

Chapter 4.5 | Temporary Abandonment

BP developed a temporary abandonment procedure for Macondo that unnecessarily introduced significant risks into the operation. BP disagrees with this finding and argues instead that the specific procedure it used at Macondo was necessary under the circumstances.¹ The Chief Counsel's team disagrees. BP could have avoided the additional risks created by the procedure by making a few simple changes.

Temporary Abandonment

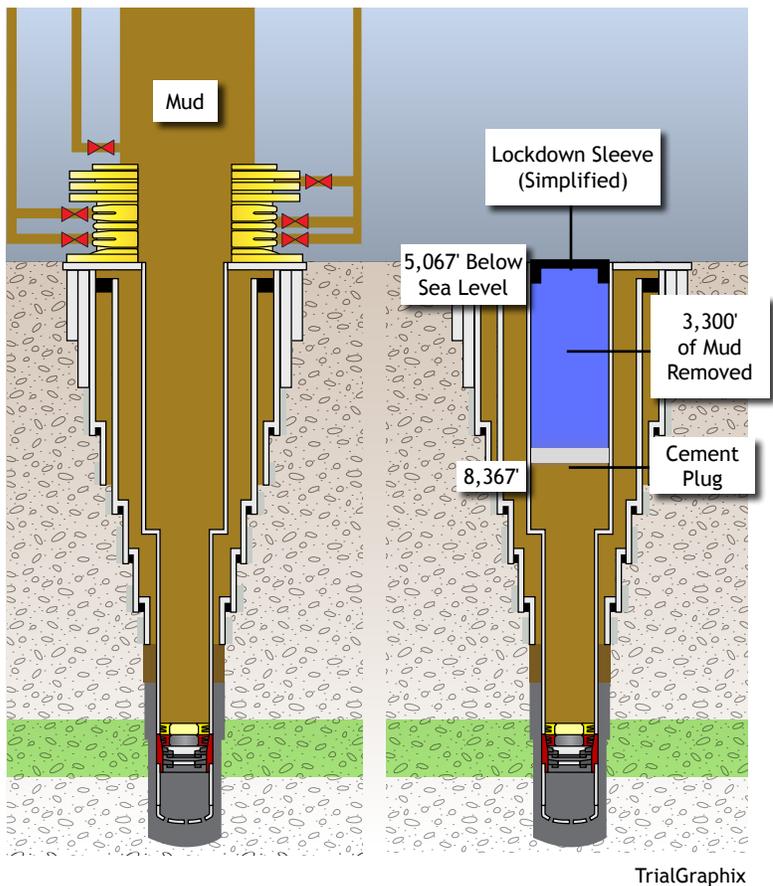
Temporary abandonment refers to the procedures that a rig crew uses to secure a well so that a rig can safely remove its blowout preventer (BOP) and riser from the well and leave the well site. BP planned to have the *Deepwater Horizon* temporarily abandon the Macondo well after the rig finished its drilling operations so that another rig could later move to the Macondo site and complete the well construction process. (That rig would perforate the casing and install equipment to collect hydrocarbons.)

Many operators divide operations in this way to save costs; deepwater drilling work requires a large and expensive rig like the *Horizon*, but completion work can be done by a smaller and less expensive rig.

There does not appear to be any standard industry procedure for temporary abandonment. Instead, different operators perform the process differently based on their internal technical guidance, the design preferences of individual engineers, the capabilities of individual rigs, and the needs of particular wells.

At the time of the Macondo incident, MMS regulations did impose some important requirements on operators that wished to temporarily abandon a well. The regulations specified that the operator must set “a retrievable or a permanent-type bridge plug or a cement plug at least 100 feet long in the inner-most casing” and that the top of the plug must be “no more than 1,000 feet below the mud line”² (as discussed in [Chapter 6](#)). Operators typically refer to this plug as a **surface plug** to distinguish it from other plugs that may be set deeper in the well. Despite the name, surface plugs are not set at the surface or even at the very top of the well.

Figure 4.5.1. Planned configuration after temporary abandonment.



After finishing cementing the production casing (left), the rig crew began temporary abandonment procedures that would have allowed the *Deepwater Horizon* to remove its riser and BOP from the well and move on to another job (right). The blowout occurred before the rig crew set the cement plug and lockdown sleeve.

Temporary Abandonment at Macondo



BP's temporary abandonment procedure for the Macondo well had the following basic sequence:

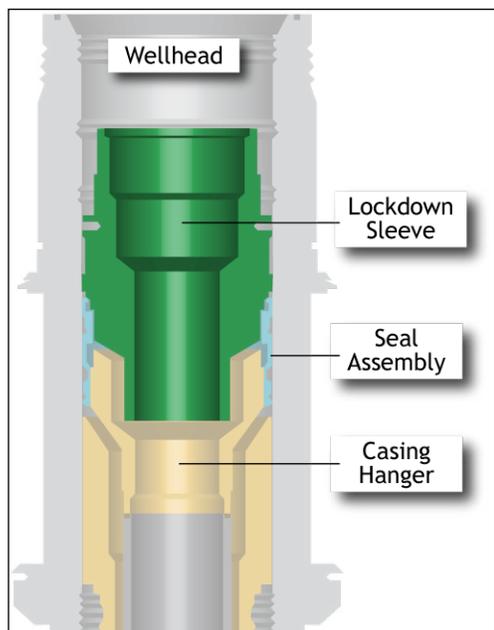
- run the drill pipe into the well to 8,367 feet below sea level (3,300 feet below the mudline);
- displace 3,300 feet of mud in the well with seawater, lifting the mud above the BOP and into the riser;
- perform a negative pressure test to assess the integrity of the well (including the bottomhole cement) and ensure that outside fluids (such as hydrocarbons) are not leaking into the well;
- displace the mud in the riser with seawater;
- set the surface cement plug at 8,367 feet below sea level; and
- set the lockdown sleeve (LDS) in the wellhead to lock the production casing in place.

