IN THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF LOUISIANA

In re: Oil Spill by the Oil Rig Deepwater Horizon in the Gulf of Mexico on April 20, 2010 (MDL No. 2179)

Before the Honorable Judge Carl J. Barbier

EXPERT REPORT OF CALVIN BARNHILL

Macondo Engineering, Operations and Well Control Response

Submitted by Transocean Offshore Deepwater Drilling, Inc.

INTRODUCTION

This report outlines the findings and conclusions of Calvin Barnhill relating to Macondo engineering, operations and well control response. This report also presents the basis and reasoning for the opinions and conclusions reached on these subjects, including the data and information considered in forming such opinions and conclusions.

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Executive Summary

The Macondo Well blowout was the culmination of multiple factors, decisions, oversights and mistakes.

During the final stages of well construction and the temporary abandonment (TA) of the well, inputs from a variety of sources within BP were altering and changing the risk status of the Macondo Well. This appears to have been done without an overarching review process, or person, that was effectively evaluating the overall ramifications of the various changes and modifications. The net effect was to un-necessarily place the Macondo Well at risk during the TA.

BP generated multiple TA procedures between April 12th and April 20th, with the installation of the Lockdown Sleeve (LDS) becoming the focus of the plans in lieu of the well. The April 14th procedure created the lowest risk for the Macondo Well of all the plans. If it had been followed, or a variety of other known options had been incorporated into the TA procedure, the risk level of the well would have been greatly reduced or effectively eliminated.

Furthermore, no one within BP appeared to be assessing the overall aspects of the operation before proceeding with the final displacement of the synthetic base mud (SBM) and the subsequent potential significant underbalancing of the Macondo Well. Attachment A to the report is a list of issues, factors or questions that existed concerning the Macondo Well prior to the final displacement. A key component of the list is the problematic negative test which indicated the lack of confirmed primary flow barriers or zonal isolation which were required to secure the well given the BP TA procedure being followed. Given the uncertainty surrounding the primary flow barriers, BP should not have continued with the SBM displacement from the riser on the Macondo Well. The overall risk status of the well was not fully appreciated by BP nor shared with its contractors who were actively engaged with the drilling and TA of the well. Attachment B is a list of the Acronyms used in this report.

Actual confirmation by BP of the isolation of the hydrocarbon bearing zones in the well did not occur, even though a negative test was conducted. The hydrostatic pressure in the Macondo Well was significantly reduced due to following the BP TA procedure without having actual confirmation of flow barriers but instead with only having a perceived confirmation of such barriers. The reduction of wellbore hydrostatic pressure led to the underbalancing of the well due to the lack of zonal isolation; ***creating the well control event.*** This series of events placed a very high degree of dependence on the rig site drilling personnel fully understanding the developing situation, adjusting their perception of the well's secured status and responding with limited misinterpretation. The drilling personnel on the rig involved with the well were the BP well site leaders, the Transocean drill crew, the Sperry Sun mud loggers and the MI personnel.

The negative test actually confirmed the lack of well integrity and a lack of adequate primary flow barriers in the Macondo Well. However, due primarily to the effects created by the unorthodox spacer, and a lack of understanding of the results being viewed, the negative test was approved by BP and BP then allowed the displacement to continue. However, this information should have resulted in the recognition that zonal isolation was not confirmed and that the SBM displacement should not proceed.

BP's acceptance of the negative test added a major component to a perception on the rig that the well was safe. Rightly or wrongly the perception on the rig would be that any well related issues were securely behind cemented pipe in a well that had been fully tested.

The information and data available on the blowout of the Macondo Well indicates the following as to the well control event.

1. The high quality hydrocarbon bearing zone(s) exposed during the drilling of the Macondo Well were not isolated by the cemented production casing.

2. The hydrostatic pressure in the Macondo Well was significantly reduced by design as part of the BP TA procedure that was implemented.

3. Due to the lack of zonal isolation and the significant reduction in wellbore hydrostatic pressure - a pressure differential (i.e. underbalance) occurred that resulted in hydrocarbon movement out of the high quality hydrocarbon bearing zone(s) into the well; thus ***creating the well control situation***.

4. The hydrocarbons flowed from the high quality producible rock through the annulus space outside of the production casing, into the production casing and to the surface. The flow path would have involved some and possibly all of the unconfirmed primary flow barriers.

5. Well conditions were misinterpreted and not understood; both during the negative testing and during the SBM displacement to seawater.

6. Observation of the developing well control indications were likely confused and confounded by the lack of certain information, by certain events and by accepted beliefs as to the well's secured condition. Initial developing well control signs were not noted by any of the personnel monitoring the well real time. This should not have happened. It is unknown why the Sperry Sun mud logger never noted any anomalies at all. Once the driller noted an anomaly the actions taken were consistent with trying to diagnose a problem but were not indicative of a realization of an eminent large scale well control event. The Macondo Well should have been immediately flow checked and shut in but was not due to the drill crew attempting to diagnose and understand the situation. At some point in the diagnostic process

the realization occurred that the well was not secure and was live, but the combined diagnostic and response time was too long for the developing well control situation.

7. The initial fluid discharge onto the rig was a result of the conditions in the riser above the BOP. The diverter was closed and fluid flowed through the MGS, which appeared to be a typical line up due to pollution concerns. It is unknown if the drill crew ever switched the routing overboard; or if they had the opportunity, or the realization to consider such, given what was occurring.

8. The BOPs were activated and created a seal. However, conditions within the BOPs resulted in the effective loss of any seal that occurred and/or prevented the sealing of any additional BOP components; allowing the re-establishment of well flow.

Discussion

At the time of the surface blowout of the Macondo Well TA operations were underway. The Transocean rig the Deepwater Horizon (DWH) had completed the drilling of the well and the Macondo Well's production casing had been installed and cemented in place. BP chose to finish the completion of the Macondo Well at a later date. Several TA procedures had been prepared by BP, with the final TA procedure being performed on the DWH, under the supervision of the BP onsite well site leaders. Attachment C is an organizational chart showing the BP well site leaders. The rig was also being prepared to move off (i.e. de-mob) from the well in concert with the TA operations.

Well construction in deepwater involves very unique and challenging situations to include the TA of a well. The Macondo well actually starts +/- 5,000' below the surface of the Gulf of Mexico. The well was connected to the DWH by a riser/blowout preventer (BOP) system during the time the rig was drilling the well, the production casing was being installed and the TA operations were being performed. Primary well control was maintained in the Macondo Well by the weighted SBM that exerted pressure to overbalance and control the fluid pressure in the rock that was exposed during the drilling of the well. The hydrostatic pressure exerted by the SBM was a result of both the weight of the fluid and vertical length of the column of SBM. However, one of the unique situations that occur during the TA of a deepwater well is that a significant length of the weighted drilling fluid column will be removed and replaced with seawater; given that the riser/BOP system will be removed from the well shortly before the rig leaves the well. This fact creates the situation that requires that the deepwater well be secured with additional flow barriers prior to displacing the drilling fluid with seawater in the riser/BOP system and a portion of the well.

BP's and Transocean's requirement, along with the general industry and the federal government's requirement, is that a well has to contain redundant well control barriers. During active drilling operations the well control barriers are the drilling fluid, which serves as the primary well control mechanism, and the BOP/diverter and wellhead systems that provide secondary well control. In a deepwater situation the primary well control capability provided by the drilling fluid is reduced or eliminated when the riser/BOP system and a portion of the wellbore are displaced with seawater. Therefore, other types of downhole primary well control (i.e. flow) barriers are required. Furthermore, BP requires that its redundant primary flow barriers be confirmed before having to be relied on.

The Macondo Well had two pathways that required primary flow barriers be in-place, tested and confirmed prior to reducing the hydrostatic pressure inside the production casing and potentially under-balancing the well. Attachment D shows the two pathways. One pathway was the annular space outside of the production casing. The primary flow barrier system for that pathway was comprised of the hydrostatic pressure of the annular fluids, the cement in the annular space and the production casing seal assembly in the wellhead. The other pathway was through the inside of the production casing. The primary flow barrier system for that pathway was the cement in the annular space outside the production casing coupled with the cement in the shoe tract, the double float valves and the production casing itself. Prior to the removal of the riser/BOP from the well, the BOPs were available to provide secondary well control, if activated.

Prior to the blowout occurring, the primary flow barriers were not confirmed by accurate and complete testing. The BOPs (a secondary well control barrier) were satisfactorily tested. Positive tests were also successful for the production casing seal assembly, the production casing down to the top cement wiper plug and the top cement wiper plug. However, no positive test was ever conducted on the production casing shoe track or the cement in the annular space outside of the casing. The negative test, which at best was confusing and inconclusive, certainly did not confirm the adequacy of the primary flow barriers. The condition of the cement was believed to be adequate but was not actually confirmed given the anomalous results of the negative test. Furthermore, the Weatherford doubled valved float collar's condition was unknown and there was no certainty that it had properly converted. There is also conflicting opinion as to the float collars usage as a well control device. Therefore, the facts indicate that adequate primary flow barriers, much less redundant primary flow barriers, were never tested or confirmed for the Macondo Well. Given the uncertainty surrounding the primary flow barriers, BP should not have continued with the SBM displacement from the riser on the Macondo Well.

The displacement of the SBM with seawater reduced the hydrostatic pressure in the Macondo Well to a greater degree than normal; creating a potential underbalance for any formations not isolated or protected by a primary flow barrier. BP's implemented TA procedure displaced the SBM in the Macondo Well with seawater to a depth of 8,367' below the rig floor. This equated to removing 45.6% of the SBM from the well system and replacing it with seawater. This further equates to reducing the hydrostatic pressure in the Macondo Well to a level that is underbalanced to the hydrocarbon bearing zones in the Macondo Well. Knowing that the displacement was going to place greater than normal stresses on the already questionable unconfirmed downhole primary flow barriers in the Macondo

Well, BP should have taken steps to assure the well was fully tested and secured before proceeding with the final displacement of the riser on the Macondo Well.

Given the fact that the surface blowout and subsequent explosions occurred, it is known that the hydrocarbons were not isolated and therefore did not remain in the hydrocarbon bearing zone(s) once the well became underbalanced during the TA procedure. The pressure differential created between the formation fluid pressure and the wellbore pressure during the displacement of the SBM was significant in two ways. One, it created the flow potential to allow the hydrocarbons to flow from the formation(s) to the wellbore and two, the fact the pressure differential was applied between the formation(s) and the wellbore established that a communication path existed between the formation(s) and the inside of the wellbore where the pressure reduction was occurring.

The acceptance of the negative testing by BP as confirming well integrity is indicative of the fact that the well conditions were misinterpreted and not understood. The negative test actually confirmed the lack of well integrity and a lack of adequate primary flow barriers in the Macondo Well. However, due primarily to the effects created by the unorthodox spacer, and a lack of understanding of the results being viewed, the negative test was approved by BP and BP then allowed the displacement to continue. The acceptance of the negative test added a major component to a perception on the rig that the well was safe. The perception on the rig would be that any well related issues were securely behind cemented pipe in a well that had been fully tested. BP had judged the Macondo Well to be in satisfactory condition to move forward with the final displacement of the riser on the well. Rightly or wrongly, it had to appear to the drilling personnel on the DWH they were no longer dealing with a live well but were dealing with a well that was completely secured. The production casing had been run without any significant problems. It was believed that the production casing had been successfully cemented in place. The Macondo Well had been subjected to a series of tests, both positive and negative, and had been deemed to have passed those tests. The task at hand was to finish the displacement of the riser, complete the TA, de-mob the rig and go to the next well.

Initially during the displacement of the heavy SBM/spacer from the riser the Macondo Well's pressure appeared to be greater than the formation pressures of the exposed zones that were not truly isolated from the wellbore. The initial surface responses appeared normal for the operations being conducted. It was noted the BP well site leaders did not have a displacement pump schedule prepared. Further it does not appear the BP well site leaders had expected fluid volume data prepared for the displacement. (As a side note – a similar fact was noted for the negative test – in that it appears that the BP well site leaders did not have an expected bleed off volume prepared). Therefore, even though conditions were generally reacting as expected, the personnel monitoring the well (driller, assistant driller, Sperry Sun mud logger, BP well site leader, MI personnel) had no expected data to see if an anomaly was occurring in a complicated well system. The complicated well system was a function of the well being a deepwater well, having multiple geometries due to the combination displacement/cementing string and the presence of the unorthodox spacer.

At some point enough SBM was displaced by seawater that the Macondo Well went from being overbalance to being underbalance. The non-isolated zones that had the capability to flow fluids would have begun to contribute formation fluid to the wellbore. The early developing well control signs would have been subtle and very hard to detect on a real time presentation given the operation being conducted. They were not noted by any of the personnel monitoring the well real time. Later observation of the developing well control indications were likely confused and confounded by the lack of certain information, by certain events and by accepted beliefs as to the wells condition. The information that was lacking included the expected pressure profile at a specified pump rate (i.e. displacement pump schedule). The events included bringing the rig pumps on line and off line, empting trip tanks and the unexpected tripping of one of the mud pumps pressure relief valves (PRV). The accepted beliefs were that the well had been both positively and negatively tested and was secured, with any potential zones isolated by the cemented production casing.

Based on a review of the post incident expanded Sperry Sun chart of the real time mud logger data it is unknown why the personnel monitoring the well during the displacement did not recognizes the developing well control situation at least by the end of the sheen test. A pressure build up with the pumps off for the sheen test is clearly indicated on the Sperry Sun chart. This anomaly should have triggered action by the drill crew and the Sperry Sun mud logger to check out the anomaly. The BP night well site leader was in the driller's shack during that time. He was the only person in the driller's shack at the time that is believed to have survived. The BP night well site leader's interview notes by the BP investigative team indicates that during the time he was in the driller's shack everything looked fine. The Sperry Sun mud logger was also monitoring the well and indicated he did not observe an anomaly that he believed was indicative of a developing well control situation during the sheen test. Furthermore he indicated he did a visual flow check and noted the well was not flowing prior to the flowline valve being closed.

The post sheen test displacement was chopped up by the ramping up of various rig mud pumps and the inadvertent tripping of one of the rig mud pump's pressure relief valve (PRV). The PRV tripping would have diverted the drill crew's attention away from the well for some period of time but the Sperry Sun mud logger would have been monitoring the well throughout the time. A general increasing pressure trend was also noted on the post incident Sperry Sun chart of the real time data after +/- 21:00 hours. It is unknown why this trend was not detected, except for the items discussed. It was further noted that when the displacement was re-started after the tripping of the PRV the pressures appeared to be acting in a more expected manner with the pressure increasing with increasing pump rate and generally decreasing otherwise.

An anomaly began developing with the kill/choke line pressure around the time the driller got the rig pumps lined out after the PRV incident. This anomaly was detected by either the driller or the assistant driller and the displacement was stopped to diagnose the situation. Once the driller noted an anomaly the actions taken were consistent with trying to diagnose a problem but were not indicative of a realization of an eminent large scale well control event. At some point in the diagnostic process the realization occurred that the well was live but the combined diagnostic and response time was too long for the developing well control situation.

The shutdown to diagnose a problem illustrates that the driller and/or assistant driller were actively monitoring the well during the displacement. Further the initial actions taken during the shutdown are consistent with an initial belief that the well was secured. The initial steps taken are more consistent with concerns over trapped pressure or a plugging problem and not a well control response for the magnitude of the problem that existed. It is believed that the initial response by the driller and toolpusher was a misinterpretation of either the problem they were facing and/or the magnitude of the problem they were facing. Once the rig pumps were shut down, a manual flow check followed by an immediate shut in of the Macondo Well, should have occurred. This is basic well control that both men were schooled in and had successfully engaged in, in the past. Why it did not happen in this situation will never be known but gives credence to a finding that they misinterpreted and at some point underestimated what they saw. Factors that led to a misinterpretation of the situation would stem from the drill crew's belief the well was isolated and tested and therefore was fully secured. Clearly, at some point the toolpusher's, driller's and assistant driller's views turned from the belief that the well was fully secure to the realization that a well control event was under way. Depending on when the change in view on the status of the well occurred, coupled with the signs they were seeing, they may have believed the influx was still deep enough that they had some reaction time to fully evaluate the situation. However, that view would have quickly been dispelled as fluid was blown out of the riser under tremendous force revealing that a significant surface problem existed. The well was initially diverted, with the flow going through the MGS. Testimony of the DWH senior toolpusher onsite indicates that the diverter system was normally lined up on the MGS pre-incident – due to pollution concerns. The BOPs were then activated. Given the magnitude of the situation the MGS was rapidly overcome followed quickly by a series of explosions.

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Gentlemen:

Introduction

A surface blowout occurred on the Mississippi Canyon Block 252 Well 001 ST00 BP01, (Macondo Well) during the evening of April 20, 2010. Drilling operations had been completed on the well and the production casing had been installed, cemented and tested. Operations to temporarily abandon the well were being conducted at the time of the surface blowout. These operations were being conducted aboard the mobile offshore drill unit the Deep Water Horizon. As a result of the surface blowout a series of explosions occurred aboard the rig at approximately 22:00 hours on April 20, 2010. Of the 126 persons aboard the rig at the time of the explosions: 115 were evacuated; 10 were unaccounted for; and 1 was a known fatality. The 115 persons evacuated included certain injured persons. The events that transpired as a result of the surface blowout ultimately resulted in the sinking of the Deep Water Horizon. The surface blowout coupled with the design of the well created conditions that resulted in the uncontrolled flow of formation fluids into the Gulf of Mexico for 87 days before the well was successfully killed, then plugged and abandoned .

Mississippi Canyon Block 252

Mississippi Canyon Block 252 (MC 252) is a +/- 3 mile by +/- 3 mile area located in United States federal waters in the central Gulf of Mexico. It is one of numerous such areas found in the Gulf of Mexico designated for oil and gas exploration and potential development. MC 252 is located +/- 50 miles south-southeast of the mouth of the Mississippi River and is +/- 110 miles south of the Mississippi-Alabama state line. The nearest major city is New Orleans, Louisiana, located +/- 130 miles northwest of MC 252.

MC 252 was part of Lease Sale 206 conducted by the Minerals Management Service (MMS) on March 19, 2008. Lease Sale 206 covered portions of federal lands located in the central Gulf of Mexico. The MMS has been reorganized since the April 20th blowout with jurisdiction for federal offshore oil and gas operations now being under the jurisdiction of the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE).

BP Exploration & Production, Inc., (BP) acquired MC 252 under federal Oil, Gas & Mineral (OG&M) lease OSC-G-32306 during Lease Sale 206. OG&M lease OCS-G-32306 was for a term of 10 years. BP developed a prospect underlying a portion of the MC 252 area which it named the Macondo prospect. Geological and geophysical interpretation coupled with engineering work for prospect generation and development are tasks performed by the oil company. The Macondo prospect was delineated using a combination of 3-D seismic, local knowledge and offset well information. With the acquisition of MC 252, BP continued its development of the Macondo prospect which included the design of a test well which BP referenced as the Macondo well. The Macondo well was designed to test certain Miocene zones located +/- 13,000' to +/- 15,000' below the seabed. Water depth at MC 252 is in the range of 5000'. The zones were believed to be hydrocarbon bearing turbidite sands capable of supporting high rate economic development in a deepwater environment. BP marketed its Macondo prospect in the oil industry, turning a portion of the prospect to 2 partners. Anadarko Petroleum corporation (Anadarko) acquired a 25% non-operating working interest (NOWI) in the Macondo prospect. MOEX Offshore 2007, LLC (MOEX) acquired a 10% NOWI in the Macondo prospect. BP retained the remaining 65% WI and retained operatorship of the prospect.

BP submitted an Exploration Plan (EP) for Lease OCS-G-32306, which was approved by the MMS on April 6, 2009. The EP called for drilling 2 wells at MC 252 approximately 10 months apart. Both of which were Miocene tests designed with a total depth (TD) +/- 20,000' below sea level. Given the +/- 5000' water depth, BP planed on using a moored semi-submersible mobile offshore drilling unit (MODU) to drill the wells. The MMS approved a revised EP ten days later on April 16, 2009. The revision appears to have dealt with increasing the anchor spread for the rig.

The initial Application for Permit to Drill (APD) the Macondo test well was approved by the MMS on May 22, 2009. The initial Macondo test well was to be drilled from the MC 252 A location. The well designation was the MC 252 Well 001, ST00, BP00; API number 608174116900. BP designated the well the Macondo Well in the APD. Two other APDs were noted for the Macondo Well. The second APD had an MMS approval date of October 16, 2009. The third APD had an MMS approval date of October 29, 2009. All three APDs showed a TD of 25,000' - based on rig floor elevation measured from the rotary Kelly bushing (RKB - i.e. the rotary table). Further the three APDs indicated the well would be drilled utilizing the Transocean semi-submersible MODU the Marianas.

Macondo Well Design (Pre-drill)

BP technical personnel, aided by outside technical personnel, prepared the well design for the Macondo Well. Well design and planning is a function performed by the Oil Company. The well plan was completed and reviewed by July 2009. Macondo was described in the well plan as a moderate depth Miocene prospect located in the Mississippi Canyon area. The primary target specified in the well plan was the M56 sand; a Miocene sand located at a target dept of +/-

18,400' RKB. The projected TD listed in the well plan was 19,650' RKB. The deeper target depth was to allow the Macondo Well to test the older Miocene section below the primary target M56 sand.

The well plan called for drilling a vertical (i.e. straight hole) from the seafloor to TD. The well was to be spudded by jetting 36" conductor pipe into place. Well construction included the drilling of multiple hole sections, with the installation of casing in each hole section. The wellhead system to be employed was a Dril-Quip ES Big Bore II system which included a 36" low pressure (LP) external wellhead, a supplemental 28" casing hanger and an 18 ¾" high pressure (HP) internal wellhead. The 18 ¾" HP internal wellhead system included 18" and 16" supplemental adapters and a 9 7/8" hanger.

The well plan envisioned eight hole sections, with eight casing strings installed; four full strings of casing and four drilling liners. All of the deeper casing/liner designs utilized high strength premium grade casings. One of the drilling liners, the 11 7/8" liner, was a contingency that could potentially be eliminated if hole conditions allowed. The bottom hole open hole size to be drilled through the prospective target interval was designed to be 12 ¼". The well plan indicates that moderately high formation pressures and temperature were expected to be encountered. Maximum formation (pore) pressure was estimated to be 14.0 pound/gallon (PPG) equivalent mud weight (EMW). Maximum required mud weight (MW) was estimated as 14.4 PPG. {For purposes of this report the mud weights or EMWs given will be based on the reported surface static mud weight, unless otherwise specified.} Maximum estimated bottom hole temperature (BHT) was estimated as 262 degrees F. Maximum estimated fracture gradient (Fg) was estimated to be 16.1 PPG EMW. The Macondo Well was not planned as, nor indicated to be, a high pressure, high temperature (HPHT) well. However, as with any deepwater well drilling margins were critical. The final casing string planned was the 9 7/8" production casing which would set in the +/- 12 ¼" open hole section, if exploration was successful. The estimated time to drill the Macondo well was +/- 78 days, with an estimated target time of +/- 53 days. The estimated cost, as per the well's authority for expenditure (AFE), was +/- $96 million.

Upon the completion of the drilling of the Macondo Well and the full evaluation of the target zones, along with any other potentially productive intervals, a decision would be made as to the future plans for the well. The possibilities included; running the production casing and temporarily abandoning (TA) the well, if the exploration was successful; plugging and abandoning (P&A) or TA the well, if the exploration was not successful; or sidetracking the well to a different target position, to improve the chances of exploration success.

The well design incorporated various features to contend with the potential for annular pressure buildup (APB) during the productive life of the well. These features included the use of multiple drilling liners, rupture/burst disks in the 16" intermediate casing string and not cementing into the liner lap. These design features would add complications during the attempts to control the well after the surface blowout occurred.

The Macondo Well plan contained an Appendix D, "Dispensations". There were six items contained within Appendix D that required various dispensations. The dispensations were required where the design of the Macondo Well failed to meet BP's design requirements contained in either the BP Deepwater Operations Plan (DWOP) or the BP Casing Design Manual or possibly other criteria. The six items covered in Appendix D were: 22' casing burst design; 16" casing burst design; 9 7/8" production casing collapse design; auto-fill float Equipment – (being run through hydrocarbon bearing zones prior to conversion); Design Pore Pressure (DPP) requirements; and kick tolerance – (less than 25 barrels with a 1.0 PPG kick intensity).

Deepwater Issues

The Macondo Well was drilled in a water depth of 4,992'. Generally speaking current oil and gas industry consensus is that deepwater is considered to be water depths greater than +/- 1,000'. Water depths greater than +/- 5,000' are considered to be ultra-deepwater. Deepwater well planning and execution requires special attention to a host of issues that have even greater significance than normal in a deepwater environment. Many of these issues relate directly to maintaining control of the well.

