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Deepwater Horizon Accident Investigation Report

September 8, 2010

Section 3. Chronology of the Accident

The chronology of events in the hours leading up to and including the *Deepwater Horizon* accident are presented here as a factual timeline to allow a straightforward description of events as they unfolded.

The major activity sets covered in this timeline include:

- Events Prior to April 19, 2010.
- Final Casing Run.
- Cement Job.
- Positive-pressure and Negative-pressure Tests.
- Well Monitoring and Simultaneous Operations.
- Well Control Response.
- Explosion and Fire.
- BOP Emergency Operations.

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The investigation team consulted the following primary sources to construct this chronology of events:

- Real-time data: real-time data transmissions from the Sperry-Sun logging system.
- *OpenWells®*: BP's daily reporting system entitled *OpenWells® Drilling Morning Report*.
- Interviews: witness accounts collected by the investigation team.
- Marine Board Investigation (MBI) testimony: testimony given during the MBI hearings on May 26–29 and July 19–23, 2010.
- *Deepwater Horizon* piping and instrumentation diagrams (P&IDs).
- Incident management team (IMT) reports: records from BP's accident response effort.
- OLGA® well flow modeling: transient multiphase well flow simulations run by third party experts on behalf of the investigation team.
- Unified Command: the unified command of the *Deepwater Horizon* accident response.
- Other sources as noted.

In the chronology, conclusions reached by the investigation team as a result of modeling or calculations are shown in italics within brackets.

Events Prior to April 19, 2010

Date	Time	Description	Source
2009 October 6		Spudded Macondo well with Transocean's *Marianas*.	*OpenWells®*
November 8–27		Pulled riser and evacuated *Marianas* for Hurricane Ida. *Marianas* subsequently damaged and moved to safe harbor for repairs.	*OpenWells®*
2010 January 31–February 6		Transocean's *Deepwater Horizon* on location to replace *Marianas*. Six days of pre-job maintenance and testing of blowout preventer (BOP) followed. Drilling activities recommenced on February 6.	*OpenWells®*
February 23–March 13		Pilot valve leak of 1 gpm noticed on yellow pod of BOP; leak reduced after switching to blue pod.	*OpenWells®*
March 8		Well control event at 13,305 ft. Pipe stuck; severed pipe at 12,146 ft.	*OpenWells®*
March 12–22		Contingency liner utilized, a new drilling liner was added and production casing changed to a 9 7/8 in. x 7 in. long string. Minerals Management Service (MMS) approved changes.	Macondo well plan MMS applications
April 5–6		Stripped drill pipe through upper annular preventer from 17,146 ft. to 14,937 ft. while addressing wellbore losses.	*OpenWells®*
April 9–14		Total depth of 18,360 ft. reached and data collected for five days. Reservoir sands contained hydrocarbons at pressures of approximately 11,850 psi.	*OpenWells®*
April 14		Halliburton OptiCem™ cement model review concluded zonal isolation objectives could be met using 9 7/8 in. x 7 in. long string as production casing.	Halliburton *9 7/8 in. x 7 in. Production Casing Design Report*
April 15		OptiCem™ model updated with open hole caliper and survey data. Input included 21 centralizers and 70% standoff above the top centralizer.	Company emails
April 15		Decision made to order 15 additional centralizers. Order placed.	Company emails
April 16	11:51	Fifteen slip-on bow spring centralizers delivered to rig by helicopter.	*OpenWells®*

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Date	Time	Description	Source
April 16	12:48–12:53	Mechanical integrity concerns regarding the bow spring centralizers. Decision made not to run bow spring centralizers.	Company emails Interviews
April 18	20:58	Partial lab test results, a new OptiCem™ model report (using seven inline centralizers) and Halliburton's cementing recommended procedure for the Macondo well cement job were provided to BP and Halliburton staff. [*Complete lab test results on planned slurry design not provided to BP before job was pumped.*]	Email from Halliburton in-house cementing engineer to BP and Halliburton staff

Final Casing Run

Date	Time	Description	Source
April 19	13:30	Completed final (production) casing run to 18,304 ft. (job took 37 hours). The shoe track included a Weatherford float collar installed at the top and a reamer shoe at the bottom.	*OpenWells®*
April 19	14:30–16:20	Nine attempts made to establish circulation. Circulation established with 3,142 psi.	*OpenWells®* Real-time data
April 19	16:20–19:30	Circulation pressure of 340 psi did not match modeling results of 570 psi.	*OpenWells®*

Cement Job

Date	Time	Description	Source
April 19–20	19:30–00:36	Cement job pumped as planned with full fluid returns observed. Bottom plug burst disk ruptured at higher-than-planned pressure, 2,900 psi. Cement job completed; bumped top wiper plug at 00:36 hours.	*OpenWells®* Real-time data
April 20	00:40	Bled off 5 bbls of fluid to reduce drill pipe pressure from 1,150 psi to 0 psi. No flow observed after bleeding 5 bbls.	Real-time data *OpenWells®*
April 20	00:40–07:00	Dril-Quip seal assembly installed in subsea wellhead. Two pressure tests successfully completed. Drill pipe pulled out of riser.	Real-time data *OpenWells®* Interviews
April 20	~07:30	BP and service providers discussed running cement bond log (CBL) during morning operations call. Decision made, in accordance with pre-established BP Macondo well team decision tree, not to run CBL.	Interviews

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Positive-pressure and Negative-pressure Tests

Date	Time	Description	Source
April 20	10:55–12:00	Successful positive-pressure test of the production casing.	Real-time data Interviews
April 20	12:00–15:04	Drill pipe run in hole to 8,367 ft. Displacement procedure reviewed in preparation for mud displacement and negative-pressure test. At 13:28 hours, *Deepwater Horizon* started offloading mud to M/V *Damon Bankston*. Mudlogger told assistant driller that pit levels could not be monitored during offloading. Assistant driller told mudlogger that notice would be provided when offloading to M/V *Damon Bankston* ceased.	Real-time data M/V *Damon Bankston* log Interviews
April 20	15:04–15:56	Seawater pumped into boost, choke and kill lines to displace mud. 1,200 psi left trapped in the kill line (i.e., not bled off).	Real-time data
April 20	15:56–16:53	A total of 424 bbls of 16 ppg spacer followed by 30 bbls of freshwater pumped into well. Displacement completed with 352 bbls of seawater, placing the spacer 12 ft. above the BOP. [*From ~16:00 hours–17:50 hours, trip tank was being cleaned. Recorded flow data unreliable during this period.*]	Real-time data M-I SWACO displacement procedure
April 20	16:54	Upon shutting down pumps, drill pipe pressure was at 2,325 psi. Pressure in kill line remained at 1,200 psi. An annular preventer was closed for the negative-pressure test.	Real-time data Interviews
April 20	16:54–16:56	Drill pipe pressure bled from 2,325 psi down to 1,220 psi in order to equalize with the 1,200 psi on the kill line.	Real-time data
April 20	16:57–16:59	Kill line opened and pressure decreased to 645 psi; drill pipe pressure increased to 1,350 psi. Attempt made to bleed system down to 0 psi. Drill pipe pressure decreased to 273 psi. Kill line pressure decreased to 0 psi. Kill line shut in.	Real-time data Interviews
April 20	16:59–17:08	At 16:59 hours, drill pipe pressure increased from 273 psi to 1,250 psi in 6 minutes. Annular preventer closing pressure was increased from 1,500 psi to 1,900 psi to create a seal. The riser was topped up with approximately 50 bbls of mud from the trip tank to replace the volume bled off through the drill pipe. [*Spacer fluid was then across the BOP.*]	Real-time data MBI testimony