This procedure is notable in at least two respects. First, it called for rig personnel to set a surface plug deep in the well, 3,000 feet below the mudline. (BP requested and obtained authorization to depart from MMS regulations

in order to do this.) Second, the procedure called for rig personnel to displace the wellbore and riser to seawater before setting the surface plug.

After the incident, the BP Macondo team uniformly explained that it developed its particular temporary abandonment procedure in order to set a lockdown sleeve during temporary abandonment and to do so as the last step in the process.³ The lockdown sleeve decision triggered a cascade of derivative decisions regarding the temporary abandonment procedure that are summarized here and described in greater detail below.

- BP engineers decided to set the lockdown sleeve during temporary abandonment because the *Deepwater Horizon* could do that job more quickly and efficiently than a completion rig.
- Having decided to set the lockdown sleeve during temporary abandonment, BP engineers wanted to ensure that other temporary abandonment operations would not damage the sleeve. To address this concern, they decided to set the sleeve last.⁴

Figure 4.5.2. Lockdown sleeve.

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BP's desire to set a lockdown sleeve during temporary abandonment drove the development of its temporary abandonment procedure. The lockdown sleeve locks down the casing hanger and seal assembly.

- Deciding to set the sleeve last then drove BP's decision to set its "surface" cement plug unusually deep in the well. The process of setting the Macondo lockdown sleeve would require the rig crew to press (or pull) down on the sleeve with 100,000 pounds of force. The Macondo team chose to generate that force by hanging close to 3,000 feet of drill pipe below the lockdown sleeve.⁵ In order to leave room for that length of drill pipe, BP needed to set the surface cement plug even farther down, from 3,000 to 3,300 feet below the mudline.⁶
- Deciding to set the cement plug deep in the well in turn led BP engineers to decide to remove a great deal of drilling mud from the well during temporary abandonment. The Macondo team believed that cement plugs set up better in seawater than in mud.⁷ To set the deep cement plug in seawater, the team instructed the rig crew to replace 3,300 feet of mud in the well with seawater before setting the plug.⁸

Lockdown Sleeve. BP planned to set a **lockdown sleeve** during its temporary abandonment procedure at Macondo. A lockdown sleeve is a piece of equipment that is installed in the wellhead to guard against uplift forces that may be generated during the production of hydrocarbons at a well. The sleeve locks the production casing hanger and seal assembly to the high-pressure wellhead housing so that the forces generated during hydrocarbon production do not lift the casing hanger and seal assembly out of place.

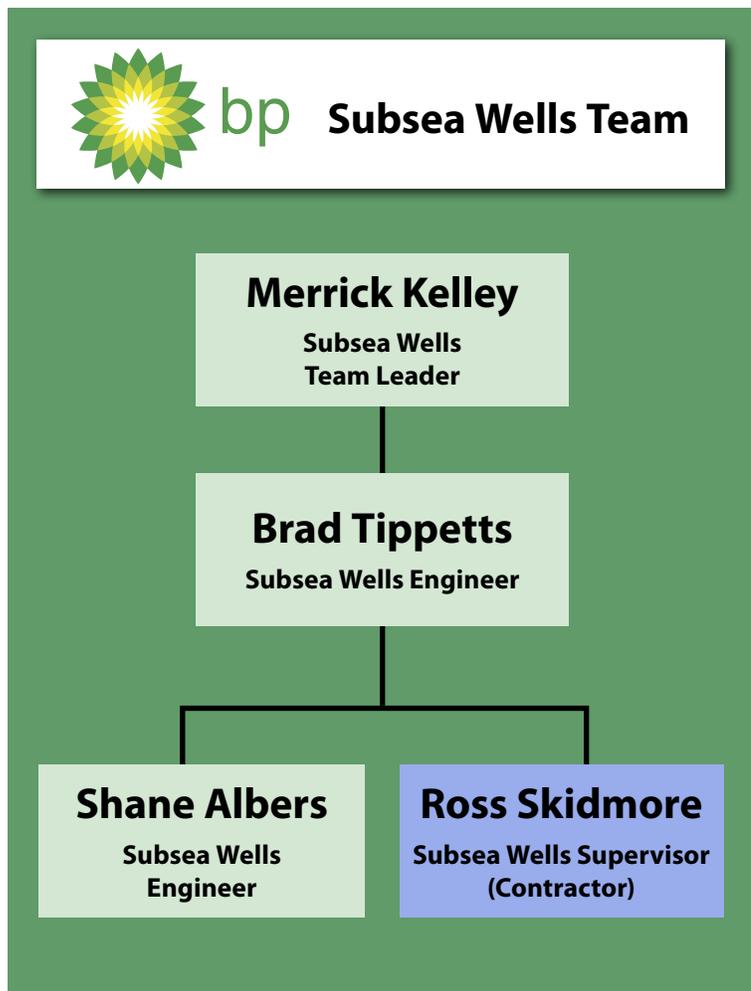
Operators do not normally set lockdown sleeves during temporary abandonment.⁹ They normally set lockdown sleeves later in the life of a well.¹⁰ BP decided to set the lockdown sleeve during temporary abandonment because it believed that a drilling rig, such as the *Marianas* or *Deepwater Horizon*, could do this job more quickly and at a lower cost than a completion rig.

This series of design decisions ultimately led BP to instruct the *Deepwater Horizon* crew to replace 8,367 feet of drilling mud from the riser and well with lighter seawater *before setting any* additional mechanical barriers in the well, such as the surface cement plug.

Decision to Set Lockdown Sleeve During Temporary Abandonment

Lockdown sleeves need not be set during temporary abandonment. Indeed, the Macondo team originally planned to leave the job for a completion rig.¹¹

Figure 4.5.3. BP subsea wells organization.



