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Macondo Relief Well Drilling Program

MC-252 #3

Section 12: 8 ½-in Intercept Interval

Revision 1

	PRINT Name above	Sign Above	Date	Time
RPIC APPROVAL :	JEFF BRAUN	J.M. Braun	9/11/2010	0935
BOEM APPROVAL :	Michael Prendergast	Michael Prendergast	9/11/10	15:00
CGIC (USCG) APPROVAL :	N/A			
BOEM (Houston Review) :	David J. Trocquet	David J. Trocquet	9/11/10	1215 hrs
USCG (Houston Review) :	N/A			

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September 9, 2010

		Signature	Date
Prepared by:	Harry Prewett Drilling Engineer		9/10/10
	Louise Jacobsen Plutt Drilling Engineer		9/10/10
	Barb Lasley Drilling Engineer		9/10/10
Reviewed by:	Doug Chester Drilling Excellence Team Lead		9/10/10
	Jonathan D. Sprague Drilling Engineering Manager		9/10/10
	Robert Sanders Wells Team Leader		9/10/10
	David Sims E&A Drilling Operations Manager		9/10/10
	Mark Mazzella Segment Technical Authority - Well Control		9-10-2010
Authorized by:	Pat O'Bryan VP DC&I		9/10/10

Table of Contents

12 8 ½-IN OPEN HOLE INTERVAL 3
12.1 Introduction 3
12.2 Objectives 3
12.3 Concerns 5
12.4 Drilling Operations Procedure 6
12.4.1 8½-in Intercept Interval 6
Attachment 1a: Approved MOC to Release HOS Strongline 7
Attachment 1b: Approved MOC to Release HOS Centerline and BJ Blue Dolphin 18
Attachment 2: Drill and Range BHA Schematic 19
Attachment 3: Downhole Devices PBL Sub Spec Sheet 20
Attachment 4: MOP for 5⅞-in Drill Pipe at 8½-in Interval to Total Depth 21
Attachment 5: 6¾-in Sperry Drill Lobe 7/8, 3-Stage Motor Specs 22
Attachment 6a: $5^{7}/_{8}$-in Drill Pipe Spec Sheet 23
Attachment 6b: 3½-in Drill Pipe Spec Sheet 24
Attachment 7: BOEM Requirements for BOP Testing 25
Attachment 8: Original Pore Pressure/Frac Pressure Estimates 26
Attachment 9: Macondo Sand Identification Log Section 27
Attachment 10: K&B Pump-in Sub 28
Attachment 11: Well Kill, Control and Cementing Team Organization Chart 29
Attachment 12: Intercept, Kill & Cement Operations RACIE Chart 30
Attachment 13: Rig Choke and Kill Manifold Layout 31
Attachment 14: Macondo Relief Wellbore Sketch 32
Attachment 15: MC252#1 Wellbore Sketch 33
..... 34

Amendment Record

Name	Date	Amendment
Barbara Lasley	9/11/10	1) Throughout: Change BOEMER to BOEM 2) Pg 7 step 3: Add comment to ensure DDII has the BSR closed and are monitoring well. 3) Pg 8 step 7: Delete "Drill down to the MC252#1, 9-7/8" shoe at 17,914-ft MD (shallowest), and on to 17,927-ft MD (17,170-ft MD)". 4) Pg 8 step 8: Add comment that depth of RR16 should be below the MC252#1 shoe. 5) Pg 16 step 17: Change volumes for squeeze from 5 bbls / 5 bbls to 8 bbls / 7 bbls for a total of 15 bbls squeezed (rather than 10 bbl); which will lower the TOC to –17,210-ft. 6) Insert Attachment #15: wellbore sketch illustrating the MC252#1 with potential configuration given DDII tag depth. 7) Updated Attachment #12: RACIE chart 8) Pg 7 step 1: Add comment "BOP test must be started before midnight on Tuesday Sept 14th as per BOEM Regulations. Do not start any operations that may preclude testing BOPs on the required date.

12 8 ½-in Open Hole Interval

12.1 Introduction

Based on changing circumstances, this *Macondo Relief Well Drilling Program, MC-252#3, Section 12: 8½-in Intercept Interval, Revision 1*, will supersede the previously approved *Section 12: 8½-In Intercept Interval, Revision 0 (2200-T2-DO-PR-4689)*, and *Operational File Notes 27 (2200-T2-DO-PR-4700) and Operational File Notes 28 (2200-T2-DO-4730)*.