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Date	Time	Description	Source
April 20	17:08–17:27	Drill pipe pressure decreased from 1,250 psi to 1,205 psi.	Real-time data
April 20	17:17	Mud offloading from *Deepwater Horizon* mud pits to M/V *Damon Bankston* ceased. Mudlogger not notified.	M/V *Damon Bankston* log Interviews
April 20	17:27–17:52	Drill pipe pressure reduced from 1,205 psi to 0 psi by bleeding off 15 bbls to 23 bbls of fluid to the cement unit. Rig crew and well site leader discussed negative-pressure test procedure. Well site leader stated the negative-pressure test needed to be done on the kill line in accordance with the BP plan submitted to MMS.	Real-time data Interviews
April 20	17:52–18:00	Kill line opened to the cement unit. Cementer bled off 3 bbls to 15 bbls of seawater. A witness reported continuous flow from the kill line that spurted and was still flowing when instructed to shut in the line.	Real-time data Interviews
April 20	18:00–18:35	Drill pipe pressure gradually increased to 1,400 psi over 35 minutes. Build profile showed distinct pressure fluctuations at fairly uniform intervals.	Real-time data
April 20	18:35–19:55	Discussion ensued about pressure anomalies and negative-pressure test procedure. Seawater pumped into the kill line to confirm it was full. Opened kill line and bled 0.2 bbl to mini trip tank; flow stopped. Kill line opened and monitored for 30 minutes with no flow. At 19:55 hours, the negative-pressure test was concluded and considered a good test.	Real-time data Interviews

Well Monitoring and Simultaneous Operations

Date	Time	Description	Source
April 20	20:00	Internal blowout preventer (IBOP) and annular preventer opened and pumping of seawater commenced down the drill pipe to displace mud and spacer from the riser.	Real-time data
April 20	20:50	Pumps slowed for the spacer arriving at surface.	Real-time data
April 20	~20:52	[*Calculated that the well went underbalanced and started to flow.*]	OLGA® model

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Date	Time	Description	Source
April 20	20:58-21:08	Flow out from the well increased. Trip tank was emptied into the flow-line at this time. [*Taking into account the emptying of the trip tank, calculated a gain of approximately 39 bbls over this period.*]	Real-time data Calculations
April 20	21:01–21:08	Drill pipe pressure increased from 1,250 psi to 1,350 psi at constant pump rate.	Real-time data
April 20	21:08	Spacer observed at surface. Pumps shut down to enable sheen test to be conducted.	Real-time data Interviews
April 20	21:08–21:14	With pumps off, drill pipe pressure increased from 1,017 psi to 1,263 psi in 5 1/2 minutes. Overboard dump line opened during sheen test; Sperry-Sun flow meter bypassed. Successful result from visual sheen test indicated that fluids could be discharged overboard. [*OLGA® well flow modeling calculated that in-flow to the well during this period was approximately 9 bbls/min.*]	Real-time data Interviews *Deepwater Horizon* P&IDs OLGA® model
April 20	21:14–21:31	Pumps restarted to continue displacement. Displaced well fluids discharged overboard. Drill pipe pressure on continually increasing trend.	Real-time data Interviews
April 20	21:17	Pump #2 started and pressure spiked to 6,000 psi. [*Inferred that the pump likely started against a closed valve and the pressure lifted the relief valve.*]	Real-time data MBI testimony
April 20	21:18	Pumps #2, #3 and #4 were shut down. Pump #1 stayed online (boost line).	Real-time data
April 20	~21:18–21:20	Toolpusher was called to rig floor.	Interviews
April 20	~21:20	Assistant driller was called to either the pit room or the pump room.	Interviews MBI testimony
April 20	~21:20	Senior toolpusher called toolpusher and asked how the negative-pressure test had gone. Toolpusher responded that the test result was "good," and the displacement was "going fine."	MBI testimony
April 20	21:20–21:27	Pumps #3 and #4 restarted. Some pressure started to build on pump #2, reaching 800 psi at 21:27 hours.	Real-time data

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Date	Time	Description	Source
April 20	21:26–21:30	Drill pipe pressure declined by 400 psi at constant pump rate.	Real-time data
April 20	21:30	[*Calculated that the spacer was fully displaced from the riser.*]	Real-time data OLGA® model

Well Control Response

Date	Time	Description	Source
April 20	21:31	Pumps shut down; first pumps #3 and #4, then #1 (boost pump).	Real-time data
April 20	21:31–21:34	Drill pipe pressure increased from 1,210 psi to 1,766 psi. ~21:33 hours, chief mate observed toolpusher and driller discussing "differential pressure." Toolpusher told chief mate that cement job may be delayed.	Real-time data MBI testimony
April 20	21:36–21:38	Over a 90-second period, drill pipe pressure decreased from 1,782 psi to 714 psi and then increased from 714 psi to 1,353 psi. [*Inferred to have been caused by opening and closing a 4 in. valve on the standpipe manifold.*]	Real-time data OLGA® model
April 20	21:38	[*Calculated that at approximately 21:38, hydrocarbons passed from well into riser.*]	OLGA® model
April 20	21:38–21:42	Drill pipe pressure held briefly, then decreased steadily from 1,400 psi to 338 psi.	Real-time data
April 20	~21:40–21:48	Chief electrician de-isolated pump #2. Chief electrician observed four personnel (including the assistant driller) completing repair of the pressure relief valve on pump #2 at the time he left the area (~21:48 hours).	MBI testimony

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Date	Time	Description	Source
April 20	21:40–21:48	~21:40 hours—Mud overflowed the flow-line and onto rig floor. ~21:41 hours—Mud shot up through derrick. ~21:41 hours—Diverter closed and flow routed to mud gas separator (MGS); BOP activated (believed to be lower annular preventer). [*Drill pipe pressure started increasing in response to BOP activation.*] ~21:42 hours—M/V *Damon Bankston* was advised by *Deepwater Horizon* bridge to stand off 500 m because of a problem with the well. The ship began to move away. ~21:42 hours—Drill pipe pressure increased steadily from 338 psi to 1,200 psi over 5-minute period. ~21:44 hours—Mud and water exited MGS vents; mud rained down on rig and M/V *Damon Bankston* as it pulled away from rig. ~21:44 hours—Toolpusher called well site leader and stated they were "getting mud back" and that they had "diverted to the mud gas separator" and had either closed or were closing the annular preventer. ~21:45 hours—Assistant driller called the senior toolpusher to report that "The well is blowing out . . . [the toolpusher] is shutting it in now." ~21:46 hours—Gas hissing noise heard and high-pressure gas discharged from MGS vents towards deck. ~21:47 hours—First gas alarm sounded. Gas rapidly dispersed, setting off other gas alarms. ~21:47 hours—Roaring noise heard and vibration felt. ~21:47 hours—Drill pipe pressure started rapidly increasing from 1,200 psi to 5,730 psi. [*This is thought to have been the BOP sealing around pipe. Possible activation of variable bore rams [VBRs] at 21:46 hours.*] ~21:48 hours—Main power generation engines started going into overspeed (#3 and #6 were online).	Real-time data Interviews MBI testimony

Explosion and Fire

Date	Time	Description	Source
April 20	21:49	Rig power lost. Sperry-Sun real-time data transmission lost. First explosion occurred an estimated 5 seconds after power loss. Second explosion occurred an estimated 10 seconds after first explosion.	Real-time data Interviews MBI testimony
April 20	21:52:57	Mayday call made by *Deepwater Horizon*.	M/V *Damon Bankston* log
April 20	~21:52–21:57	Subsea supervisor attempted to activate emergency disconnect sequence (EDS) for the BOP at the panel on the bridge. Lights changed on panel, but no flow was observed on the flow meter. Lower marine riser package did not unlatch. *Deepwater Horizon* master announced the activation of the EDS at 21:56.	MBI testimony Interviews
April 20	~22:00–23:22	Transfer of 115 personnel, including 17 injured, to M/V *Damon Bankston*. 11 people were determined to be missing, and search and rescue activities ensued. U.S. Coast Guard arrived on-site at 23:22 hours.	MBI testimony
April 22	10:22	*Deepwater Horizon* sank.	Unified Command
April 23	17:00	The search for the 11 missing people was suspended.	Unified Command

BOP Emergency Operations

Date	Time	Description	Source
April 21–22	18:00–01:15	Remotely operated vehicle (ROV) operations were initiated. ROV attempted hot stab interventions to close VBRs and blind shear rams (BSRs); ROV attempts were ineffective.	IMT reports
April 22	~02:45	ROV simulated automatic mode function AMF in an attempt to activate BSR. Well continued to flow.	IMT reports
April 22	~07:40	On the third attempt, ROV activated autoshear function. (BSR thought to have closed.) Well continued to flow.	IMT reports
April 25–May 5		Seventeen further attempts by ROVs using subsea accumulators to close various BOP rams and annular preventers. Well continued to flow.	IMT reports

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Section 4. Overview of *Deepwater Horizon* Accident Analyses

Introduction

This section provides an overview of the detailed analyses undertaken by the investigation team. The investigation team considers the findings and conclusions from the detailed analyses a strong foundation for the recommendations in *Section 6. Investigation Recommendations* of this report.