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BP decided to set the lockdown sleeve during temporary abandonment because it believed that a drilling rig could do this job more quickly and at lower cost than a completion rig. As Chapter 3 discusses, BP began drilling Macondo with Transocean's *Marianas* rig. BP's subsea wells team (Figure 4.5.3) accordingly developed a lockdown sleeve setting procedure in October 2009 for the *Marianas*.¹² They reviewed the procedure on November 10, 2009, with Dril-Quip representative Barry Patterson.¹³ Two days later, BP subsea wells engineer Brad Tippetts sent a request to Patterson for the information necessary to develop a final lockdown sleeve setting procedure.¹⁴ Patterson included BP drilling engineer Brian Morel in this initial November conversation, but it does not appear that Morel participated or responded.¹⁵

After BP decided that the *Deepwater Horizon* would replace the hurricane-damaged *Marianas*, BP engineers developed a revised drilling program. On December 31, BP subsea wells team leader Merrick Kelley checked in to ask if the Macondo engineering team still planned to install the lockdown sleeve as part of its new drilling program.¹⁶ Senior drilling engineer Mark Hafle said no: "We do not plan on installing lock down sleeve with the *Horizon*."¹⁷

Kelley responded by noting the time (and hence money) that BP could save by setting the lockdown sleeve with the *Horizon*. He explained that setting the lockdown

sleeve during temporary abandonment "saves an incremental 5.5 days of rig time on the back side" and, with it, more than \$2 million.¹⁸ (Doing the job with a completion rig would take seven days, whereas the *Horizon* could do the job in 1.5 days during temporary abandonment.¹⁹) Hafle discussed the issue with BP drilling and completions operations manager David Sims,²⁰ and the Macondo team eventually decided to set the lockdown sleeve using the *Horizon*.

The Macondo team also considered an **open water** lockdown sleeve installation, in which a boat would set the lockdown sleeve using ROVs.²¹ The open water installation process would save \$120,000 in additional costs over having the *Horizon* do the installation.²² But it also presented a greater risk of damaging the lockdown sleeve.²³ Kelley therefore recommended against it: "At the end of the day it boils down to the amount of risk we are willing to take to potentially save \$120,000 by using a boat. To be honest and frank with you, performing this operation from the rig is the easiest and simplest way I know to install a[n] LDS.... For my money, it is just the right thing to do...."²⁴

Ultimately, the Macondo team decided to set the lockdown sleeve with the *Horizon* during temporary abandonment.²⁵

Development of the Lockdown Sleeve Setting Procedure

Finalizing the procedure for setting the lockdown sleeve was a necessary first step in developing the overall temporary abandonment procedure. The Macondo team did not finalize its lockdown sleeve setting procedure until very late in the drilling process. Indeed, as late as mid-April, the Macondo team was still reconsidering its decision to have the *Horizon* set a lockdown sleeve at all.

On April 8, 2010, Patterson again sent Morel the information about setting the lockdown sleeve that Morel had first received five months earlier.²⁶ Morel reviewed the procedure later that day.²⁷ Four days later, on April 12, BP well site leader Murry Sepulvado asked Morel via email for the temporary abandonment procedures (among other things), saying that rig personnel were “in the dark and nearing the end of logging operations.”²⁸ Morel emailed BP subsea wells engineers Shane Albers and Tippetts to ask for a lockdown sleeve running procedure: “I need a procedure this morning, do you have one available?”²⁹ Tippetts responded five minutes later by attaching the detailed lockdown sleeve setting procedure that the subsea team had originally written for the *Marianas*. Tippetts said, “this should do for now,” but noted that Albers was modifying the procedure “slightly” for the *Horizon* and that Albers “will send out the updated version later today.”³⁰ Morel told Sepulvado, “I will have you something this morning.”³¹

Later in the afternoon of April 12, Morel asked Kelley via email when BP would be setting a lockdown sleeve at Isabela, another BP well.³² Morel knew that BP planned to set the Isabela lockdown sleeve using open water installation tools. Morel's question therefore suggests that he (and perhaps the Macondo team) was still considering another option for setting the lockdown sleeve—namely, using the open water tools that BP would use at Isabela instead of using the *Horizon*. But late that night, Kelley advised Morel and Hafle against that approach. Kelley said that the subsea team would not make it a priority to “combine the Isabela and Macondo lockdown sleeve jobs.” Kelley also warned that others in BP might challenge a decision to use open water tools to set the lockdown sleeve in order to save just 24 hours of rig time.³³

Morel did not send out a final updated procedure on April 12. Instead, after the close of business on April 13, Morel sent BP wells team leader John Guide the *Marianas* procedure, with the caveat that the subsea wells engineers “are updating for the *Horizon*, but mostly will remain the same.”³⁴ A little less than an hour later, at 6:50 p.m. on April 13, Albers sent Morel the final updated procedure.³⁵

Numerous Last-Minute Changes During the Final Development of the Temporary Abandonment Procedure

In the nine days before BP began the temporary abandonment of the Macondo well, the company went through at least four different versions of temporary abandonment procedures.³⁶ Each version switched the order of several key steps.

April 12 Well Plan

In response to the April 12 prodding from Murry Sepulvado, Morel circulated a draft plan for upcoming operations at Macondo later that day.³⁷ The draft plan included temporary

Figure 4.5.4. Multiple last-minute revisions to the temporary abandonment procedure.