The primary changes/modifications to *Revision 0*, and *Operational File Notes 27 and 28* are:

1. Boats
2. Lockdown Sleeve or Perforated/Squeezed annulus
3. Development Driller II BOP Stack
4. Cement Squeeze
5. Elimination of 7-in Casing Milling Requirement

The current Base Case assumption is that the Development Driller II subsea BOP has been installed on the MC252#1 wellhead and tested, and either; 1) the 9⅞-in production casing in the MC252#1 well has been perforated and squeezed with cement, or 2) a Dril-Quip lockdown sleeve has been installed in the wellhead, thereby eliminating the potential for the MC252#1 well to flow to the mudline. The HOS Strongline, HOS Centerline, and BJ Blue Dolphin are released (refer to **Attachment 1a and 1b**, which are the approved BIZFLOW MOCs).

The objective for the Development Driller III is to drill and range from the current total depth of 17,909-ft MD (17,152-ft TVD) to the projected intersection depth in the Macondo MC252#1 of 17,969-ft MD (17,212-ft TVD). The plan is to come in contact with the MC252#1, 7-in casing. If loss circulation occurs, indicating communication with the Macondo reservoir, or failed burst disks, a cement squeeze job will be conducted for isolation (previously referenced as "Scenario 2, Intercept Cementing Procedure", now reference as "Cement Squeeze Procedure"). If no losses occur, a balanced cement plug will be placed in the MC252#3 wellbore from the point of intersection and a low pressure bradenhead squeeze carried out. This is referenced herein as "Balanced Plug and Squeeze Procedure".

A detailed Plug and Abandonment (P&A) procedure will be provided under separate cover.

Interval Notes	
Bits	8½-in Smith XR+ (1-1-7) Mill Tooth Bit w/ center jet 1-18/32 and 3 -20/32 jets, 1.169 in^2 TFA (150 psi prs drop @ 400 gpm) Restrictor Sub with 28/32 jet, 0.6013 in^2 TFA (580 psi prs drop @ 400 gpm).
Motor	Sperry 6¾-in, 7:8 Lobe, 3.0 Stage (200 psi prs drop @ 400 gpm) 0.29 revs/gal **(Attachment 5)**
BHA	WSAB, Motor with ARWD "Drill and Range" BHA **(Attachment 2)**
Special Equipment	Dril-Quip First Position Wear Bushing ID = 12.395-in (already installed in wellhead); Dril-Quip Multi-Purpose Tool and Dual Cam Tool, K&B Pump-in Sub **(Attachment 10)**, Downhole Devices PBL Sub **(Attachment 3)**
Drillstring	5⅞-in 34.03 ppf (0.500-in), S-135, XT57 **(Attachment 6a)**
Cement Stinger	3½-in 13.30 ppf (0.368-in), S-135, XT57 **(Attachment 6b)**
Mud Logging and Sampling Requirements	The subsurface sampling requirements for the OCS-G 32306 No.3 Mississippi Canyon Block 252 #3 are included in the Sample Requirements Document from the Macondo PDDP. The subsurface crew will consist of a Wellsite Geologist, Mud Logger, LWD crew, and one Sample Catcher. Sperry Mud Logging services will continue to provide Mud Logging services on the rig. Mud Log, LWD displays and data will continue to be posted daily in all usual formats. All hydrocarbon occurrences will be documented in show reports and clearly identified on the Mud Log. Any unusual cuttings occurrences will be documented and photographed. Any significant differences in stratigraphy from the MC 252 #1 will be documented by the Wellsite Geologist. Cuttings samples will continue to be collected and labeled as outlined in the sample requirements document. All cuttings samples will be collected at 10 foot intervals upon drill out of the 9⅞-in shoe. Wet samples will be shipped in on available transportation for biostratigraphic analysis in Houston. Bulk mud samples and iso-jars will be collected at 30 foot intervals once new formation is drilled below the 9⅞-in shoe, labeled as per the sample document. Spot samples shall be collected if any unusual occurrences are documented. Any unusual mud observations shall be documented and reported to the BP Well Site Leader and Mud Engineer.
DD3 Drilling Mud	Baroid ENCORE SOBM Drill ahead MW = 14.0 ppg SMW / +/-14.3 ppg DMW Approximate Mud Volume onboard: 9,885 bbls