A complex and interlinked series of mechanical failures, human judgments, engineering design, operational implementation and team interactions came together to allow the initiation and escalation of the *Deepwater Horizon* accident. Multiple companies, work teams and circumstances were involved over time.

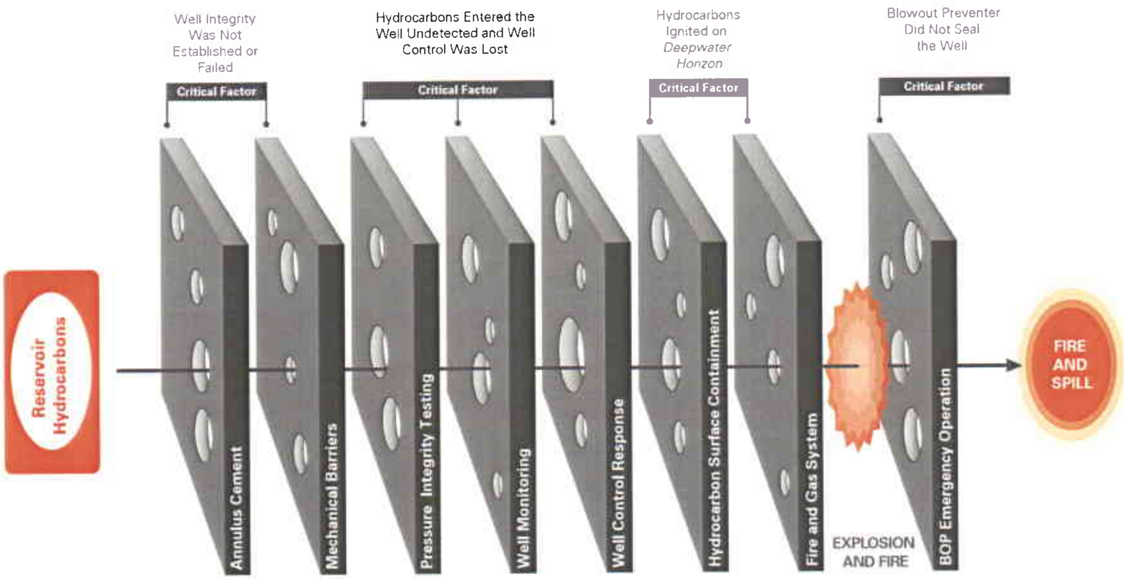
The investigation pursued four primary lines of inquiry, based on the initial review of the accident events. For the accident and its aftermath to have occurred, the following critical factors had to have been in place:

- Well integrity was not established or failed.
- Hydrocarbons entered the well undetected and well control was lost.
- Hydrocarbons ignited on *Deepwater Horizon*.
- The blowout preventer (BOP) did not seal the well.

The investigation of this complex accident became four linked investigations into the facts and causes underlying these critical factors. (Refer to *Section 5.* Deepwater Horizon *Accident Analyses* of this report.) Using fault tree analysis, various scenarios, failure modes and possible contributing factors were considered. Eight key findings emerged:

1. The annulus cement barrier did not isolate the hydrocarbons.
2. The shoe track barriers did not isolate the hydrocarbons.
3. The negative-pressure test was accepted although well integrity had not been established.
4. Influx was not recognized until hydrocarbons were in the riser.
5. Well control response actions failed to regain control of the well.
6. Diversion to the mud gas separator resulted in gas venting onto the rig.
7. The fire and gas system did not prevent hydrocarbon ignition.
8. The BOP emergency mode did not seal the well.

In *Figure 1*, the eight blocks represent the defensive physical or operational barriers that were in place to eliminate or mitigate hazards. The holes represent failures or vulnerabilities in the defensive barriers. The eight key findings are represented by the holes that lined up to enable the accident to occur.



Adapted from James Reason (Hampshire: Ashgate Publishing Limited, 1997).

Figure 1. Barriers Breached and the Relationship of Barriers to the Critical Factors.

If any of the critical factors had been eliminated, the outcome of *Deepwater Horizon* events on April 20, 2010, could have been either prevented or reduced in severity. *Section 5.* Deepwater Horizon *Accident Analyses* of this report documents the investigation team's analysis and conclusions regarding each key finding or barrier breach.

Background

Deepwater Horizon, which was built in 2001, was a fifth generation, dynamically-positioned semi-submersible drilling unit. The unit employed an automated drilling system and a 15,000 psi-rated BOP system and had operated in water depths (WD) greater than 9,000 ft. The rig had drilled wells up to 35,055 ft. in the nine years it had been owned and operated by Transocean under contract to BP in the deepwater Gulf of Mexico.

The Macondo well was an exploration well in Mississippi Canyon Block 252 in 4,992 ft. WD. The well had been drilled to 18,360 ft. from its last casing point at 17,168 ft. The well penetrated a hydrocarbon-bearing Miocene reservoir and was deemed a commercial discovery. The decision was made to temporarily abandon the Macondo well and complete it as a production well in the future.

At the time of the accident, the final string of casing had been run into the well, and the cement barrier had been put in place to isolate the hydrocarbon zones. Integrity tests had been conducted, and the top 8,367 ft. of mud was being circulated out using seawater in preparation for temporary abandonment of the well. The remaining steps were to set a cement plug in the casing and to install a lockdown sleeve on the casing hanger seal assembly prior to disconnecting the BOP and suspending the well.

For the purposes of this report, the BP Macondo well team refers to BP's Houston-based wells team that worked on the Macondo well, excluding BP's cementing services provider (Halliburton) and also excluding the BP well site leaders aboard *Deepwater Horizon*.

The rig crew describes Transocean's rig crew leaders who were aboard *Deepwater Horizon* (senior toolpusher, toolpushers, drillers and assistant drillers) collectively, or to the individuals in one or more of these roles, and includes personnel acting at their direction. References to the BP well site leaders are to the day and night well site leaders who were aboard *Deepwater Horizon*.

References to mudloggers are the Halliburton Sperry-Sun mudloggers who were aboard *Deepwater Horizon*. M-I SWACO provided the mud engineers.

Key Finding 1. The annulus cement barrier did not isolate the hydrocarbons.

The annulus cement barrier failed to prevent hydrocarbons from migrating into the wellbore. The investigation team's analysis identified a probable technical explanation for the failure. Interactions between BP and Halliburton and shortcomings in the planning, design, execution and confirmation of the cement job reduced the prospects for a successful cement job.

A 9 7/8 in. liner was set in place at 17,168 ft. prior to drilling the production section of the well to a total depth of 18,360 ft. This last hole section was difficult to drill due to a reduction in fracture gradient at the bottom of the wellbore. This condition required selecting the correct mud weight to maintain overbalance on the formation while avoiding fluid losses to the well.

Considering the narrow margin between pore pressure and fracture gradient, a number of different options were evaluated prior to selecting the design for the production casing string, cement formulation and placement plan.

The investigation team reviewed the decision to install a 9 7/8 in. x 7 in. long string production casing rather than a 7 in. production liner, which would have been tied back to the wellhead later, and concluded that both options provided a sound basis of design.