April 12 Well Plan	April 14 Morel Email	April 15 Well Plan/ April 16 MMS Permit	April 20 Ops Note	April 20 Actual Procedure
Set lockdown sleeve	Run in hole to 8,367'	Negative pressure test to seawater gradient (with base oil to wellhead)	Trip in hole to 8,367'	Trip in hole to 8,367'
Run in hole to 6,000'	Set 300' cement plug in mud Barrier	Run in hole to 8,367'	Displace mud with seawater from 8,367' to above wellhead (BOP)	Displace mud with seawater from 8,367' to above wellhead (BOP)
Displace mud in well and riser from 6,000' with seawater	Negative pressure test with base oil to wellhead	Displace mud in well and riser from 8,367' with seawater	Negative pressure test with seawater to depth 8,367' rather than with base oil to wellhead	Negative pressure test with seawater to depth 8,367' rather than with base oil to wellhead
Set 300' cement plug in seawater Barrier	Displace mud in well and riser from 6,000' with seawater	Monitor well for 30 minutes/conduct second negative pressure test	Displace mud in riser with seawater	Displace mud in riser with seawater BLOWOUT
	Set lockdown sleeve	Set 300' cement plug in seawater Barrier	Set 300' cement plug in seawater Barrier	
		Set lockdown sleeve	Set lockdown sleeve	

TrialGraphix

abandonment procedures that instructed the rig crew to set the lockdown sleeve *first* and then to set a surface cement plug in seawater. The plug would be set just 933 feet below the mudline.³⁸

Morel's draft did not include a negative pressure test. After reviewing it, well site leader Ronnie Sepulvado reminded Morel that he needed to include a negative pressure test.³⁹

April 14 Morel Email

Two days later, Morel sent out a procedure that was different in several important respects.⁴⁰

First, the new procedure stated that BP would set the cement plug first and *then* set the lockdown sleeve.

Second, Morel changed the depth of the cement plug in order to create the clearance necessary to set the lockdown sleeve. Morel moved the cement plug from 933 feet below the mudline to 3,300 feet below the mudline.

Third, Morel changed the procedure so that the rig crew would set the surface cement plug in *drilling mud instead of seawater*.

Fourth, Morel included a negative pressure test. Morel's procedure instructed the rig crew to perform the test "with base oil in kill/choke line to the wellhead."⁴¹ Using **base oil** for a negative pressure test is a normal industry practice. Filling the choke or kill lines with base oil can simulate the pressure effects of displacing drilling mud in the riser and some portion of the wellbore with seawater *without* actually displacing any mud. This is because base oil is lighter than seawater. Morel presumably included this step to account for the new procedure to displace a large amount of mud from the wellbore before setting the surface cement plug. (Interestingly,

the procedure called for the negative pressure test to be done after the cement plug had been set,⁴² so that the test would examine the quality of the cement in the surface plug rather than the bottomhole cement.)

April 15 Well Plan and April 16 MMS-Approved Procedure

By April 15, with the approval of Guide and drilling engineering team leader Gregg Walz, Morel changed the plan again in at least two important respects.⁴³

First, Morel's new plan required rig personnel to conduct a negative pressure test before setting the surface cement plug, so that the test would check the integrity of the bottomhole cement.⁴⁴

Second, the new plan called for the rig crew to displace the riser to seawater immediately after conducting the negative pressure test.⁴⁵ Morel apparently made this change because one of the well site leaders had asked to set the cement plug in seawater.⁴⁶

The Macondo team clearly recognized that its plan called for an unusually deep cement plug. Morel included an alternative plan with a shallower plug in the event that MMS did not approve the deep plug.⁴⁷

Morel and Hafle worked together to develop an application for an MMS permit allowing the team to use the "deep plug" option. As part of that application, filed on April 16, Morel listed BP's planned temporary abandonment procedure and included a negative pressure test (even though MMS regulations did not require a negative pressure test, as discussed in [Chapter 6](#)). That test would now be conducted "with [the] kill line"—yet another change in the procedure.⁴⁸ MMS approved the permit application—and with it, BP's plan to use a deep plug—in less than 90 minutes.⁴⁹

The language in BP's April 16 permit application describing the negative pressure test and displacement procedure was unclear. Some have said that the language, like that in the April 15 well plan, required BP to conduct its negative pressure test *before* displacing mud in the well with seawater.⁵⁰ Others have said (after the blowout) that the only sensible time to do the negative pressure test would have been *after* the rig crew displaced the mud beneath the wellhead with seawater to the depth of the cement plug.⁵¹ This argument may be important; if the former interpretation is correct, the rig crew did not adhere to the approved MMS procedure.⁵² In any event, the debate highlights the lack of specificity in the permitted language.

After MMS approved the temporary abandonment procedure, Morel realized there was a problem. By planning to set its surface cement plug very deep in the well *and* set it in seawater, BP would be severely underbalancing the well during temporary abandonment. BP could not generate enough differential pressure to simulate those conditions merely by pumping base oil through the kill line down to the wellhead. Accordingly, the base oil negative pressure test procedure would not constitute a proper negative pressure test of the system.⁵³

The solution, as the drilling team saw it, was to conduct two negative pressure tests. The rig would conduct the first test as planned, with base oil to the wellhead *before* displacement to 8,367 feet. They would conduct the second test *after* that displacement.⁵⁴

April 20 "Rig Call" and Morel "Ops Note"

The Macondo team had still not resolved the negative pressure test procedures even during the 7:30 a.m. "rig call" between the rig crew and shoreside personnel on April 20—the day of the blowout. The rig crew asked wells team leader Guide how they were supposed to run the negative

pressure test. Guide responded that he would confer with the engineers onshore and get back to them.⁵⁵

Guide decided that the crew would conduct only one negative pressure test. There would be no “first” test using base oil in the kill line. Instead, there would be a single test midway through the displacement at 8,367 feet. It is difficult to determine whether there was significant disagreement with this decision. Hafle stated that there was “some discussion but [that] John Guide [was] hard to argue with” and that “Walz was in discussion but didn’t argue with John.”⁵⁶ Morel (who was visiting the rig) stated that the well site leaders did not have strong opinions either way.⁵⁷ According to Guide, however, there was never any plan to perform more than one negative pressure test.⁵⁸

Three hours after the rig call, Morel sent an “Ops Note” to the shoreside team and well site leaders. The Ops Note reflected the Macondo team’s final changes to the temporary abandonment procedure.⁵⁹ The first time the rig crew saw the procedure was during the 11 a.m. pre-tour meeting on April 20.⁶⁰

