4 Key Findings

Transocean

This summarizes the key findings of the investigation team based on its extensive review of available information concerning the Macondo well incident.

As operator of the Macondo well, BP directed all aspects of its development. It chose the drilling location, designed the drilling program that included all operational procedures, set the target well depth, and created the temporary abandonment procedure for securing the well before departure of the drilling rig.

As drilling depths increased at Macondo, the window for safe drilling between the fracture gradient and the pore-pressure gradient became increasingly narrow. Maintaining the appropriate equivalent circulating density (ECD) became difficult, and BP experienced several kicks and losses of fluid to the formation. BP's knowledge of the narrowing window for safe operations guided key decisions during the final stage of operations. BP's changes from the original well plan in the final phase included:

- Reducing the target depth of the well
- Considering changes to the well casing
- Using a lower circulating rate than the parameters specified to convert the float collar
- Reducing cement density with nitrogen foam
- Using a lesser quantity of cement than that specified in BP procedures
- Deciding not to perform a complete bottoms-up circulation before cementing

Although aimed at protecting the formation and allowing operations to continue toward completion of the well, these decisions set the stage for the well control incident.

4.1 Running Production Casing

BP chose a long-string production casing design that required the development of a minimal and technically complex cement program to avoid damaging the formation during cementing, leaving little margin for error within normal field accuracy. BP and Halliburton then increased the risk by failing to adequately test the cement program.

The investigation confirmed that the operator's long-string casing design met the loading conditions that were experienced prior to and during the well-control incident. The use of this design, however, drove other plan departures that ultimately increased risk and contributed to the incident. Primarily, cementing the casing required a complex, small-volume, foamed cement program to prevent over-pressuring the formation. The plan allowed little room for normal field margin of error; it required exact calculation of annular volume and precise execution in order to produce an effective barrier to the reservoirs.

The operator had other abandonment alternatives. BP could have either installed a liner and tie-back or deferred the casing installation until the future completion operations began. Either approach would have placed additional and/or different barriers in the well prior to the negative pressure test and displacement.[A] Deferring installation until future completion operations would have allowed additional time for detailed planning and verification of the design.

4.2 Converting the Float Collar

BP deviated significantly from its plan to convert the float collar, but proceeded despite observations of anomalies. The investigation team found it possible that the float collar did not convert and thus left a clear path for hydrocarbons to flow from the formations to the rig.

BP's planned procedure to convert the float collar called for slowly increasing fluid circulation rates to 5–8 barrels per minute (bpm) and to generate pressure of 500–700 psi at the float, consistent with the float manufacturer's guidelines. However, because of the increasingly narrow window to avoid fracturing the formation, BP deviated from its planned conversion procedure.

A 30CFR250.1714–21.

BP made nine attempts to convert the float collar over the course of two hours. BP never circulated at a rate of more than 2 bpm, but it did increase the pressure applied on each successive attempt, finally achieving circulation at a pressure of 3,142 psi — almost five times that planned — and a flow rate of 1 bpm, less than ¼ of that planned. BP took this result as an indication that the float collar had converted even though the resulting circulating pressure was lower than BP's model had predicted. The BP well site leader expressed concern about the issue, took steps to investigate it, and discussed the question of whether the float collar had converted with the Halliburton cementing engineer and BP's shore team. Halliburton and BP proceeded, apparently having concluded that the float collar had converted.

The investigation team found it likely that debris in the wellbore may have plugged the shoe-track assembly and float collar and blocked circulation during the first eight attempts to convert the float collar. The increase to 3,142 psi may have cleared debris from the system without converting the float collar. If the float collar failed to convert, the cement program may have been further compromised.

4.3 Cementing

The precipitating cause of the Macondo incident was the failure of the cement in the shoe track and across the producing formations. This failed barrier allowed hydrocarbons to flow into the well.

The cement failed as a result of a number of factors that stemmed from BP's ECD-driven management decisions between April 12 and 20, 2010. These factors include the complexity of the cement program; inadequate testing of the cement; likely cement contamination during the operation; and inadequate testing of the cement after it had been pumped.

Complexity of Cement Job

BP required a cement program that would exert minimal pressure on the formations. To minimize pressure, Halliburton devised a plan that called for pumping a small volume of cement, much of it nitrified, at a low rate. While this plan would help BP avoid losing cement into the formations, it required precise execution, left little room for error, and increased the risk of cement contamination.