The investigation team found no indication that hydrocarbons entered the wellbore prior to or during the cement job. To determine how the hydrocarbons entered the well after the cement job, the investigation team assessed the cement slurry design, cement placement and confirmation of the placement.

Cement Slurry Design

Due to the narrow margin between pore pressure and fracture gradient, the accuracy of cement placement was critical. Several design iterations were conducted by Halliburton using the OptiCem™ wellbore simulation application to establish an acceptable slurry design and placement plan. A complex design for the cement job with base oil spacer, cementing spacer, lead (cap) cement, foam cement and tail cement, was recommended and implemented.

The Halliburton and the BP Macondo well team's technical reviews of the cement slurry design appeared to be focused primarily on achieving an acceptable equivalent circulating density during cement placement to prevent lost returns. Other important aspects of the foam cement design, such as foam stability, possible contamination effects and fluid loss potential did not appear to have been critically assessed in the pre-job reviews.

The evidence reviewed suggests that the cement slurry was not fully tested prior to the execution of the cement job. The investigation team was unable to confirm that a comprehensive testing program was conducted. The test results reviewed by the investigation team indicated that only limited cement testing such as thickening time, foam density, mixability and ultrasonic compressive strength, was performed on the slurry used in the Macondo well. The tests reviewed did not include fluid loss, free water, foam/spacer/mud compatibility, static gel strength transition time, zero gel time or settlement.

To evaluate the effectiveness of the Halliburton cement slurry design that was used, the investigation team requested a third party cementing lab, CSI Technologies, to conduct a series of tests. To test the cement slurry design, a representative slurry was formulated to match, as closely as possible, the actual slurry used for the Macondo well (the investigation team did not have access to the actual Halliburton cement and additives that were used for the job).

The results of these tests indicated it was not possible to generate a stable nitrified foam cement slurry with greater than 50% nitrogen (by volume) at the 1,000 psi injection pressure. For the Macondo well, a mixture of 55% to 60% nitrogen (by volume) was required at 1,000 psi injection pressure to achieve the design mixture of 18% to 19% nitrogen (by volume) foam cement at downhole pressure and downhole temperature conditions.

These third party test results suggest that the foam cement slurry used for the Macondo well was likely unstable, resulting in nitrogen breakout.

The investigation team identified cement slurry design elements that could have contributed to a failure of the cement barrier, including the following:

- The cement slurry yield point was extremely low for use in foam cementing, which could have increased the potential for foam instability and nitrogen breakout.
- A small slurry volume, coupled with long displacement and the use of base oil spacer, could have increased the potential for contamination and nitrogen breakout.
- A defoamer additive was used, which could have destabilized the foam cement slurry.
- Fluid loss control additives were not used for cementing across the hydrocarbon zone, which could have allowed formation fluids to permeate the cement.

Conclusion
Based on CSI Technologies' lab results and analysis, the investigation team concludes that the nitrified foam cement slurry used in the Macondo well probably would have experienced nitrogen breakout, nitrogen migration and incorrect cement density, which would explain the failure to achieve zonal isolation of hydrocarbons. Nitrogen breakout and migration would have also contaminated the shoe cement and may have caused the shoe track cement barrier to fail.

Cement Placement

Effective cement placement is necessary for the isolation of permeable hydrocarbon zones. The Macondo well cement placement plan was to place the top of cement (TOC) 500 ft. above the shallowest identified hydrocarbon zone in compliance with Minerals Management Service (MMS) regulations.

The 500 ft. TOC design was chosen to:

- Minimize annulus hydrostatic pressure during cement placement in order to avoid lost returns.
- Avoid cementing into the next casing string and creating a sealed annulus. A sealed annulus would have increased the risk of casing collapse or burst due to annular pressure build-up during production.

When the placement model was run using 21 centralizers, the results indicated that the possibility of channeling above the main hydrocarbon zones would be reduced. The 7 in. casing string that had been purchased for the job was supplied with six inline centralizers. An additional 15 slip-on centralizers were sourced from BP inventory and sent to *Deepwater Horizon*. The BP Macondo well team erroneously believed that they had received the wrong centralizers. They decided not to use the 15 centralizers due to a concern that these slip-on centralizers could fail during the casing run and cause the casing to lodge across the BOP. To mitigate the risk of channeling associated with using fewer centralizers, the six inline centralizers were positioned across and above the primary hydrocarbon zones.

Conclusion
Although the decision not to use 21 centralizers increased the possibility of channeling above the main hydrocarbon zones, the decision likely did not contribute to the cement's failure to isolate the main hydrocarbon zones or to the failure of the shoe track cement.

Planning for Temporary Abandonment

The cement job was pumped with expected volumes and mud returns. The BP Macondo well team used final lift pressure and returns to declare a successful cement placement. After discussion with Macondo well contractors and consistent with a decision tree developed by the team, the team decided that no further evaluation was needed at that time.

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BP's *Engineering Technical Practice (ETP) GP 10-60 Zonal Isolation Requirements During Drilling Operations and Well Abandonment and Suspension* specifies that TOC should be 1,000 ft. above any distinct permeable zones, and centralization should extend to 100 ft. above such zones. If those conditions are not met, as in this case, TOC should be determined by a "proven cement evaluation technique," such as conducting a cement evaluation log, which would typically be done during the completion phase of the well. The investigation team has not seen evidence of a documented risk assessment regarding annulus barriers.

Conclusion

Evaluating lift pressure and lost returns did not constitute a "proven cement evaluation technique" per *Section 5* of *ETP GP 10-60*. By not conducting a formal risk assessment of the annulus cement barriers per the *ETP* recommendations, it is the view of the investigation team that the BP Macondo well team did not fully conform to the intent of *ETP GP 10-60*.

A formal risk assessment might have enabled the BP Macondo well team to identify further mitigation options to address risks such as the possibility of channeling; this may have included the running of a cement evaluation log.

Overarching Conclusion for Key Finding 1

Improved engineering rigor, cement testing and communication of risk by Halliburton could have identified the low probability of the cement to achieve zonal isolation.

Improved technical assurance, risk management and management of change by the BP Macondo well team could have raised awareness of the challenges of achieving zonal isolation and led to additional mitigation steps.

Key Finding 2. The shoe track barriers did not isolate the hydrocarbons.

After the annulus cement did not effectively isolate the reservoir, a mechanical barrier failure enabled hydrocarbon ingress to the wellbore. The investigation team considered three possibilities for ingress:

- *Ingress through the shoe track barriers.*
- *Ingress through the casing hanger seal assembly.*
- *Ingress through the production casing and components.*

Available evidence and analysis conducted by the investigation team leads it to conclude that initial flow into the well came through the shoe track barriers.

The Shoe Track

The shoe track comprised a float collar with two check valves, 7 in. casing and a ported reamer shoe. (Refer to Figure 2.) If hydrocarbons breached the annulus cement barrier, ingress to the casing should have been prevented by the cement in the shoe track and the check valves in the float collar.

The entrance of initial influx and flow through the shoe was confirmed by extensive OLGA® well flow modeling of wellbore flow dynamics and comparison to pressures and flows observed in the real-time data.

The investigation team identified the following possible failure modes that may have contributed to the shoe track cement's failure to prevent hydrocarbon ingress:

- Contamination of the shoe track cement by nitrogen breakout from the nitrified foam cement. (Refer to Key Finding 1.)
- Contamination of the shoe track cement by the mud in the wellbore.
- Inadequate design of the shoe track cement.
- Swapping of the shoe track cement with the mud in the rat hole (bottom of the hole).
- A combination of these factors.