Drilling Margins

There are critical margins that must be maintained during the safe drilling of a well. One such margin is the differential between the pressure of the fluids in the rocks being drilled and the hydrostatic pressure exerted by the drilling fluid being used. When the hydrostatic pressure exerted by the drilling fluid is greater than the pressure of the fluid in a formation the differential is expressed as overbalance. When the opposite is true the differential is expressed as underbalance. A federal drilling regulation for offshore drilling 30 CFR 250.414 refers to the overbalance differential as a drilling margin.

The Gulf of Mexico typically has oil and gas reservoirs that have both good porosity (% of the rock that contains pore (void) spaces that are fluid filled) and good permeability (the measure of the rock's ability to flow the fluid found in the pore spaces). Therefore, oil and gas reservoirs in the Gulf of Mexico can contain significant quantities of hydrocarbons and can flow those hydrocarbons at substantial rates under certain conditions. Therefore, during drilling in the Gulf of Mexico the hydrostatic pressure exerted by the drilling fluid must exceed the formation (or pore) pressure if primary control of a well is to be maintained.

Another critical margin is the differential between the competency or strength of the rock the well is being drilled through and the hydrostatic pressure associated with the drilling fluid being utilized in the well. Rock strength is expressed in terms of fracture pressure (Frp) or fracture gradient (Fg). Again to safely drill a well in the Gulf of Mexico a sufficient drilling margin must be maintained between the Fg and the hydrostatic pressure exerted by the drilling fluid being used.

Sufficient drilling margins between both the pore pressure and the drilling fluid pressure, and the drilling fluid pressure and the fracture strength, are essential to the successful drilling of a well in a region like the Gulf of Mexico. To be able to successfully drill a well through the various layers of the earth to its intended target safe workable drilling margins must be maintained. Therefore, the design and drilling of a well requires that close attention be paid to both the pressure of the fluids found in the various formations that are being drilled through and the strength of those formations. However, as water depth increases formation strength decreases (i.e. Fg decrease). In deepwater the drilling margin between formation strength and the drilling fluid density (i.e. weight) needed to maintain primary well control are more critical than normal given the relationship between increased water depth and decreased formation strength. This relationship in the Macondo Well was further complicated due to the formation pressure noted in the primary hydrocarbon zones being lower than predicted - likely resulting in even lower formation strength in the productive interval.

The Macondo Well's drilling margins between the required SBM weight to control the well and the Fg was thin (i.e. tight) throughout much of the drilling of the well. The lack of sufficient drilling margins due to reduced Fg led to the premature setting of liners, the setting of additional liners and finally contributed to calling the TD of the well early as a result of loss circulation and well control issues. Furthermore, the concern for the indicated problems drove many of the decisions that ultimately played a major role in the surface blowout.

Drilling operations conducted on Federal leases in the Gulf of Mexico under 30 CFR 250 require that safe drilling margins be maintained at all times. At the time the Macondo Well was being drilled the MMS - Gulf of Mexico Region further required that a drilling margin of at least a 0.5 PPG be maintained. The MMS would grant a waiver to allow the drilling margin to drop to 0.3 PPG in hole sections where no hydrocarbon bearing zones were anticipated to be encountered.

Well System Geometry

Exploration drilling operations in deepwater are routinely conducted from floating drilling rigs; semi-submersibles or drill ships. In the Gulf of Mexico metocean (meteorology and oceanography) conditions dictate that the wellhead (i.e. top of well) be located on the seafloor. The drilling rig is connected to the well through a blowout preventer (BOP) and riser configuration during the drilling of the deeper sections of the well. Therefore, the active wellbore system during the drilling of the deeper sections of the well will consist of the well itself plus the riser system attached back to the rig. As the water depth increases the ratio between the riser length and the actual well depth will also increase. The geometry of the system has ramifications and consequences both for well construction and well control.

The Macondo Well was drilled to a depth of +/- 13,293' below the mud line (bml). Water depth plus the distance from the sea surface to the rig floor was +/- 5,067'. As a result, the drilling TD of the well was noted as 18,360' RKB. Further, the rig's BOPs were attached to the wellhead at the bottom of the riser on the seafloor - +/- 5,067' RKB. Therefore, the well system was comprised of two components: the Macondo Well itself; and the riser/BOP system connected from the rig to the Macondo's wellhead located on the seafloor.

In a deepwater well control situation the distance any influx needs to travel to reach the top of the well and the rig's BOPs is the length of the wellbore itself not the length of the well system. As water depth increases this can have a dramatic effect on reaction time and evaluation time during a well control event.

Further, well control on floaters (semi-submersibles and drill ships) that utilize a riser/BOP system have two major components: control of the well and control of the riser. Once the riser/BOP system is in place the well is protected by the BOPs (if closed) but the riser is not. The riser is protected by a relatively low pressure diverter system that sits on top of the riser underneath the rig floor. The purpose of the diverter is to divert the well flow away from either the rig floor or the rig itself if conditions warrant. If the formation fluid influx gets past the BOPs and into the riser a serious situation can potentially develop.

Formation Deliverability

The ability of deepwater productive zones to deliver hydrocarbons at high rates is critical to the success of deepwater exploration and development. The costs of operations in deepwater environments is tremendous. To be economical the returns have to be also. Deepwater productive intervals are typically turbiditic sands that have high porosity and permeability and can rapidly deliver fluid into a wellbore. The high deliverability of the deepwater hydrocarbon bearing zones can have a significant impact on well construction, well stability and well control operations.

Well Control (general)

Well control is more difficult and much more challenging in a deepwater environment. The BOPs are located on the seafloor and are subject to the harsh environment that being under thousands of feet of water can bring. The BOPs are connected to the rig by way of the riser system which has to be managed separately in a well control situation. The difficulty associated with certain well control issues increases as water depth increases. Some well control activities are affected by the simple fact that the exploration rigs are floaters that move based on metocean conditions.

Many standard well control issues such as kick detection, reaction time, friction pressures, shut in times, gas effects in choke lines and off bottom operations become more problematic in an exploration deepwater environment. Deepwater well control can also present issues associated with the water depth, the nature of floating operations and the reservoir environments to include: reduced Fgs;

increased formation fluid deliverability; hydrates; and well system geometry issues: such as bubble chopping: riser integrity; and riser control.

MODUs

Marianas

The Marianas is a harsh environment semi-submersible MODU. The rig is a Earl & Wright Sedco 700 Series enhanced design, with a working water depth of 7,000' when built. The Marianas was built in 1998. It is equipped with a 18 ¾" 15,000 PSI rated BOP stack and a 21" OD marine riser.

Deepwater Horizon

The Deepwater Horizon (DWH) is a harsh environment semi-submersible MODU. The rig is a Reading and Bates Falcon RBS-8D, with a working water depth of 10,000'. The DWH was built in 2001 at Hyundai Heavy Industries Shipyard, Ulsan, South Korea. It is equipped with a 18 ¾" 15,000 PSI rated BOP stack and a 21" OD marine riser.

The DWH worked for BP, or one of its predecessors, from the time it was built until it sank on April 22, 2010. BP used the rig predominately to drill deepwater exploration wells. The rig saw limited service performing completion type operations on wells. The DWH and its crews were on the forefront of deepwater frontier exploration drilling activity, drilling some of the most challenging wells ever drilled. The rig drilled the deepest well in the Gulf of Mexico, the Tiber well, in 2009; which was drilled to 35,056' in 4,132' of water. Further, the DWH drilled an exploration well in 9,576' of water. The DWH worked on +/- 50 wells in its +/- 9 year history.

The DWH's OIM and senior toolpusher coupled with the on tour toolpusher, driller and assistant driller were well control certified. All of the personnel, with the exception of one of the assistant drillers, had been accredited for several years. The one exception was the assistant driller, believed to be in the drillers shack, who had been accredited for five months at the time of the blowout. These personnel were all certified through the Transocean in house well control school that was accredited through the International Association of Drilling Contractor's (IADC) Well Cap program. Various IADC reports reviewed indicate that well control drills were held weekly for each crew. A clerical issued was noted at times with the notations recorded on the IADC forms not fully documenting all of the well control drill information as indicated should be done by the Transocean Well Control Handbook. A review of the BP DWOP indicated that all well control drills had to be performed to the satisfaction of the BP well site leader. No information was noted to indicate that the BP well site leaders were not satisfied with the drill crews' performance of any well control drill. The two BP well site leaders from the DWH that provided testimony indicates that they were satisfied with the crew's well control abilities prior to the incident; with one of the BP well site leaders being on the rig on March 8, 2010 during a well control event.

Macondo Well Operations – Marianas

The Transocean semi-submersible Marianas was mobilized (Mob'd) from offshore Galveston Texas at 17:00 hours on September 30, 2009 for the drilling of the Macondo Well. The Marianas arrived at MC 252 and began deploying its anchors during the early morning hours of October 4th. The Macondo Well was spudded at 16:25 hours on October 6, 2009. Operations conducted by the Marianas included: Jetting in the 36" conductor and installing the low pressure (LP) wellhead; drilling the open hole section below the 36" conductor and installing the 28" casing; drilling the open hole section below the 28" casing and installing the 22" casing, to include the 18 ¾" high pressure (HP) housing with the external connector for the rig's blowout preventer (BOP) stack; and drilling the open hole section below the 22" casing and installing the 18" drilling liner.

The drilling work performed prior to the installation of the 22" casing was done with the wellbore open to the seafloor. Either seawater (SW) or water base mud (WBM) was utilized in drilling the well, with returns being taken onto the seafloor. Both the 28" and 22" casings were cemented in place utilizing a foam cement job. The rig's riser/BOP system was connected to the well's wellhead located at the seafloor once the 22" casing and HP wellhead housing was installed in the well. After the riser/BOP system was attached to the well, synthetic based mud (SBM) was utilized for the drilling of the lower sections of the Macondo Well.

All of the casing strings set below the 36" conductor and above the 18" drilling liner were set within rat hole margins of their planned depth. However, the 18 1/8" X 22" open hole section associated with the 18" drilling liner did not reached its planned depth. The BP well plan called for setting the 18" drilling liner at a depth of 9,900' RKB; 4,819' bml. BP's estimated Fg at 9,900' was +/- 12.3 PPG EMW. The 18 1/8" X 22" open hole section was drilled to a depth of 9,076' RKB (4,022' bml), with the 18" drilling liner being set at 8,983' RKB (3,929' bml). The actual liner setting depth was 917' shallower than planned. Formation fracture strength issues coupled with well control issues (i.e. drilling margin issues) resulted in the 18 1/8" X 22" open hole section being stopped significantly shallower than its planned depth. Simply put the well had run out of drilling margin requiring the 18" drilling liner to be set 917' high. The following two paragraphs discuss the factors that resulted in the 18" liner being set significantly shallower than planned.

The 22" casing shoe, located at 7,952' RKB (2,871 bml), was tested multiple times utilizing a leak off test (LOT) both prior to and during the drilling of the 18 1/8" X 22" open hole section. The 22" casing shoe was noted to hold up to a +/- 10.4 PPG EMW. The SBM weight used during the LOTs was initially a 10 PPG but was cut back to a 9.7 PPG for the later tests. A cement squeeze job was performed after drilling +/- 50 below the 22" casing shoe but the strength of the 22' casing shoe was not enhanced. BP received verbal permission from the MMS to drill the 18 1/8" X 22" open hole section to its planned TD of 9,900' RKB using a SBM weight up to a 10.0 PPG. This SBM weight yielded a static drilling differential or static drilling margin between the SBM weight and the LOT of +/- .4 PPG

During the drilling of the 18 1/8" X 22" open hole section at a depth of 8,970' RKB a small flow increase was noted. The SBM weight in use at the time was a 9.9 PPG. The well was shut in and well control operations were initiated. The well was controlled with a 10.1 PPG. Equivalent circulating density (ECD) was noted to be running about .4 PPG above the SBM weight at normal drilling circulating rates, yielding an ECD of 10.5 PPG. During the well control operation mud losses were experienced. Drilling resumed and the Macondo Well was drilled +/- 100' to a depth of 9,073' RKB, with little to no drilling margin. A pit gain was noted, drilling was stopped and a flow check was made. A gain of 19 barrels was noted. The well was circulated out using a 10.15 PPG. The well was noted as static. The drill string was then removed and the 18" drill liner was installed.

The 18" drilling liner was landed in a supplemental adapter at 7,489' RKB (2,408' bml), with the liner extending down to 8,969' RKB (3,888' bml). It was cemented in place, utilizing premium cement with additives. A fluid loss of 20 barrels was reported during the cement job. The cement job was noted to be designed such that cement did not extend up the entire open hole section and into the 22" casing due to future APB concerns. Installation of the 18" drilling liner was completed by October 31, 2009, with both a positive test and a negative test being performed on the liner/well.

A Parabow plug was set in the Macondo Well at a depth of 6,081' RKB (1000' bml) on October 31, 2009. A 200' premium cement plug was placed on the Parabow plug from 6081' RKB to 5,881' RKB. The combination of the +/- 200' cement plug plus the undrilled shoe tract of the 18" drilling liner served to secure the Macondo Well so that the BOPs could be unlatched and retrieved for service, along with other rig work. The BOPs were unlatched from the Macondo Well at 05:05 hours on November 1, 2009. The rig was reposition 165' east of the well for the rig work.

Operations were initiated on November 7th to secure the rig in preparation for Hurricane Ida and the rig was evacuated on November 8th. The Marianas sustained damage during Hurricane Ida that required the rig to be de-moored and sent in for repairs. As noted above the Macondo Well had been temporarily abandoned (TA'd) prior to the storm by leaving the cement in the 18" drilling liner shoe tract undisturbed and by also placing a 200' cement surface plug in the 22" casing in the well at +/- 5,881' RKB (+/- 800' bml). The Marianas was demobilized (de-mob'd) from the Macondo Well in late November 2009. By the time the rig repairs were completed at the ship yard the Marianas' contract with BP had ended. BP chose to finish drilling the Macondo Well utilizing the Transocean Semi-submersible MODU the DWH.

Macondo Well Final Design

The final drilling program for the Macondo Well was issued in January 2010 once the change over from the Marianas to the DWH was known. It was prepared by Brian Morel, the Macondo team's drilling engineer. The drilling plan was reviewed and signed off on by Mark Hafle, the Macondo team's senior drilling engineer, and Brett Cocales, the Macondo team's operations drilling engineer. It was approved and signed off on by David Sims, the Macondo team's drilling engineer team leader, John Guide, the Macondo team's well team leader, and Ian Little, the Macondo team's wells manager.

The Macondo Prospect - January 2010 - Final Drilling Program dealt with the re-entry of the Macondo Well coupled with the continued drilling of the well to test the Macondo prospect. The final drilling program adopted the initial Macondo Well Drilling Program for the portions of the program that dealt with drilling the well below the TA point left by the Marianas.

Macondo Well Operations -DWH

Original wellbore

The DWH departed MC 272 in late January 2010 in route to MC 252 to re-enter and finish drilling the Macondo Well. Rig maintenance and repair work was started during the rig move from MC 727 and included BOP maintenance work. Drills were also conducted for the Emergency Disconnect System (EDS) and the accumulator system. The Auto Shear function was also tested.

The DWH arrived at MC 252 during the afternoon of January 31, 2010. Rig work, including BOP maintenance and stump testing, continued once the DWH was on location at the Macondo Well. At 18:00 hours on February 6th operations were initiated to pick up and run the DWH's BOPs and riser. The DWH subsea BOPs were latched up on the Macondo Well's wellhead shortly before noon, February 8, 2010. Once surface riser rig up operations were completed, the BOPs were tested subsea. Operations then commenced to re-enter the Macondo Well. The TA surface plug near the mud line was drilled out and the 22" casing was cleaned out to the top of the 18" drilling liner. The 18" drilling liner was then cleaned out to its shoe track and tested. The 18" drilling liner's shoe track was then drilled out. The DWH starting drilling new hole in the Macondo Well at 06:30 hours, February 12, 2010.

After +/- 10' of new hole was drilled, the 18" drilling liner shoe was tested utilizing a LOT. The 18" drilling liner shoe did not test to the planned fracture gradient requirements. Therefore the 18" drilling liner shoe was squeezed with premium cement, drilled out and re-tested to an 11.71 PPG EWM. The indicated shoe test results were +/-.3 PPG EMW below the pre-drill predicted FG value. BP received a waiver from the MMS to drill the next hole section utilizing a SBM weight up to an 11.5 PPG, yielding a SBM weight to Fg drilling margin of .21 PPG.

The DWH utilized a 16 ½" X 20" drilling assembly as per the BP well plan to drill the open hole well section below the 18" drilling liner. The BP final well plan called for drilling the open hole section for the 16" casing to a depth of +/- 12,500' RKB (7,433' bml). However, given the fact that the 18" drilling liner had to be set shallower than planned, the expectation was that the 16 ½" X 20" hole section would not reach its planned TD. The final well plan further indicates that the 16" casing point needed to be pushed as deep as possible in an attempt to minimize the number of casing strings required in the well.

The 16 ½" X 20" open hole section was drilled to a depth of 12,350' RKB. Once the well reached 12,350' RKB drilling was stopped so the mud could be circulated and conditioned to reduce the ECD. Circulation was lost during the operation to circulate and condition the mud. The SBM weight at the time was 11.53 PPG. The indicated drilling margin between the SBM weight and the noted Fg was .18 PPG. Several days were spent fighting the loss circulation problem. No well control problems were noted to have occurred while fighting the loss circulation problems. The BOPs were both function and pressure tested during this time on both the yellow and blue pods from both the driller's and the toolpusher's BOP control panel.

The 16" intermediate casing string was run and set in place at a depth of 11,585' RKB in the Macondo Well on March 1, 2010. The setting depth was 765' shallower than the 16 ½" X 20" hole was drilled. The 16" casing was landed in a supplemental hanger at 5,227' RKB (160' bml). The casing was cemented in place, with premium cement plus additives. A fluid loss of 2,714 barrels was noted during the cement job. The top of cement (TOC) behind the 16" casing was estimated to be 11,402' RKB. The 16" hanger and seal assembly was set, with the seal assembly being tested to 250 PSI (low) and 3600 PSI (high). The cement was allowed to cure +/- 21 hours. The 16" casing covered the 18" liner but did not cover the full extent of the 16 ½" X 20" open hole section.

A 14 ¾" X 16 ½" drilling assembly was picked up and tripped into the riser. The blind shear rams and casing were tested to 250 PSI (low) and 3500 PSI (high), with the blind shears being operated from the driller's control panel utilizing the blue pod. The casing was cleaned out with the 14 ¾" X 16 ½" drilling assembly and the 16" casing shoe track was drilled out. Circulation was lost once the 16" casing shoe tract was drilled out. Operations were conducted over the next few days working on the lost circulation problem. The BOPs and diverter were function tested during that time from the toolpusher's BOP control panel utilizing the yellow pod. A Braden Head cement squeeze of the open hole section below the 16" casing shoe was performed utilizing the lower annular preventer. The cement was drilled out at 11,614' RKB and two formation integrity tests (FIT) were conducted. The first FIT results equated to a 12.41 PPG EMW and the second FIT results equated to a 12.55 PPG EMW. The 16 ½" X 20" open hole section was then cleaned out by washing and reaming to its TD of 12,350' RKB.

Drilling resumed utilizing the 14 ¾" X 16 ½" drilling assembly on March 8, 2010. The SBM weight was noted as 11.8 PPG, yielding a drilling margin between the SBM weight and the FIT results of .75 PPG. The Macondo Well was drilled from 12,350' to 13,305' RKB, where a gain of 10 to 12 barrels was noted. Drilling was stopped and the driller had other activities on the rig halted that could affect a flow check. Such activities were noted to have included crane movement. A flow check was made and the Macondo Well was found to be flowing. The well was shut in with an estimated total gain of 35 barrels. During the ensuing well control operation the drill string was noted to be stuck.

BP received approval to P&A the original wellbore at 15:41 hours on March 10th. Further BP received MMS approval for a BOP test extension at 17:07 hours on March 10th. The drill string was plugged at +/- 12,160' RKB and was severed in the bottom hole assembly (BHA) at +/- 12,146' RKB. The kick was circulated out and the well was killed with kill weight mud (KWM). Operations then commenced to abandon the lower section of open hole below the 18" drilling liner and bypass that section of the Macondo Well. A cement plug was set at 11,893' RKB to isolate the lower portion of the open hole. The BOPs were then tested from the driller's BOP control panel utilizing the blue pod and the diverter was tested from the toolpusher's BOP control panel utilizing the yellow POD. After testing the BOPs subsea, a cement kickoff plug was set at 11,600' RKB. Operations were then conducted to drill off the cement kickoff plug and bypass the abandoned open hole section of Macondo Well.

Bypass Wellbore

The MMS assigned the Macondo Well the new well designation of Well 001, ST 00, BP01 as a result of the bypass operation. The well's revised API number was 608174116901. The bypass depth was noted as +/- 11,700' RKB (6,633' bml). SBM weight at the bypass depth was a 12.1 PPG SMW. The indicated drilling margin between the SBM weight and the noted FIT results was a .4 PPG. The SBM weight was increased to a 12.3 PPG SMW by the time the well reached a depth of 12,793' RKB. As noted above, the last FIT yielded a 12.55 PPG EMW, for a drilling margin between the SBM weight and the FIT of .25 PPG. The 14 ¾" X 16 ½" new hole sections was drilled to 13,150' RKB, where the SBM weight was increased to a 12.4 PPG. The drilling margin between the SBM weight and the FIT at that depth was +/- .155 PPG. Operations then commenced to install a 13 5/8" drilling liner. The 13 5/8" liner was set on March 20, 2010 at a depth of 13,145' RKB. The top of the liner (TOL) was set with a hydraulic set liner hanger at a depth of 11,153' RKB. The 13 5/8" liner was cemented in place, with premium cement plus additives, A fluid loss of 76 barrels were noted during the cement job. The cement job was noted to be designed such that cement did not extend up the entire open hole section and into the 16" casing due to concerns over future APB issues. A liner top packer was installed and the liner top was tested to 1500 PSI utilizing a positive test. No negative test was noted. Installation of the 13 5/8" drilling liner was completed by March 21, 2010.

A 12 ¼" X 14 ½" drilling assembly was picked up and tripped into the riser. Prior to the drilling assembly entering the well the blind shears rams on the BOP stack were closed and the blind shears and the casing/liner were tested for 30 minutes to 250 PSI (low) and 2500 PSI (high). The BOPs and diverter was function tested from the driller's BOP control panel utilizing the blue pod. The 13 5/8" liner was cleaned out, its shoe track drilled out, the rat hole was cleaned out and 10' of new formation was drilled. A FIT was run with the 13 5/8" liner shoe testing to a

14.6 PPG EMW. The reported FIT results appear to be an anomaly when compared to the pre-drilled estimated Fg and the prior actual Fg data obtained from the Macondo well. A 14.6 PPG EMW FIT result is significantly higher than predicted for this depth in the Macondo Well. The predicted Fg from the well plan for the indicated depth was +/- 13.9 PPG EMW.

Drilling of the 12 ¼" X 14 ½" open hole section resumed utilizing a 12.8 PPG SBM on March 22nd. By March 24th the Macondo Well had reached a depth of 15,113' with a SBM weight of 13.4 PPG. The indicated SBM weight to Fg drilling margin would be at a .5 PPG using the predicted Fg in lieu of the FIT results, which suggest that BP questioned the FIT results. However, this action placed the well back within a more normal drilling margin environment than the well had been able to achieve previously. A contingent 11 7/8" drilling liner was installed at 15,103' RKB, allowing a 10' rat hole. By the time the Macondo Well was ready to drill below the 11 7/8" drilling liner it was a full hole size below its designed configuration.

The 11 7/8" drilling liner was set on March 25, 2010 to a depth of 15,103' RKB. The top of the liner (TOL) was set with an expandable liner hanger at a depth of 12,817' RKB. An anti-surge system was run with the liner. The Allamon system converted; however the float collar was never seen to convert. The 11 7/8" liner was cemented in place, with 307 barrels of fluid being lost during the cement job. The cement slurry used was premium cement with additives. The cement job was noted to be designed such that cement did not extend up the entire open hole section and into the 13 5/8" drilling liner. A liner top packer was installed and the well was tested to 1800 PSI utilizing a positive test. No negative test was noted. Installation of the 11 7/8" drilling liner was completed by March 26, 2010.

A 10 5/8" X 12 ¼" drilling assembly was picked up and tripped into the riser. Prior to the drilling assembly entering the well the blind shear rams on the BOP stack were function tested and the choke manifold was tested. The drilling assembly was tripped into the well and the BOPs were tested from the toolpusher's BOP control panel utilizing the yellow pod. The 11 7/8" drilling liner was cleaned out, its shoe track drilled out, the rat hole was cleaned out and 10' of new formation was drilled. A FIT was run with the 11 7/8" liner shoe testing to a +/- 14.7 PPG EMW, which was in fairly good agreement with the pre-drill estimated Fg in the well plan.