Whereas BP’s April 16 submission to MMS may have stated that rig personnel would conduct the negative pressure test before displacement, the April 20 Ops Note directed the crew to conduct the negative pressure test midway through the displacement process.⁶¹ The rig crew would first displace mud with seawater from beneath the wellhead to 8,367 feet. The crew would then conduct the negative pressure test on the kill line. After the test, the crew would displace the mud remaining in the riser and then set the cement plug.⁶² Like the other procedures, the Ops Note lacked basic information about how the negative pressure test was to be conducted.⁶³

The Macondo team apparently recognized that conducting a negative pressure test midway through displacement (rather than before displacement) was different from the procedure MMS had approved. But BP decided not to notify MMS of the change or seek further MMS approval.⁶⁴ According to members of the Macondo team, such notification and further approval were unnecessary because conducting the negative pressure test during displacement would be a more rigorous test than conducting it beforehand.⁶⁵ This explanation is called into question by the fact that BP did seek MMS approval before making a similar change in a negative pressure test procedure during temporary abandonment operations in 2006.⁶⁶

According to BP well site leader Bob Kaluza, Hafle called him on the afternoon of April 20 to discuss the Ops Note. Hafle had been away on vacation while the rest of the shoreside team had put together the procedures in the Ops Note. Reviewing it, Hafle was concerned that the Ops Note procedure was different than the procedure MMS had approved. Kaluza woke up Morel. Morel explained that the rest of the shoreside team had decided to “deviate” from the procedure in the MMS-approved permit, which called for conducting the negative pressure test before displacement. “The team in town wanted to do something different,” Kaluza later explained according to notes of BP’s post-blowout interviews. “They decided we could do the displacement and negative test together – don’t know why – maybe trying to save time.... Anytime you get behind, they try to speed up.”⁶⁷

It is impossible to know whether the changes to the negative pressure test procedure (including elimination of a second negative pressure test at a different depth) contributed to the blowout. As [Chapter 4.6](#) explains in detail, personnel on the *Deepwater Horizon* missed clear warning signals from the negative pressure test they did conduct. Conducting an earlier version of the test may have removed one of the factors confounding successful interpretation of the test and eliminated the crew’s erroneous explanation for the warning signals they observed.⁶⁸ And conducting a

second test at a different depth might have given the rig crew another opportunity to recognize those signals.

Technical Findings

BP's Temporary Abandonment Procedure Created Significant Risks

BP's design decisions had significant consequences and increased the risks associated with the temporary abandonment at Macondo in several important ways.

First, the procedures created a severe hydrostatic underbalance in the well. By requiring the rig crew to remove so much mud from the wellbore during temporary abandonment, BP's procedures greatly reduced the balancing pressure that the mud column in the wellbore exerted on the hydrocarbons below. This increased stress on the bottomhole cement.⁶⁹ While temporarily abandoning a deepwater well typically involves placing some amount of stress on the bottomhole cement, BP's procedures stressed the cement more than usual⁷⁰—to an extent never before seen by many in the industry.⁷¹

Second, the procedures led the rig crew to conduct riser displacement operations with *only one physical barrier in the well* (the bottomhole cement) and only one backup barrier (the BOP).⁷² That backup barrier, in turn, was highly dependent on well control monitoring. As a result, BP's temporary abandonment procedure placed a high premium on kick detection and response during the displacement.⁷³ Unless the rig crew recognized a kick, they could not activate the BOP in time for it to function as a barrier.

Third, and as a result, the procedures placed a high premium on the integrity of the bottomhole cement and the negative pressure test that evaluated it.⁷⁴ Rig personnel could not rely on the bottomhole cement as a barrier until it had been verified, and the only procedure BP planned to use to verify the cement's integrity was the negative pressure test.

BP Did Not Need to Set a Lockdown Sleeve as the Last Step in Temporary Abandonment

As explained above, BP made many of its procedural decisions regarding temporary abandonment based on its decision to set a lockdown sleeve during the temporary abandonment phase of the well. BP did not need to set a lockdown sleeve during the temporary abandonment phase. The fact that BP nevertheless chose to do so is not problematic in itself. Indeed, locking down the casing earlier rather than later can increase safety by mitigating against potential uplift forces during drilling and abandonment (explained in [Chapter 4.1](#)). But BP increased overall risks by deciding to set the lockdown sleeve last in the temporary abandonment sequence.

A lockdown sleeve need not be set last in the temporary abandonment sequence. It can be set in mud prior to displacement and setting of the surface plug.⁷⁵ This is commonly done in the industry,⁷⁶ and BP engineers considered doing it this way at Macondo.⁷⁷

Outer Lock Ring. Setting a lockdown sleeve before temporary abandonment can reduce the risk that underbalancing a well might lift the production casing out of place in the wellhead. Another mechanism for locking a production casing in place is an **outer lock ring**. Rig personnel can install an outer lock ring when they first set the casing in place. While this was not a common practice at the time of the Macondo incident,⁷⁸ some industry experts have recommended that it become standard.⁷⁹

Indeed, the Macondo team initially planned to set the lockdown sleeve in mud, before setting a shallow surface cement plug in seawater. In a March 3 email, Hafle stated that the team would “set the plug after [lockdown sleeve] installation”; with no plug in the way, they could easily “supply the correct weight for installation.”⁸⁰ On April 8, Morel checked with Dril-Quip representative Barry Patterson to make sure the lockdown sleeve procedure was compatible with “100,000 lbs air weight in 14.0 ppg mud.”⁸¹ On April 12, Morel emailed Tippetts to confirm that the plan was “to still have mud in the riser and wellbore when we set the LDS.”⁸² Subsea well supervisor Ross Skidmore preferred to set the lockdown sleeve in mud because the hole would be in its cleanest state at that point.⁸³

As described above, by April 14, BP had changed its plan so that it would run the lockdown sleeve last, after setting a surface plug and displacing the riser to seawater.⁸⁴ When Skidmore heard about the change, he approached one of the BP drilling engineers on the rig and expressed his preference to set the lockdown sleeve in mud; the engineer indicated the decision had come from personnel onshore and was final.⁸⁵

