.

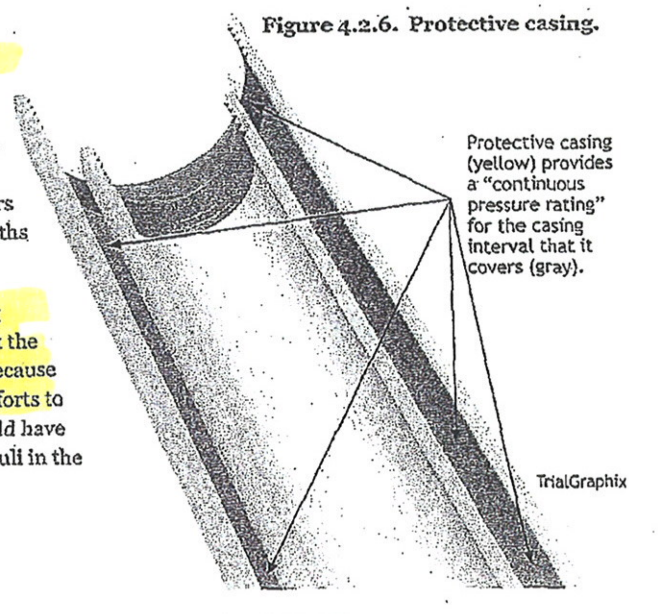
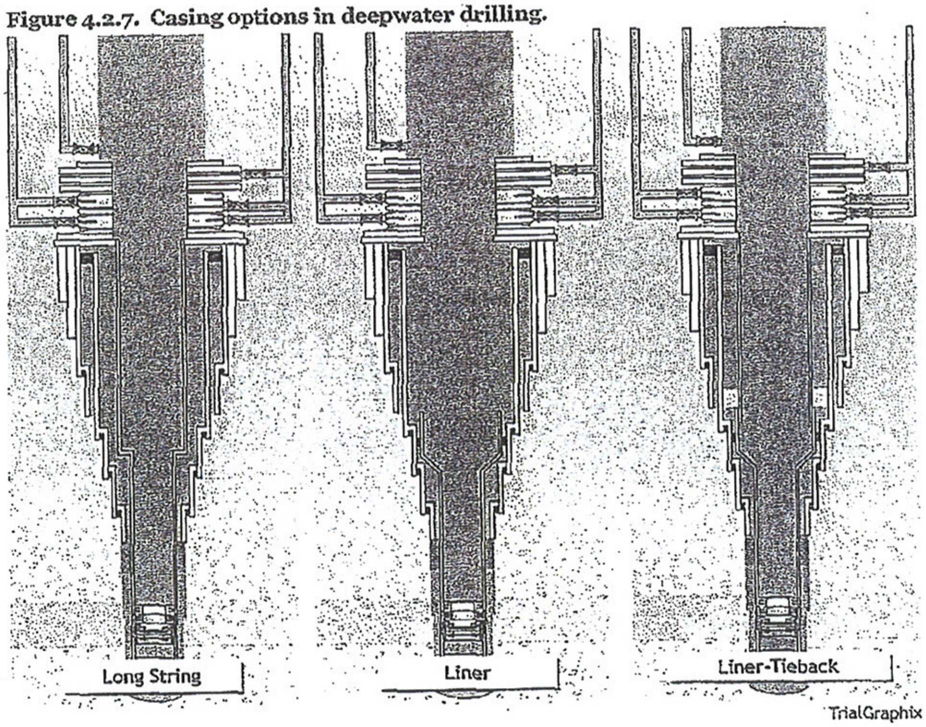


Figure 4.2.7. Casing options in deepwater drilling.



Long String Production Casing

Third, BP's Macondo well design called for a long string production casing, or **long string**, stretching from the bottom of the well all the way to the wellhead. This was true of the initial well design as well as the final well design.[28]

As shown in Figure 4.2.7, the alternative to a long string production casing would have been a **liner**. A liner is a shorter string of casing hung from a casing hanger lower in the well. In order to connect the liner back to the wellhead, BP would eventually have had to install a **tieback**—a string of casing pipe stretching between the top of the liner on one end to the wellhead on the other end. Setting the tieback adds two annular flow barriers to the well design.

In the weeks just prior to the blowout, BP briefly considered using a liner instead of a long string at Macondo. There is no evidence that the Macondo team ever considered having the *Deepwater Horizon* crew install the tieback before temporarily abandoning the well.[29] They presumably would have left that job for a completion rig.