Cement Program Tests

Despite the inherent risks of cementing the long-string production casing in the conditions at Macondo, BP did not carry out a number of critical tests (e.g., fully testing setting time and cement compatibility with drilling fluid) before or after pumping the cement. Post-incident testing by both CSI Technologies and Chevron demonstrated that the nitrified cement slurry used at Macondo likely failed.

Cement Contamination

Contrary to best practices, BP decided not to perform full circulation — or a "bottoms-up" — to condition the drilling fluid in the well before the cement job. A full bottoms-up circulation would have required approximately 2,750 barrels of clean mud to be pumped into the well over about 11.5 hours to keep the ECD under the maximum limit. Instead, BP decided to circulate only 346 barrels to reduce the chance of fracturing the formation, increasing the likelihood that debris remained in the wellbore after circulation.

The failure to run a full bottoms-up, coupled with the fact that drilling mud in the well had not been circulated for more than three days, suggests that cement in the annulus could have channeled and become contaminated. This could have delayed or prevented the cement from setting and developing the required compressive strength. Pre-job testing of the cement and spacer/mud/cement compatibility was not sufficient to rule out contamination.

Post-Cement Program Review

Testing of the adequacy of the cement program could have identified areas of concern, but was not done. After approving the cement program, BP proceeded with its temporary abandonment plan.

4.4 Temporary Abandonment Procedure

BP's final temporary abandonment plan contained unnecessary risks that were not subjected to formal risk analysis.

BP engineers generated at least five different temporary abandonment plans for the Macondo well between April 12 and April 20, 2010. The plans varied considerably, as did the level of risk they introduced. The abandonment procedure ultimately implemented at Macondo never received the required MMS approval. Further, it was not developed and delivered to the *Deepwater Horizon* until the morning of April 20, 2010, after the rig had commenced temporary abandonment operations. The investigation team found no evidence that BP personnel on the rig or onshore subjected any of the successive temporary abandonment plans or changes to a formal risk assessment process.

The safest of the five versions (that dated April 14) provided that the surface cement plug be set in mud rather than seawater and that a negative pressure test be conducted before the drilling mud was displaced with seawater. The plan that was finally implemented lacked both of these features.

The most significant deficiency in the final plan was the cumulative lack of barriers to flow. The final plan required displacing the drilling mud to a depth of 8,367 ft. (approximately 3,300 ft. below the mudline), which was much greater than the normal displacement depth of between zero and 1,000 ft below the mudline. In addition, the plan removed the mud before testing the cement barrier with a negative pressure test and before setting the surface cement plug. As a result, no secondary cement barrier was in place during the negative pressure test and displacement.

4.5 Displacement

The initial displacement was planned incorrectly, and the execution did not meet the objective of allowing for a valid negative pressure test.

The final temporary abandonment plan required displacing the casing annulus below the annular blowout preventer (BOP) with seawater to achieve the desired negative pressure test conditions. However, post-incident analysis determined that this objective was not achieved because of calculation errors in the final displacement procedure, lower pump efficiencies which may have been caused by the unconventional spacer materials, potential downhole losses, and the movement of spacer below the closed annular. These factors resulted in a large volume of spacer in the annulus during the negative pressure test that went unidentified due to inadequate fluid volume tracking and lack of procedures to identify the appropriate pressure readings for a satisfactory initial test configuration.

With heavy spacer in the annulus below the closed annular BOP, a valid negative pressure test could not be achieved by monitoring the kill line, which was the method BP decided to use.

4.6 Negative Pressure Test

The results of the negative pressure test were misinterpreted. After the test, BP decided to proceed with the final displacement.

A negative pressure test is necessary to confirm that the cement will block flow from the reservoir into the well after mud is replaced with seawater. There is no established industry standard or MMS procedure for performing a negative pressure test, and procedures vary from well to well. At Macondo, BP was responsible for overseeing the test and determining if the test was successful.

Post-incident analyses confirmed that the test failed. Anomalous pressure observed on the drill pipe during the test should have alerted all of those monitoring the well to the fact that the cement barrier was not effective, that pressure was being transmitted past the cement and float equipment, and that the well was in communication with the formations.

Central to the misinterpretation of the test results was BP's decision to monitor the kill line instead of the drill pipe when conducting the test. Had the drill crew continued monitoring flow from the drill pipe, as they had been doing previously, those monitoring the well would have detected flow indicating that the well was in communication with the formation.

4.7 Sheen Test and Final Displacement

Post-incident analysis indicated a change in flow path from the well during the final displacement masked influxes into the wellbore.

Following its approval of the negative pressure test, BP directed the drill crew to proceed with displacing the riser with seawater and, when the spacer was expected at the surface, to stop operations for a sheen test.