BP Did Not Need 3,000 Feet of Drill Pipe Below the Wellhead to Achieve the 100,000 Pounds Necessary to Set the Lockdown Sleeve

BP did not need to use 3,000 feet of drill pipe in order to generate the 100,000 pounds of downward force necessary to set the lockdown sleeve. Instead, BP could have instructed the rig crew to hang a much shorter length of pipe that included **drill collars** (a heavier type of drill pipe). Because drill collars are much heavier than other drill pipe, the crew could have used a much shorter length of them to generate the same downward force. BP could also have instructed the rig crew to generate some of the setting force using weight pushing down from *above* the running tool instead of hanging below it.⁸⁶ Using these methods, BP could have set the lockdown sleeve in place without requiring 3,000 feet of clearance beneath the sleeve, as called for in its final plan.⁸⁷

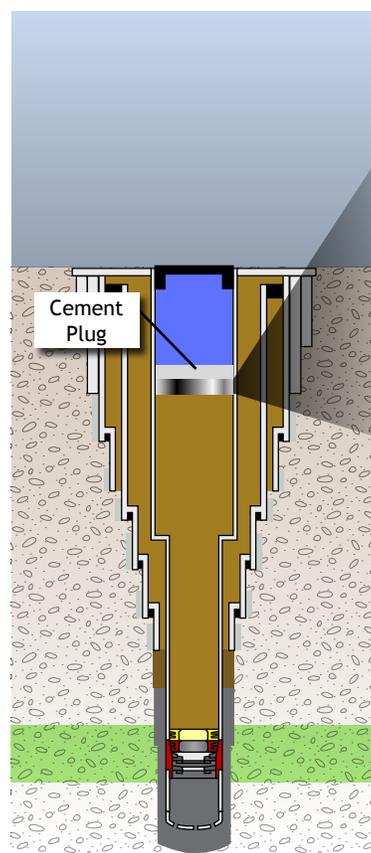
BP engineers were well aware that they did not have to set the lockdown sleeve using 3,000 feet of hanging drill pipe. BP had previously set a lockdown sleeve with the same running procedures and weight requirement (100,000 pounds) at another well in the Gulf of Mexico, in Mississippi Canyon Block 129.⁸⁸ BP used drill collars at that well to generate the required setting force⁸⁹ and was thus able to set its surface plug only 1,600 feet below the mudline.⁹⁰ Similarly, BP set a lockdown sleeve with an even greater force requirement (125,000 to 135,000 pounds) in Mississippi Canyon Block 777.⁹¹ There again, BP used drill collars to generate the required setting force and set a surface plug 1,500 feet below the mudline.⁹² Such depths were more typical for pre-lockdown sleeve plugs.⁹³

At one point, the Macondo lockdown sleeve was supposed to be set in much the same manner.⁹⁴ As far back as November 12, 2009, the Macondo team had planned to run drill collars beneath

the lockdown sleeve in order to achieve the necessary setting weight.⁹⁵ That was still the plan on February 3 when the lockdown sleeve setting procedure was submitted for inclusion in the Macondo well planning spreadsheet.⁹⁶ But by March 2, Hafle had told Tippetts, “Here’s the final plan.... We will *not* be using any drill collars. The rig has 5-1/2" [heavyweight drill pipe] and we will rent additional 5-1/2" [heavyweight drill pipe] to have 100k buoyed weight below” the lockdown sleeve.⁹⁷

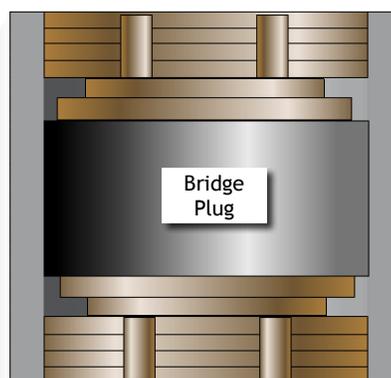
Despite Hafle’s email, BP obtained drill collars and had them on the rig by April 17.⁹⁸ As late as April 12, Walz mentioned using drill collars to set the lockdown sleeve in an email to Morel,⁹⁹ and Morel included them in the April 12 drilling program.¹⁰⁰ The last final updated procedure that Albers sent to Morel on April 13 also included drill collars.¹⁰¹ But by the time drill collars arrived on the rig, Morel had changed the procedures to specify a deep surface plug, 3,000 feet below the mudline, which suggests that he had not envisioned using drill collars to set the lockdown sleeve.¹⁰² According to BP wells team leader Guide, the team changed the plan because the rig already had heavyweight drill pipe “racked back” and ready to run into the well.¹⁰³ In order to use drill collars at that point, the rig would need to make up each piece of pipe individually, which would take time and add to the general risk of personal injury.¹⁰⁴

Figure 4.5.5. Bridge plug.



BP could have used a mechanical plug in lieu of or in addition to a cement plug.

BP Could Have Set Its Surface Cement Plug in Mud Instead of Seawater



BP did not have to displace mud from the well and riser in order to set a cement plug; it could have set the cement plug in drilling mud instead.