Drilling of the 10 5/8" X 12 ¼" open hole section resumed from 15,123' utilizing a SBM weight of 13.6 PPG on March 28th. The Macondo Well reached a depth of 17,173' with a SBM weight of 14.1 PPG on March 29th. An 9 7/8" drilling liner was set on March 31, 2010 at a depth of 17,163' RKB. The top of the liner (TOL) was set with an expandable liner hanger at a depth of 14,759' RKB. An anti-surge system was run with the liner. The 9 7/8" liner was cemented in place, with premium cement plus additives. During the circulation prior to pumping the cement 50 barrels of fluid were lost. The cement job was noted to be designed such that cement did not extend up the entire open hole section and into the 11 7/8" liner due to concerns over future APB issues. No negative test was noted.

A 8 ½" X 9 7/8" drilling assembly was picked up and tripped into the riser. Prior to the drilling assembly entering the well the blind shears rams on the BOP stack were closed and the blind shears and the casing/liner were tested for 30 minutes to 250 PSI (low) and 914 PSI (high). The blind shear rams were function tested from the toolpusher's BOP control panel on the yellow pod. The 9 7/8" liner was cleaned out, its shoe track drilled out and 10' of new formation was drilled to 17,183' RKB. A FIT was run with the 9 7/8" liner shoe testing to a 16.0 PPG EMW. The reported FIT results again appear to be an anomaly when compared to the pre-drilled estimated Fg and the prior actual Fg data obtained from the Macondo well. A 16.0 PPG EMW FIT results is significantly higher than predicted for this depth in the Macondo Well. The predicted Fg from the well plan for the indicated depth was +/- 15.2 PPG EMW. The FIT result was initially questioned by BP and was later confirmed by BP to be non-representative of open hole conditions below the 9 7/8" drilling liner; particularly in light of the lower formation pressures actually obtained by test during drilling.

Drilling of the 8 ½" X 9 7/8" open hole section resumed on April 2nd utilizing a SBM weight of 14.3 PPG. By the time the Macondo Well reached a depth of 17,761' RKB on April 3rd loss circulation problems were occurring, with a loss of 134 barrels being noted. Drilling was stopped and a flow check was made. Whether the well was flowing or not could not be confirmed so the well was shut in and monitored. The Macondo Well appeared to be experiencing a ballooning problem, experiencing both fluid loss and flow, with some pressure build up during shut in. The BOPs and diverter were function tested from the toolpusher's BOP control panel on the yellow pod during this interval. The next few days were spent spotting loss circulation material (LCM) pills, working the well while shut in and drilling ahead. The loss circulation pills included the specialty LCM pills "Form-A-Set" and "Form-A-Squeeze".

Two down hole pressure reading were attempted at +/- 18,089' RKB. The first attempt was tight but the second attempt indicated a pressure of a 12.58 PPG EMW (11,833 PSI).

Operations continued to fight the loss circulation problems and well stability issues while attempting to drill ahead. The 8 ½" X 9 5/8" hole section was drilled to +/- 18,132' RKB by mid-day April 4th. The 8 ½" bit reached a depth of 18,260' RKB, but the 8 ½" X 9 7/8" reamer was 128' above the bit in the BHA. The SBM weight was increased to a 14.4 PPG at that depth. However, operations commenced on April 5th to reduce the wellbore hydrostatic due to the continued fluid loss issues to include using base oil and displacing the well and riser with a SBM weight of 14.0 PPG. The drill string was stripped from 18,272' RKB to 14,937' RKB using the lower annular preventer. Operations were then conducted to set and squeeze Form-A- Set and Form-A-Squeeze LCM pills into the loss zones of the well. The multiple specialty LCM pills appeared to work, with the returns being re-established in the well. Total fluid losses encountered in the open hole section below the 9 7/8" drilling liner ran into the thousands of barrels.

The Macondo Well was checked for flow with no flow being noted. Operations were then conducted to trip out of the hole with the drill string. The blind shear rams were function tested from the toolpusher's BOP control panel on the yellow pod. An 8 ½" drilling assembly was then run back into the well. The well was washed and reamed back to 18,234' RKB were the flow rate dropped. The flow rate was reduced to reduce the ECD from a 14.5 PPG to a 14.4 PPG and a LCM pill was set. Washing and reaming continued with the well reaching bottom at 18,260' RKB. The 8 ½" drilling assembly was then utilized to drill an addition 100' of hole. The Macondo Well's TD was called at 18,360' RKB, some 1,290' short of the planned TD. The Macondo Well's called TD was reached shortly after noon on April 9th, 2010. The Macondo Well had again run out of drilling margin; this time with hole size becoming critical. The BP daily drilling report for April 9th show a cumulative well cost of $111.74 Million and 137.56 rig days. Comparison of these numbers with the BP well plan numbers indicates that for the called TD the Macondo Well was +/- $33 Million over AFE and +/- 82 days behind schedule. After TD was called the Macondo Well was circulated and conditioned with a SBM weight of 14.0 PPG. The drill string was short tripped into the 9 7/8" liner to 17,144' RKB. The BOPs were then tested from the driller's BOP control panel on the blue pod. The drill string was then tripped out of the well and operations were commenced to evaluate the open hole section of the Macondo Well.

The Macondo Well had penetrated its primary objective, the M56 sand, but had not seen all of its secondary objectives below the M56 sand nor had it reached its planned TD of 19,650' RKB at the time that drilling operations were halted. Significant concerns existed as to the real potential of losing the open hole potentially productive section of the well, or perhaps the well itself. The Macondo Well had reached a critical decision point. Set yet another sting of casing/liner further reducing the hole size, or add an expandable liner, or TD the well. The hole problems encountered during the drilling of the final open hole section that covered the well's potentially productive interval drove all future decisions and actions concerning the completion operations. These problems included, loss circulation, ballooning and no drilling margin.

Productive Intervals

The prospective production interval in the open hole section of the Macondo Well was logged and evaluated from April 11th to April 15, 2010. Based on the evaluation worked performed, BP estimated that more than 90 feet of hydrocarbon pay was present in the open hole section of the well below the 9 5/8" liner shoe. The hydrocarbons were predominately located in the M56D and M56E sands. The M56D was noted to be located at a depth of +/- 18,070' wireline measurement (WLM). The M56E was noted to be located at a depth of +/- 18,135' WLM. The M56D sand had +/- 22 feet of pay and the M56E had +/- 65 feet of pay.

The M56D and M56E sands were noted to be permeable and porous, with high hydrocarbon saturations (83% to 90%). The hydrocarbons in the zones were noted to be volatile oil, with a Gas/Oil Ratio (GOR) of around 3000 SCF/STB and an API gravity of 35 degrees. No water bearing, or aquifer, sections were noted to be associated with the pay zones, as no hydrocarbon-water contact in either zone was noted. A salt water bearing zone, the M57C, was noted in the open hole section above the hydrocarbon bearing zones.

The M56D sands was noted to have a formation pressure of +/- 11,850 PSI; an 12.5 PPG – 12.6 PPG EMW. The M56E sand was noted to have a formation pressure of +/- 11,900 PSI; an 12.5 PPG – 12.6 PPG EMW. The M57C salt water sand was noted to have a formation pressure of +/- 13,000 PSI; an 14.1 EMW.

BP identified various other thin sand stringers in the open hole section of the Macondo Well. The M56F was identified at a depth of +/- 18,250' WLM, just below the M56E, and was believed to be oil bearing. The M56C was identified at a depth of +/- 18,040' WLM, just above the M56D, and was believed to be wet or saltwater bearing. The M56B was identified at a depth of +/- 17,990' WLM and was believed to be wet or saltwater bearing. The M56A was identified at a depth of +/- 17800' WLM and was identified as oil or gas bearing. The M57B was identified at a depth of +/- 17,470' WLM, just above the M56D sand. It was identified as probable gas bearing though BP later evaluation indicates that the hydrocarbon response observed was due to SBM invasion.

Post Drilling Operations

BP elected to case off the productive interval in the Macondo Well prior to temporarily abandoning (TA'ing) the well. Three alternatives had been considered by BP: One was to TA the well with the open hole uncased below the 9 7/8" drilling liner; another was to install a full tapered casing string in the well and then TA the well; and another was to install a production liner across the open hole section below the 9 7/8" casing and TA the well.

The Macondo Well Plan (both original and final) had called for installing a 9 7/8" production casing string in the well. However, problems encountered during the drilling of the well resulted in the final open hole sized being too small to allow the pre-drill design to be utilized. Therefore, as a result of the information gained during the drilling of the well the different alternative plans were developed and considered. Both the open hole/TA option and liner/TA option were rejected by BP for various reason to include increased cost. Each alternative had pros and cons that argued for and against each respective alternative. The operational plan BP ultimately developed and settled on was to install a tapered production casing string that extended from the wellhead at the seafloor through the productive interval to +/- 18,300' RKB. This alternative was more in keeping with the original and final well plans. Once set in place the tapered casing string would be cemented in keeping with BP's design philosophy of protecting against APB. Further, the cement job was to be of a type and design to minimize the chance of loss circulation that could possibly result in the loss of the potentially productive interval or possibly the well. The installation of the production casing was to be followed by the TA of the Macondo Well and the de-mob of the DWH.

Wellbore Prep

Once the rig site well evaluation work was completed an 8 ½" clean out assembly was tripped into the well. The SBM was circulated and conditioned on the trip in. The open hole section was worked, washed and reamed, with the 8 ½" clean out assembly reaching TD (18,360' RKB) during the early morning hours of April 16th. The Macondo well was then circulated and conditioned with a 14.0 PPG SBM from 04:30 hours until 14:00 hours on April 16, 2010. Gas was circulated out of the well during this circulation. This was the last time the Macondo Well was completely circulated and conditioned prior to the blowout on April 20th. After circulating and conditioning the SBM a flow check was made and the well was found to be static. Operations then commenced to trip out of the well to run the tapered production casing. The BOPs and diverter were functioned tested from the driller's BOP control panel on the blue pod on the way out of the hole.

Due to BP's concerns about loss circulation a heavier mud weight pill was not set at the bottom of the well in the area that would become the rat hole once the production casing was set. This is typically done to prevent the cement from being contaminated with the rat hole mud during the primary cement job for the casing.

Production Casing

The production casing (i.e. tapered long string) was comprised of two sections of casing. The lower section consisted of 5,816' of 7", Q125, 32 #/ft, HYD 153 casing that extended from +/-18,303' to 12,487' RKB. A 7" X 9 7/8' cross over was located at +/-from 12,483' to 12,487' RKB. The upper section consisted of 7,404' of 9 7/8", Q125, 62.8#/ft HYD 153 casing that that extended from the crossover at 12,483' RKB to the wellhead hanger profile located at +/-5,079 RKB.

Operations began shortly after midnight on April 18th to rig up the casing running equipment. The first joint of casing was picked up at 03:30 hours. A reamer shoe was attached to the bottom of the first joint of casing followed by 4 joints of 7" casing and then a Weatherford double valved float collar. The lower section of casing from the float collar to the reamer shoe was +/- 189' in length and comprise the shoe track of the production casing. Base on the information reviewed it is believed that three centralizer subs were spaced out in the shoe tract. The shoe tract was followed by the remaining joints of casing. Further base on the available information it is believed that three centralizer subs were spaced out through the remaining potentially productive interval above the shoe tract. A casing hanger was installed on the top joint of casing. A 6 5/8" drill pipe running string, with running tool, was utilized to run the production casing string from the rig floor to the 9 7/8" wellhead profile on the seafloor (+/- 5,079' RKB). A cementing head was installed on the top joint of the running string. The production casing was in place, with the hanger landed in the wellhead by 14:00 hours on April 19, 2010.

The production casing's shoe track covered the open hole interval from 18,114'to 18,303' RKB. The section of open hole covered by the production casing's shoe tract included the main productive sand, the M56E. Normally the production casing's shoe track is positioned below any productive interval such that the shoe tract does not have to be drilled out to complete the well. However, due to the well problems the Macondo Well's TD was called before the open hole was deep enough to place the shoe track below the main objective M56E sand.

Float Collar Conversion

Once the production casing was landed operations commenced to rig up the cementing lines to the cementing head on top of the casing running string. Operations then followed to convert the Weatherford double valved float collar for cementing operations. The Weatherford double valve float collar played a dual role in the casing running and cementing operations. During the running of the casing an internal sleeve held the two check valves in the float collar in the open position so that the SBM in the well could flow up into and fill the casing. This reduced the surge effect created by running the casing in the hole, helping to reduce the risk of loss circulation or other well problems. The Weatherford float collar acted in concert with the Allamon equipment as an anti-surge system for the running of the production casing. The open float collar also allowed the casing to be filled automatically and eliminated the need to stop at regular intervals and fill the casing with mud. Filling casing with mud manually is time consuming and increases the running time for the casing, which increases the risk of hole problems while attempting to install the casing

The primary function to be provided by the Weatherford double valve float collar was to stop cement from u-tubing back above the production casing's shoe track once the cement was in place. To accomplish the normal check valve function of the float collar the conversion of the float collar from a fixed open conduit to a check valve configuration had to be accomplished. To convert the float collar the insert sleeve had to be pumped out of its position across the two check valves. To accomplish pumping the insert out of place required the shearing of shear pins under both given rate and pressure conditions. The indicated rate and pressure requirements for conversion of the Weatherford doubled valve float collar were 500 to 700 PSI at 5 to 7 barrels per minute (BPM).

Operations commenced to convert the float collar shortly after 14:30 hours on April 19th. Nine attempts were made to convert the float. The first eight attempts were not successful as circulation could not be established, suggesting that either the float collar or somewhere lower in the shoe track was plugged. Each subsequent attempt was made utilizing higher pressures. The rate utilized was 1 to 2 BPM. During the ninth attempt the well was pressured up to 3142 PSI at 1 BPM.

The 3142 PSI was held for 2 minutes and circulation was established. The Well was circulated at 1 BPM followed by the pumps being staged up to a rate of 4 BPM.

The post conversion circulation rates were lower than expected based on flow modeling by both Halliburton and M-I Swaco (MI). MI was the company that supplied the drilling fluids, mud engineers and compliance person to BP for the Macondo Well. Several different rates were tried and two different rig mud pumps were used with the same result. The BP day well site leader was concerned enough to discuss the situation with certain BP onshore personnel that had responsibility for the well. The BP day well site leader was instructed by the BP onshore wells team leader to cement the well. The reasons for the lower than predicted circulation pressure was never resolved. Speculation by the BP personnel on the rig included the possibility that something may have been blown off or failed in the production casing. Later work performed by BP during its post incident investigation of the blowout suggest the circulating pressure were in line with what they should have been. However, the affect - pre-blowout - was to cast serious doubt on the integrity of the float collar, the shoe track and the lower part of the casing.

As noted above float valves (either in the float collar or - if used - in the float shoe) are designed and used to prevent the backflow of cement into the casing, either through or above the shoe track. In my experience they are not designed, used or considered as a well control devise. Also, questions would exist as to whether a float valve would be considered to be bubble tight or not if gas flow was a potential.

Productive Casing Cement Job

Planning for the production casing cement job had been underway for several weeks prior to the Macondo Well reaching its called TD. The open hole problems experienced during the drilling of the final open hole section led to a flurry of BP office activity that dealt with a variety of well issues. These well issues included developing and vetting setting a production casing string verses a production liner and the proper cement program to use. In the days leading up to the cement job the Halliburton representative stationed in the BP office in Houston ran several cement simulations utilizing Halliburton's Opticem program. The different Opticem runs were made using various parameters supplied by BP, to include the number of centralizers to be run with the production casing. The outputs given by the Opticem program include a prediction of channeling and a prediction of gas flow potential. The final Opticem run was made on April 18th, with an input of 7 centralizers. The April 18th Opticem run predicated a high chance of channeling of the cement and a severe gas flow potential. This information was received by BP prior to the incident but was not utilized by BP nor was it relayed to the Transocean rig supervisory drilling personnel. BP has challenged the accuracy of the final Opticem run indicating that some of the entered data was not accurate. However, the pre-blowout affect of the Opticem results concerning channeling and potential gas flow severity should have been to alert everyone who was aware of the pre-blowout findings that a potentially severe problem could occur. If BP did not believe the results pre-blowout, it should have had the simulation re-run to verify or condemn those results. Unfortunately, the prediction of a sever gas flow problem made by the final Opticem run proved to be accurate; proper input data or not.

The Macondo Well was circulated at a rate of 4 BPM for +/- 30 minutes prior to initiating the cement job. The volume of SBM circulated during the float conversion attempts, coupled with the SBM circulated while trying to understand the low pump pressure, coupled with the SBM circulated prior to the cement job did not total up to a complete bottoms up volume for the well. Further the circulating rates were such that the annular velocities were inadequate for proper hole cleaning, particularly in the larger annular spaces.

The cement job as planned by BP, and designed by Halliburton, was driven by BP's primary concerns which were wellbore stability and integrity (i.e. not loosing returns and potentially risking the well) and future potential APB. The primary driver of minimizing the chance of loss of returns was dealt with by designing the cement job to control the ECD during pumping and the hydrostatic pressure as the cement was setting up. This resulted in a cement job that utilized low pump rates coupled with a foamed cement slurry used in concert with the lead and tail neat cement slurries that limited the volume of cement pumped (ie the height that the cement reached in the open hole section). The limited cement volume was also related to the future potential ABP concerns, as it fit with BP's plan of not cementing into the prior casing string. The result was a primary cement job that was a low volume, deep, foamed cement job pumped at low rates.

Pumping of the cement job began at 19:00 hours April 19th. Halliburton, based on its post job report, pumped the cement job as follows: 7 barrels of 6.7 PPG base oil at 4 BPM; followed by 10 barrels of 14.3 PPG tuned spacer at 4BPM; the cement lines were then tested to 5,000 PSI; followed by 62 barrels of 14.3 PPG tuned spacer at 4 BPM; followed by 4 barrels of 16.4 PPG lead (cap) cement at 2 BPM; Dart #1 was dropped; followed 1 barrels of 16.4 PPG lead (cap) cement at 2BPM; followed by 48 barrels of 14.5 PPG foamed cement at 2 BPM; followed by 7 barrels of 16.4 PPG tail (shoe tract) cement at 2BPM; 3 barrels of 14.3 PPG tuned spacer at 4 BPM; Dart #2 was dropped; followed by 17 barrels of 14.3 PPG tuned spacer at 4 BPM. Halliburton then pumped 133 barrels of 14.0 SBM to displace the cement down the running string. The displacement was then taken over and completed by the rig pumps. The rig pumps pumped 728.5 barrels of 14.0 PPG SBM at 4 BPM. The total mud displacement was noted as 860 barrels at 4 BPM. The top cement wiper plug bumped, with 1150 PSI (1000 PSI) over pump pressure. Once the top cement wiper plug bumped, circulation was stopped. The pressure was bled off, with +/- 5 barrels SBM being bled back. The cement job was completed by 00:43 hours April 20, 2011.

The observed bleed back volume corresponded with the calculated bleed back volume so it was noted in the work reports that the floats were holding. BP and Halliburton personnel believed lift pressure was achieved during the cement job.

Therefore, the bleed off was interpreted to be due to the floats holding. BP and Halliburton interpreted the cement job results to indicate that the job had gone as planned, was successful and that full returns were maintained during the cement job.

BP had set up a contingency plan to run a cement bond log (CBL) if problems were experienced with the cement job. Given the interpretation of a successful cement job BP canceled the CBL even though the Schlumberger wireline crew was already on the rig. The CBL would not have been able to be run below the top wiper plug, which was located immediately above the float collar. However, the planned top of the cement (TOC) was +/- 17,300' RKB. Therefore, the CBL would have been able to see if the top of the cement was in the right general area and the general quality of the cement bonding from the top of the cement down to the area of the float collar (+/- 18,114' RKB).

<u>Positive Tests</u>

After completion of the cement job the Dril-Quip running tool was released from the hanger and the Dril-Quip seal assembly was set and secured at 5,059' RKB. The purpose of the seal assembly is to seal off the circulation ports in the casing hanger, thereby sealing the wellhead from the annular space outside of the production casing. The seal assembly was isolated and tested twice, once before the running tool was sheared out of the seal assembly and once after the running tool was sheared out of the seal assembly. Each test included testing to a maximum pressure of 10,000 PSI for 10 sec and then reducing the pressure to +/- 6500 PSI and holding pressure for 1 hour. The seal assembly positive test was conducted with SBM. The seal assembly positive test was deemed to be successful.

The running string was tripped out of the riser and the running tool was laid down. The well was checked for flow and was noted to be static. A combination displacement string and cementing string was then run into the riser. The combination string was tripped to a depth of 4,817' RKB in the riser. At that point the blind/shear rams were closed and pressure was applied to the well by pumping SBM in to the wellbore below the blind/shear rams. The blind/shear rams, the wellhead/seal assembly, the production casing down to the top cement wiper plug and the top cement wiper plug were tested to 250 PSI (low) and 2500 PSI (high) for 30 minutes. This positive test required pumping in 8.5 barrels of SBM to pressure up the well to the positive test high pressure level. A corresponding 8.5 barrels of SBM were bled off once the test was completed. The fact that the pressure held and the pump in and bleed off values were the same indicated a successful positive test of the components tested. However, the positive test did not test the production casing shoe tract or the annular cement for pressure integrity or zonal isolation. Further a positive test only tests the well from the inside out. This is not the direction that hydrocarbon flow will occur. It also should be noted that the positive test was conducted using SBM. Drilling fluids, such as SBM, contain solids that can create a sealing affect and at times mask a problem, yielding a false result.

Temporary Abandonment (TA)

TA Procedures

After the installation and initial testing of the production casing was completed the TA operations commenced. The TA procedures performed on the DWH were conducted under the supervision of the BP onsite well site leaders as were the prior well operations. As noted previously in the report BP had chosen to finish the completion of the Macondo Well at a later date. Therefore, the well had to be secured in preparation for the removal of the rig's riser/BOP system and for the well being left in a semi-completed state for some period of time. Deepwater wells that are TA'd have to comply with federal regulations under 30 CFR 250.1721. Submission of an Application for Permit to Modify (APM) and approval of same is required to conduct TA operations on a well. The rig was also being prepared to move off or de-mob from the well in concert with the TA operations.

BP generated at least five TA procedures between April 12th and April 20th, with the final TA procedure being sent to the BP well site leader on the rig by email at +/- 10:43 hours the morning of the blowout. The TA procedures were presented in various formats and also varied in their level of detail and risk exposure.

The TA plans BP developed between April 12th and April 20th included the installation of a Dril-Quip Lock Down Sleeve (LDS) to lock the 9 7/8" casing in the wellhead. The LDS is typically installed to prevent casing movement while the well is in production due to temperature and pressure effects. The Macondo Well could have been TA'd without the installation of the LDS. However, it appears that the installation of the LDS became the focus of the TA plans.

The Dril-Quip installation procedure for the LDS required the application of 100,000 pounds of weight during the process. The BP Macondo design team chose to connect drill pipe, that would readily be available - standing in the derrick, below the LDS to generate this type of loading. This decision would be carried throughout and affect all of the TA procedures.

The April 12th draft TA procedure called for setting the LDS first. Once the LDS was installed the drill pipe would be run to 6,000' RKB (933' bml), where the 14.0 PPG SBM would be displaced with +/- 8.6 PPG seawater. A 300' cement plug would then be set and tested. This procedure would have displaced 33% of the hydrostatic column of SBM with seawater prior to setting and testing the surface cement plug. The displacement of the SBM to seawater would cause the hydrostatic pressure in the Macondo Well to be lower that the formation pressure of certain formations with potential exposure to the wellbore (potential underbalance). This TA plan does not include a negative test to test for influx into the well. If this plan would have been performed the only tests performed would have been a series of positive tests on the production casing's seal assembly and a positive test on the production casing down to the top wiper plug. No test of any type would have been conducted on either the production casing's shoe tract or the cement in the annulus space outside of the production casing prior to setting the 300' surface cement plug. Given the lack of verification or confirmation of the integrity of the annular cement or production casing shoe track, the April 12th TA procedure is viewed by me as being very high risk.

Several changes were made to the April 12th draft TA procedure after the procedure was reviewed by BP personnel both onshore and on the rig. The April 14th procedure was emailed to a BP well site leader on the rig in a Forward Ops email. This procedure included some positive changes and some negative changes but on the whole is viewed by me as the TA procedure with the lowest risk of any of the TA procedures prepared by BP. If the April 14th TA procedure had been followed, or a variety of other known options had been incorporated into the TA procedure, the risk level of the Macondo Well would have been greatly reduced or eliminated.

Based on a desire to set the LDS in water and to expose the LDS to the least amount of activity during the TA procedure the installation of the LDS was moved to the end of the TA procedure. This change created some very significant issues in the subsequent TA procedures. First for BP to be able to attain the desired 100,000 pounds of load with drill pipe attached below the LDS, the surface cement plug had to be set much deeper in the well. The April 14th TA procedure called for setting the surface cement plug at a depth of 8,367' RKB (3,300' bml). However, it also call for setting the surface cement plug in the 14 PPG SBM and weight testing the plug. It further included conducting a negative test utilizing base oil to the wellhead in the kill/choke line. Given that base oil is significantly lighter than water, this would have had the effect of negatively testing the well for a deeper seawater displacement. The SBM would then be displaced with seawater to a depth of 6,000' RKB (933' bml). The LDS would then be installed and the riser pulled. The important positive features were that the weight tested surface plug would have been in place plus the negative test would have done before the SBM was displaced. Further the negative test included in the April 14th TA procedure would have more than replicated the pressured condition of the well once the rig had left location.