Drilling the Macondo Well

BP encountered a series of complications while drilling the Macondo well. This included two previous kicks, a ballooning event, lost circulation events, and trouble determining pore pressures (as shown in Figure 4.2.8). Together, these issues made Macondo "a difficult well."[30]

Kicks and Ballooning

Twice prior to April 20, the Macondo well experienced an unwanted influx into the wellbore, or a "kick." On October 26, 2009, the well kicked at 8,970 feet. The rig crew detected the kick and shut in the well. They were able to resolve the situation by raising the mud weight and circulating the kick out of the wellbore.[31] On March 8, 2010, the well kicked again, at 13,305 feet.[32] The crew once again detected the kick and shut in the well.[33] But this time, the pipe was stuck in the wellbore.[34] BP severed the pipe and sidetracked the well.[35]

On March 25 the Macondo well also had a ballooning, or "loss/gain," event. The rig lost fluids into the formation. When the crew decreased the pressure of the mud in the wellbore, the rig then received an influx of fluids from the formation.

Lost Circulation During Drilling

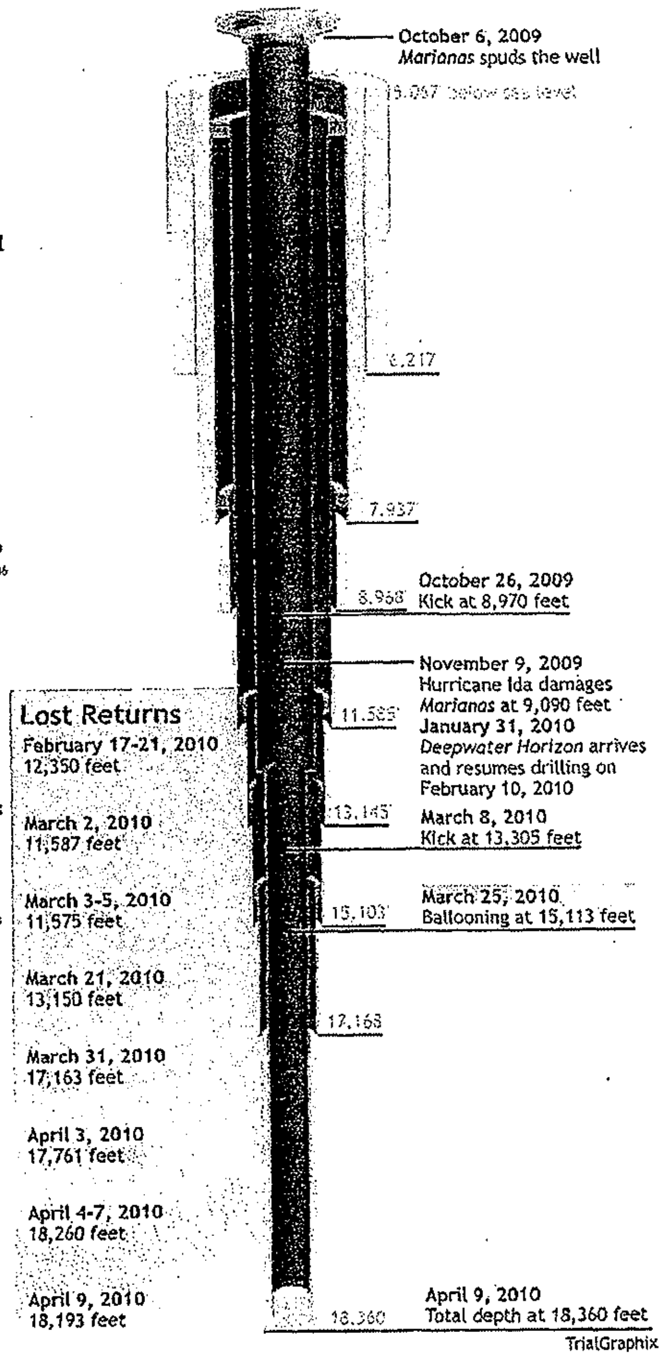
A major risk at Macondo was the loss of drilling fluid into the formation, called **lost circulation or lost returns.**[36] At various points in February, March, and April, the pressure of drilling fluid exceeded the strength of the formation, and drilling fluid began flowing into the rock instead of returning to the rig.[37] Lost circulation events are common in offshore drilling. The *Horizon* rig crew generally responded with a standard industry tactic: It pumped thick, viscous fluid known as **lost circulation material** into the well and thereby plugged the fractures in the formation.