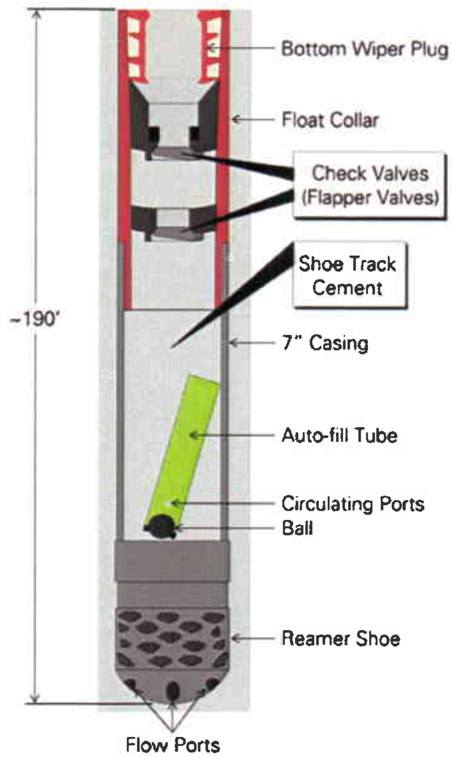

Figure 2. Shoe Track Barriers.

Three possible failure modes for the float collar were identified:

- Damage caused by the high load conditions required to establish circulation.
- Failure of the float collar to convert due to insufficient flow rate.
- Failure of the check valves to seal.

At the time this report was written, the investigation team had not determined which of these failure modes occurred.

Conclusion

Based on available evidence, hydrostatic pressure calculations, OLGA® well flow modeling and analysis of data from the Macondo well static kill on August 4, 2010, hydrocarbons entered the casing through the shoe track. Therefore, the shoe track cement and the float collar must have failed to prevent this ingress. The investigation team has not established whether this failure was attributable to the design of the cement, contamination of the cement by mud in the wellbore, commingling of cement with nitrogen due to nitrogen breakout from the nitrified foam cement slurry, swapping of the shoe track cement with the mud in the rathole (bottom of the well) or some combination of these factors.

The Casing Hanger Seal Assembly

The casing hanger seal assembly was run and installed according to the installation procedure, and the positive-pressure test verified integrity of the seal. At the time of the accident, the seal assembly was not yet mechanically locked to the wellhead housing.

In this scenario, engineering analysis identifies that it is possible for the seal assembly to be uplifted if sufficient force is applied. Uplift forces approached (if the casing was secured by cement), but did not reach, loads sufficient to unseat the seals during the negative-pressure test. However, the analysis indicates that with sustained flow from the reservoir, the temperature of the casing string would have risen, thereby adding the uplift force resulting from thermal elongation of the pipe. In this case, it is plausible that the seal assembly could have lifted and an additional flow path could have been established after the well had been flowing for a sustained period.

Conclusion
The investigation team has concluded that initial flow into the wellbore was through the shoe track, not through the casing hanger seal assembly. This supports the conclusion that the uplift forces during the negative-pressure test did not unseat the seal assembly. With no locking mechanism installed, thermal stresses caused by sustained hydrocarbon flow from the reservoir through the shoe track may have subsequently opened a flow path through the seal assembly.

The Production Casing and Components

The production casing consisted of a casing hanger, a 9 7/8 in. production casing, a 9 7/8 in. x 7 in. crossover joint and a 7 in. production casing. The investigation team reviewed manufacturing data, inspection reports, installation reports, casing-running operations and positive-pressure integrity tests. A casing design review was conducted using the actual wellbore conditions.

Conclusion
The investigation team concludes that the production casing and components met all the required design conditions and that it is highly unlikely that a casing failure mode contributed to the loss of well control.

Key Finding 3. The negative-pressure test was accepted although well integrity had not been established.

Approximately 10 1/2 hours after the completion of the cement job, the positive-pressure integrity test commenced. Following successful completion of the positive-pressure test to 2,700 psi, the negative-pressure test was conducted.

The objective of the negative-pressure test was to test the ability of the mechanical barriers (shoe track, casing hanger seal assembly and production casing) to withstand the pressure differentials that would occur during subsequent operations: the reduction of hydrostatic head to seawater and disconnection of the BOP and riser.

The investigation team concludes that the negative-pressure test results indicated that well integrity had not been established. This situation was not recognized at the time of the test, therefore, remedial steps were not taken.

During the negative-pressure test, the well was placed in an underbalanced state when hydrostatic pressure in the wellbore was reduced below reservoir pressure.

To prepare for this test, mud in the boost line, choke line, kill line, drill pipe and upper part of the production casing was displaced to seawater. To provide separation between the mud and the seawater in the casing, a spacer was pumped down the drill pipe ahead of the seawater.

With the heavier fluids in position, the annular preventer was shut to isolate the hydrostatic head of the fluids in the riser from the well. At this time, the annular preventer did not seal around the drill pipe, resulting in heavy spacer leaking down past the annular preventer. After adjustment of the regulator hydraulic pressure for the annular preventer, an effective seal was established. The residual pressure of 1,260 psi in the drill pipe was bled off from the well. According to witness accounts, 15 bbls of fluid returns were taken. The investigation team's analysis indicates that approximately 3.5 bbls should have been expected. This excess flow from the drill pipe, with the well in an underbalanced condition, should have indicated to the rig crew a communication flow path with the reservoir through failed barriers.

The BP Macondo well team provided broad operational guidelines for the negative-pressure test. The rig crew and well site leader were expected to know how to perform the test. The rig crew began the negative-pressure test by monitoring the drill pipe flow. According to witness accounts, this was the rig crew's preferred practice. However, the *Application for Permit to Modify (APM)* to MMS for the Macondo well temporary abandonment stipulated that the negative-pressure test should be conducted by monitoring the kill line. The well site leader noticed the discrepancy and after a discussion with the rig crew, preparations for continuing the negative-pressure test were made by bleeding the kill line. According to witness accounts, between 3 bbls and 15 bbls of seawater flowed from the kill line, which was then shut in.

From 18:00 hours to 18:35 hours, the drill pipe pressure increased from approximately 50 psi to 1,400 psi. To resume the negative-pressure test, the kill line was filled and then opened, 0.2 bbls flowed, and no further flow was observed from the kill line during a 30-minute period of monitoring. The drill pipe pressure was constant at 1,400 psi.