It should be noted that to set the LDS last in water did not require setting the surface cement plug at 8,367'. The required weight for the LDS installation procedure could have been generated by using shorter lengths of heavier tubulars and/or by utilizing a combination of weight on top coupled by weight below the LDS to achieve the desired results. It was further noted that the LDS did not need to be set in water but in fact could be set in mud. However, it was possible to set the LDS last in water, while still TA'ing the well in a manner that complied with the written federal requirements and normal industry practice.

Further discussions on the TA procedures by BP personnel resulted in additional changes and the issuing of subsequent procedures. A new TA procedure was issued on April 15th due to comments from a well site leader about setting the surface cement plug in seawater instead of SBM. The April 15th TA procedure called for performing the negative test with base oil in the kill/choke line to the wellhead. Then displacing the SBM with seawater to a depth of 8,367' RBK (3,300' bml). This would displace 45.6% of the hydrostatic column of SBM with saltwater prior to setting and testing the surface cement plug. Further, it would create a significantly greater underbalance potential in the well that was neither needed, nor negatively tested for, nor had been done before. The surface cement plug would then be set in seawater at the depth of 8,367' RKB (3,300' bml) and weight tested. The LDS would then be installed and the riser pulled. This procedure creates additional risk that was not present in the April 14th procedure by displacing the SBM with seawater to a deeper depth and creating a greater potential underbalance in the well.

It should be noted that cement plugs are routinely successfully set in drilling mud. However, the request to set the cement plug in water coupled with the desire to set the LDS last using the already standing back drill pipe morphed the TA procedure into higher risk. The TA procedure could have been adapted to accommodate the focus on the LDS, while at the same setting the surface plug in water, without placing the well at substantial risk.

The April 16th TA procedure essentially follows the April 15th TA procedure with the exception that the negative test is conducted with seawater (in lieu of base oil) in the kill/choke line to the wellhead. Therefore, the negative test would not replicate the wellbore conditions at the time the SBM is displaced with seawater to a depth of 8,367' RKB (3,300' bml). As with the April 15th TA procedure the displacement occurs before the surface cement plug is set and tested. The April 16th procedure is viewed as being high risk by me and represents an increasing level of risk as the TA procedures progressed from the April 14th TA procedure. The April 16th TA procedure was the procedure BP submitted to the MMS for approval of its APM to TA the Macondo Well. It is my understanding it took the MMS 90 minutes to approve BP's TA permit based on the April 16th TA procedure.

A revised TA procedure was sent to the BP day well site team leader on the rig as part of an ops note email on April 20th; the date of the blowout. It is my understanding that it had been realized by BP onshore personnel that the negative test in the April 16th TA procedure (as approved by the MMS) would not replicate well conditions when the SBM was displaced with seawater to 8,367' RKB. This realization prompted the last minute change. Discussion occurred among various BP personnel concerning this issue. The discussion included the possibility of doing two negative tests; one before the displacement and one after. The BP wells team leader decided to do one negative test that would be conducted during the displacement of the SBM with seawater. However, if two negative test would have been required the interpretation of the negative test may have been completely different. If the first negative test would have been performed prior to displacing the well, the unorthodox weighted spacer would not have been in the well. The absence of the viscous heavy spacer would have eliminated the possibly of the kill/choke line becoming either plugged or controlled by hydrostatic pressure. Further, if the first negative test would have been performed using base oil in the kill/choke line to the BOPs the hydrostatic pressure in the well would have effectively been lowered below the potentially exposed formation pressures. Therefore, an open, unobstructed kill/choke line, monitoring a leaking underbalanced well should have had flow coming back during the negative test. Flow out of the kill/choke line, alone or in combination with the shut in drill pipe pressure, would have been interpreted as a failure of the negative test based on the information available to date.

To replicate the wellbore conditions after displacement the TA plan sent to the rig the morning of April 20th was to: displace the kill/choke lines with seawater and isolate the kill/choke lines; then displace the SBM (and spacer) with seawater from 8,367' RKB to above the BOPs utilizing a displacement string; then close the BOP and open the kill/choke line. This would replicate a full column of seawater from 8,367' RKB to the rig while maintaining the riser full of SBM and spacer. Once the negative test was completed the displacement of the SBM with seawater in the riser would be completed. The April 20th procedure is also viewed as being high risk by me and further represents an increasing level of risk as the TA procedures progressed from the April 14th TA procedure. It was at the end of the riser displacement that the blowout occurred.

The changes to the TA procedures demonstrates that inputs and changes to operations and procedures occurred for the Macondo Well from various sources within BP. However, no one involved with the TA procedures ever stepped back and looked at the net effect that a series of changes was having on the operation, or the procedure under consideration, or the well as a whole. The initial change to the TA procedure between April 12th to April 14th was a net positive but most of the changes thereafter served to increase the risk that the Macondo Well was under.

The TA procedure did not have to be conducted under the level of risk it was. If someone within BP had simply stepped back and considered an overview of the entire situation to include: the history of the well; coupled with the fact that adequate flow barriers, much less redundant flow barriers, had not been tested nor confirmed; further coupled with the fact that the TA operations about to be carried out would potentially significantly underbalance the well by displacing it to a significantly deeper depth than normal - other options could have been explored that would have significantly reduced the risk. However, once the BP personnel became convinced the cement job had gone as planned and was successful, coupled with the production casing being in place, it appears that the belief was the worst was behind them and that the well was no longer a live threat but was secure.

Other options available to secure the well for TA included: 1. Following the April 14th TA procedure. If setting the surface cement plug in mud was an issue, a mechanical plug could have been set, or both could have been done; 2. Setting and testing an intermediate plug - either mechanical or cement or both - prior to performing the shallow TA operations; 3. Doing a combination of #1 and #2. 4.

Displacing the upper wellbore/riser with seawater with the BOP closed; 5. Not under-balancing the well – with the casing and cement in place a heavy weight SBM pill could have been set just above the shoe track to maintain the necessary hydrostatic once the displacement occurred. The downside to this option is that if there was communication through the cement to the thief zone the heavy pill may have resulted in fluid loss and possible formation damage. The Macondo was a +/- $130 million dollar well that had just tested a potential 500 million barrel hydrocarbon discovery. Going the extra step to make certain it was locked up tight should not have been an issue.

In all of the TA procedures the surface cement plug was to be set as a balance plug. There was no indication that any type of mechanical plug was going to be employed in concert with the surface cement plug despite the earlier history in the Macondo Well. Utilizing a cement retainer with cement spotted above and/or below or a retrievable or drillable mechanical plug with cement spotted above may have eliminated any perceived issues of setting the surface cement plug in SMB.

Surface SBM handling

The displacement of the SBM from 8,367' RKB to the surface in the Macondo Well required the surface handling of several thousand barrels of additional fluid. The seawater for the displacement was pumped into the well from the Gulf of Mexico through the rig's deep well pumping system (i.e. the sea chest). The SBM in the well from the 8,367' to the surface was circulated into the rig's drilling fluid containment system. The net effect of the displacement was a gain of +/- 2,000 barrels of SBM, which had been in the well that would now need surface handling and storage. The DWH was equipped with a sophisticated mud handling, storage and monitoring system that allowed for the movement, monitoring and off loading of drilling fluid through a variety of configurations. The rig's drilling fluids containment system contained 20 pits that could be monitored in a variety of ways, to include monitoring by the Sperry Sun mud loggers.

It is my understanding that in preparation for the displacement of the SBM from the well, the rig's drilling fluid containment system was configured for the SBM coming out of the well to go to holding pits that were monitored as part of the well's circulation system. SBM from other pits in the system that were offline from the well's fluid monitoring system was transferred to a containment pit where it was pumped to the Motor Vessel Damon Bankston. BP provided the Damon Bankston, along with other vessels, to transport and store BP materials, equipment and required personnel for the Macondo well. The vessels were also provided for servicing the rig. The last transfer of mud to the Damon Bankston occurred at 17:17 hours. The transfer of the SBM to the Damon Bankston did not cause the Macondo Well surface blowout.

The SBM utilized in the drilling of the Macondo Well was owned by BP. The SBM displaced from the well during the TA operations could be retained, treated and potentially reused for other applications or properly disposed of depending on its condition. BP hired MI to both provide the SBM and to provide the technical personnel to take care of the SBM. MI's job was to oversee the development, handling and maintenance of the drilling fluids both in the well and at the surface. MI was the drilling fluids specialist on the rig for the drilling of the Macondo Well. Both the BP well site leaders and the MI personnel on site would have had various computer programs at their disposal to allow them to determine both the expected well pressure responses and volume handling needs for operations involving the drilling fluids in the Macondo Well.

To better understand the pit volume changes occurring as a result of the SBM displacement to seawater the BP well site leader could have utilized the MI personnel to generate expected pit volume and pit level change schedules. MI personnel, through the instruction of the BP well site leader, could have organized and directed the surface handling of the SBM during the displacement; coordinating the efforts of both the rig personnel related to fluid handling and to the Sperry Sun personnel monitoring the drilling fluid containment system. Sperry Sun's mud loggers, utilizing the Sperry Sun system, also had the capability to track volumes and pressures associated drilling fluid handling. The Sperry Sun Mud logger did in fact track fluid movements during the well displacement. By having a defined plan, with designated pits - and knowing expected volume and level changes in those pits, the personnel monitoring the displacement would have known if what they were observing was expected or was an anomaly.

Initial SBM Displacement

Upon the successful completion of the positive test of the Macondo the blind/shear rams were opened. The combination displacement/cementing string was then tripped through the BOPs and into the well. The final depth that the combination string was tripped to was 8,367' RKB (3,300' bml). The final configuration of the combination string consisted of 821' of 3 ½' tubing, 3,443' of 5 ½" drill pipe and 4,103' of 6 5/8" drill pipe, for a total string length of 8,367'. The displacement string was in place shortly after 15:00 hours, April 20th. The boost and kill/choke lines were then displaced with seawater and isolated. Operations commenced sometime before16:00 hours for the initial phase of displacing the SBM with seawater. The displacement was conducted utilizing a spacer fluid between the SBM and the seawater to prevent contamination of the SBM and allow for a more efficient displacement. A reported +/- 446 barrels of spacer was pumped followed by 352 barrels of seawater. Once the Macondo well was displaced with the indicated strokes/volumes it was believed that seawater occupied the well from 8,367' RKB to the riser. The initial phase of the displacement operation was deemed to be completed.

Spacer

Seawater does not efficiently displace SBM. Therefore a spacer fluid is required to be pumped before the seawater is pumped to displace the SBM. The spacer is normally a liquid with sufficient properties to efficiently displace the SBM.

The properties of the spacer are typically such that the interface between the SBM and the spacer stays relatively in-tack providing for an efficient displacement. The properties of the spacer are also designed to provide a relatively efficient interface between the spacer and the seawater that will replace the SBM. Spacer sizes typically are in the range of 200 barrels to allow for any mixing that occurs between the SBM and the spacer and the spacer and the seawater.

The spacer that BP used for the displacement of the weighted SBM in the Macondo Well was unorthodox to say the least. It was composed of two high viscosity, weighted, specialty lost circulation material (LCM) pills that were left over from the drilling of the well. The two LCM pills were supplied by MI. One specialty LCM pill was Form-A-Set pill and the other was Form-A-Squeeze pill. The two LCM pills were approximately the same volume and when combined created the 446 barrel reported volume of the spacer. MI suggested BP mix and use these pills as the spacer in lieu of having to transport the pills back to shore and dispose of them. It is my understanding that by regulation the specialty LCM pills could only be discharged overboard if they were circulated out of the well but could not be discharged overboard directly if they had not been used in the well.

Prior to using the spacer one of the MI mud engineers tested the two pills by mixing a sample of each together and letting them sit overnight. No adverse affects or significant settling was noted. One of the BP well site leaders also checked with a BP fluids expert, with no issues being raised. However no testing was ever conducted between the specialty LCM mixture and seawater to determine if any adverse affects or settling issue would occur. After the fact testing indicated that significant settling did occur when the mixture was tested in seawater.

The combination LCM pill spacer was highly viscous and weighed 16.0 PPG. Therefore, it should have been very efficient at displacing the lighter 14.0 PPG SBM. However, because of the spacer's weight and viscosity the displacement of it by the much lighter 8.6 PPG seawater would be problematic. The interface between the two fluid types would be maintained largely by velocity but would be expected to deteriorate over time.

Given the indicated displacement volumes, coupled with the effect of the spacer on the spacer/seawater interface, and the possibly effect the spacer could have on pump efficiency, it is highly unlikely that the specialty LCM spacer had cleared the wellbore and was above the BOPs at the time the initial displacement was stopped to conduct the negative test. The location of the unorthodox spacer in the BOPs and the top of the wellbore created a situation that confused and confounded the negative test; either through plugging or hydrostatic pressure effect. The use of the unorthodox spacer also quite possibly confounded and confused certain critical events that followed the negative test.

Displacement Pressure Schedule

It was noted that a displacement pump schedule was not prepared prior to displacing the Macondo Well. A displacement pump schedule indicates the pump pressure expected for either a given number of strokes or barrels pumped. It will also key on certain milestones such as when the spacer reaches the end of the displacement string or when the saltwater reaches the end of the displacement string, etc. Given the complexity of the situation a displacement pump schedule was critical for the well site leader, driller and mud loggers to understand the pressure profile they were seeing during the displacement. The factors that added to the complexity of the displacement were: three internal displacement string geometries; five displacement string by well/riser annulus geometries and the use of an unorthodox spacer. The well site leader should have prepared a displacement pump schedule or had one of the MI mud engineer prepare a displacement pump schedule. The task of preparing a displacement pump schedule does not fall to the driller.

Negative Test

With the initial phase of the displacement deemed to be completed, operations commenced to perform the negative test on the Macondo Well. The purpose of a negative test is to test the well's integrity in the direction of flow. It was the only complete test of the Macondo Well's integrity for purposes of TA. The negative test tested the wellhead assembly, the casing and the cement; to include the shoe track and the annular cement that was to provide annular isolation from the drilled formations.

The lower annular preventer was closed shortly before 17:00 hours to isolate the heavy fluid in the riser from the well. Differential pressure existed on the drill pipe that resulted from the displacement of the heaver fluids with the significantly lighter seawater. The differential drill pipe pressure at the time the well was shut-in was noted to be 2,325 PSI. This reading was over 700 PSI too high indicating that the initial phase of the displacement may not have placed the heavy spacer above the BOPs into the riser or that other issues were occurring. However, it is unknown if the overpressure was recognized. As already noted in this report, no displacement pump schedule was prepared and available for use. If a displacement pump schedule had been provided the issue would have been readily apparent. Steps could have easily been taken to pump additional seawater until the proper pressure was observed indicating that the heavy spacer was cleared out of the BOPs and upper well area, if that was the problem. If under-displacement was not the problem then steps could have been taken early on to check for potential leaks.

Negative testing was conducted over the next +/- 3 hours. Initially the negative test was conducted by attempting to bleed the shut in differential pressure off of the drill pipe. The rig personnel were accustomed to performing a negative test by utilizing the drill pipe as the bleed down and monitoring point for the test. If the well has integrity then the differential drill pipe pressure can be bled off in an isolated system. The drill pipe can then be either shut back in and monitored for a pressure build up or left open and monitored for flow. Either a pressure build up on a shut in system or flow on an open system would be a failure of the negative test and would indicate the well lacked integrity.

In this situation, several issues were noted: 1st, attempts to bleed the drill pipe to 0 PSI were not successful; 2nd the volume of fluid bled off appeared excessive. It appears that the well site leader had not prepared or had the MI mud engineer prepare an expected bleed off volume to be able to compare actual bled volumes with expected bled volumes; 3rd, the drill pipe would build pressure when shut in; 4th, kill/choke line pressures and drill pipe pressures were inconsistent; and 5th, kill/choke line pressure dropping suggesting heavier fluid was entering the kill/choke line. Noting a problem, the drill crew started trying to diagnose the situation. As is normal, the first check was to see if there was a surface or an equipment leak. It was discovered that the fluid level in the riser had fallen indicating that U-tubing of the heavy riser fluid against the lighter seawater in the drill pipe was occurring. The u-tubing could account for the issues being observed.

The closing pressure on the lower annular preventer was increased and the riser was topped off (i.e. filled back up) with +/- 60 barrels of SBM from a trip tank. The riser fluid level was observed and found to be holding. Then negative testing continued. The drill pipe was again bled off, with 15 to 23 barrels being reported as being bled back to the cement unit. The same issues continued to plague the negative testing. Sometime before 18:00 hours the BP day well site leader had the bleed off switched from the drill pipe to kill/choke line with the drill pipe pressure still being monitored. The kill/choke line was opened to the cementing unit and then bled off. The volume of seawater bled from the kill/choke line is not known exactly but a range of 3 barrels to 15 barrels has been reported. It was further reported that the kill/choke line was still spurting and flowing when closed in. The ranges of the reported possible bleed amounts from both the drill pipe and kill/choke line would exceed the expected amount. However, as noted previously, without an expected bleed back volume any comparison was simply a rough approximation.

After attempting to bleed off the kill/choke line the BP day well site leader left the rig floor to confer with the BP night well site leader. At some point both BP well site leaders and a BP well site leader trainee were on the drill floor and involved in the discussion involving the issues with the negative test.

Crew change for certain individuals occurred around 18:00 hours as the 2nd round of diagnostics was occurring. The BP well site leaders were changing tours along with the toolpushers and certain other rig personnel. The rig's drill crew had changed tours at noon. There was also a VIP tour being conducted on the rig during this time. Management personnel from both BP and Transocean were on the rig and were on the rig floor during part of the time that the negative testing was being conducted.

During the shut in period - post kill/choke line bleed off - the shut in drill pipe pressure gradually increased to 1400 PSI. The drill pipe pressure increase to 1400 PSI occurred over a period of +/- 35 minutes. After continued discussion on the rig floor, the BP night well site leader decided that the negative testing should be lined up and performed as per the BP plan approved by the MMS. The kill/choke line was pumped into and was noted to be full; taking very little fluid. The kill/choke line was then lined up and opened to the mini trip tank near the driller's shack. The open kill/choke line was monitored for 30 minutes with no flow being noted. The 1400 PSI remained on the shut in drill pipe. The negative test was then concluded to be a good test by the BP well site leaders. Negative testing was completed at 19:55 hours (7:55 PM) April 20, 2011. The BP night well site leader then issued the instruction to complete the displacement of the Macondo Well either explicitly or implicitly by approving the negative test.

A kick, several barrels in size, was introduced into the Macondo Well during the bleed offs conducted during the negative testing. However, during much of the negative testing the well was at least balanced and once the well was put back into communication with the heavy fluid in the riser the well was again over-balanced. The influx material introduced during the negative test likely remained at the bottom of the well, with certain components hydrocarbons likely going into solution in the SBM. It is unlikely that any gas migrated up the well during the final SBM displacement prior to the well becoming underbalanced. However, if such migration occurred a two tier affect may have occurred at the surface.

In the BP post incident investigation the BP day well site leader and the BP trainee well site leader indicates that they had been advised by the toolpusher on duty that the 1400 PSI on the shut in drill pipe was due to a "bladder affect". Reportedly both the on tour toolpusher and on tour driller indicated they had seen this phenomena before. Tragically neither the on tour toolpusher nor the on tour driller survived the incident. Furthermore, the Transocean post incident investigation did not confirm the BP well site leaders comments concerning the bladder affect. The BP night well site leader indicates he was advised by the on tour toolpusher that the drill pipe pressure was due to annular compression. As described the bladder affect appears to be slightly akin to annular packer compression. However, there are some significant differences between the two that would indicate they are not the same phenomena, at least as described by the two BP well site leaders. The bladder affect as described by the two BP well site leaders is a phenomena that I am not familiar with. It is possible that the toolpusher was attempting to explain why the annular had leaked when his relief was on tour and in the confusion concerning the negative test the BP well site leaders missed the distinction. The bladder affect as described by the BP well site leaders would be easily remedied by simply bleeding fluid off the well. The pressure should bleed off and not come back unless there is a leak in the system somewhere.

Once the BP well site leaders recognized that there was shut in drill pipe pressure coupled with: 1. no flow on kill line; 2. knowing that a high viscosity weighted unorthodox spacer was in the well; and 3. knowing that the unorthodox spacer had leak through lower annular – the BP well site leader(s) should have instructed that the well be circulated through the kill/choke lines to clear any spacer that was either blocking or adding pressure to the kill line. The negative pressure test then should have been repeated.

If the well site leaders' versions are correct this illustrates too much reliance on the drill crew in my opinion. The drill crew, while having training in their respective jobs and having work experience on some of the most technically advanced wells ever drilled, were not formally trained engineers and did not have a complete knowledge of all facts. The BP well site leaders had multiple onshore BP technical personnel at their disposal to assist them in resolving the issue. The BP personnel, both on the rig and onshore, were in a better position, with more data, to understand all the events and make the necessary decisions to safely TA the Macondo Well. If there was any questions the BP well site leaders could have, should have and ultimately did get BP onshore involved.

At the very least a BP onshore engineer was advised of the situation of no flow on the kill/choke line and 1400 PSI on the drill pipe prior to the blowout occurring. The BP night well site leader, in his BP post investigation statement, indicates that he did call and discuss the negative testing with a BP engineer onshore. The BP interview notes of the BP night well site leader indicates the discussion occurred while the negative testing was occurring. However, there is some indication that the call to the BP engineer occurred after the negative testing was completed. Nevertheless a conversation did occur. It is my understanding at the time the BP night well site leader and the BP engineer were talking the BP engineer had the Sperry Sun real time data called up on his computer. When advised about the pressure/flow anomaly, even post event, the BP engineer should have attempted to resolve the anomaly and should have instructed the BP well site leader to halt the displacement operations and secure the well until the situation could be completely checked out.

The negative test for the Macondo Well during the TA procedure seems to have been treated almost nonchalantly by BP; when in fact it was most the important test conducted. A negative test was not part of the original draft BP TA procedure. The negative test was added to a revised TA procedure by the BP engineer at the request of a BP well site leader; who was no longer on the rig when the negative test was actually conducted. The BP day well site leader on the rig on April 20th did not include the negative test in the pre-tour meeting. The need for the negative test was brought up by the rig's offshore installation manager (OIM). Further, the BP day well site leader did not arrive on the rig floor during the negative testing until the fluid level in the riser was being checked.

The negative testing revealed that the Macondo Well lacked integrity and was not secure. The Macondo Well was still a live well, potentially lacking the zonal isolation necessary to prevent a significant well control event from occurring. However, no one within BP, either on the rig or onshore, appeared to be tracking the combined impact of the issues and increasing number of risks confronting the Macondo Well. The overarching issues needing to be considered included: the questions concerning the negative test, the lack of confirmation of the down hole flow barriers, the history of the Macondo Well, the high flow rate potential of the well and what was at stake given the scope of the discovery that had been made by the Macondo Well.

It was noted that the BP onshore deepwater team responsible for the Macondo Well had under gone a significant realignment in the weeks prior to the incident. This likely had an impact on the overall focus on the Macondo project during a critical period of the well's operations. Further it was noted that one of the more experienced BP well site leaders assigned to the DWH that was working the Macondo Well was not on his assigned tour on the rig at the time the incident occurred due to having to attend a well control school. His replacement was a qualified BP well site leader that had worked on the DWH several years before but had not worked on the Macondo well.

Attachment A is a list of issues, factors or questions that existed if anyone overseeing the well for BP would have stepped back and considered all aspects of the operation before proceeding with the displacement of the SBM and the subsequent potential significant under-balancing of the Macondo Well.

Final SBM Displacement

The final stage of the SBM displacement from the Macondo Well started at approximately 20:00 hours, April 20th. Surface pressures were noted to be responding as generally expected, with the pump pressure increasing as the pumps were brought on line and then steadily decreasing as the seawater replaced the heavier SBM in the well. Give the perceived secured condition of the well during this part of the displacement all of the surface indicators would have appeared normal.

Based on the perception that: the casing was installed without issue; the primary cement job had gone well and was successful; and that the well had passed both positive and negative tests - it is likely the BP well site leaders and the drill crew held the view that the well was no longer live but was fully secured. Therefore, other operations were being conducted during the displacement that had the potential to mask or distort certain surface indicators. These operations included empting trip tanks; conducting crane operations and moving fluids which could mask or distort pit volumes and/or return flow readings. However, as previously discussed, it appears that expected changes in pit volumes/levels due to the SBM displacement had not been determined ahead of time so that pit level changes were likely inconclusive in any event.

Post incident examination of expanded real time Sperry Sun mud logger data indicates that at approximately 20:50 a change in slope of the drill pipe pressure occurred. This change in pump pressure coincided with the initial slowing down of the pumps as the spacer was believed to be getting close to the surface and again would appear to be normal. However, post incident work performed by both Transocean and BP indicates that the Macondo well became underbalanced to non-isolated formation(s) somewhere around 20:50 hours on April 20, 2011.