Replacing the heavier drilling mud with lighter-weight seawater during final displacement eliminated the remaining hydrostatic barrier to flow, leaving the inadequate cement barrier at the bottom of the well as the primary barrier. According to post-incident calculations, the well became underbalanced to one or more of the exposed formations sometime between 8:38 p.m. and 8:52 p.m., but there was no clear indication of an influx at that time.

Just before the pumps were shut down for the sheen test, the trip tank was dumped into the flowline to send oil-based mud back to the mud pits. Based on post-incident analysis, the resulting increase in flow from the trip tank across the flow sensors masked an influx into the well.

More than one individual on the rig indicated the well was not flowing when the mud pumps were shut down for the sheen test. It is possible that no flow was seen because the flow path had been changed to overboard to dispose of the spacer before the visual confirmations. Post-incident data analysis shows that hydrocarbons flowed into the well during the sheen test, but the overboard discharge may have masked the flow.

Although the compliance engineer concluded and reported that the sheen test was successful, post-incident analysis indicates that the spacer had not reached the surface at the time the test was conducted. This report gave the driller an erroneous confirmation that the displacement was on track when, in fact, it was not.

Pump operations following the sheen test masked an underlying trend of increasing pressure which resulted from an influx into the well. It is not known what data the drill crew was monitoring or why they did not detect an anomaly until approximately 9:30 p.m. At that time, the drill crew acted upon a differential pressure anomaly between the kill line and drill pipe. Actions taken indicate behaviors consistent with a belief that the well was secure and a plug existed in the well. At 9:42 p.m., the pressure trend provided a conventional influx indication with a drop in pressure. At that time a flow check was completed on the trip tank and well control action followed.

4.8 Activation of the BOP

The BOP functioned and closed but was overcome by well conditions.

The *Deepwater Horizon* BOP and electro-hydraulic/multiplex (MUX) control system were fully operational at the time of the incident, and the equipment functioned. The equipment was maintained in accordance with Transocean requirements, and all modifications that had been made to the BOP either maintained or improved the performance of the device. Minor leaks identified pre-incident did not adversely affect the functionality of the BOP for well control.

Upon detecting flow, the drill crew shut in the well by (1) closing the upper annular BOP; (2) closing the diverter packer and diverting the flow to the mud-gas separator; and, (3) closing the upper and middle VBRs, which initially sealed the well.

However, because of the high flow rate of hydrocarbons from the well, the annular BOP element did not seal and the concentrated flow eroded the drill pipe just above the annular. The closing of the VBRs isolated the annular space and temporarily stopped the influx, but increased pressure inside the drill pipe until it ruptured at the point of erosion above the upper annular. The ruptured drill pipe allowed hydrocarbons to again flow into the riser. When the *Deepwater Horizon* lost power and drifted off location, the drill pipe parted fully.

The explosions and fire disabled the communication link between the BOP and the rig, preventing activation of the BOP emergency disconnect system (EDS) from the toolpusher control panel.

The automatic mode function (AMF) operated as designed to close the blind shear rams following the explosion. However, high pressure bowed the drill pipe partially outside of the BSR shearing blades, trapping it between the ram blocks and preventing the BSR's from completely shearing the pipe, fully closing, and sealing the well.

4.9 Muster and Evacuation

All personnel who survived the explosions made their own way or were assisted to the forward lifeboat muster station and successfully evacuated the rig. Despite the obstacles and challenges, the muster and evacuation plans and training facilitated the evacuation of all 115 survivors.

The Macondo incident created extremely challenging conditions for everyone onboard. The explosions and fire happened in the evening, when many off-tour crew were asleep or in their cabins. The blast damage blocked some normal muster points. Some crew were injured and could not evacuate without assistance. It appears that, under the stress of the emergency, four persons evacuated independently rather than pursuant to the procedure in which they were trained.

Despite these obstacles and challenges, the muster and evacuation plans and training facilitated the evacuation of all 115 survivors to the *Damon B. Bankston* supply vessel nearby. One hundred people evacuated in the forward lifeboats, seven evacuated in one of the forward life rafts, and eight jumped from the forward end of the rig into the ocean and were recovered by the *Bankston* fast rescue craft (FRC). After the survivors reached the *Bankston*, the 17 most seriously injured survivors were airlifted by USCG helicopters to hospitals for treatment.

In addition to the heroic actions of many of the crew, assistance from the crew of the *Bankston* was critical in the evacuation and rescue effort.