The *Horizon* crew successfully addressed repeated lost circulation events while drilling the Macondo well.[38] The events occurred frequently and at various depths, and sometimes lasted several days: once in mid-February, four times in March, and three times in April.[39] In total, BP lost approximately 16,000 barrels of mud while drilling the well, which cost the company more than $13 million in rig time and materials.[40]

Uncertain Pore Pressures Affect the Well Design

The kicks, ballooning, and lost circulation events at Macondo occurred in part because Macondo was a "well with limited offset well information and preplanning pressure data [were] different than the expected case."[41] Given BP's initial uncertainty about the pore pressures

Figure 4.2.8. Timeline of drilling events.



of the rock, the company had to adjust its well design as it drilled the well and gained better pore pressure information.

This was particularly true after the March 8 kick. According to contemporaneous communications among BP engineers, the "kick and change in pore pressure...completely changed" the forward design[42] and did so "rapidly."[43] "Due to well pressure uncertainty, it [was] unknown how many more liners [BP would] need to set before getting to TD."[44] Accordingly, the Macondo team decided to proceed more conservatively and set casing strings shallower in the well.[45] They installed an intermediate 11⅞-inch liner (at 15,103 feet) that had been set aside as a contingency in the original plan.[46] They then set an additional liner, 9⅞ inches in diameter, above the reservoir (at 17,168 feet).[47] And they planned for yet another smaller casing size in the final hole section.[48]

Rig Crew Calls Total Depth Early Due to Narrow Drilling Margin

The last of the lost circulation events occurred on April 9, after the rig had begun to penetrate the pay zone.[49] At 18,193 feet below sea level, the drilling mud pressure exceeded the strength of the formation, and the rig crew observed lost returns. The point at which the formation gave way—when ESD was approximately 14.5 pounds per gallon (ppg)—came as a surprise to the Macondo team.[50] The crew had to stop drilling operations until they could seal the fracture and restore mud circulation. They pumped 172 barrels of lost circulation material down the drill string, hoping to plug the fracture.[51] The approach worked, but BP's onshore engineering team realized the situation had become delicate.[52] In order to continue drilling, they had to maintain the weight of the mud at approximately 14.0 ppg in order to balance the pressure of hydrocarbons pushing out from the formation. But drilling deeper would exert even more pressure on the formation. Engineers calculated that drilling with 14.0 ppg mud would yield an ECD of nearly 14.5 ppg—presenting the risk of once again fracturing the rock and losing returns.[53] At that point, "it became a well integrity and safety issue."[54] The engineers had "run out of drilling margin."[55] The well would have to stop short of its original objective of 20,600 feet.

Rig personnel were able to carefully drill ahead an additional 167 feet and called total depth at 18,360 feet. In that sense, drilling was successful: BP reached the targeted reservoir zone and was able to run a comprehensive suite of evaluation tools.[56]

ECD Concerns Influence Final Production Casing Design

BP engineers then began preparing to install a production casing. BP had Halliburton run a series of computer models to help plan for cementing the production casing.

March 23 Meeting Considers Both Long String and Liner Production Casing

On March 23, Hafle, Morel, and in-house BP cementing expert Erick Cunningham met with Halliburton cementing engineer Jesse Gagliano to discuss ECD concerns in the modeling.[57] The team was trying to decide what size production casing to install and cement at the bottom of the well.[58] Earlier that month, the engineers had modeled both long string and liner production casing designs on two sizes of pipe—7⅝-inch and 7-inch.[59] They were concerned the 7⅝-inch pipe would create a narrow annulus and increase friction to the point that the formation would break.[60] According to Halliburton's models, a smaller 7-inch pipe reduced ECD significantly.[61] Though no decision was made as to casing design or diameter, the group decided to find out how much 7-inch pipe was available should they decide to use that size production casing at the bottom of the well.[62]

April Meetings Finalize Well Design

BP and Halliburton continued to meet and review Halliburton's computer models of the production casing. The team met on April 9 but decided Halliburton's model was inaccurate because it predicted an ESD of 13.9 ppg, which was erroneously low because the weight of the mud in the wellbore was itself heavier than 13.9 ppg.[63] Gagliano created a new model, but on April 12 BP drilling and completions operations manager David Sims determined the ESD in this model was now too *high*[64] and requested that Cunningham review and lend his expertise to the well plan.[65]