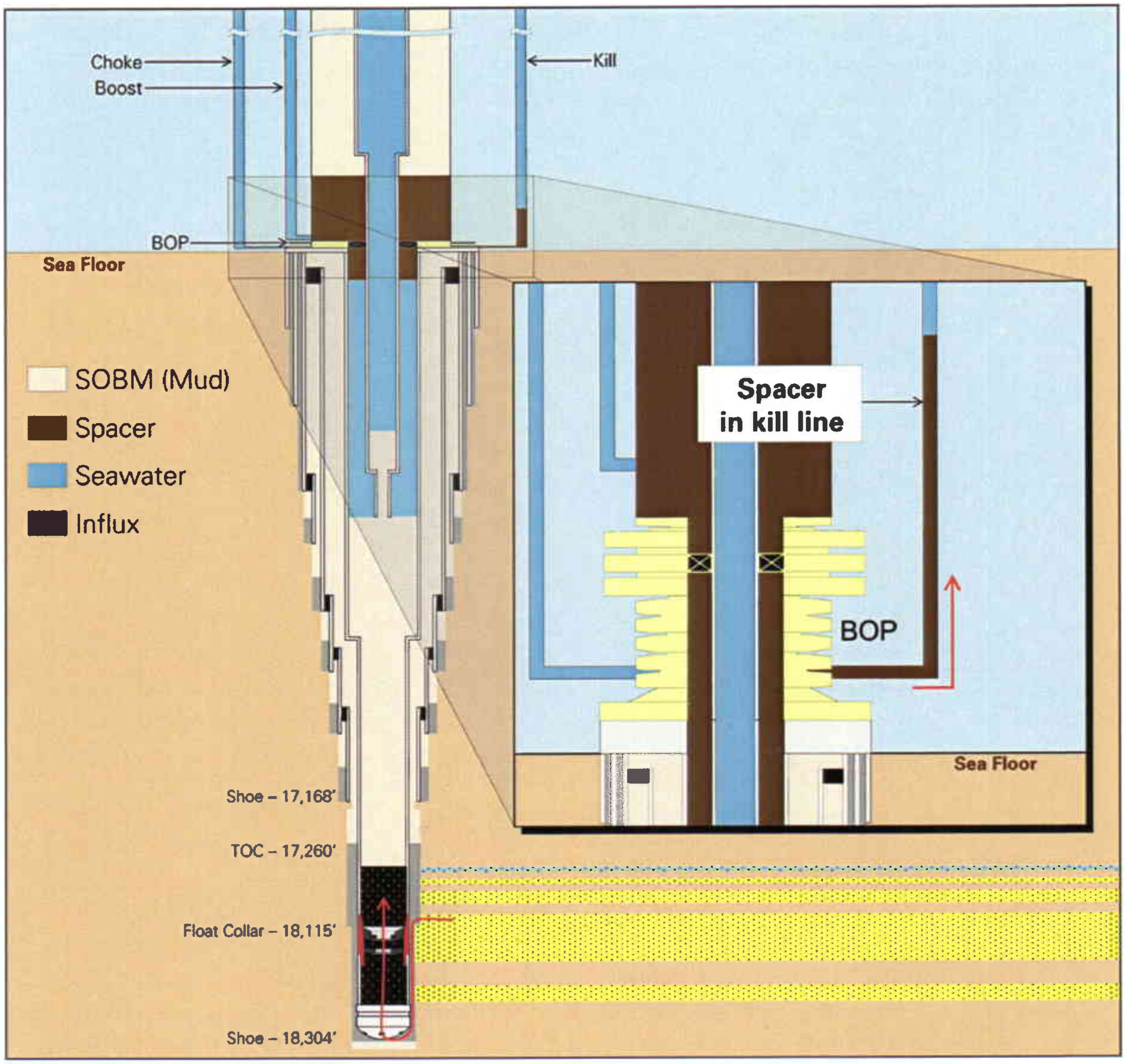

Figure 3. Possible Movement of Spacer into the Kill Line.

This pressure of 1,400 psi on the drill pipe was misinterpreted by the rig crew and the well site leaders. According to witness accounts, the toolpusher proposed that the pressure on the drill pipe was caused by a phenomenon referred to as 'annular compression' or 'bladder effect.' The toolpusher and driller stated that they had previously observed this phenomenon. After discussing this concept, the rig crew and the well site leaders accepted the explanation. The investigation team could find no evidence that this pressure effect exists.

The investigation team has identified two possible reasons that flow did not exit the kill line:

- The kill line may have been plugged with solids from the spacer. (Refer to Figure 3.)
- The system may not have been lined up correctly; a valve may have been inadvertently left closed.

Conclusions

The investigation team concludes that the lack of flow from what was believed to be an open kill line, coupled with the erroneous explanation for the 1,400 psi on the drill pipe, led the well site leaders and the rig crew to the incorrect view that the negative-pressure test was successful and that well integrity was established. The well site leaders and the rig crew maintained this view despite the contradictory information of 1,400 psi on the drill pipe connected through the wellbore to the non-flowing kill line with 0 psi.

The guidelines for the negative-pressure test, a critical activity, did not provide detailed steps and did not specify expected bleed volumes or success/failure criteria. Therefore, effective performance of the test placed a higher reliance on the competency and leadership skills of the BP and Transocean rig leaders.

Key Finding 4. Influx was not recognized until hydrocarbons were in the riser.

A fundamental requirement for safe Drilling and Completions (D&C) operations is to maintain control of the well and prevent influx of hydrocarbons. During all phases of these operations, fluid returns, pressure and flow indicators should be continuously monitored to detect influx into the well as soon as possible. On the Macondo well, the rig crew apparently did not recognize significant indications of hydrocarbon influx during the displacement of the riser to seawater.

Following the negative-pressure test, the annular preventer was opened, and the hydrostatic head of fluid in the riser returned the well to an overbalanced state. The rig crew began the displacement of the mud in the riser to seawater. As the mud was displaced from the riser, the pressure at the bottom of the wellbore decreased. Analysis of OLGA® well flow modeling indicates that the well became underbalanced again at approximately 20:52 hours, and hydrocarbon influx resumed. The rate of influx would have gradually increased as the well became more underbalanced with heavier fluids being displaced by lighter seawater and hydrocarbons. Flow increase from the well was discernable in the real-time data after approximately 20:58 hours.

The investigation team's analysis of fluid volumes shows an approximate gain of 39 bbls by 21:08 hours. No well control actions were taken at that time, indicating that this fluid gain was not detected.

Simultaneous end-of-well activities were occurring and may have distracted the rig crew and mudloggers from monitoring the well. These activities included preparing for the next operation (setting a cement plug in the casing), bleeding off the riser tensioners and transferring mud to the supply vessel M/V *Damon Bankston.*

The investigation team did not find evidence that either the Transocean rig crew or the Sperry-Sun mudloggers monitored the pits from 13:28 hours (when the offloading to the supply vessel began) to 21:10 hours (when returns were routed overboard).

At 21:08 hours, the spacer reached the top of the riser, and the rig crew shut down pumping operations to complete a sheen test prior to discharging the spacer to the sea. During the sheen test, the rig crew configured the flow path to route the spacer overboard. This flow path bypassed the mudlogger's flow meter and the mud pits; therefore, fluid flow could no longer be monitored at the mudlogger's console. However, drill pipe pressure should have been observable at the mudlogger's console, and flow and drill pipe pressure should have been observable at the driller's console.

During the sheen test between 21:08 hours and 21:14 hours, the mud pumps were shut down, and real-time data showed flow continuing and drill pipe pressure increasing by 246 psi. The rig crew apparently did not recognize these indications of flow, and displacement was recommenced.

Analysis of OLGA® well flow modeling suggests that by 21:30 hours there would have been approximately 300 bbls of hydrocarbon influx in the well.

At 21:31 hours, the mud pumps were shut down. Witness accounts indicated that a conversation between the toolpusher and the driller took place on the rig floor regarding 'differential pressure.' Between 21:31 hours and 21:34 hours, the pressure on the drill pipe increased by approximately 560 psi.

Analysis suggests that between 21:31 hours and 21:41 hours, with the pumps shut down, the well was unloading at an average rate of approximately 60 bpm to 70 bpm. Analysis also suggests that hydrocarbons did not enter the riser until approximately 21:38 hours. (Refer to Figure 4.) The investigation team believes that the first well control action taken by the rig crew was at 21:41 hours.

Conclusions

Analysis indicates that the first indications of flow from the well could be seen in the real-time data after 20:58 hours. The rig crew and mudloggers either did not observe or did not recognize indications of flow until after hydrocarbons entered the riser at approximately 21:38 hours. The first well control response likely occurred at 21:41 hours.

The *Transocean Well Control Handbook* stated that the well was to be monitored at all times. However, the policy did not specify how to monitor the well during in-flow testing, cleanup or other end-of-well activities.