At approximately 21:00 hours (9:00 PM) the circulating drill pipe pressure began to change direction, with a very subtle increase being observed in the expanded post incident Sperry Sun data presentation. The pump rates were further slowed and empting of the trip tanks began. The trip tanks emptied into the return flowline upstream of the return flow sensors which would affect any flow out changes due to well conditions. The BP night well site leader indicates he returned to the rig floor as the spacer got back and was likely getting to the driller's shack around this time. The mud logger indicates he was on a +/- 10 minute break sometime between 20:30 and 21:00 hours; if so then he should have been either back from his break or just getting back from his break. All primary monitoring was being performed from the rig floor while the mud logger was on his break. Given the noted indications it would have been virtually impossible for anyone monitoring the well at this point to have deduced a problem.

Over the next +/- 8 minutes the well was circulated at a reduced rate in anticipation of the spacer reaching the surface. The circulating drill pipe pressure appears to have increased +/- 100 PSI during that time while the pump rate remained constant. The BP night well site leader is believed to have been in the driller's shack around this time and the Sperry Sun mud logger was likely back from his break. It was noted that the Sperry Sun mud logger indicates that when he returned from his break he checked his monitoring sensors and did not detect any problems. In real time, with the data scrolling forward on any type of normal speed presentation format and with the potential for routine pump pressure fluctuations occurring, it would have been unlikely that anyone monitoring the well would have noted this anomaly, particularly given the belief that the well was secure.

By 21:08 hours it was believed that the spacer had reached the surface. The rig pumps were shut down for a sheen test to be conducted. The purpose of the sheen test was to determine if the spacer was free of SBM and could be pumped overboard into the Gulf of Mexico. By 21:14 the results of the sheen test was reported by the MI compliance person conducting the sheen test, with the results being noted that overboard discharge could begin. The rig's return flow line was routed for the returns coming out of the well to be sent overboard. The rig pump on the riser boost line was brought on line first followed by the other rig pumps lined up on the displacement string. During the time the rig pumps were being brought on line the pump pressure was increasing as would be expected.

A review of the expanded post incident Sperry Sun real time data indicates that two anomalies occurred during the shut down for the sheen test. First the pump pressure did not drop to the proper level. Given the indicated fluid volumes in the well the expected shut in drill pipe pressure would be lower than what was actual noted on the expanded post incident Sperry Sun chart. If a displacement pump schedule had been prepared and utilized this anomaly may have been detected. Second, during the +/- 6 minutes the pumps were off the drill pipe pressure increased by approximately 200 PSI. If the data displays on the rig were similar to the post-event reconstructions, the pump pressure increase should have been picked up by the personnel in the driller's shack monitoring the data and by the Sperry Sun mud logger. The Sperry Sun mud logger indicates that he did not observe the pressure anomaly as he was monitoring the data. It is unknown if the anomaly was noted in the driller's shack. It is believed that the only person in the driller's shack during this time that survived was the BP night well site leader. He left the driller's shack after the sheen test. The fact that the Sperry Sun mud logger indicates that he did not observe the pressure anomaly the night of the incident creates questions as to the presentation format of the data on the rig compared to the post incident expanded Sperry Sun real time data presentation. Even if it is assumed that the Sperry Sun mud logger was still on break when the increase occurred, he should have observed the pressure anomaly when he checked the data upon his return; but did not. Further, the Sperry Sun mud logger's testimony indicates that he should have been back from his break around the time the sheen test occurred, if not before.

Prior to restarting the displacement that had been stopped for the sheen test the Sperry Sun Mud logger indicates that he checked for flow on the rig's closed circuit television (CCTV) system and observed the well was not flowing. The Sperry Sun mud logger further indicates that he could observe the flowline valve used to route the fluid overboard and could see that the valve was open. The personnel in the drill shack would have also had access to the rig's CCTV system and could have viewed the flowline the same as the Sperry Sun mud logger. Further, the CCTV system was available to many other parts of the rig to include the DWH offices of the rig, BP and other third party personnel. The BP night well site leader was in the driller's shack during this time and indicated that everything looked fine. This comment by the BP night well site leader is significant in that it indicates that the data being viewed in the driller's shack did not reveal any anomalies to the personnel in the driller's shack, to include the BP night well site leader; further raising question as to the data being viewed on the rig versus the post incident expanded Sperry Sun real time mud logger data.

At the conclusion of the sheen test the BP night well site leader issued the instruction to start dumping overboard. He then left the driller's shack and returned to his office. The BP night well site leader indicates that he did not go and check the dump line.

The displacement then continued with the spacer being pumped overboard. By this time the well would have been underbalanced for 12 to 14 minutes, with hydrocarbons flowing into the well. Well control indications were masked by the ramping up of the rig pumps and the fact that flow was diverted overboard. Pumping the spacer overboard bypassed the Sperry Sun return flow sensor but did not bypass the rig's Hitec return flow sensor. Initially rig pumps #3 and #4 were brought on line at +/- 21:14 hours. Rig pump #1 was brought on line to boost the riser at +/- 21:16. Immediately after rig pump #1 went on line rig pump #2 was brought on line to pump down the kill/choke line. Approximately a minute later, at

21:17 hours, rig pump #2's pressure spiked to over 7,000 PSI apparently due to a closed valve or plugging of the kill/choke line. The kill/choke line in question may have been the same line utilized during the negative test and if so may have been plugged with spacer. The sudden pressure spike caused rig pump #2's pressure relief valve (PRV) to open. Rig pumps, #2, #3, and #4 were immediately shut down, with rig pump #1 continuing to pump seawater in the riser through the boost line. The pump pressure noted on the post incident Sperry Sun data did not return to as low a value or a lower value than during the sheen test. Again, having a displacement pump schedule may have aided the personnel monitoring the well by allowing them to compare the pressures being seen with what should have been expected. The driller immediately dispatched drilling personnel from both the driller's shack and other areas to the pump room to assist the derrick hand. At some point the on tour toolpusher also left the driller's shack and went to the pump room. This event injected distraction into the displacement operation and well monitoring efforts for the drill crew. However, it should not have affected the monitoring focus of the Sperry Sun Mud logger.

The rig pumps that had been shut down were brought back on line at +/- 21:20 hours. Ramp up time for the rig pumps was +/- 2 minute. The driller continued to manually ramp up the pumps over the next +/- 4 minutes. Also during that time the kill/choke line pressure was noted to be gradually increasing until approximately 21:26 hours when the kill line pressure started to significantly increase to over 800 PSI. This was an indication that the kill/choke line may have been plugged and was now partially opened and was now in communication. The kill line pressure peaked at +/- 830 PSI and then began a gradual decline.

It appears that after noting the anomaly the driller shut down to diagnose the situation. Rig pumps #3 and #4, which were on the displacement string, were shut down by 21:30 hours. Rig pump #1 was shut down by 21:31 hours. Repairs to rig pump #2's PRV were being completed so it was still offline. Once the rig pumps were offline a steady build up of drill pipe pressure was noted. The drill pipe pressure steadily increased for the next +/- 3 minutes building up from +/- 1200 PSI to 1800 PSI. The drill pipe pressure then stabilized and began to slightly decrease over the next 2 minutes, to +/- 1700 PSI.

At 21:36 hours the drill crew opened a valve on the standpipe manifold and bled the drill pipe pressure for +/- 2 minutes. The drill pipe pressure dropped significantly (to +/- 800 PSI) but did not bleed off. The drill pipe was then shut back in, with drill pipe pressure building back to +/- 1400 PSI, which was lower that the pre-bleed drill pipe pressure. The drill pipe pressure stabilized at 1400 PSI for 1 minute and then began to decline steadily. Over the next 3 minutes the drill pipe pressure declined to a low of +/- 300. During this period of time the well was lined up on the trip tank and significant flow from the well was noted. The drill pipe pressure then started to increase again. Well fluid overflowed onto the rig floor and shot up into the derrick.

Post incident investigations have concluded the rig's diverter was closed, with the returning flow going through the diverter system to the rig's mud gas separator (MGS). Having the diverter routinely lined up on the MGS would be consistent with both BP's and Transocean's concern for pollution control. Given the speed at which events were unfolding it is unknown if the drill crew had the opportunity, or the realization, to switch from the MGS to the overboard diverter lines immediately prior to the explosions occurring. Post incident investigations further agree that an initial attempt was made to shut in the Macondo Well around +/- 21:43. Post incident investigative interviews of rig and vessel personnel to include: the BP night well site leader; the DWH senior toolpusher; certain DWH bridge personnel; and certain Damon Bankston personnel indicate being notified by the rig floor of a well control situation and/or the well being shut in within the indicated time frame. The post incident Sperry Sun real time data chart shows a pressure spike occurring at 21:47 hours which is believed to coincide with the rig's BOPs shutting in the well. The Sperry Sun data transmission to shore was lost at 21:49 hours based on the Sperry Sun real time data chart. The post incident investigations have concluded the explosions were occurring around this time and were responsible of the loss of signal.

Post Events

After control of the well was lost and the major explosions occurred abandonment of the rig ensued. At the time of the incident there were 126 people on board the DWH. Of the 126 people on board: 11 were lost (as a result of the explosions - due to their locations) – and 115 were evacuated to the Damon Bankston. The personnel evacuated to the Damon Bankston included a number of injured persons. The rig continued to burn until it sank at +/- 10:00 hours, April 22, 2010. The Macondo Well continued to flow into the Gulf of Mexico until it was plugged and abandoned.

Well Monitoring

The personnel responsible for real time monitoring of the Macondo Well were the DWH on tour driller, the on tour assistant driller assigned to the B chair and the Sperry Sun mud loggers on tour. Other personnel on the rig who had the responsibility and the ability to monitor and understand the condition and status of the Macondo Well were: the BP well site leaders; the DWH toolpushers and OIM; and the on tour MI mud engineers. BP onshore personnel and Sperry Sun onshore personnel connected with the Macondo Well had the ability to monitor the well on a real time bases for support purposes through the use of the BP leased Sperry Sun real time data transmission system.

The drilling personnel on the DWH had a variety of ways to monitor the status of the well. These methods ranged from using sophisticated data acquisition systems to the more mundane techniques of using drill crew members to manually check certain well criteria. The DWH was equipped with a National Oil Well – Varco (NOV) Hitec Cyberbase drilling system (Hitec). The Hitec system was used to operate drilling machinery and monitor a wide variety of drilling sensors dealing with the hoisting system, the drilling fluids systems, the rotating system and the well control system. BP also provided a well monitoring system aboard the DWH for the drilling of its wells. The BP supplied system was provided by Sperry Sun. The Sperry Sun system was integrated with the rig's Hitec system. Sperry Sun also provided the mud loggers whose job was to specifically monitor the drilling activity and well control status for the well being drilled. The various monitoring systems on the rig were available to the BP well site leaders in the BP rig office and also should have been available to other third party personnel working on the well.

As discussed in detail previously in this report, at the time of the incident the drilling of the Macondo Well had been completed. The production casing had been run without any significant problems. It was believed that the production casing had been successfully cemented in place. The Macondo Well had been subjected to a series of tests, both positive and negative, and had been deemed to have passed those tests. The perception on the rig would be that any well related issues were safely behind cemented pipe in a well that had been fully tested. BP had judged the Macondo Well to be in satisfactory condition to move forward with the TA of the well. Rightly or wrongly, it had to appear to the drilling personnel on the DWH they were no longer dealing with a live well but were dealing with a well that was secured. The task at hand was to finish the TA, de-mob the rig and go to the next well.

The next step in finishing the TA after testing the integrity of the well was to complete the displacement operation by pumping the SBM/spacer out of the riser with seawater. Typically a routine operation, that is done on every similar type well once the well has been secured.

Sperry Sun's monitoring responsibilities would have continued throughout the TA of the Macondo Well, even though drilling of the well was completed. During the initial part of the riser displacement the Sperry Sun mud logger would have been monitoring real time parameters including: return flow rate; pressure; pump rate; hook load; and gas returns. During the sheen test the real time parameters for the Sperry Sun mud logger to monitor included: potential return flow; pressure; and hook load; coupled with a visual flow check. Once the conversion was made to pump the spacer overboard the real time parameters the Sperry Sun mud logger would have been monitoring on the Sperry Sun system included: pressure, pump rate, and hook load. The Sperry Sun system's return flow sensor and gas detector(s) would have been bypassed.

The on tour driller and assistant driller would have been monitoring the well during the pumping of the SBM/spacer out of the riser. While it is unknown with certainty which Hitec screen they may have had called up, it is likely the driller would have been monitoring pump pressure, pump strokes and return flow rate among other parameters. It is also likely the Sperry Sun data was configured in a normal manner showing similar parameters. The setting of the CCTV is less certain. As noted earlier no displacement pump schedule was available to assist the driller or Sperry Sun mud logger with the data they were observing. However, during the initial phase of the riser displacement the parameters appeared nominal.

It is unknown why the driller, assistant driller or the Sperry Sun mud logger apparently did not respond to the changes that started occurring around 20:50 hours. However, initially the changes were minor and/or were confounded and/or confused with other operation, such as pumping out the trip tanks, that were occurring. Also the +/- 20:50 hour time frame appears to have possibly include the time that the Sperry Sun mud logger chose to take a break. Both the occurrence of the other operations and the Sperry Sun mud logger taking a break speaks to the perceived routine nature of the operation and the belief that the well was secure and no threat. Further the BP night well site leader and the on tour toolpusher may have been in the driller's shack during a least a part of this time and apparently did not detect or react to any issues either.

By the time the shut down for the sheen test occurred the BP night well site leader and most probably the on tour toolpusher were in the driller's shack. Again it is unknown why no one in the driller's shack or the Sperry Sun mud logger did not respond to the pressure increase that occurred during the shut down for the sheen test. Perhaps initially during the shutdown things appeared nominal. It may be that after an initial check the driller and/or the others became occupied with another task. However, it is unknown why the Sperry Sun mud logger did not pick up on it. The information reviewed indicates that he was back at least prior to the end of the sheen test and indicated that he checked his data and everything look fine. It was also noted that the Sperry Sun mud logger indicated that prior to the restarting of circulation he used the CCTV to make a flow check and believed he confirmed no flow.

It should be noted that the personnel monitoring the well would be seeing the data scrolling off in real time over some data/time scale and did not have the benefit of seeing all of the future data plotted out on a expanded graph that could be analyzed for an extended period of time. In the investigations that followed the incident the Sperry Sun real time mud logger data that had been transmitted from the rig to both BP and Sperry Sun's offices was closely analyzed over an extended period of time by all parties. This data was expanded and used by all of the parties investigating the incident to recreate the pressure, volume and flow profiles that occurred leading up to the incident. However, as noted previously, the reported responses as to the well's condition at the time of the sheen test by both the BP night well site leader and the Sperry Sun mud logger raises questions concerning the comparability of the transmitted real time data and the data being viewed on the rig the night of the incident.

The pressure anomaly noted on the post incident Sperry Sun mud logger chart which occurred during the sheen test should have prompted action from the personnel in the driller's shack and the Sperry Sun mud logger. The displacement should not have resumed until the anomaly was diagnosed and the appropriate action taken. The information provided indicates that some form of check was done to include a perceived flow check. At least both the BP night well site leader and the Sperry Sun mud logger (the only survivors involved) believed they had checked the well from their respective locations and everything looked fine before the riser displacement resumed.

Given what is now known from the incident occurring, a review of the expanded post incident Sperry Sun real time data and a review of the negative test it is understood that the well was live and a well control situation was developing from +/- 20:50 hours forward. Further, it is now known that the well should have been shut in after the sheen test. The Macondo Well was in communication with one or more of the hydrocarbon bearing zones that the rig believed to be isolated by casing and cement. Comparison of the recorded real time data with simulated expected responses clearly show a well control problem unfolding. However, lacking a displacement pump chart and given a belief the well was fully secured the discrepancies were not detected or acted on until later in the displacement.

Once pumping resumed the driller, assistant driller and the Sperry Sun mud logger would all have been monitoring the well. Initially the pump pressure and return flow would have been affected by bringing various rig pumps online and ramping the pumps up. Unfortunately within a minute of getting the pumps lined out on the well an attempt to bring a rig pump on line to pump down the kill/choke line created a major distraction for the drill crew. The PRV blew on one of the rig mud pumps. This would have captured the attention of the toolpusher, driller and assistant driller. However, the Sperry Sun mud logger was still available to monitor the well, at least by the pressure responses.

After dispatching personnel to assist the derrick man with the rig pump issue the driller resumed the displacement. At this point the driller may have been the only person in the driller's shack for some period of time as both the assistant driller and the toolpusher went to the pump room. At some point the toolpusher and the assistant driller returned to the driller's shack. The driller either did not check or did not analyze or misinterpreted the pressure or return flow readings prior to re-engaging the rig pumps. Likewise the Sperry Sun mud logger did not recognize or report any anomalies. The next several minutes were spent ramping up various mud pumps which would have impacted pressure and return flow. During this time the Sperry Sun pressure data indicates that the pressure began to behave in a more expected manner, with the pressure increasing with pump rate increases and generally decreasing otherwise. However, post incident analysis indicates a sustained general pressure increase starting at +/- 21:00 hours.

An anomaly began developing with the kill/choke line pressure around the time the driller got the rig pumps lined out. This anomaly was detected by either the driller or the assistant driller and the displacement was stopped to diagnose the situation. The rig pumps were ramped down, starting at +/- 21:29 hours and were offline +/- 2 minutes later at +/- 21:31 hours. Attempts were then made to diagnose the situation. It was reported in the BP investigation report that the DWH's chief mate went to the driller's shack at +/- 21:33 where he observed the toolpusher and driller discussing a pressure differential. The diagnostic attempts included monitoring the pressure changes with the pumps shut down. These changes included a 3 minute pressure build up followed by a 3 minute period with the pressure initially stabilizing and then slightly decreasing. The diagnostic attempts also included attempting to bleed the pressure off the well for +/- 2 minutes. When the well was shut back in the pressure rebounded to a lower value than before the bleed off and then briefly stabilized at the lower pressure for 1 minute. The diagnostic attempts then included routing the return flow to the trip tank as the well pressure dropped significantly. At some point in the diagnostic process the realization occurred that the well was live but the combined diagnostic and response time was too long for the developing well control situation.

The shut down at +/- 21:30 hours illustrates that the driller and/or assistant driller were actively monitoring the well during the displacement. Further the initial actions taken during this shut down are consistent with an initial belief that the well was secured. The initial steps taken are more consistent with concerns over trapped pressure or a plugging problem and not a well control response for the magnitude of the problem that existed. It is believed that the initial response by the driller and toolpusher was a misinterpretation of either the problem they were facing and/or the magnitude of the problem they were facing. Once the rig pumps were shut down by 21:31, a manual flow check followed by an immediate shut-in of the Macondo Well, should have occurred. This is basic well control that both men were schooled in and had successfully engaged in, in the past. Why it did not happen in this situation will never be known but gives credence to a finding that they misinterpreted and at some point underestimated what they saw. As discussed multiple times in this report factors that led to a misinterpretation of the situation would stem from the drill crew's belief the well was isolated and tested and therefore was fully secured. Clearly, at some point the toolpusher, driller and assistant driller views turned from the belief that the well was fully secure to the realization that a well control event was under way. Depending on when the change in view on the status of the well occurred, coupled with the signs they were seeing, they may have believed the influx was still deep enough that they had some reaction time to fully evaluate the situation. However, that view would have quickly been dispelled as fluid was blown out of the riser under tremendous force revealing that a significant surface problem existed. The well was initially diverted, with the flow going through the MGS. If the diverter system was already lined up to the MGS pre-incident – this would be consistence with pollution concerns. The BOPs were then activated. Given the magnitude of the situation the MGS was rapidly overcome followed quickly by a series of explosions.

Observations and Conclusions

The Macondo Well blowout was the culmination of multiple factors, decisions, oversights and mistakes.

During the final stages of well construction and the temporary abandonment (TA) of the well, inputs from a variety of sources within BP were altering and changing the risk status of the Macondo Well. This appears to have been done without an overarching review process, or person, that was effectively evaluating the overall ramifications of the various changes and modifications. The net effect was to un-necessarily place the Macondo Well at risk during the TA.

BP generated multiple TA procedures between April 12th and April 20th, with the installation of the Lockdown Sleeve (LDS) becoming the focus of the plans in lieu of the well. The April 14th procedure created the lowest risk for the Macondo Well of all the plans. If it had been followed, or a variety of other known options had been incorporated into the TA procedure, the risk level of the well would have been greatly reduced or effectively eliminated.

Furthermore, no one within BP appeared to be assessing the overall aspects of the operation before proceeding with the final displacement of the SBM and the subsequent potential significant underbalancing of the Macondo Well. Attachment A to the report is a list of issues, factors or questions that existed concerning the Macondo Well prior to the final displacement. A key component of the list is the problematic negative test which indicated the lack of confirmed primary flow barriers or zonal isolation which were required to secure the well given the BP TA procedure being followed. Given the uncertainty surrounding the primary flow barriers, BP should not have continued with the SBM displacement from the riser on the Macondo Well. The overall risk status of the well was not fully appreciated by BP nor shared with its contractors who were actively engaged with the drilling and TA of the well.

Actual confirmation by BP of the isolation of the hydrocarbon bearing zones in the well did not occur, even though a negative test was conducted. The hydrostatic pressure in the Macondo Well was significantly reduced due to following the BP TA procedure without having actual confirmation of flow barriers but instead with only having a perceived confirmation of such barriers. The reduction of wellbore hydrostatic pressure led to the underbalancing of the well due to the lack of zonal isolation; ***creating the well control event.*** This series of events placed a very high degree of dependence on the rig site drilling personnel fully understanding the developing situation, adjusting their perception of the well's secured status and responding with limited misinterpretation. The drilling personnel on the rig involved with the well were the BP well site leaders, the Transocean drill crew, the Sperry Sun mud loggers and the MI personnel.

The negative test actually confirmed the lack of well integrity and a lack of adequate primary flow barriers in the Macondo Well. However, due primarily to the effects created by the unorthodox spacer, and a lack of understanding of the results being viewed, the negative test was approved by BP and BP then allowed the displacement to continue. However, this information should have resulted in the recognition that zonal isolation was not confirmed and that the SBM displacement should not proceed.

BP's acceptance of the negative test added a major component to a perception on the rig that the well was safe. Rightly or wrongly the perception on the rig would be that any well related issues were securely behind cemented pipe in a well that had been fully tested.

The information and data available on the blowout of the Macondo Well indicates the following as to the well control event.

1. The high quality hydrocarbon bearing zone(s) exposed during the drilling of the Macondo Well were not isolated by the cemented production casing.

2. The hydrostatic pressure in the Macondo Well was significantly reduced by design as part of the BP TA procedure that was implemented.

3. Due to the lack of zonal isolation and the significant reduction in wellbore hydrostatic pressure - a pressure differential (i.e. underbalance) occurred that resulted in hydrocarbon movement out of the high quality hydrocarbon bearing zone(s) into the well; thus ***creating the well control situation***.

4. The hydrocarbons flowed from the high quality producible rock through the annulus space outside of the production casing, into the production casing and to the surface. The flow path would have involved some and possibly all of the unconfirmed primary flow barriers.

5. Well conditions were misinterpreted and not understood; both during the negative testing and during the SBM displacement to seawater.

6. Observation of the developing well control indications were likely confused and confounded by the lack of certain information, by certain events and by accepted beliefs as to the well's secured condition. Initial developing well control signs were not noted by any of the personnel monitoring the well real time. This should not have happened. It is unknown why the Sperry Sun mud logger never noted any anomalies at all. Once the driller noted an anomaly the actions taken were consistent with trying to diagnose a problem but were not indicative of a realization of an eminent large scale well control event. The Macondo Well should have been immediately flow checked and shut in but was not due to the drill crew attempting to diagnose and understand the situation. At some point in the diagnostic process the realization occurred that the well was not secure and was live, but the combined diagnostic and response time was too long for the developing well control situation.

7. The initial fluid discharge onto the rig was a result of the conditions in the riser above the BOP. The diverter was closed and fluid flowed through the MGS, which appeared to be a typical line up due to pollution concerns. It is unknown if

the drill crew ever switched the routing overboard; or if they had the opportunity, or the realization to consider such, given what was occurring.

8. The BOPs were activated and created a seal. However, conditions within the BOPs resulted in the effective loss of any seal that occurred and/or prevented the sealing of any additional BOP components; allowing the re-establishment of well flow.

Final Comments

These remarks and conclusions are based on information reviewed and my training, knowledge and experience in the oil and gas industry. I am a Registered Professional Petroleum Engineer with two (2) degrees in Petroleum Engineering. Over the course of the past +/- 42 years, I have worked in many aspects of the oil and gas industry, including time spent working on many different offshore drilling projects, to include deepwater projects. I have taught various well control, drilling and production schools, that have included deepwater issues; both domestically and internationally.