At that point, the team considered running a liner instead of a long string in the production interval. The Macondo team believed that ECD would be lower in running the liner.[66] But BP engineering manager John Sprague raised additional technical concerns and requested a review of annular pressure buildup issues related to running a liner.[67]

The potential for a last-minute switch had BP engineers scrambling. Morel asked casing design specialist Rich Miller for a "quick response" on the annular pressure buildup review.[68] "Sorry for the late notice," he added, "this has been a nightmare well which has everyone all over the place."[69] Miller replied, "We have flipped design parameters around to the point that I got nervous," but with respect to annular pressure buildup issues related to the liner he determined "[a]ll looks fine."[70]

Although the onshore engineers had not yet decided the final casing parameters, the rig crew was still supposed to set the casing in a few days, so BP wells team leader John Guide instructed the BP well site leaders on the rig to ready the equipment necessary to run either a liner or a long string.[71] BP had a number of boat and helicopter runs to the rig over the next several days, trying to coordinate the logistics of equipment and people necessary for the upcoming casing and cement jobs. Well site leader Don Vidrine complained to Guide about the last-minute changes. "[T]here [have] been so many last minute changes to the operation that the WSL's have finally come to their wits end," Guide recounted. "The quote is 'flying by the seat of our pants.'"[72]

Transocean also expressed concern to Guide about the long string/liner decision being made "very late in the day."[73] The contractor needed sufficient advance notice to verify logistics and, in particular, that the rig's equipment was fit to handle the final casing string's weight.[74]

Engineers Decide to Run Long String at April 14 Meeting

On April 14, Hafle, Morel, Cunningham, BP operations engineer Brett Cocales, and drilling engineering team leader Gregg Walz met to review Halliburton's ECD modeling.[75] The group identified another limitation of the model—they determined that its data inputs did not reflect the actual latest data acquired during the well logging process.[76] After reassessing well conditions with Cunningham,[77] the team decided they could successfully run and cement a long string.[78]

Several factors appear to have motivated the decision to install and cement a long string production casing:[79] a desire to stick with the original design basis of the well,[80] a desire to mitigate future annular pressure buildup by avoiding a trapped annulus,[81] a desire to eliminate an extra mechanical seal that could leak during production,[82] and a desire to save $7 million to $10 million in future completion costs.[83]

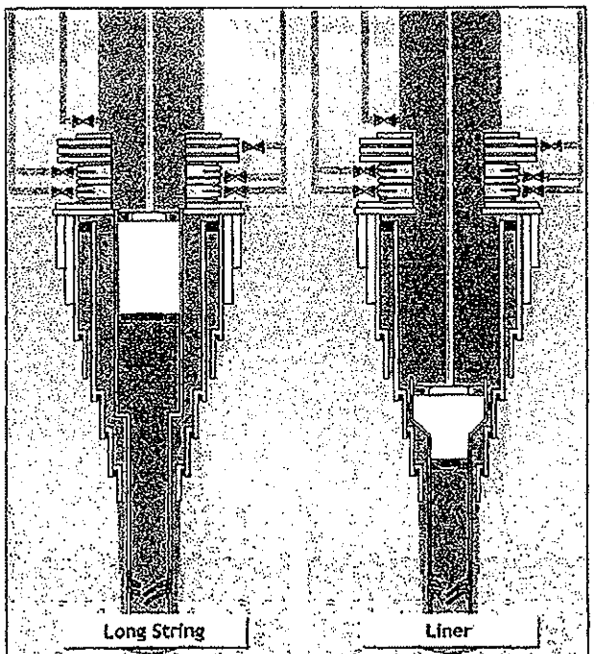
The team made the decision official in a **management of change** (MOC) document—part of BP's process for documenting changes in well design.[84] According to the MOC, the long string provided the best "well integrity case for future completion operations," "the best economic case" for the well, and could be cemented successfully with careful cement job design.[85] The document also discussed the risk that the primary bottomhole cement would not act as a barrier (as discussed in Chapter 4.3).[86] Senior BP managers—including Sims, Walz, Guide, Sprague, and others—reviewed the management of change document and approved.[87]

Technical Findings

Choosing a Long String Production Casing Made the Primary Cement Job at Macondo More Difficult

Operators in the Gulf of Mexico routinely use long string production casings in deepwater wells.[88] But BP's decision to use a long string at Macondo triggered a series of potential problems, particularly with the bottomhole cement job.

Figure 4.2.9. Cementing a long string vs. cementing a liner.