Surface cement plugs can be set in mud just as they can be set in

seawater.¹⁰⁵ Setting a cement plug in mud can present a risk of contamination and certain other chemical complexities.¹⁰⁶ But contamination issues can exist with cement plugs set in seawater as well,¹⁰⁷ and the complexities can be managed with proper cement slurry design and the use of spacer.¹⁰⁸ In order to help ensure that cement plugs set in drilling mud are secure, engineers also use **mechanical retainers** or **bridge plugs**—metal and rubber devices that fit into the casing and hold the cement,¹⁰⁹ as shown in Figure 4.5.5. The mechanical plug then serves as an additional barrier, apart from the cement it helps to set.¹¹⁰

BP generally, and the Macondo team specifically, were familiar with these options.¹¹¹ When an earlier surface cement plug at Macondo failed to set up, Morel and another BP engineer involved with the earlier plug discussed how “the biggest single factor for plug success is having a good

base.”¹¹² The engineers discussed how they could design that base by several means, including by contrasting fluid densities (lighter cement on heavier drilling fluid) and by using mechanical

devices (retainers and bridge plugs).¹¹³ Another engineer involved with the earlier plug commented, “We need to get better at setting plugs regardless of the method.”¹¹⁴

BP representatives have acknowledged that surface cement plugs can be set in mud¹¹⁵ and that doing so is not a mistake.¹¹⁶ Indeed, BP has set surface cement plugs in mud before¹¹⁷ and apparently considered doing so at Macondo as late as April 14.¹¹⁸ BP has also frequently made use of mechanical devices for surface plugs, including both drillable and retrievable bridge plugs.¹¹⁹

In fact, BP engineers affirmatively considered running a mechanical plug at Macondo—specifically, a Baker Hughes model GT retrievable bridge plug.¹²⁰ The GT plug was much more expensive than a cement plug, but Morel preferred it (at least initially) because of its greater reliability. In an email to Hafle and others, he noted: “If Baker’s GT plug wasn’t available, we would either set a cement plug in its place or a Halliburton Fast Drill plug. Both are much cheaper options, but leave us with potential issues during the completions. They could potentially cost us more as well, because extra rig time might be involved with removing these type of plugs.”¹²¹

BP engineers planned at various points to use a GT plug at Macondo.¹²² The Macondo team would have rented that plug pursuant to a long-term GT plug rental contract that BP was arranging with Baker Hughes for several wells at the same time.¹²³ Because the BP personnel arranging the contract believed there was a “high probability of a long term installation of this plug at Macondo,” they affirmatively committed to the rental.¹²⁴ BP initiated rental of the Macondo plugs on April 6.¹²⁵ The company paid \$42,902 to Baker Hughes to make up, test, and keep a primary and backup GT plug on standby.¹²⁶

On April 9, a Baker Hughes representative emailed Morel and Hafle to ask for an update on whether BP had decided to use the standby plug or not.¹²⁷ Morel responded with additional details but still no final decision: “If we need it, the rig will probably want to call it out next weekend or early the following week (18-19th of April). I will keep you informed.”¹²⁸ Morel explained that the Macondo team would not commit to using the GT plug until it had decided if production casing was required.¹²⁹ But by April 12, two days before finalizing the decision to run production casing, the Macondo team decided to use a plain cement surface plug.¹³⁰ When the Baker Hughes representative emailed the two BP engineers again on April 19 to ask if they would need the plug he had kept on standby “since early April,”¹³¹ Hafle responded, “We will be setting a cement plug instead.”¹³² Baker Hughes stopped the rental.¹³³

It is not clear why the Macondo team chose to set a plain cement plug. Morel told one engineer that the reason was cost:¹³⁴ “Plan is to set a cement plug instead of running the GT plug as it doesn’t cost us anything to leave it in the hole.”¹³⁵ Morel told another set of engineers (the completion engineers) that the reason was risk: The “GT plug poses risks leaving it in the wellbore for an unknown amount of time.”¹³⁶

BP Could Have Planned a Safer Temporary Abandonment Procedure Even Without Changing Its Design Assumptions

Even assuming that BP truly had to set the lockdown sleeve last and set its surface cement plug

* Some members of the Macondo team were concerned that leaving a mechanical plug in the well for an indefinite period of time might present complications during re-entry and completion. Retrievable plugs left in the wellbore for too long can corrode and become difficult to retrieve. Drillable plugs (like cement plugs) can produce debris when drilled out. Nevertheless, BP appears to have addressed or accepted these complications in other wells where the company set mechanical plugs. Indeed, a BP completion engineer reacted to Morel’s email with wonderment: “I am curious about what risks he speaks of with leaving GT plugs in place for long periods. We had them in place at Dorado for a couple of years without problems.”

deep in the well in seawater, BP could have taken at least three measures to mitigate the risk created by its unusual procedure. Each of these measures would have increased or improved the physical barriers in the wellbore during the displacement. While each would have taken some additional time,¹³⁷ they would have ensured that the cement job at the bottom of the well was not the only barrier physically in place during the displacement.

BP Could Have Retained Hydrostatic Overbalance

BP still could have retained hydrostatic overbalance even with the removal of 3,300 feet of mud from the wellbore. To do so, they could have replaced the mud at the bottom of the wellbore with heavier “kill weight” mud.¹³⁸ BP engineers should have been familiar with this concept,¹³⁹ and it is a common industry practice.¹⁴⁰ In doing so, they would have retained mud as a physical barrier in the wellbore during the displacement.^{141†}

BP Could Have Set Intermediate Plugs

BP could have set additional plugs between the bottomhole cement and the surface plug.¹⁴² BP engineers were familiar with this option, as the company had set multiple intermediate plugs (often including mechanical plugs) on previous wells.¹⁴³ Indeed, some in the industry treat the setting of intermediate plugs as standard practice.¹⁴⁴ But it appears that the Macondo team never considered it.¹⁴⁵ Setting intermediate mechanical or cement plugs would have increased the number of physical barriers in the wellbore during the displacement.

BP Could Have Conducted the Displacement (of Both the Wellbore and the Riser) With the BOP Closed

BP could have closed an annular preventer (or variable bore ram) before beginning the displacement and, in various configurations, then displaced the casing and riser using the drill pipe and choke, kill, and boost lines.¹⁴⁶ This would have been considered a particularly conservative approach in the industry, and unnecessary for most wells.¹⁴⁷ But the unusually deep cement plug and the uncertain nature of the bottomhole cement job at Macondo warranted extra caution.¹⁴⁸ Indeed, since the blowout, the industry appears to be moving in the direction of making this practice more prevalent.¹⁴⁹ Closing the BOP before the displacement would have eliminated the BOP's dependence on human monitoring and thereby converted it into a physical barrier in place during the displacement. The well would already have been shut in at the time of the kick, enabling the crew to more easily respond to and control the kick.