As other additional information and data becomes available, please furnish the same to me so that I may adjust my findings accordingly. Supplemental reports will be issued as necessary based on the new or additional information and data that is provided. If you have any questions or if I can be of any further assistance, please let me know. With kind regards, I remain

Sincerely,

Calvin Barnhill

Calvin Barnhill, P.E.

Attachment A

1. The lack of drilling/well control margins (PP/MW – Fg) during the drilling of the well.
2. Loss circulation/ballooning problems in final open hole section of the well.
3. Need for tight control of MW and ECD during many, to include final, well operations.
4. Called total depth (TD) +/- 1290' early due to lack of drilling/well control margins.
5. Major issues whether to run tapered long string or production liner.
6. Major issues on number of centralizers to use.
7. Ran lowest number of centralizers considered.
8. Halliburton final cement simulation showed potential for severe gas flow problems using 7 centralizers; 6 centralizers were actually run.
9. Problems with Float Collar confirmation:
    a. Possible damage or lack of conversion;
    b. Condition of float valves unknown;
    c. Could not rely on float valves to act as barrier to flow for well control purposes:
        i. Question to whether float valves bubble tight if not damaged;
        ii. While float valves are a barrier to return cement flow they are not consider a well control device.
10. After possible FC conversion - circulation pressures lower than predicted:
    a. Possible float valve issues;
    b. Possible damage to casing shoe track;
    c. Possible casing damage.
11. Given tight drilling margins - prior to production casing cement job:
    a. Could not circulate at rate for sufficient AV to clean hole given ECD concerns;
    b. Did not Circ full bottoms up prior to cementing.
12. No heavy pill in rat hole.
13. Minimal - non-standard primary cement job:
    a. Low pump rates;
    b. Small Volume;
    c. Density issues;
    d. N2 stability questions;
    e. Lab test not completed and in field prior to job execution.
14. Did not cement into last casing string due to:
    a. Concerns about ECD;
    b. Concerns about future APB.
15. Minimum cement coverage above top of primary hydrocarbon zones.
16. Base oil spacer in annular cement column.
17. Tapered casing string:
    a. Used wiper/dart system.
18. Little to no lift pressure.

19. Float valves not tested by differential pressure across valves at end of cement job (little to no lift pressure).
20. Setting time for cement not finalized:
    a. No setting time for foamed cement.
21. Top of Cement (TOC) estimated based on volume pumped and caliper log:
    a. No actual measurement or determination of TOC.
22. Condition of cement in annulus and shoe tract not known:
    a. No confirmation that cement had set up or was pressure worthy.
23. Ran combination displacement and cement string.
24. Positive test tested:
    a. Production casing seal assembly;
    b. Production casing down to top cement wiper plug;
    c. Top cement wiper plug;
    d. No definitive positive test of shoe tract or annular cement
    e. Possible false positives.
25. Spacer used for SBM displacement:
    a. Highly unusual/unorthodox;
    b. Combination of two different high viscosity, weighted, loss circulation pills.
26. No spacer test conducted with sea water.
27. Negative test:
    a. Problematic:
        i. Conflicting results at best;
    b. 1st attempt - utilized drill pipe to monitor test - normal for rig:
        i. Question as to location and condition of spacer material relative to wellhead/BOP;
        ii. Annular leak;
        iii. Known spacer material into and below BOP area;
        iv. Failed to get good test.
    c. 2nd attempt- utilized kill line as per MMS APD – not normal for rig:
        i. Drill pipe continued to show pressure:
            1. Stabilized at differential consistent with communication with HC zones;
        ii. Kill/choke line open, with no flow;
            1. Possible spacer plugging issues
            2. Possible hydrostatic pressure issues
        iii. Bladder effect – if postulated:
            1. Questionable explanation at best:
                a. Better explanations existed;
                b. If thought through does not make sense with known data;
        iv. Conflicting results between drill pipe and kill/choke line
        v. Failed to get a conclusive good test without any anomaly.
28. Displacement significantly deeper than normal:
    a. +/- 3300' below the mud line – 8,760' below RKB.

29. Well hydrostatic pressure reduction significantly greater than normal:
    a. High potential underbalance.
30. Higher than normal stress placed on downhole flow barriers.
31. Displacement to be performed prior to testing downhole flow barriers.
32. Displacement to be performed relying on shoe tract acting as barrier:
    a. Shoe tract barrier status unknown/unconfirmed:
        i. Relying on a questionable negative test at best;
        ii. Cement:
            1. Unknown condition and height;
            2. Unconfirmed flow barrier;
        iii. Float valves:
            1. Unknown condition;
            2. Unconfirmed flow barrier.
33. Displacement to be performed relying on annular cement to have accomplished zonal isolation:
    a. Annular cement status unknown/unconfirmed:
        i. Relying on a questionable negative test at best;
        ii. Cement:
            1. Unknown condition and height;
            2. Unconfirmed flow barrier.
34. Displacement to be performed without additional flow barriers:
    a. Installed;
    b. Tested.
35. Hydrocarbon zones:
    a. High pressure;
    b. High flow rate potential;
    c. Large volume of reserves estimated.

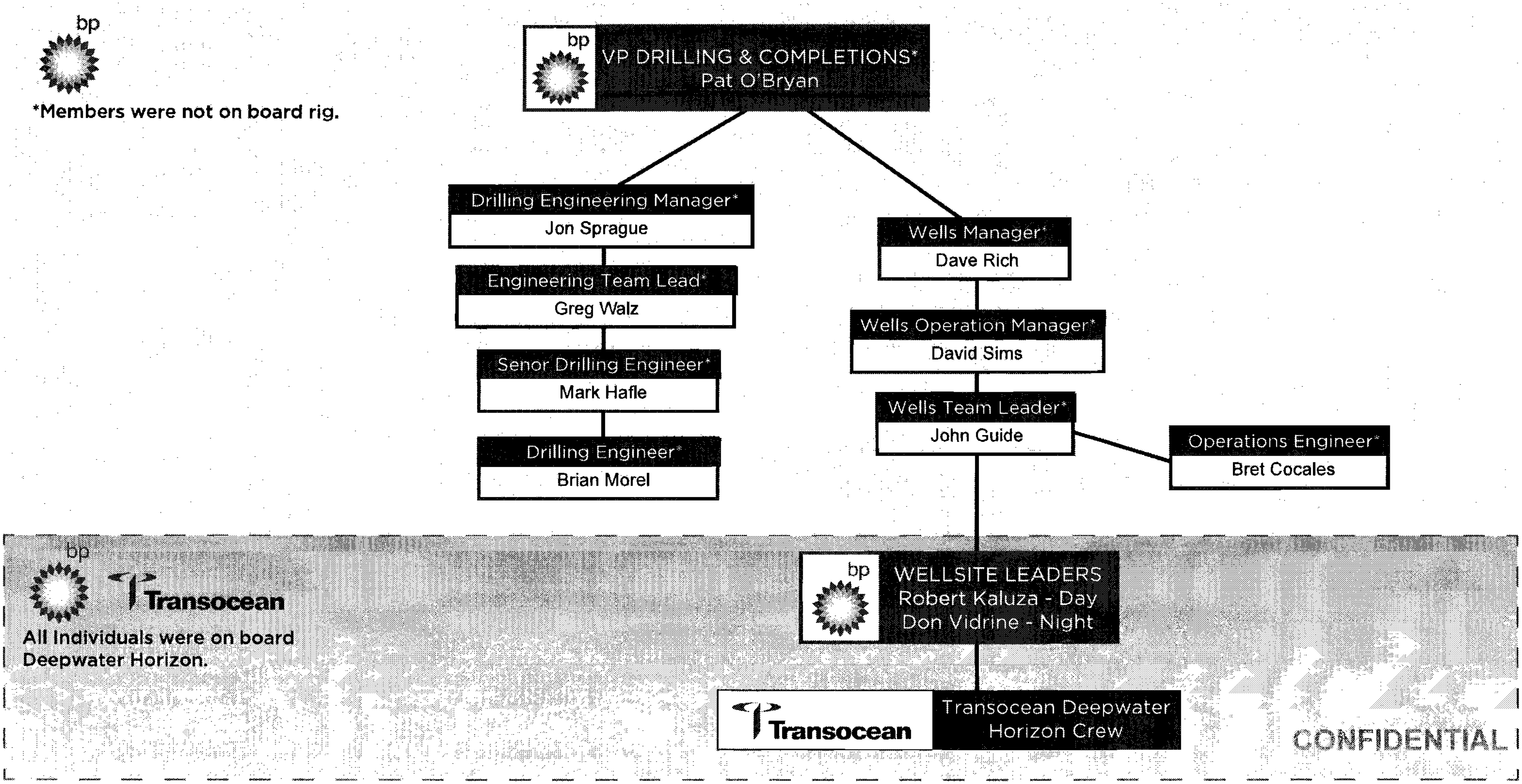
Attachment B

List, with explanation, of Acronyms found in the report; in order of use.

1.	MC 252	Mississippi Canyon Block 252
2.	MMS	Minerals Management Service
3.	BOEMRE	Bureau of Ocean Energy Management
4.	BP	BP Entities involved with well or lease
5.	OG&M	Oil, Gas or Mineral Lease
6.	OCS	Outer Continental Self
7.	Anadarko	Anadarko Petroleum Corporation
8.	NOWI	Non-operating Working Interest
9.	MOEX	MOEX Offshore 2007, LLC
10.	EP	Exploration Plan
11.	TD	Total Depth
12.	MODU	Mobil Offshore Drilling Unit
13.	APD	Application for Permit to Drill
14.	RKB	Rotary Kelly Bushing – (Rig Floor datum)
15.	LP	Low Pressure
16.	HP	High Pressure
17.	PP	Pore Pressure – (same as Formation Pressure)
18.	PPG	Pounds per Gallon
19.	EMW	Equivalent Mud Weight
20.	MW	Mud Weight
21.	BHT	Bottom Hole Temperature
22.	BHP	Bottom Hole Pressure
23.	Fg	Fracture Gradient
24.	HPHT	High Pressure High Temperature
25.	AFE	Authority for Expenditure
26.	TA	Temporarily Abandon
27.	P&A	Plug & Abandon
28.	APB	Annular Pressure Build up
29.	DWOP	Deepwater Operations Plan
30.	DPP	Designed Pore Pressure
31.	Frp	Fracture Pressure
32.	Metocean	Meteorology & Oceanography
33.	BOP	Blowout Preventer
34.	bml	Below the Mud line
35.	DWH	Deepwater Horizon
36.	IADC	International Association of Drilling Contractors
37.	SW	Salt Water
38.	WBM	Water Base Mud
39.	SBM	Synthetic Base Mud
40.	LOT	Leak Off Test
41.	ECD	Equivalent Circulating Density

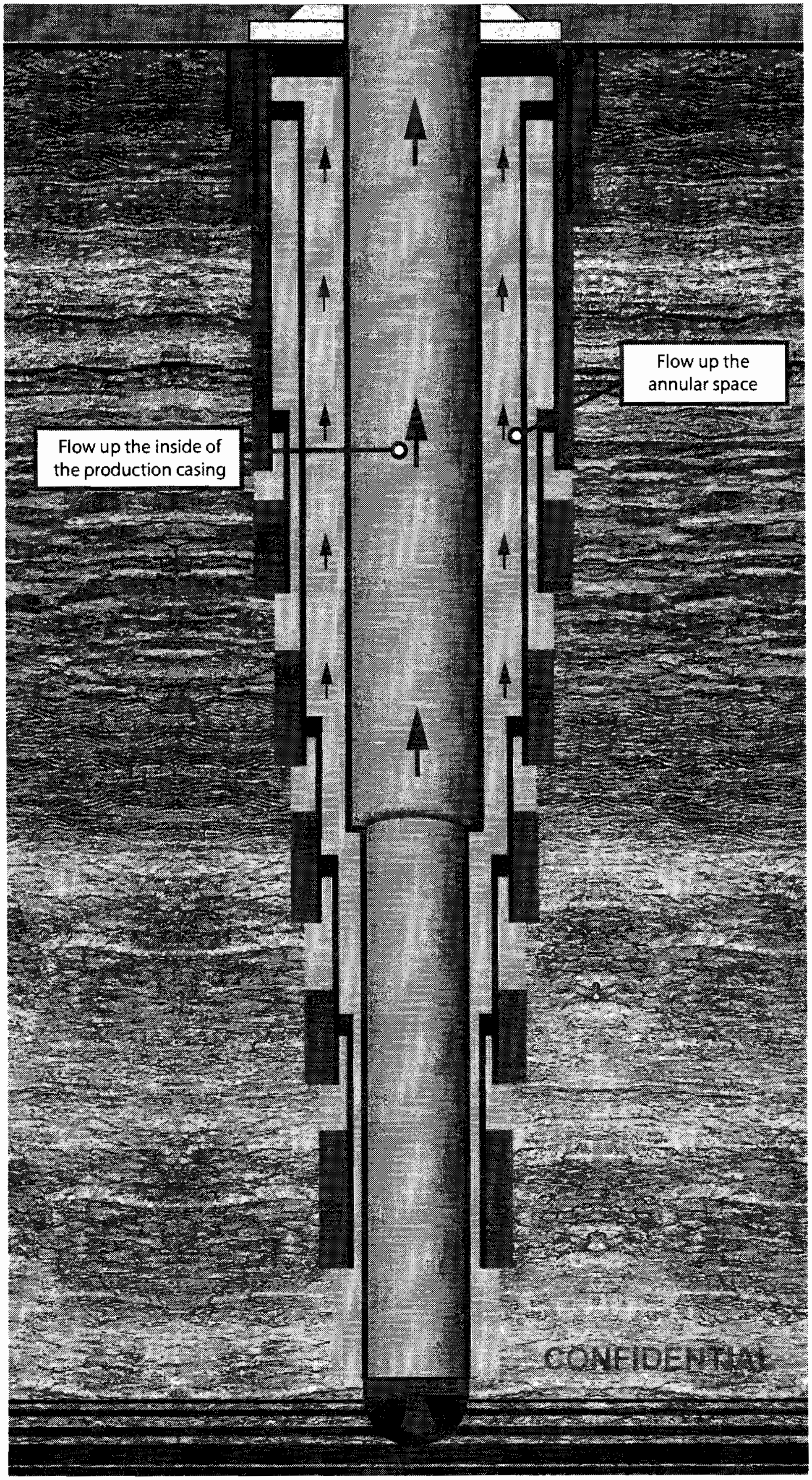
42. EDS	Emergency Disconnect
43. TOC	Top of Cement
44. FIT	Formation Integrity Test
45. BHA	Bottom Hole Assembly
46. KWM	Kill Weight Mud
47. TOL	Top Of Liner
48. LCM	Loss Circulation Material
49. PSI	Pounds per Square Inch
50. GOR	Gas Oil Ratio
51. BPM	Barrels per Minute
52. MI	M-I Swaco
53. CBL	Cement Bond Log
54. APM	Application for Permit to Modify
55. LDS	Lock Down Sleeve
56. OIM	Offshore Installation Manager
57. CCTV	Closed Circuit Television
58. PRV	Pressure Relief Valve
59. MGS	Mud Gas Separator
60. NOV	National Oilwell Varco
61. Hitec	NOV Cyberbase Drilling System

ATTACHMENT C



CONFIDENTIAL

ATTACHMENT D



Cirriculum Vitae

RESUME AND
PERSONAL DATA

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Telephone:
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Fax: (337) 233-9772
Home: (337) 989-8075

PERSONAL DATA

Date of Birth:	September 13, 1950
Height:	5'10"
Weight:	200 Lbs.
Health:	Excellent

PROFESSIONAL EDUCATION

High School:	Graduated 1968. Curriculum - College Preparatory
College:	B.S. in Petroleum Engineering - L.S.U., 1975 M.S. in Petroleum Engineering L.S.U., 1977, with an additional 33 hours of graduate level environmental course work

INDUSTRY EDUCATION

I.A.D.C. Blowout School (L.S.U.)
U.S.L. Blowout School
PETEX (UT) well control School
Advanced Well Control School
Bariod Basic Mud School
Bariod Advanced Mud School
Preston Moore Drilling Practices
Hughes Bit and Hydraulics School
Halliburton Sand Control School
Wilson Fishing Tools and Fishing Practices
B-J Seminar on Gravel Packing
Baker Seminar on Gravel Packing
Tenneco Oil Company Economics School

First Aid School
Pal Mix Workover and Completion Fluids School
Drilling Problems and Practical Solutions
Well Planning School
Drilling Optimization School
Abnormal Pressure Detection School
Hydrogen Sulfide School
Well Planning II
Advanced Casing Design

HONORS

Pi Epsilon Tau - The Petroleum Engineering Honor Society

L.L.&E. Scholarship - Awarded for Petroleum Engineering Studies

R.C. Baker Scholarship - Awarded for Petroleum Engineering Studies

W.A.A.I.M.E. National Scholarship and Grant - Awarded for Petroleum Engineering Studies

FELLOWSHIP

Louisiana Water Resource Research Institute - Awarded for Graduate Work in Petroleum Engineering Studies at L.S.U. - Duties: Research work for Miscible Storage Processes

ORGANIZATIONS AND BOARDS

National Society of Professional Engineers
Louisiana Engineering Society
Society of Petroleum Engineers
American Association of Drilling Engineers
Society of Independent Professional Earth Scientists
National Association of Corrosion Engineers
Acadiana Safety Association
American Society of Safety Engineers
I.A.D.C.
Who's Who Registry of Business Leaders
University Of Texas PETEX Advisory Board
Chairman of PETEX Publications Committee
PETEX IADC Well CAP Representative
Episcopal School of Acadiana

PROFESSIONAL STATUS

Registered Professional Engineer
State of Louisiana
Number 18851

MANUALS/PUBLICATIONS

The Effect of Mixed Zone Length on the Growth of Viscous Fingers during a Miscible Displacement. (Masters thesis L.S.U.)

Blowouts - Wasteful of Time, Money and Natural Resources - Presented at the Congress of Petroleum Engineers - Mexico City, Mexico, March, 1979.

Underground Blowouts in Deep Well Drilling - S.P.E. Paper 7855 - Presented at the Deep Drilling Symposium - Amarillo, Texas, April, 1979.

MMS certified Well Control Manual for the Marlin Drilling/Tenneco Oil Company
MMS certified Well Control School – Basic and Advanced Level.

Drilling Manuals for Marlin Drilling and Tenneco Oil Company.

EMPLOYMENT HISTORY

Current: Northstar Exploration Company – Lafayette Louisiana
Company President:

Exploration/Production Operations
Work with geologists and geophysicists generating and developing prospects in south Louisiana, offshore Louisiana, southeast Texas and southwest Mississippi. My duties involve the management, engineering, geological, land, legal and funding aspects of oil and gas exploration. This includes overseeing operations for Northstar and its associated partners while developing various prospects.

Engineering/Safety/Consulting Operations
Registered Professional Engineer - duties include: Reservoir engineering studies including lease evaluations, reservoir analysis and economic forecast on properties; designing drilling, completion and workover operations; designing surface production process facilities, including pumping units and salt water disposal systems; on-site rig supervision work; office and field supervision of drilling, completion and workover operations; office and field supervision of production operations; teaching various schools to include: Deep water drilling operations and well control courses; Rig Inspection Courses; drilling

and production phase of Petex Offshore Operations School; and an accident investigation course; incident investigation for both litigation and non-litigation purposes; presentation of investigative results to State and Federal agencies; pre-job rig inspection surveys on both offshore and onshore drilling, completion and workover rigs; certification of offshore production platform safety systems to comply with 30 CFR 250 as per API 14C; University of Texas Petroleum Extension Service's (Petex) representative for IADC Well Cap committee; University of Texas' Petroleum Extension Service (Petex) Advisory Board Member and Chair of the Petex Publications Committee.

Analysis / Investigative Work
Worked with the United Stated Department of Justice, Texas Attorney General's office, various domestic and international insurance companies and various law firms in Louisiana, Texas, Mississippi, Oklahoma, Alabama, California, West Virginia, North Dakota, Utah, Kentucky and Alaska. Work performed included well control, drilling, completion, workover and production operations issues plus design issues, equipment failures, reservoir analysis and economic evaluation issues to include lost and/or deferred production claims, safety issues and environmental issues. I have testified in and have been accepted in Texas state and federal courts, Louisiana state courts, Louisiana Western District Federal Court, Middle District Federal Court and Eastern District Federal Court, Mississippi federal courts, California state courts and New Mexico state courts. Investigated incidents both domestically and internationally to include: offshore Egypt, offshore Spain, offshore Malaysia, offshore Italy, the North Sea and the South China Sea.

Blowout Investigation
Investigated over one hundred (100) major blowouts (both surface and underground) for various companies. These wells ranged in depth from a few thousand feet to wells in excess of 21,500 feet. This work included wells located both domestically and internationally. H_2S was a major consideration in some of the deeper wells.

Arbitration
Worked as an arbitrator in resolving disputes between various companies involving drilling operations and/or equipment failures.

Environmental
Supervised drilling, completion and workover procedures to include waste management disposal, pit closures, salt water and hydrocarbon disposal and location clean up and restoration work. Managed

production facilities to include waste management and fluids disposal. Supervised the P&A and site restoration of producing wells and production facilities, to include NORM contaminated sites.

1979 – 1985: C & B Exploration Co., Inc., (CBX) – Lafayette Louisiana
Company President, managed engineering, exploration and consulting operations.

Exploration/Production Operations
CBX maintained an exploration staff and operated its producing properties. I was involved in all phases of these operations. I worked with and managed geologist in determining prospects: raised funds for the prospects; acquired leases; worked with lawyers on title opinions; drilled and completed wells; put wells on line; worked with pipeline companies making distributions; managed production payments; managed field personnel and oversaw drilling and production operations.

Engineering Operations
Designed, drilled and completed wells (performed both in office and onsite operations); designed, installed and maintained surface equipment, production facilities, pipelines, pumping units, and salt water disposal systems; performed lease evaluations, reservoir analysis and economic forecast on properties.

Consultant/Safety/Operations
Designed wells and oversaw drilling operations from the office for several rigs simultaneously for major independents; worked on site as a company man for major independents; performed lease evaluation, reservoir analysis and economic forecast for individuals and small independent oil companies; wrote and taught U.S.G.S. Certified well control schools and wrote a drilling practices manual for a major international drilling contractor; taught U.S.G.S. certified well control schools for the University of Texas; performed expert witness work for various Law Firms in Louisiana, Mississippi and Texas.

Environmental
Supervised onshore and offshore drilling completion and workover operations to include waste management and disposal, pit closures, salt water and hydrocarbon disposal and location clean up and restoration.

1978 - 1979: Independent Self Employed Consultant
Worked for Prentice and Records Enterprises, Inc., of Lafayette,

Louisiana as a Certified Well Control Instructor in the following schools: The U.S.L. Certified Well Control School; The U.S.L. Certified Well Control Refresher School; and the International Well Control School. (The certification is by the MMS). Instructor for the Prentice and Records Drilling Practices and Practical Solutions Course. This course is a two week course which covers well control, drilling fluids, drilling optimization and well planning.

Worked for Louis Records & Associates of Lafayette Louisiana doing well planning and well history analysis.

1977 - 1978: Tenneco Oil Company - Lafayette, Louisiana
Worked as a Drilling Engineer in the Offshore Division. The duties performed consisted of the following: Well planning work for normal and abnormal pressured wells; well completion planning; rig site supervision of drilling, workover, and completion operations; bringing out new rigs; budget work and computer work. Duties included all safety and environmental aspects of drilling, completion and workover operations offshore.

1976 - 1977: I.A.D.C. Blowout School - L.S.U. Baton Rouge Louisiana
Instructed classroom sessions, well site sessions and simulator sessions in all phases of Well Control work.

Masters Degree Program - L.S.U. Baton rouge Louisiana
Work to obtain a Masters Degree in Petroleum Engineering consisted of the following: constructing a sandstone reservoir and determining its flow characteristics; performing fluid flow test through the model to determine the effects of fluid behavior in a reservoir using an unfavorable mobility ratio during a miscible displacement; analyzing all results to determine the most efficient method for conducting a miscible type secondary recovery project. Upon completion of the work, a thesis was prepared. This work was done in conjunction with the Civil Engineering Department.

Penrod Drilling Company - False River Field
Worked as derrickman and relief driller while attending L.S.U.

1974 - 1976: Louisiana Water Resource Research Institute - L.S.U.
Worked while attending L.S.U. for a B.S. in Petroleum Engineering. The work consisted of working with the larger reservoir flow models in the graduate laboratories. The studies consisted of the following: water storage and recovery in underground reservoirs; effects of bed dip on storage and recovery of fluid from reservoirs; effects of fluid characteristics in a homogeneous system; favorable and unfavorable

mobility ratio studies; effects of boundary wells and image wells for fluid control and boundary effects. These studies were conducted through the Petroleum Engineering Department and the Civil Engineering Department.

Penrod Drilling Company, H&P Company, and Noble Drilling Company - False River
Worked as roughneck and derrickman while attending L.S.U. for B.S. in Petroleum Engineering.