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The lost circulation event at the pay zone in early April led the company's engineers to carefully analyze whether they could circulate cement successfully around the production casing (or liner) without fracturing the already delicate formation. Because cementing a liner is typically easier than cementing a long string, the decision by BP engineers to stay with the long string design further complicated an already complex cement procedure in several ways.[89]

First, the use of a long string increased the risk of cement contamination. Cementing a long string instead of a liner required cement to travel through a larger surface area of casing before reaching its final destination, as shown in Figure 4.2.9. That increased surface area translates into increased exposure of cement to the film of mud and cuttings that adheres to the casing.[90] That risk was exacerbated by the fact that the long string production casing was tapered, making it more difficult for wiper plugs to reliably wipe clean.[91]

Second, using a long string eliminated the possibility of rotating or otherwise moving the casing in place during the cement job. Rig personnel could have rotated a liner, which would have improved the likelihood of a quality cement job.[92] But it is more difficult to rotate a long string than it is to rotate a liner, so choosing that design eliminated one option for mitigating cementing risks.

Third, cementing a long string typically requires higher cement pumping pressure (and higher ECD) than cementing a liner.[93] To compensate for that pressure increase in a fragile wellbore like the one at Macondo, BP engineers made other adjustments to the cement job. As Chapter 4.3 explains, some of the adjustments the engineers made to reduce ECD increased the risk of cementing failure. If BP engineers had chosen to use a liner, they not only could have obtained lower ECDs, but also may have been able to ignore ECD entirely. This is because the liner hanger includes a mechanical seal that serves as a barrier to annular flow.[94] By relying on that seal, engineers can design a more robust primary cement job—they can, for instance, deliberately exceed ECD limits, risk lost returns, and then plan to remediate cement problems later without *having to rely on the cement as a barrier to flow.*[95]

Fourth, it is harder to remediate a cement job at the bottom of a long string than it is to remediate one at the bottom of a liner. With a liner, rig personnel can remediate the cement job, before completing the setting of the liner, by lifting the stinger above the liner hanger and pumping additional cement over the top of the liner hanger.[96] That method is more effective and less complex than remediating a long string.[97] With a long string, rig personnel must perform a squeeze job (as defined in Chapter 4.3). A squeeze job is complicated and time-consuming—it can take several days.[98] And BP classifies the time spent squeezing as nonproductive time,[99] an undesired disruption that the company expects its employees to minimize.[100]

BP's Design Efforts to Mitigate the Risk of Annular Pressure Buildup Compromised Containment Operations

BP's decision to install rupture disks at Macondo and not to use a protective casing complicated its containment efforts and may have delayed the ultimate capping of the well. (Commission Staff Working Paper #6, titled "Stopping the Spill: the Five-Month Effort to Kill the Macondo Well," discusses these issues in more detail.) Had BP's design omitted the disks and included the casing, the company would have had increased confidence about the Macondo well's integrity. This, in turn, may very well have allowed the company to shut in the well earlier.

In BP's early analyses of its failed late-May top kill attempt, the company concluded that the rupture disks in the 16-inch casing may have collapsed inward during the initial blowout.[101] The disks could have collapsed if hydrocarbons had entered the annular space between the 16-inch casing and the production casing. Those hydrocarbons would have been much lighter than the heavy drilling mud that would have been in the annular space outside the 16-inch casing. That weight difference would have generated a pressure differential significant enough to collapse the rupture disks.[102]

Based on this theory, as well as pressure readings and visual observations from the field,[103] BP concluded that its top kill operation may have failed because the mud it pumped down the well had flowed out through the collapsed rupture disks rather than remaining within the well as intended.[104] Although BP vice president of engineering Paul Tooms emphasized several months later that rupture disk collapse was just one of several theories that could have explained the top kill results,[105] BP presented the theory to the government as the most likely scenario and changed its subsequent containment strategy to reflect it.[106] Although the government remained skeptical of certain elements of BP's analysis,[107] it too believed the rupture disks may have collapsed and that emergency workers needed to consider that possibility when moving forward.[108]

Before the top kill operations, BP had told Interior Secretary Ken Salazar and Energy Secretary Steven Chu that if the top kill failed, the company might try next to cut the riser, remove the lower marine riser package, and install a second blowout preventer on top of the existing one to shut in the well.[109] But BP and others deemed this approach unwise after theorizing that the rupture disks had collapsed.[110] If hydrocarbons had entered the annular space between the production casing and 16-inch casing and the rupture disks had collapsed, capping the well might divert hydrocarbon flow out the rupture disks and sideways into the rock formation around the well. This would have caused a "subsea blowout" in which hydrocarbons would have flowed up to the surface through the rocks below the seafloor. It would have been nearly impossible to contain that flow. To avoid this situation, BP and the government temporarily stopped trying to shut in the well.