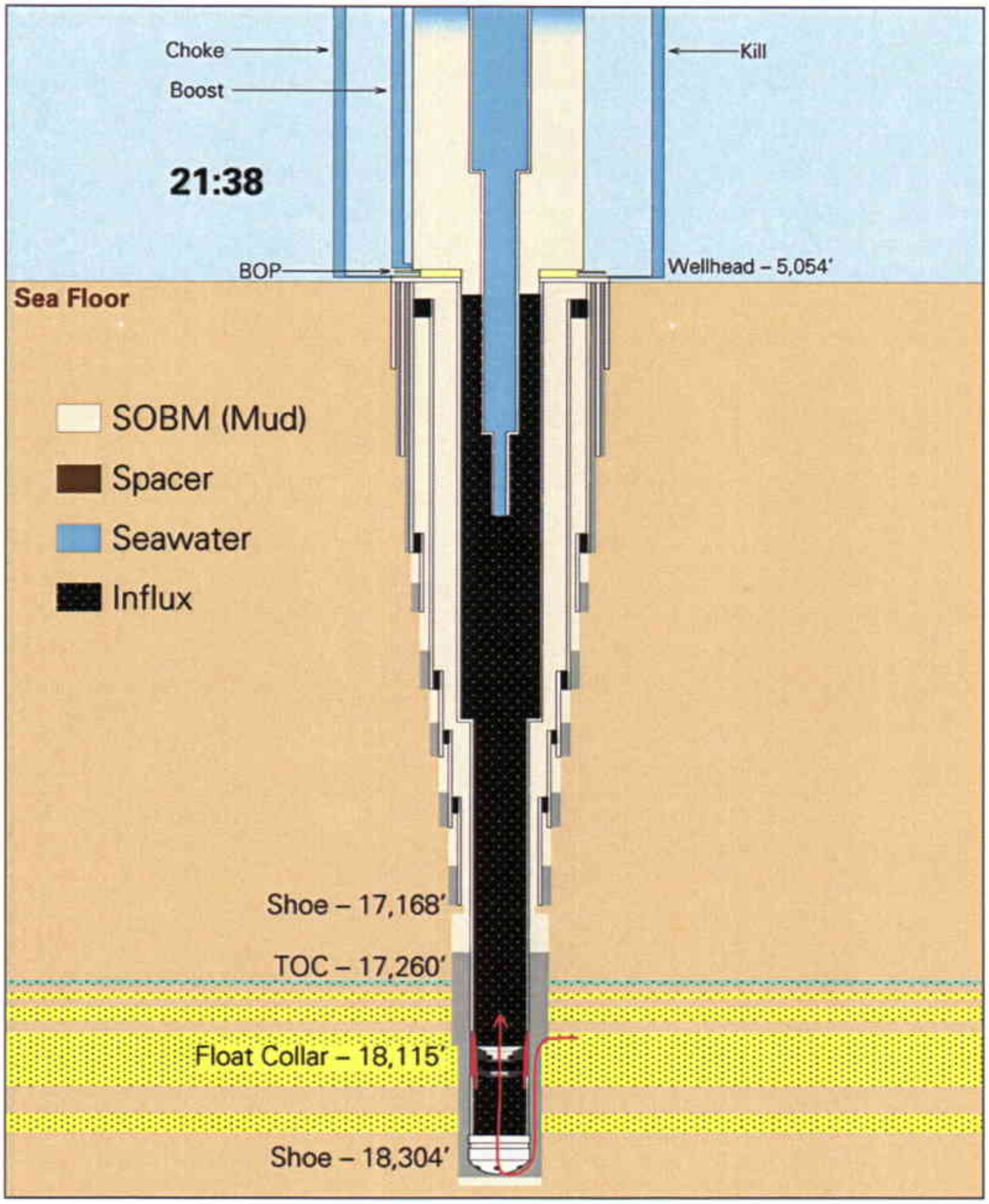

Figure 4. Hydrocarbons Entering the Riser.

Key Finding 5. Well control response actions failed to regain control of the well.

When well influx occurs, rapid response is critical. The rig crew needs effective procedures and must effectively implement them to maintain control over deteriorating conditions in the well.

Key members of the rig crew need to be trained and demonstrate competency. Their actions need to be correct and immediate, especially when control of the well has been lost and the flow of hydrocarbons has escalated.

Witness accounts and real-time data were combined with OLGA® well flow modeling to infer which actions were taken by the rig crew prior to the explosion. Although it is uncertain what the rig crew actions were, separate indications and analyses support the following events.

At approximately 21:40 hours, witness accounts indicated that mud flowed uncontrolled onto the rig floor. Real-time data and further witness accounts suggest that the rig crew attempted to control the well by closing an annular preventer in the BOP at approximately 21:41 hours. This first action was too late to prevent the release of hydrocarbons, which were already in the riser. Modeling suggests that the annular preventer did not fully seal around the drill pipe, allowing hydrocarbons to continue entering the riser.

The rig crew diverted hydrocarbons coming through the riser to the mud gas separator (MGS), which was quickly overwhelmed and failed to control the hydrocarbons exiting the riser. The alternative option of diversion overboard through the 14 in. starboard diverter line did not appear to have been chosen; this action would probably have vented the majority of the gas safely overboard.

Real-time data indicated that at 21:47 hours, drill pipe pressure rose from 1,200 psi to 5,730 psi within one minute. This was likely caused by the closure of one or two variable bore rams (VBRs), which sealed the annulus. At approximately 21:49 hours, rig power and real-time data were lost. Witnesses recall an explosion on the rig, followed closely by a larger explosion. After the explosions, fires continued on the rig.

The subsea supervisor attempted to activate the emergency disconnect sequence (EDS) some time after the explosion. This would have sealed the well and disconnected the riser from the BOP stack. There were no indications that the sequence activated.

Conclusions

No apparent well control actions were taken until hydrocarbons were in the riser. The actions that were taken after that did not control the well.

An annular preventer was likely activated at 21:41 hours, and it closed around the drill pipe. It failed to seal the annulus for approximately five minutes, allowing further flow of hydrocarbons into the riser until the annulus was sealed at 21:47 hours, likely by the closure of a VBR.

The diversion of fluids overboard, rather than to the MGS, may have given the rig crew more time to respond and may have reduced the consequences of the accident.

Transocean's shut-in protocols did not fully address how to respond in high flow emergency situations after well control has been lost. Well control actions taken prior to the explosion suggest the rig crew was not sufficiently prepared to manage an escalating well control situation.

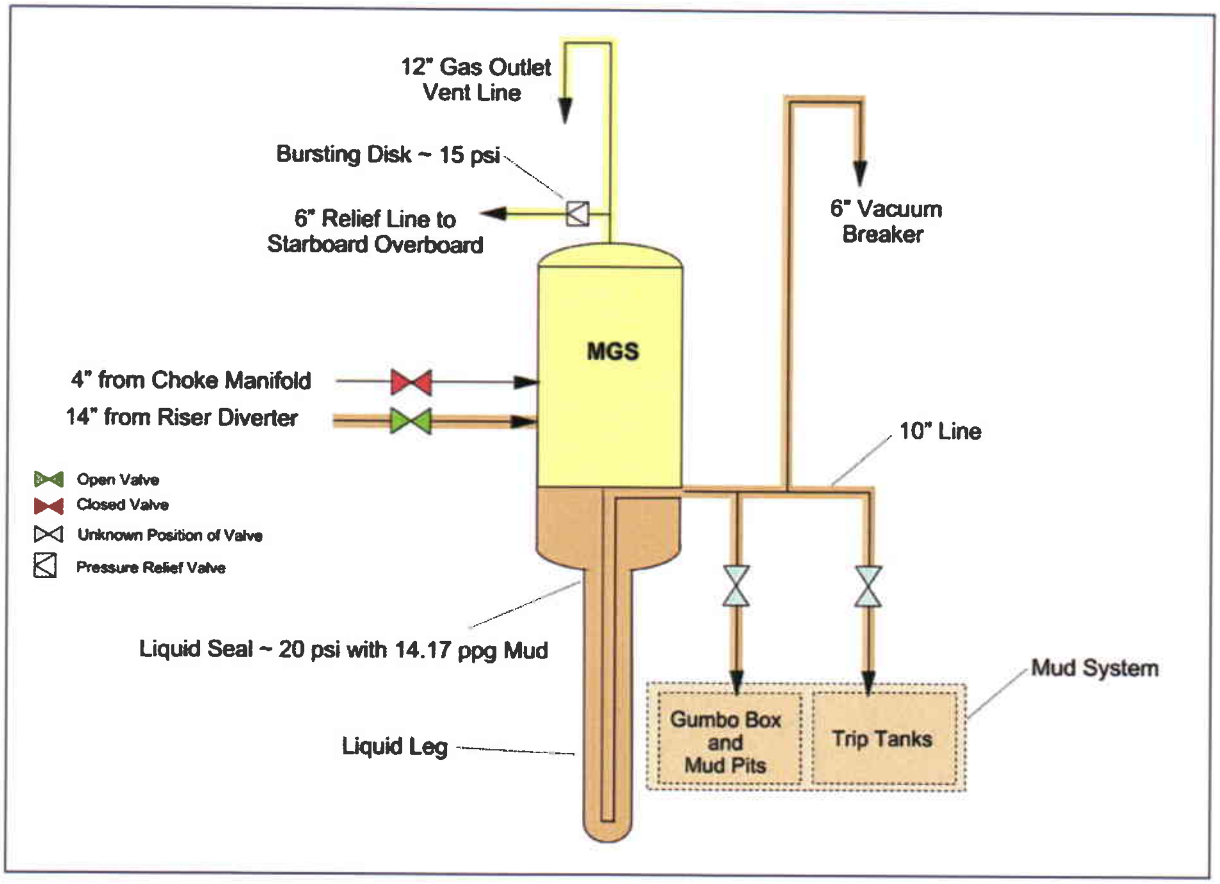

Figure 5. Mud Gas Separator.