Amoco Oil Company - New Orleans, Louisiana
Worked as a Reservoir Engineer in the division office in the special Reservoir Engineering section. Duties were to evaluate offshore reservoirs for the potential of conducting secondary recovery processes. This included determining which reservoirs were secondary recovery candidates and determining what processes would be used in which reservoir.

Getty Oil Company - Houston Texas Research Laboratory
Work consisted of conducting polymer based secondary recovery floods to determine the feasibility of actual polymer floods working in given West Texas fields.

1971 - 1973: Penrod Drilling Company; The Mayronne Company
Work consisted of all types of rig work from roughnecking to drilling. Worked on various new rigs. Worked on both offshore and onshore locations. Worked offshore Louisiana and Texas. Worked onshore in North Louisiana, South Alabama and North East Florida. Worked in normal and abnormal pressured environments and H2S environments.

Summers / Holidays
1968 - 1970: Chevron Oil Company - Gulf of Mexico
Worked as a contract production hand on offshore production platforms and bay facilities.

NORTHSTAR EXPLORATION COMPANY
A Registered Professional Engineering Firm
P.O. BOX 5-A
LAFAYETTE, LA 70505
(337) 233-0830 – Fax (337) 233-9772

FEE SCHEDULE

SENIOR ENGINEER / SENIOR PROJECT MANAGER	$400/HOUR
SENIOR GEOLOGIST / SENIOR PROJECT MANAGER	$400/HOUR
STAFF ENGINEER / PROJECT MANGER	$300/HOUR
STAFF GEOLOGIST / PROJECT MANGER	$300/HOUR
ENGINEER	$225/HOUR
GEOLOGIST	$225/HOUR
SENIOR TECHNICIAN	$175/HOUR
TECHNICIAN	$125/HOUR
OFFICE STAFF	$100/HOUR
MILAGE	$1.00/MILE
ALL OUT OF POCKET EXPENSES	AS INCURRED

ALL RATES AND EXPENSES SUBJECT TO REVISION BY NORTHSTAR EXPLORATION COMPANY

Invoice payment due upon receipt. Payments not received within 90 days shall bear interest at the rate of 12% per annum from date of issuance until payment in full. Should it be necessary for Northstar to retain third party services to collect amounts invoiced hereunder client agrees to be responsible for all such costs, including attorney's fees and other costs of litigation.

Materials Considered

- Daily Work Reports
    - Marianas IADC Reports
        - TRN-INV-00734940-TRN-INV-00735223
    - DWH IADC Reports
        - **Exh. 4278:** 1/31/10-4/18/10
        - **Exh. 1455:** 4/19/10
        - **Exh. 820:** 4/20/10
    - DWH Morning Reports
        - TRN-INV-00128817-TRN-INV-00771652
    - M-I Swaco Daily Drilling Fluids Reports
        - **Exh. 1026:** *Drilling Fluids Program*
            - BP-HZN-2179MDL00016162 - BP-HZN-2179MDL00016226
        - **Exh. 1035:** *Daily And Total Drilling Fluid Discharges, Losses And Recovering Volumes* (spreadsheet)
            - BP-HZN-2179MDL0000452101
        - MI-Swaco Synthetic-Based Mud Reports
            - MI-Swaco Volume Accounting
            - MI-Swaco Wellsite Chemical Inventory
    - BP Daily Drilling Reports
        - BP-HZN-2179MDL02423083, (1/31/10)
        - BP-HZN-2179MDL01958188, (2/01/10)
        - BP-HZN-2179MDL01263022, (2/02/10)
        - BP-HZN-2179MDL01263012, (2/03/10)
        - BP-HZN-2179MDL01285576, (2/04/10)
        - BP-HZN-2179MDL01262990, (2/07/10)
        - BP-HZN-2179MDL01262985, (2/08/10)
        - BP-HZN-2179MDL01969331, (2/09/10)
        - BP-HZN-2179MDL02703407, (2/10/10)
        - BP-HZN-2179MDL01899895, (2/11/10)

- BP-HZN-2179MDL02459652, (2/12/10)
- BP-HZN-2179MDL01938374, (2/13/10)
- BP-HZN-2179MDL02669642, (2/14/10)
- BP-HZN-2179MDL02539254, (2/15/10)
- BP-HZN-2179MDL02467657, (2/16/10)
- BP-HZN-2179MDL02042863, (2/17/10)
- BP-HZN-2179MDL02527614, (2/18/10)
- BP-HZN-2179MDL03062970, (2/19/10)
- BP-HZN-2179MDL00006317, (2/20/10)
- BP-HZN-2179MDL00006262, (2/21/10)
- BP-HZN-2179MDL02116145, (2/22/10)
- BP-HZN-2179MDL03775185, (2/23/10)
- BP-HZN-2179MDL03772688, (2/24/10)
- BP-HZN-2179MDL03772792, (2/25/10)
- BP-HZN-2179MDL03772385, (2/26/10)
- BP-HZN-2179MDL03774634, (2/27/10)
- BP-HZN-2179MDL00001908, (2/28/10)
- BP-HZN-2179MDL00007499, (3/01/10)
- BP-HZN-2179MDL03773555, (3/02/10)
- BP-HZN-2179MDL02912103, (3/03/10)
- BP-HZN-2179MDL03774080, (3/04/10)
- BP-HZN-2179MDL03772623, (3/05/10)
- BP-HZN-2179MDL03773306, (3/06/10)
- BP-HZN-2179MDL03774758, (3/07/10)
- BP-HZN-2179MDL02636019, (3/08/10)
- BP-HZN-2179MDL00032054, (3/09/10)
- BP-HZN-2179MDL03774558, (3/10/10)
- BP-HZN-2179MDL03772704, (3/11/10)
- BP-HZN-2179MDL03773330, (3/12/10)
- BP-HZN-2179MDL00005599, (3/13/10)
- BP-HZN-2179MDL03773181, (3/14/10)
- BP-HZN-2179MDL03774773, (3/15/10)

- BP-HZN-2179MDL03775291, (3/16/10)
- BP-HZN-2179MDL03775142, (3/17/10)
- BP-HZN-2179MDL00014477, (3/18/10)
- BP-HZN-2179MDL00002849, (3/19/10)
- BP-HZN-2179MDL00003212, (3/20/10)
- BP-HZN-2179MDL00024721, (3/21/10)
- BP-HZN-2179MDL00004855, (3/22/10)
- BP-HZN-2179MDL01285686, (3/23/10)
- BP-HZN-2179MDL00016515, (3/24/10)
- BP-HZN-2179MDL00003061, (3/25/10)
- BP-HZN-2179MDL00001999, (3/26/10)
- BP-HZN-2179MDL00002703, (3/27/10)
- BP-HZN-2179MDL00004326, (3/28/10)
- BP-HZN-2179MDL00005388, (3/29/10)
- BP-HZN-2179MDL00002855, (3/30/10)
- BP-HZN-2179MDL00020996, (3/31/10)
- BP-HZN-2179MDL00021053, (4/01/10)
- BP-HZN-2179MDL00010446, (4/02/10)
- BP-HZN-2179MDL00011493, (4/03/10)
- BP-HZN-2179MDL00003449, (4/04/10)
- BP-HZN-2179MDL00007479, (4/05/10)
- BP-HZN-2179MDL00004095, (4/06/10)
- BP-HZN-2179MDL03772344, (4/07/10)
- BP-HZN-2179MDL02055260, (4/08/10)
- BP-HZN-2179MDL01287507, (4/09/10)
- BP-HZN-2179MDL01287513, (4/10/10)
- BP-HZN-2179MDL00001788, (4/11/10)
- BP-HZN-2179MDL00015911, (4/12/10)
- BP-HZN-2179MDL03490019, (4/13/10)
- BP-HZN-2179MDL00002674, (4/14/10)
- BP-HZN-2179MDL00003614, (4/15/10)
- BP-HZN-2179MDL00003541, (4/16/10)

  - BP-HZN-2179MDL00005433, (4/17/10)
  - BP-HZN-2179MDL03426590, (4/18/10)
  - BP-HZN-2179MDL00004012, (4/19/10)
- DWH Geological Report April 2010 (or Exh. 4776: 4/1-4/15)
  - BP-HZN-2179MDL00058326 - BP-HZN-2179MDL00058329, (4/05/10)
  - BP-HZN-2179MDL00058345 - BP-HZN-2179MDL00058347, (4/14/10)
  - BP-HZN-2179MDL00058450 - BP-HZN-2179MDL00058452, (4/13/10)
  - BP-HZN-2179MDL00058467 – BP-HZN-2179MDL00058469, (4/06/10)
  - BP-HZN-2179MDL00058504 – BP-HZN-2179MDL00058507, (4/03/10)
  - BP-HZN-2179MDL00058539 - BP-HZN-2179MDL00058541, (4/09/10)
  - BP-HZN-2179MDL00058634 - BP-HZN-2179MDL00058637, (4/04/10)
  - BP-HZN-2179MDL00058665 - BP-HZN-2179MDL00058667, (4/11/10)
  - BP-HZN-2179MDL00058733 - BP-HZN-2179MDL00058735, (4/08/10)
  - BP-HZN-2179MDL00058918 - BP-HZN-2179MDL00058920, (4/07/10)
  - BP-HZN-2179MDL00058954 - BP-HZN-2179MDL00058956, (4/12/10)
  - BP-HZN-2179MDL00059185 - BP-HZN-2179MDL00059187, (4/15/10)
  - BP-HZN-2179MDL00059370 - BP-HZN-2179MDL00059372, (4/02/10)
  - BP-HZN-2179MDL00059483 - BP-HZN-2179MDL00059485, (4/01/10)
  - BP-HZN-2179MDL00059852 - BP-HZN-2179MDL00059854, (4/10/10)
- DWH PPFG Report
  - **Exh. 1344:** 4/03/10
    - BP-HZN-2179MDL00058858
  - BP-HZN-2179MDL00058851, (4/04/10)
  - **Exh. 1967:** 4/05/10
    - BP-HZN-2179MDL00059632

- USCG/BOMRE JIT Hearings
  - Testimony – Attended/Transcripts
  - Exhibits
- OSC Hearings
  - Viewed Expert Testimony
  - Viewed Chief Counsel's Presentation

- Supporting Documents for Waxman/Stupak Letter
    - BP
    - Halliburton
    - Schlumberger
    - MMS
    - Transocean
- Depositions[1]
    - Albers, Shane
    - Albertin, Martin
    - Bellows, Jonathan
    - Bodek, Robert
    - Breazeale, Martin
    - Breland, Craig
    - Brown, Doug
    - Burgess, Micah
    - Canducci, Gerald
    - Chaisson, Nathan
    - Cocales, Brett
    - Cunningham, Eric
    - Ezell, Randy
    - Faul, Ronald
    - Gagliano, Jessie
    - Gisclair, John
    - Gray, Kelly
    - Guide, John
    - Hay, Mark
    - Holloway, Caleb
    - Johnson, Paul
    - Keith, Joseph
    - Lambert, Lee

[1] Additional transcripts are being reviewed as received.

- LeBleu, John
- LeNormand, William
- Lee, Philip Earl
- Little, Ian
- Millsap, Kris
- Morgan, Patrick
- Paine, Kate
- Pleasant, Chris
- Price, Vincent
- Quitzau, Robert
- Rainey, David
- Rich, David
- Sabins, Fred
- Sepulvado, Murray
- Sepulvado, Ronnie
- Sims, David
- Skidmore, Ross
- Skripnikova, Galina
- Tabler, Vincent
- Vargo, Richard
- Walz, Greg
- Winslow, Daun
- Winters, Warrent

- Witness Statements
  - USCG
    - Joseph Anderson
    - Daniel Barron, III
    - Steve Berton
    - Craig Breland
    - Douglas Brown
    - Micah Burgess
    - Mike Burrell

- Stanley Carden
- Christopher Choy
- Charles Cochran
- Kennedy Cola
- Thomas Cole
- Jason Cooley
- Bill Coon
- Truitt Crawford
- Stephen Davis
- Eric Estrada, Sr.
- John B. Evans, III
- Miles R. Ezell
- Andra Fleytas
- Bill Francis
- Michael Glendenning
- Anthony Graham
- Troy J. Hadaway
- Jimmy Wayne Harrell
- David Mark Hay
- Caleb Holloway
- James Ingram
- Jerry Issac
- Matthew Seth Jacobs
- William Harold Jernigan
- Dustin Johnson
- William Johnson
- Cole Jones
- Jonathan Kersey
- Stenson Roark
- Darin Rupinski
- Micah Sandell
- Allen J. Seraile

- Terry Sellers
- Stephen Stone
- William Wilton Stoner
- Carl Taylor
- William Terrell
- Buddy Trahan
- Nickolus Watson
- Michael Williams
- Daun Winslow
- David William Young
- Shane Albers
- Robert Kaluza
- Lee Lambert
- Pat O'Bryan
- David Sims
- Ross Skidmore
- Brad Tippetts
- Donald Vidrine
- Oleander Benton
- Matthew Davis
- Tyrone Benton
- Darren Costello
- Frank Ireland
- Brandon Bouillion
- Lance John
- Charles Credeur
- Shane Faulk
- Benjamin LaCroix
- Heath Lambert
- Carl Lavergne
- Coby Richard
- Kevin Senegal

- Christopher Haire
- Vincent Tabler
- Joseph Keith
- Cathleenia Willis
- Leo Lindner
- Gregory Meche
- John Quebodeaux
- Robert Splawn
- James Wilson
- Kenneth Bounds
- Paul C. Erickson
- Jonathan Escala
- Anthony Geruosso
- Elton Johnson
- Alwin Landry
- Gary LeBlanc
- John Logan
- Norman Logsdon
- Louis Longloss
- Jeffery Malcolm
- Billy Marsh
- Germone Vaughn

- BP
  - **Exh. 0007:** *Brian Morel Interview Notes,* (4/27/10)
    - BP-HZN-MBI00021304 - BP-HZN-MBI00021347
  - **Exh. 004:** *Interview with Don Vidrine*
    - BP-HZN-MBI00139573 - BP-HZN-MBI00139576
    - BP-HZN-CEC020346 - BP-HZN-CEC020350
  - **Exh. 0195:** *Handwritten Notes - John Guide Interview,* (5/12/10)
    - BP-HZN-BLY00104243 - BP-HZN-BLY00104239
  - **Exh. 0220:** *Transcription of John LeBleu Interview Notes,* (4/29/10)

- **Exh. 0221:** *Transcription of Brad Tippets Interview Notes,* (4/27/10)
- **Exh. 0222:** *Transcription of Shane Albers Interview Notes,* (4/28/10)
- **Exh. 0224:** *BP Incident Investigation Team - Notes of Interview with Erick Cunningham,* (7/16/10)
    - BP-HZN-BLY00061269- BP-HZN-BLY00061272
- **Exh. 0284:** *BP Incident Investigation Team - Notes of Interview with Greg Walz,* (7/29/10)
    - BP-HZN-BLY00111497 - BP-HZN-BLY00111507
- **Exh. 0296:** *Interview with Mark Hafle,* (7/08/10)
    - BP-HZN-BLY00103032- BP-HZN-BLY00103038
- **Exh. 0358:** *Jim McKay Handwritten Notes - Brian Morel Interview,* (5/10/10)
    - BP-HZN-BLY00061629 - BP-HZN-BLY00061643
- **Exh. 0506:** *Interview with David Sims,* (6/24/10)
    - BP-HZN-BLY00125436 - BP-HZN-BLY00125446
- **Exh. 0526-A:** *Interview with Ronnie Sepulvado,* (8/31/10)
    - BP-HZN-BLY00061692 - BP-HZN-BLY00061695
- **Exh. 0824:** *Shane Albers Interview Notes,* (4/28/10)
- **Exh. 0907:** *Interview with John Sprague*, (7/07//10)
    - BP-HZN-BLY00125462 - BP-HZN-BLY00125462
- **Exh. 2033:** *Telephone Interview of: Jesse Gagliano,* (6/11/10)
- **Exh. 2158:** *Interview of Lee Lambert,* (4/29/10) (with Handwritten Notes)
    - BP-HZN-BLY00130264 - BP-HZN-BLY00130268
- **Exh. 3188:** *Bob Kaluza Interview*, (4/28/10)
    - BP-HZN-BLY00061514 – 61517
- **Exh. 3203:** *Cathleenia Willis Interview Notes*
- **Exh. 3572:** *Interview of Robert Kaluza*(4/23/10)
    - TRN-HCJ-00121085 – 21096
- **Exh. 3576:** *Notes from interview of Robert Kaluza* (4/25/10)
    - BP-HZN-BLY00045995 – 45999
- **Exh. 4447:** *Interview with Mark Hafle,* (7/08/10)

        - BP-HZN-BLY00144208 - BP-HZN-BLY00144214
      - **<u>Exh. 4506:</u>** *Brian Morel Interview,* (5/10/10)
        - BP-HZN-CEC020266 - BP-HZN-CEC020275
      - **<u>Exh. 7085:</u>** *Interview with John Guide*, (7/01/10)
- Reports
  - BP DWH Accident Investigation Report and Appendices
    - **<u>Exh. 1:</u>** *Bly Report*
    - **<u>Exh. 2</u>:** *Appendices*
  - Project Spacer
    - BP-HZN-BLY00038424
  - Transocean Investigation Report
    - **<u>Exhs. 3808</u>; <u>4304</u>**
  - OSC Report; to include the Chief Counsel's Report
    - **<u>Exh. 0986:</u>** *Chief Counsel's Report 2011: National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling*
  - OSC Report of Cement Testing
    - **<u>Exh. 0806:</u>** *National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling Cement Testing Results*
      - HAL_0502206 - HAL_05022062
  - DNV BOP Report
    - **<u>Exh. 1164:</u>** *DNV - Final Report for United States Department Of The Interior,* Volume I, (3/20/2011)
    - **<u>Exh. 1165:</u>** *DNV - Final Report for United States Department Of The Interior*, Volume II, (3/20/2011)
  - USCG/BOMRE JIT Report
  - NEA Report
  - Boots & Coots Negative Pressure Test Analysis
    - **<u>Exh. 0102:</u>** *Boots/Coots - Incident Investigation of Well MC252#1 - Review of 9-7/8" x 7" Casing Negative Test*
      - BP-HZN-BLY00094096 - BP-HZN-BLY00094143
- BP Documents

- Macondo APDs
  - **Exh. 4751:** *Application for Permit to Drill a New Well,* (5/13/09)
    - BP-HZN-CEC008683-BP-HZN-CEC008711
  - *Application for Revised New Well,* (1/12/10)
    - BP-HZN-2179MDL00062905-BP-HZN-2179MDL00062912
  - *Application for Revised New Well,* (1/25/10)
    - BP-HZN-2179MDL00001449-BP-HZN-2179MDL00001456
- Macondo APMs
  - *Application for Permit to Modify,* (3/10/10)
    - BP-HZN-2179MDL00001333-BP-HZN2179MDL00001336
  - *Application for Permit to Modify*, (4/16/10)
    - BP-HZN-2179MDL00526317-BP-HZN-2179MDL00526317
- Macondo Applications for Bypass
  - **Exh. 1339:** *Application for Bypass,* (3/15/10)
  - **Exh. 4006:** *Application for Revised Bypass*
    - BP-HZN-BLY00235651-BP-HZN-BLY00235660
  - **Exh. 4030:** *Application for Revised Bypass,* (4/14/10)
    - BP-HZN-SNR00000441-BP-HZN-SNR00000450
  - **Exh. 4044:** *Application for Revised Bypass,* (4/15/10)
    - BP-HZN-OGR000748-BP-HZN-OGR000756
  - **Exh. 404:** *Application for Revised Bypass*, (4/15/10)
    - BP-HZN-OGR000735-BP-HZN-OGR000747
  - **Exh. 4752:** *Application for Revised Bypass,* (3/25/10)
    - BP-HZN-2179MDL00001748- BP-HZN-2179MDL00001763
- Exploration Plan
  - Initial Exploration Plan: Macondo 252 (2/09)
    - BP-HZN-FIN00000501-542
- Well Plan
  - September 2009 Drilling Program
    - TRN-MDL-01534954-01535172
  - January 2010 Drilling Program

- BP-HZN-2179MDL01313651-01313766

- DWOP
  - **<u>Exh. 1376:</u>** *Drilling and Well Operations Practice-E&P Defined Operating Practice*
    - BP-HZN-BLY00163802 –BP-HZN-BLY00408043
  - **<u>Exh. 0215:</u>** GP 10-10 - *Well Control: Group Practice - BP Group Engineering Technical Practices*
    - BP-HZN-2179MDL00408005 - BP-HZN-2179MDL00408026
  - **<u>Exh. 1513:</u>** GP 10-15 - *Pore Pressure Prediction: Group Practice - BP Group Engineering Technical Practices*
    - BP-HZN-2179MDL01016932 - BP-HZN-2179MDL01016950
  - **<u>Exh. 1514:</u>** GP 10-16 - *Pore Pressure Detection During Well Operations: Group Practice - BP Group Engineering Technical Practices*
    - BP-HZN-2179MDL00408027 - BP-HZN-2179MDL00408043
  - **<u>Exh. 0094:</u>** GP 10-35 - *Well Operations: Group Practice - BP Group Engineering Technical Practices*
    - BP-HZN-2179MDL00373833 - BP-HZN-2179MDL00373852
  - **<u>Exh. 1721:</u>** GP 10-40 - *Drilling Rig Audits and Rig Acceptance: Group Practice - BP Group Engineering Technical Practices*
    - BP-HZN-2179MDL00643468 - BP-HZN-2179MDL00643481
    - BP-HZN-2179MDL00408099 - BP-HZN-2179MDL00408123
  - **<u>Exh. 95:</u>** GP 10-45 – *Working with Pressure*
    - BP-HZN-2179MDL00353757 – BP-HZN-2179MDL00353773
  - **<u>Exh. 0184:</u>** GP 10-60 - *Zonal Isolations Requirements during Drilling Operations and Well Abandonment and Suspension: Group Practice - BP Group Engineering Technical Practices*
    - BP-HZ-2179MDL00269659 - BP-HZ-2179MDL00269673
  - **<u>Exh. 1575:</u>** GP 10-75 - *Simultaneous Operations: Group Practice - BP Group Engineering Technical Practices*
    - BP-HZN-2179MDL00408286 - BP-HZN-2179MDL00408296

- **<u>Exh. 0765:</u>** *Group Defined Operating Practice - Assessment, Prioritization and Management of Risk.*
    - BP-HZN-MBI00195280 - BP-HZN-MBI00195301
- **<u>Exh. 2200</u>**: *BP - NAX - DW Gulf of Mexico Deepwater Well Control Guidelines*
    - BP-HZN-2179MDL01340115 -
    - BP-HZN-2179MDL01340134

o Production Well Decision Tree

- **<u>Exh. 908 MC 252 #1:</u>** *Macondo Production casing & TA – Forward Planning Decision Tree,* (4/14/10)
    - BP-HZN-2179MDL00358546

o Power Point Presentations

- *Long String v. Liner*
- *Interim Incident Investigation* Power Point presented to the Presidential Commission (5/24/10)

o Well control Group Practices

- **<u>Exh. 596:</u>** *Well Control Handbook*
    - BP-HZN-2179MDL00330768-BP-HZN-2179MDL00331163
- **<u>Exh. 2386:</u>** *BP GoM Deepwater SPU-Well Control Response Guide January 2010*
    - BP-HZN-2179MDL00368642-BP-HZN-2179MDL00368768
- **<u>Exh. 2389:</u>** *Well Control Manual Volume 1 Procedures and Guidelines December 2000 Issue 3*
    - BP-HZN-2179MDL00335948-BP-HZN-2179MDL00336409
- **<u>Exh. 2390:</u>** *Well Control Manual Volume 2 Fundamentals of Well Control December 2000 Issue 3*
    - BP-HZN-2179MDL00336410-BP-HZN-2179MDL00336757
- **<u>Exh. 2391:</u>** *Well Control Manual Volume 3 HPHT Guidelines December 2000 Issue 3*
    - BP-HZN-2179MDL00336758-BP-HZN-2179MDL00336889

o Technical Memorandum, (7/26/10)

- **<u>Exh. 3375:</u>** *Gulf of Mexico SPU Technical Memorandum Post-Well Subsurface Description of Macondo* Well (MS 252)
  - BP-HZN-BLY00140873 to 910
- **<u>Exh. 3532</u>:** *Previous Draft of Technical Memorandum*
  - BP-HZN-BLY00193967 to BPHZN-BLY00193996
  - BP-HZN-2179MDL00722072-BP-HZN-2179MDL00722072

o Temporary Abandonment (TA)