A few weeks after the top kill operation, in mid-June, BP and the government revisited the idea of shutting in the well, this time using a tight-fitted capping stack. Although BP was prepared to install the capping stack in early July,[111] it appears that the government delayed installation for a few days to further analyze the stack's impact on the risk of a subsea blowout.[112] The government's team insisted on monitoring for signs of a subsea blowout using several different methods. BP eventually used ships and remotely operated vehicles (ROVs) to gather visual, seismic, and sonar information about the area around the well. It also used wellhead sensors to monitor acoustic and pressure data. All of these efforts were aimed at determining whether the Macondo well lacked the integrity to prevent oil from flowing sideways into the rock.[113] The government and BP were also concerned that closing the capping stack could increase pressures inside the well sufficiently to create new problems or burst the rupture disks (if they had not already collapsed).[114]

Management Findings

BP Appears to Have Sought the Long-Term Benefits of a Long String Without Adequately Examining the Short-Term Risks

BP engineers displayed a strong and perhaps unwarranted bias in favor of using a long string production casing.

Industry experts have stated that successfully cementing a long string casing is a more difficult enterprise than cementing a liner. BP's own engineers appear to have agreed—they considered using a liner as a means of mitigating the risks of losses during cementing. (Chapter 4.3 discusses this issue in more detail.) BP asked Halliburton to run numerous computer cementing models in an effort to find a way to make the long string casing a viable option. They appear to have approached the problem by trying to find a way to make a long string work instead of asking what design option would best address the cementing difficulties they faced.

BP has argued that its team preferred to use a long string casing because a long string offers better long-term well integrity than a liner-tieback. This may be so. But because the Macondo team did not adequately appreciate the risks of a poor cement job (as described in Chapter 4.3), they could not adequately have compared the risks and benefits of using a long string casing at Macondo. BP engineers appear to have been reluctant to switch to a liner for other reasons as well. They had already obtained peer review and approval of the long string design. And the long string approach costs substantially less than the liner.

BP's Special Emphasis on the Risk of Annular Pressure Buildup Overshadowed Its Identification and Mitigation of Other Risks

BP made several of the well design decisions discussed above in order to mitigate the risk of annular pressure buildup. Proper well design requires consideration of annular pressure buildup if the company plans to use the well for production.[115] But BP was particularly sensitive to the issue because of its experience at the Marlin platform at the Atlantis field.[116] BP attempted to mitigate the risk of annular pressure buildup in its Marlin wells by leaving the casing annuli open to the surrounding formation. But in late 1999, one of those wells nevertheless collapsed due to annular pressure buildup.[117] Debris or sediments had apparently plugged the opening in the relevant annulus. The event was a major loss for BP because casing collapse essentially destroys a well.[118]

In the aftermath of the Marlin incident, BP made it a top priority to minimize the risk of annular pressure buildup in its wells.[119] It created a dedicated group of design specialists who analyzed annular pressure buildup issues for every production well and recommended design features to mitigate those risks.[120] BP also developed standard guidance instructing its engineers to leave annuli open as part of a deepwater well's design.[121] And it encouraged the use of rupture disks as a primary annular pressure buildup mitigation measure.[122]

BP's focus on and approach to annular pressure buildup concerns effectively de-emphasized other risks and discouraged certain well design approaches. Because the Macondo team planned the well as a producer, they made several design decisions to mitigate the risk of annular pressure buildup.[123] These included adding rupture disks in the 16-inch casing, omitting a protective casing (which would have created a trapped annulus), leaving an open annulus below the 9⅞-inch liner, and using a long string production casing instead of a liner.[124] As described above, those design features complicated the cement job as well as post-blowout containment efforts.

While BP's methods of mitigating annular pressure buildup created risks, there were alternatives. For example, BP could have used insulated production tubing to protect the well from the heat generated during production. This might have allowed the company to omit burst disks and include a protective casing. BP could also have pumped compressible fluids (such as nitrogen foamed spacer or syntactic foam) into any trapped annular spaces to mitigate the risk of annular pressure buildup rather than designing its well to eliminate such spaces. This approach would have allowed BP to use a liner-tieback without worrying that the tieback would create a trapped annulus.[125]