Management Findings

BP Failed to Develop Its Temporary Abandonment Procedure in a Timely Manner

The moment an operator designs a production well, it can (and should) develop a temporary abandonment procedure.¹⁵⁰ Even though BP planned Macondo as a production well from the start,¹⁵¹ it did not include temporary abandonment procedures in its initial drilling program.¹⁵²

† BP wells team leader John Guide suggested that for some wells underbalance is necessary because mud is simply not heavy enough to compensate for the loss of the riser. That was not true of the Macondo well. To be sure, if BP had insisted on using only one plug and setting that plug at 3,300 feet below the mudline, then replacing just the mud above that plug with kill weight mud would not have prevented underbalance. But BP could have set an intermediate plug deeper in the well (about 6,900 feet below the mudline), replaced the mud above that deeper plug with kill weight mud, and then set a surface plug higher up in the well. Therefore, BP could have left the Macondo well overbalanced by using a combination of kill weight mud and intermediate plugs.

As early as January 2010, the Macondo team planned to use the *Horizon* to install a lockdown sleeve and then temporarily abandon the well. But the company's January 2010 drilling program still did not include a temporary abandonment procedure.¹⁵³ By April 9, the Macondo team knew the total depth of the well.¹⁵⁴ At that point, they had enough information to design a temporary abandonment procedure specifically tailored to the final conditions at Macondo.¹⁵⁵ But three days later, on April 12, the well site leader was forced to ask the shoreside team for procedures himself, saying, "we are in the dark and nearing the end of logging operations."¹⁵⁶

The Macondo drilling team did not begin developing a procedure in earnest until after this request. Perhaps because of the delays, the Macondo team changed its procedures repeatedly at the last minute, even up until the day the procedure was to begin (the day of the blowout). As Walz acknowledged in another context, "planning [was] lagging behind the operations."¹⁵⁷

BP Changed Its Temporary Abandonment Procedure Repeatedly at the Last Minute Without Subjecting Those Changes to Any Formal Risk Assessment

BP's temporary abandonment procedures for Macondo changed at least four times over the last nine days before the blowout. This was an unusual number of changes so close to the procedure's execution.¹⁵⁸ BP also changed its lockdown sleeve setting procedures over time.

Several of BP's decisions—not using drill collars, not using a mechanical plug, setting the plug in seawater, setting the lockdown sleeve last—may have made sense in isolation. But the decisions also created risks, individually and especially in combination with the rest of the temporary abandonment operation. For instance, BP originally planned to install the lockdown sleeve at the beginning of the temporary abandonment. BP's decision to change plans and set the lockdown sleeve last triggered a cascade of other decisions that led it to severely underbalance the well while leaving the bottomhole cement as the lone physical barrier in place during displacement of the riser.

There is no evidence that BP conducted any formal risk analysis before making these changes or even after the procedure as a whole.¹⁵⁹ For example, on April 15, Morel (who was on the rig at the time) emailed the rest of the Macondo onshore engineers about setting a deep plug in seawater: "Recommendation out here is to displace to seawater at 8300' then set the cement plug. Does anyone have issues with this?"¹⁶⁰ The response, from Hafle, was simply: "Seems ok to me."¹⁶¹ According to Guide, the team never discussed the risk of having such a deep surface plug.¹⁶²

Post-incident interviews with the Macondo team confirm that it made significant procedural changes in a relatively casual manner. Walz admitted that there was "no structured approval process" and that "changes [were] made with email and verbal discussion."¹⁶³ Coteles stated that there was "no formal process on communicating changes to [the] well plan." Murry Sepulvado stated that it was not unusual to receive emails like the Ops Note containing procedural changes that had not been risk assessed through a formal process.¹⁶⁴ And according to Guide, such Ops Notes would not even flag whether changes had been made to the well plan.¹⁶⁵

BP Allowed Equipment Availability to Drive Design and Procedure Decisions

BP inverted the normal process of well design in determining the depth of the surface cement plug, and the type and length of pipe to use in setting the lockdown sleeve.

Drilling engineers normally begin by considering their objective and the attendant risks and developing a well design and procedures that are efficient and safe. They then arrange for the equipment and materials necessary to execute the design.¹⁶⁶ BP did the opposite at Macondo. BP made decisions about what type of drill pipe to use (ordinary, heavyweight, or drill collars), and hence where to set its surface cement plug, based on the type of pipe available on the rig.¹⁶⁷ The *Deepwater Horizon* apparently already had heavyweight drill pipe “racked back” and ready to run into the well, which led the Macondo team to use that pipe instead of drill collars.¹⁶⁸

BP's lockdown sleeve setting procedure underscored this logic: “To achieve 100,000 lbs of tail pipe weight drill collars & drill pipe will be used. The combination will depend on availability and will be determined while onsite.” The caveat was repeated in step seven of the procedure, which stated “the decision on the pipe size & length will be made on the rig.”¹⁶⁹

BP Failed to Provide Written Standardized Guidance for Temporary Abandonment Procedures

BP had no consistent or standardized temporary abandonment procedure across its Gulf of Mexico operations.¹⁷⁰ Formal written guidance was minimal: The Drilling and Well Operations Practice manual and relevant Engineering Technical Practice (GP 10-36) mandated that, in each flow path, there should be two independent mechanical barriers isolating flow from the reservoir to the surface and that those barriers should be independently tested.¹⁷¹ The documents did not specify the location of those barriers or the procedure by which they should be set. This left the Macondo engineers to determine such issues for themselves on an ad hoc basis. For example, when Hafle emailed the subsea engineers—“Can we set the plug after the LDS is in place?”—one subsea engineer wrote to another, “I do not know about setting the plug after the LDS. Do you? Could you ask someone around the office tomorrow about this to figure this out?”¹⁷² Such uncertainty existed even with something as basic as regulatory requirements.¹⁷³ ♦