- TA Procedure Rev. 0 from Morel, et al. (1/27/10)
  - BP-HZN-CEC009003
- **<u>Exh. 1968</u>**: TA Procedure Rev. 1 from B. Morel (4/12/10)
  - BP-HZN-MBI00126181
  - BP-HZN-2179MDL00272297-00272317
- **<u>Exh. 1692:</u>** BP PowerPoint TD Forward Plan Review: Production Casing and TA options (4/13/10)
  - BP-HZN-CEC022025-38
  - BP-HZN-2179MDL00357044
- **<u>Exh. 1699</u>**: BP TD Forward Plan Review: Production Casing and TA Options
  - BP-HZN-CEC022150
- **<u>Exh. 1810:</u>** TA Procedure Rev. 2 from B. Morel (4/15/10)
  - BP-HZN-2179MDL00249967-987
- **<u>Exh. 1376:</u>** BP LIT and LDS Running Procedure (4/13/10)
  - BP-HZN-2179MDL00249339-356

o AFEs

- **<u>Exh. 1919:</u>** BP Authorization for Expenditure (AFE) to Anadarko (8/28/09)
  - BP-HZN-MBI00192546
  - APC-SH52A-000001082-084
- **<u>Exh. 2879:</u>** BP First Supplemental AFE to Anadarko (1/27/10)
  - BP-HZN-MBI00192552
  - DWHMX00108110

- **<u>Exh. 2846:</u>** BP Second Supplemental AFE to Anadarko (3/22/10)
  - BP-HZN-MBI00192558
  - BP-HZN-2179MDL02319416-02319419
- BP Third Supplemental AFE to Anadarko (4/14/10)
  - BP-HZN-MBI00192560

- Management of Change
  - **<u>Exh. 4538</u>**: BP MOC re: long-string verified by Hafle and reviewed by Walz, Guide, Reiter, Sims and Frazelle (4/15/10)
    - BP-HZN-CEC021656
    - BP-HZN-2179MDL03072952-54
  - **<u>Exh. 1210</u>:** 4/7/10 MOC re: Change of Total Depth for Macondo
    - BP-HZN-MBI00143255-57
    - BP-HZN-2179MDL00876814-816
- Correspondence
  - **<u>Exh. 1143</u>**: P. Vinson email to D. Sims re: Macondo (3/10/10)
    - BP-HZN-2179MDL00852514
  - **<u>Exh. 1364</u>**: Sims email to Guide re: Call (3/13/10)
    - BP-HZN-MBI00222540-541; BP-HZN-MBI00222521-22
  - **<u>Exh. 1133</u>**: Cocales email to Morel and Hafle re: FIT or LOT for Bypass (3/14/10)
    - BP-HZN-2179MDL00286880
    - BP-HZN-MBI00110676
  - **<u>Exh. 1132</u>**: Morel email to Sepulvados, Vidrine, Lee, Hafle, Guide, Cocales, Walz, Sims, etc. re: Macondo updated PPFG and Mud Schedule (3/18/10)
    - BP-HZN-MBI00112983
  - **<u>Exh. 1234:</u>** Kate Paine (QuaDril Energy) email to Robert Bodek and Gord Bennet re: PP Lessons Learned and Plan Forward (3/18/10)
    - BP-HZN-2179MDL00011120-22
  - Sims email to Peijs and Hafle re: Macondo production liner cost (3/24/10)
    - BP-HZN-MBI00059411-12

- Email from Morel to A. Crane (BP) re: long-string cost savings (3/25/10)
  - BP-HZN-CEC021880
- Morel reply email to Gagliano re: cementing Liner Proposal (3/29/10)
  - (No Bates Numbers)
- Cocales reply email to Morel's 2:08pm email re: cementing Liner Proposal, cc: Gagliano, Guide, Hafle (3/29/10)
  - (No Bates Numbers)
- Email from Morel to S. Dobbs (BP Engineer) re: long-string choice (3/30/10)
  - BP-HZN-CEC021948
- **Exh. 1025:** Albertin reply email to (Ex. 133) Morel, Bodek, Halfe, Cocales, Galina, Graham, et al. re: Macondo 9-78 LOT FIT (4/2/10)
  - BP-HZN-2179MDL00026120-21
  - BP-HZN-MBI00117976-00118015
- **Exh. 3720:** G. Bennett email to Albertin, Bellow, Bodek, Cocales, Hafle, Guide, Morel, Sims, et al. re: Macondo Update 5am (4/5/10)
  - BP-HZNMBI00118120
  - BP-HZN-2179MDL100009604
- **Exh. 1095:** M. Albertin email to Morel, Bodek, Bellow, et al re: Macondo Sand Pressures (4/5/10)
  - BP-HZN-2179MDL00004909
- **Exh. 3722:** R. Sant email to B. Morel and M. Albertin and Bodek, Bellow, et al. re: Macondo Sand Pressures (4/5/10)
  - BP-HZN-2179MDL00007611-14
  - BP-HZN-2179MDL00025983
- Hafle email to Krauss (BakerHughes) and Morel re: GT plug standby (4/19/10)
  - BP-HZN-2179MDL01313256-57
- Chaisson email to Gagliano re: cementing job and Post Job Report (4/20/10)
  - (No Bates Numbers)

- Morel email to Guide, Hafle, Cocales, Walz, and Sims re: Cement Job (4/20/10)
  - BP-HZN-MBI00195376
- Morel email to Vidrine, Kaluza, Lambert, Lee, Guide, Hafle, Cocales, Walz re: Ops Note for coming days and negative pressure test (4/20/10)
  - BP-HZN-MBI00021237
- **Exh. 3741**: P. Johnston (BP) email to Bodek, Bellow, Albertin, Fleece re: Hydrocarbon bearing zones (4/21/10)
  - BP-HZN-2179MDL00426906 and attachment
- **Exh. 3565:** R. Sepulvado email to J. Guide explaining his normal DWH negative test procedure (4/25/10)
  - BP-HZN-BLY00072942
- **Exh. 3190 or Exh. 1966**: P. O'Bryan email to M. Zanghi re: Kaluza's Bladder Effect description (4/27/10)
  - BP-HZN-2179MDL00321874-75
- **Exh. 2010**: Morel email to K. Corser re: J. Gagliano and cement testing (5/24/10)
  - BP-HZN-BLY00125127-133
- **Exh. 679:** J. Guide email to P. Johnson (TO) and B. Cocales re: Nile (4/15/10)
  - BP-HZN-2179MDL00312153; BP-HZN-2179MDL00312131
- Morel email to Walz, Cocales, Hafle, Guide re: Negative test and mud displacement (4/15/10)
  - BP-HZN-MBI00127490
- **Exh. 545:** Morel email to Sepulvado, Vidrine, Kaluza, Lambert, Guide, Hafle, Cocales, Walz and Lindner (4/16/10)
  - BP-HZN-CEC022821
- **Exh. 1390:** Morel email to Hafle, Walz, Cocales, Guide re: MMS negative test requirements (4/17/10)
  - BP-HZN-MBI 00128655
- **Exh. 1816:** email from Morel to Guide re: the negative test (4/18/10)

- BP-HZN-BLY00070087

- **<u>Exh. 1704:</u>** Gagliano email to Cocales, Vidrine, Rig, Guide, Morel, Hafle, Walz, etc. re: Updated Info for Prod Casing Job (4/18/10)
  - HAL0011208
- **<u>Exh. 4507</u>**: Morel email to J. Morel (wife) re: Kaluza (4/14/10)
  - BP-HZN-CEC021827
  - BP-HZN-2179MDL00687582-00687484
- **<u>Exh 1962:</u>** Hafle email to Doris Reiter re: Macondo risk to Pompano's current FM/AFE (4/9/10)
  - BP-HZN-BLY00110007
- **<u>Exh 529:</u>** M. Sepulvado email to Brian Morel, cc R. Sepulvado and J. Guide re: rig procedures (4/12/10)
  - BP-HZN-MBI00125959
- I. Little and J. Guide emails re: TO DWH Performance Feedback (3/24/10)
  - BP-HZN-MBI00114524-26
- J. Guide email to P. Johnson and others re: DWH 1 yr recordable free (4/2/10)
  - TRN-USCG_MMS-00044376
- **<u>Exh. 2242</u>**: M. Kelley email to Morel (and forwarded to Walz) and Hafle re: Macondo (4/12/10)
  - BP-HZN-2179MDL00045111
- Sims email to Kemper Howe, Frazelle, Rich, Sprague, O'Bryan, Guide, Walz, et al. re: Nile and Kaskida 180 day clock (4/9/10)
  - BP-HZN-2179MDL00014441-47
- **<u>Exh. 4223</u>**: S. Sauer reply email to J. Gates, et al (re: Ex. 168) re: Nile and Kaskida 180 day clock (4/12/10)
  - BP-HZN-MBI00126666-7
- **<u>Exh. 2242:</u>** M. Kelley email to Morel (and forwarded to Walz) and Hafle re: Macondo (4/12/10)
  - BP-HZN-2179MDL00045111

- **Exh. 533:** R. Sepulvado responds to B. Morel's prior email re: TA Rev. 1 Procedure (4/13/10)
    - BP-HZN-2179MDL00041229
- **Exh. 3538:** G. Skripnikova email reply to Bodek, Guide, Morel, Walz, Cocales, Hafle, et al. re: Top Hydrocarbon Bearing Zone? (4/13/10)
    - BP-HZN-MBI00126430 and
    - BP-HZN-2179MDL00249266
- **Exh. 1241**: Email from R. Bodek to M. Beirne, B. Ritchie and Hafle re: the Macondo TD and lost returns (4/13/10)
    - BP-HZN-MBI00126338
- **Exh. 537:** Email from Morel to J. Wilson and R. Sepulvado re: Forward Ops and negative pressure test and cementing job (4/14/10)
    - BP-HZN-MBI00126982
- Email reply from Miller to Morel and Hafle re: Macondo APB (4/14/10)
    - BP-HZN-CEC021857
- **Exh. 908:** BP Forward Planning Decision Tree (4/14/10)
    - BP-HZN-MBI00010575
- **Exh. 126:** Email reply from Hafle to Morel and Miller re: Macondo APB (4/14/10)
    - BP-HZN-CEC021857
    - CON 67
- **Exh. 1361:** Guide email to Sims re: Meeting (4/15/10)
    - BP-HZN-MBI00254858; BP-HZN-MBI00253828
- **Exh. 2580**: Morel reply email (to the 3:35pm email) to Gagliano, Hafle, Morel, Cocales, Walz re: OptiCem Report w/ 10 centralizers (4/15/10)
    - HAL_0010648-650
- **Exh. 831:** Morel email to B. Tippets, Hafle, et al re: Surface Plug depths and LDS (11/12/09)
    - BP-HZN-MBI00076083
- **Exh. 1036:** M. Doyle email to Cocales, Guide, Hafle, Morel, Walz, et al re: VH (4/20/10)

- BP-HZN-2179MDL00250921
- BP-HZN-MBI00129100

▪ J. Lebleu email to Morel, Hafle, Walz, et al re: Background LCM (4/30/10)
  - BP-HZN-2179MDL00452491-92)

▪ **Exh. 1020:** 8.5 x 9.875" Open Hole Mud Loss Event Summary by Lebleu to Hafle, Morel, Cocales, Guide, Walz and Sims (5/13/10)
  - BP-HZN-2179MDL00857580-83

▪ **Exh. 1390:** Morel email to Hafle re: problems with Gagliano and cement testing (4/17/10)
  - BP-HZN-MBI 00128656

▪ **Exh. 287:** Morel email to Guide re: Gagliano's 4/17/10 email re: lab tests (4/17/10)
  - BP-HZN-2179MDL00315248

▪ Reply from Walz to More, Hafle, Cocales, and Guide re: problems w/ Gagliano and cement testing (4/18/10)
  - BP-HZN-BLY00111079-80

▪ **Exh. 2584**: Morel email to B. Clawson (Weatherford) re: Circulation (4/19/10)
  - BP-HZN-MBI-00129061
  - BP-HZN-MBI00129068-9

▪ **Exh. 543:** Walz Email to Guide re: Additional Centralizers (4/16/10)
  - BP-HZN-CEC022433

▪ **Exh. 546:** R. Sepulvado email to B. Kaluza and Lee Lambert re: Relief Notes (4/16/10)
  - BP-HZN-MBI00171869

▪ **Exh. 2042:** Morel email to Hafle re: the April 15 OptiCem sent by Gagliano (4/16/10)
  - BP-HZN-2179MDL00011184

▪ **Exh. 1809**: Morel email to Cocales, Walz, Hafle re: Cement Procedure (4/16/10)

        - BP-HZN-SNR00019272
        - BP-HZN-2179MDL00250582
    - Morel email to S Dobbs (BP completions), Walz, et al re: LS (4/16/10)
        - BP-HZN-BLY00069231-34
    - **Exh. 733:** Gagliano email to Morel, cc: Halfe, Cocales, Walz re: Cement Procedure (4/16/10)
        - HAL_0010815
    - Walz reply email to Morel (from 18:19), Cocales, Hafle re: Cement Procedure (4/16/10)
        - BP-HZN-SNR00019270-72
    - **Exh 795:** Guide email to D. Sims complaining about the engineering/operations confusion, Morel's concerns, and cement spacer issues (4/17/10)
        - BP-HZN-BLY00097031-32
    - **Exh. 1804:** Galiano reply email to Morel, Hafle, Cocales, Walz re: Revised OptiCem Report with additional centralizers (4/17/10)
        - BP-HZN-SNR00019040
    - **Exh. 795:** D. Sims reply email to J. Guide's email complaining about the engineering/operations confusion, Morel's concerns, and cement spacer issues (4/17/10)
        - BP-HZN-BLY00097032)
    - **Exh 987:** Gagliano email to Morel, Hafle, Cocales, Walz re: Lab Tests (4/17/10)
        - BP-HZN-2179MDL00315248
- Transocean Documents
    - Marianas Specification Sheets
        - Provided on Transocean's Website
    - DWH Specifications Sheets
        - Provided on Transocean's Website
    - Rig Schematics
        - Obtained from Various Investigation Reports

- Power Point Presentations
  - Temporary Abandonment Power Point presented to Presidential Commission
  - Power Points provided to Committee on Energy and Commerce
- Videos
  - Obtained from Various Investigation Reports
- Well Control Handbook
  - **Exh. 1454:** *Transocean-Well Control Handbook*
    - TRN-MDL-00286767 –TRN-MDL-00287162
  - **Exh. 667:** *Well Control Handbook* (Revision Date: March 31, 2009)
    - TRN-MDL-00286767- TRN-MDL-00287075
- Well Control Events & Statistics
  - *Transocean Annual Report (2010): Well Control Events and Statistics 2005-2010*
    - TRN-MDL-01858257-01858302
- Sedco 711
  - *Daily Operation Report* (12/22/09)
    - TRN-INV-00029124-00029126
  - *Email from Barry Braniff to Bill Sannan, et al. re:* Well Control Integrity of Mechanical Barriers (4/5/10)
    - TRN-MDL-00273902-00273903
  - *Well Operations Group Advisor: Monitoring Well Control Integrity of Mechanical Barriers* (4/5/10)
    - TRN-OIG-00258941
  - *Letter From Fred Algie*: Inspector of Health and Safety (4/24/10)
    - TRN-MDL-00175126
  - *Shell UK E&P Incident Investigation Report: Bardolino Well Control Incident* (1/3/10)
    - TRN-MDL-01308084-01308122
  - *Operations Advisory: Loss of Well Control During Upper Completion* (4/14/10)

- TRN-INV-00076788-00076791
- *Learning Pack: Learning From Incidents: Transocean Actions*
  - TRN-MDL-00607578-00607582
- *Transocean Toolpusher Conference Call PowerPoint*
  - TRN-INV-00029040-00029048
- *Email from Barry Braniff to himself re: potential advisory from 711 event*
  - TRN-MDL-01292748-01292749
- *Email from Steve Robinson to Tony Brock, et al re: Transocean Safety Alert*
  - BP-HZN-BLY00168225-00168226

- DWH Emergency Response Manual
  - **Exh. 597:** *DEEPWATER HORIZON Emergency Response Manual -* Volume 1 of 2
    - BP-HZN-MBI00131953 –BP-HZN-MBI00132325
  - **Exh. 4645:** *DEEPWATER HORIZON Emergency Response Manual -* Volume 2 of 2
    - TRN-MDL-02070932 - 1196
- Feasibility Study For Quick Event Detection
  - TRN-MDL-01433128

- Transocean Training
  - *IADC Well Control Accreditation Program* (8/24/07)
    - Program Number W726
  - *Certificate of Accreditation: Transocean Houston Training Center*
  - *Approved Instructor Certificates for Transocean Houston Training Center*
  - *Training Certificates*:
    - Jimmy Harrell
    - Miles "Randy" Ezell
    - Jason Anderson
    - Dewey Revette
    - Donald Clark
    - Stephen Curtis

- *DEEPWATER HORIZON* well history spreadsheet
- Halliburton Documents
    - Macondo Well Production Casing Design (Opticem) Reports
        - **<u>Exh. 186:</u>** *Macondo #1-9 7/8"X 7" Production Casing Design Report- For: Brian Morel,* (4/18/10)
            - BP-HZN-BLY00107700 –BP-HZN-BLY00107732
        - **<u>Exh. 2040:</u>** *Macondo #1-9 7/8"X 7" Production Casing Design Report- For: Brian Morel,* (4/14/10)
            - HAL_0010336 to HAL_0010354
        - **<u>Exh. 1388:</u>** *Macondo #1 - 9 7/8"X 7" Production Casing Design Report - For: Brian Morel,* (4/10/10)
            - HAL_0010699 - HAL_0010720
        - *Macondo #1 – 9 7/8"X7" Production Casing Design Report – For: Brian Morel*, (4/15/10)
            - HAL_0010592-0010611
    - Macondo Cement Proposals
        - *9 7/8"X 7" Production Casing Proposal* (4/17/10)
            - BP-HZN-CEC011444-011455
        - *9 7/8"X 7" Production Casing Proposal* (4/18/10)
            - BP-HZN-CEC008381-008392
    - Vincent Tabler's Tally Book
        - **<u>Exh. 3036:</u>** *Tabler Tally Book-From Tabler Interview*, (5/4/10)
            - BP-HZN-BLY00061768 to BPHZN-BLY00061784
    - Nathan Chaisson's Tally book
        - **<u>Exh. 718:</u>** *Chaisson Tally Book*
            - HAL-CG0000515-HAL-CG0000527
    - Post Job Report
        - **<u>Exh. 742:</u>** *Halliburton Post Job Report-9 ⅞" x 7" Foamed Production Casing Design Post Job Report* (4/20/10)
            - HAL_0028665-0028678
    - Drilling Fluids Proposal (9/28/09)

        - Prepared by Blake Redd
            - BP-HZN-MBI00010586-00010693
    - Power Point Presentations
        - *Halliburton Power Point to the Committee on Energy and Commerce Staff Briefing* (6/3/10)
            - Prepared by Tommy Roth, Vice President Cementing Product Service Line
- M-I Swaco Documents
    - Macondo Well Displacement Procedure
        - **<u>Exh. 3196:</u>** *Email from Leo Lindner to Robert Kaluza*, (4/20/10); *Subject: Macondo Displacement Procedure*
            - BP-HZN-2179MDL00015194 - 15195
- Sperry Sun documents
    - Surface Time Log (4/20/10)
        - **<u>Exh. 1500</u>**
            - BP-HZN-2179MDL0044144
            - BP-HZN-2179MDL00417995-6
            - BP-HZN-2179MDL00418722-3
- Weatherford Documents
    - Weatherford Float Collar Schematic
- Schlumberger Documents
    - Timeline
        - SLBEC000001-000005
    - Cost to complete CBL
        - **<u>Exh. 1690:</u>** *Schlumberger Estimate*
            - BP-HZN-2179MDL00179308 SLB-EC-000909
    - **<u>Exh. 3540</u>**: *Triple Combo Log*
    - **<u>Exh. 3541</u>**: *Laminated Sand Analysis*

Prior Testimony - Calvin Barnhill

DATE	CASE STYLE	CASE NUMBER	COURT	TRIAL / DEPOSITION
Jan-07	MAYNE & MERTZ / BJS			ARBITRATION
Feb-07	WILLIAM TEBOW / BRADEX	DOCKET # 2005-7728 "B"	12TH JDC AVOYELLES PH.	TRIAL
Mar-07	IG PETROLEUM / PETROLEUM ENGINEERS	NO. 04-0179	USDC EASTERN DISTRICT	DEPOSITION
Mar-07	MATURIN / BP PRODUCTION	CV-04-2455 "L"	USDC W.D. OF LA - LAFAYETTE	DEPOSITION
May-07	BAKER HUGHES / FLASH	6:04 CV02295	USDC W. D. OF LA - LAFAYETTE	DEPOSITION
Jul-07	CHARLES MAY / GLOBAL SANTE FE	CA #03-CV-3539 "M"	USDC E.D. OF LA	TRIAL
Jul-07	ROBERT REED / D&D DRILLING	HO-2006-71	CIRCUIT COURT OF LAMAR COUNTY MISSISSIPPI	DEPOSITION
Aug-07	STEVE DAIGLE / NABORS	DOCKET 05 CV 0336	USDC WESTERN DIST OF LA	DEPOSITION
Aug-07	MORGAN / TODCO	CA #05-1351	USDC E. D. OF LA	TRIAL
Dec-07	GOODRICH	CAUSE # 2006-48924	295TH DIST. COURT OF HARRIS COUNTY TEXAS	TRIAL
Dec-07	PITCO - FEDERAL		WESTERN DISTRICT - USDC LAKE CHARLES	DEPOSITION

DATE	CASE STYLE	CASE NUMBER	COURT	TRIAL / DEPOSITION
Feb-08	TPIC	CA #2004-307	CIRCUIT COURT - LAMAR CTY., MS.	DEPOSITION
Feb-08	GARY BEAUBOUEF / EL PASO	CA # 3:06-CV-00806	USDC / SOUTHERN DISTRICT OF TX - HOUSTON DIVISION	DEPOSITION
Mar-08	PIONEER	#2006-12780	280TH JDC HARRIS CTY, TX	DEPOSITION
Mar-08	TRANSOCEAN / MAERSK	CASE #H-07-02392	USDC SOUTHERN DISTRICT OF TEXAS / HOUSTON DIVISION	DEPOSITION
May-08	TENSAS POPADOC / CHEVRON	DOCKET #40769	7TH JDC; CONCORDIA PH	DEPOSITION
Oct-08	WEYERHAEUSER / PETRO-HUNT	CA# CV04-2177A	USDC WDLA ALEXANDRIA, LA	DEPOSITION
Oct-08	GUICHARD / LEXINGTON	CA #6:08-CV-00238	USDC W. DISTRICT OF LA	DEPOSITION
Nov-08	LARRY TAYLOR / DIAMOND	CASE #06-5318	USDC E. DIST. OF LA	TRIAL

Prior Testimony - Calvin Barnhill

DATE	CASE STYLE	CASE NUMBER	COURT	TRIAL / DEPOSITION
Jan-09	AW OIL / WESTWOOD OIL TOOLS	CAUSE #C-232-06-F	HIDALGO CTY, TX	DEPOSITION
May-09	MARLIN / TETRA	#52-603	25TH JDC "B"	DEPOSITION
			PLAQUEMINE PH	
Jul-09	FOREST /DAVID LAW / DCS	CAUSE 07-CV-1211	JDC GALVESTON, TX	DEPOSITION
Aug-09	LUIS ROJAS / EOG	#08-0120	71ST JDC OF HARRISON CTY, TX	DEPOSITION
Oct-09	MARITECH	07-11-11622-CV	JDC MONTGOMERY CTY, TX	DEPOSITION
Oct-09	M J FARMS	24055 DIV "A"	7TH JDC CATAHOULA PH	DEPOSITION
Dec-09	BHPB	CAUSE # C-1721-05		ARBITRATION

DATE	CASE STYLE	CASE NUMBER	COURT	TRIAL / DEPOSITION
Feb-10	ANGLO SUISSE OFFSHORE PARTNERS /			
	UNDERWRITERS LLOYDS OF LONDON	CAUSE #2007-48157	189 JD - DIST. CT. OF HARRIS TX	DEPOSITION
Feb-10	PELTEX OIL / CERTAIN UNDERWRITERS AT			
	LLOYDS OF LONDON	C563415	17TH JDC PH. OF E. BATON ROUGI	DEPOSITION
Apr-10	MICHAEL FRUGE / ULTERRA DRILLING	CA 6:07-CV-00789	USDC W D OF LA	DEPOSITION
May-10	ORVILLE FARMER / OIL TOOL & SUPPLY	CA #06-KV-00765	CIRCUIT CT. OF ADAMS CTY MS	DEPOSITION
May-10	TRANSCONTINENTAL GAS PIPELINE /			
	TRANSOCEAN DEEPWATER DRLG	CA #06-6316	USDC EASTERN DIST. OF LA	DEPOSITION
Jul-10	SANDRA BERNARD / BP AMERICA	CD #10-16704	38TH JDC CAMERON PH.	DEPOSITION
Aug-10	NOBLE ENERGY / PITCO / DORE'	CA #2:09-CV-00748	USDC W. DIST. OF LA	DEPOSITION
Aug-10	STATE OF LA / THE LA LAND & EXPLORATIOI	SUIT #82,162, DIV D	15TH JDC OF VERM., LA	DEPOSITION
Aug-10	CCS MIDSTREAM SERVICES / HAMILTON			
	METALS	CAUSE #2009-46502	151 JDC OF HARRIS CITY TX	DEPOSITION