Key Finding 6. Diversion to the mud gas separator resulted in gas venting onto the rig.

The MGS removes only small amounts of gas entrained in the mud. Once separated, the gas is vented to the atmosphere at a safe location. When the rig crew diverted high flow to the MGS, the system was overwhelmed.

When an annular preventer appeared to be activated at 21:41 hours, the well was flowing at a high rate, and hydrocarbon fluids were above the BOP. As the hydrocarbon gas expanded, the flow of gas, oil, mud and water to the surface continued at an increasing rate.

The investigation team concludes that, at approximately 21:41 hours, the rig crew diverted the flow of hydrocarbons to the MGS. (Refer to Figure 5.) The MGS is a low-pressure system, and its design limits would have been exceeded by the expanding and accelerating hydrocarbon flow. The main 12 in. gas outlet vent from the MGS was goosenecked at its terminus on top of the derrick, and it vented gas down onto the rig. Several other flow-lines coming from the MGS vessel directed gas onto the rig and potentially into confined spaces under the deck.

The investigation team determined that large areas of the rig were enveloped in a flammable mixture within minutes of gas arriving at the surface.

Conclusion

The design of the MGS system allowed the riser fluids to be diverted to the MGS vessel when the well was in a high flow condition. When the MGS was selected, hydrocarbons were vented directly onto the rig through the 12 in. goosenecked vent exiting the MGS, and other flow-lines directed gas back onto the rig.

Key Finding 7. The fire and gas system did not prevent hydrocarbon ignition.

For operating environments where hazardous substances could be present, secondary levels of protective systems are normally part of the design philosophy. On Deepwater Horizon, *the secondary levels of protective systems included a fire and gas system and the electrical classification of certain areas of the rig.*

The fire and gas system detects hydrocarbon gas and initiates warning alarms when acceptable limits are exceeded. For some alarms, an automated function initiates when hydrocarbon gas is detected beyond acceptable limits. This automated function primarily prevents gas ingress to vulnerable locations through the heating, ventilation and air conditioning (HVAC) system. When gas is detected, the fire and gas system closes the dampers and shuts off the ventilation fans.

Areas on the rig are electrically classified, based on the probability of the presence of hydrocarbons. Equipment in electrically classified areas must meet design code criteria that reduce the possibility of providing an ignition source.

Because of the low probability of hydrocarbons being present before a well produces, only a small area of *Deepwater Horizon* was electrically classified. The two main electrically classified areas were within the rig floor and under the deck, where the mud returning from the well could convey some residual hydrocarbons. If a flammable mixture migrated beyond these areas, the potential for ignition would be higher.

Deepwater Horizon engine room HVAC fans and dampers were not designed to trip automatically upon gas detection; manual activation was required. This design was probably selected so that false gas-detection trips would not interrupt the power supply to the thrusters, which keep the dynamically-positioned rig on station. The HVAC system likely transferred a gas-rich mixture into the engine rooms, causing at least one engine to overspeed, creating a potential source for ignition.

The information used to complete the analysis is based on pre-2001 documentation; therefore, some of the equipment details and system designs may have changed. However, in the view of the investigation team, it is unlikely that any such differences would significantly affect the conclusions drawn.

Conclusion
The fire and gas system did not prevent released hydrocarbons from reaching potential ignition sources.

Key Finding 8. The BOP emergency mode did not seal the well.

None of the emergency methods available for operating the BOP were successful in isolating the wellbore. The different methods available were not fully independent; therefore, single failures could affect more than one emergency method of BOP operation. Ultimately, the only way to isolate the well at the BOP was to close a single component, the blind shear ram (BSR); that ram had to shear the drill pipe and seal the wellbore.

Emergency Disconnect Sequence

To isolate the well after the explosion, the subsea supervisor attempted to operate the EDS that would close the BSR, sealing the wellbore, and disconnect the lower marine riser package (LMRP). The EDS required a communication signal to be sent through one of two multiplex (MUX) cables routed through the moon pool, which would have been affected by the explosions and fire. Witness accounts indicated that an attempt was made to activate the EDS approximately 7 minutes after the initial explosion. The LMRP did not disconnect, and hydrocarbons continued to flow, indicating that the BSR did not seal.

Conclusion
The explosions and fire very likely damaged the MUX cables, disabling the EDS means of closing the BSR.

Automatic Mode Function

The automatic mode function (AMF) of the BOP activates the BSR to shear the drill pipe and seal the wellbore in the event of catastrophic failure of the marine riser. Two independent control pods on the BOP initiate the AMF sequence to close the BSR if specific conditions are met (i.e., when electrical power, communications and hydraulic power are all lost to both control pods). According to witness accounts, during the attempt to activate the EDS, there was a low accumulator alarm on the BOP control panel, indicating loss of hydraulic supply pressure. The AMF conditions were very likely met upon the damage to the MUX cables and loss of hydraulic supply pressure after the explosion.

The AMF requires at least one operational control pod to initiate and complete the sequence. Both the blue and yellow control pods from *Deepwater Horizon* BOP were retrieved after the accident, and their AMF functionality was tested. Insufficient charge was discovered on the 27-volt AMF battery bank in the blue pod, and a failed solenoid valve 103 was discovered in the yellow pod. If these conditions existed at the time of the accident, neither pod would have been capable of completing an AMF sequence.

Conclusion

The AMF initiation conditions were very likely met soon after the first explosion, but the AMF sequence very likely could not have been completed by either control pod, due to the failed solenoid valve 103 in the yellow pod and an insufficient charge on the 27-volt AMF battery bank in the blue pod.

Intervention by Remotely Operated Vehicle

The autoshear function is designed to activate the BSR upon inadvertent disconnection of the LMRP. Evidence indicated that the BSR closed 33 hours after the explosion, when a remotely operated vehicle (ROV) activated the autoshear function.

Though the BSR appeared to have been closed, the investigation team has not been able to determine why it failed to seal the well. Potential causes examined by the investigation team included:

- Seal failure due to the prevailing flow condition in the BOP.
- Insufficient hydraulic power to shear the drill pipe and seal the wellbore.
- Non-shearable pipe or debris across the BSR.

BOP Maintenance and Testing

A review of BOP maintenance and testing records provided by Transocean indicated instances of an ineffective maintenance management system for *Deepwater Horizon*. Examples were:

- In December 2007, the batteries in the blue pod were fully depleted when the BOP was brought to the surface.
- There were no indications that the AMF and ROV intervention systems were tested at the surface, as required by Transocean testing policy, prior to subsea deployment on the Macondo well.
- Cameron reported that a non-original equipment manufacturer (non-OEM) part was found on solenoid valve 103 during the yellow pod examination.

The diagnostic systems did not appear to have been utilized effectively in all cases to identify and remedy defects in critical components. Solenoid valve coil faults and hydraulic system leaks probably existed on the BOP prior to the accident.

Conclusion

The BOP maintenance records were not accurately reported in the maintenance management system. The condition of critical components in the yellow and blue pods and the use of a non-OEM part, which were discovered after the pods were recovered, suggest the lack of a robust Transocean maintenance management system for *Deepwater Horizon* BOP.