Interval Notes	
DD3 Cement	DD3 Cement Tank #1: 3,195 sacks 35% SF (16.5 ppg @ 1.39 ft^3/sx) DD3 Cement Tank #2: 2,742 sacks Oklahoma #1 (17.2 ppg @ 1.28 ft^3/sx) DD3 Cement Tank #3: 1,361 sacks 35% SF (16.5 ppg @ 1.39 ft^3/sx) DD3 Cement Tank #4: 3,160 sacks Oklahoma #1 (17.2 ppg @ 1.28 ft^3/sx)
9 ⅞-in Liner shoe FIT	9 ⅞ liner shoe depth is 17,856-ft MD (17,099-ft TVD). Formation Integrity Test (FIT) = 14.94 ppg downhole equivalent
MC252 #3 Relief Well 13⅝-in Casing Wear De-Rating	Original internal yield rating for the 13⅝-in casing was 11,306 psi (refer to EPT Technical File Note, June 3, 2010, Rev A, "Macondo Relief Well: 13 ⅝-in Intermediate Casing Analysis"). Following the 1st Halliburton CAST F logging run conducted on June 12, 2010 and 2nd CAST F run on July 5, 2010, the 13⅝-in casing Internal Yield rating was de-rated from 11,306 psi to 10,414 psi. Following the 3rd Halliburton CAST F logging run conducted on August 29, 2010, no further casing de-rating was required. No wear measured in excess of that measured from previous CAST F logging runs.
MC-252 #1 Target Well Interval Summary (DD3 Elev. 88-ft)	Horizon elevation 75-ft (depths below from Horizon RT datum) 9 ⅞-in shoe set at 17,168-ft MD (17,157-ft TVD) Drilled out with 14.3 ppg SMW, 14.52 ppg DMW, 14.73 ppg ECD Conducted FIT to 16.22 ppge DMW At 17,634-ft MD (17,623-ft TVD) increased MW to 14.5 ppg SMW. At 17,761-ft MD (17,750-ft TVD), minor losses, questionable flow check. At 17,700-ft TVD took GeoTap samples and found pore pressure 14.15 ppge, reduced MW from 14.5 ppg to 14.3 ppg SMW. **(see Attachment 9, "Macondo Sand Identification Log Section")** At 18,260-ft MD (18,249-ft TVD) increased MW to 14.4 ppg SMW, had lost returns, pumped tandem Form-a-Squeeze / Form-a-Set LCM pills (lost almost 1,600 bbls of mud).

12.2 Objectives

- Directionally drill and range to intercept the Target Well MC252#1 annulus and 7-in casing (without puncturing).
- Isolate the Macondo reservoir should it become in communication with the MC252#3, Relief Well upon intersection with MC252#1 wellbore.
- Place a cement plug and squeeze at the point of intersection to isolate the MC252#1 annulus and the lower portion of the MC252#3 wellbore so that P&A operations may commence.

12.3 Concerns

Concern/Hazard	Mitigation
Pore Pressures and Fracture Gradients	Original Bottomhole Pressures and Sand Fracture Pressures: M57C GeoTap **14.15 ppge** at 17,700-ft TVD (brine)-14.93 ppge Sand Frac M56A MDT 13.1 ppge at 17,800-ft TVD (oil) - 14.35 ppge Sand Frac M56D MDT 12.6 ppge at 18,075-ft TVD (oil) - 14.18 ppge Sand Frac M56E MDT 12.6 ppge at 18,150-ft TVD (oil) - 14.18 ppge Sand Frac Estimated Depleted Bottomhole Pressures (as per Macondo Technical Note of 7/21/2010, "Depleted Pressure for Well Control Planning": M57C 12.30 ppge, M56A 11.2 ppge, M56D 10.73 ppge, M56E 10.7 ppge
Loss Circulation Strategy	Have an emergency 80-lb/bbl, 200-bbl pill mixed and ready to pump at all times (10 ppb Baroseal M, 15 ppb Baroseal C, 10 ppb Baroseal F, 15 ppb Steel Seal 400, 15 ppb Safe Carb 500, 15 ppb Baracarb 600).
Tight Clearance Profiles	9⅞-in Casing ID and Casing Hanger ID = 8.625-in 9⅞-in Casing ID = 8.535-in 1st Position Bit Run Retrievable Wear Bushing ID = 12.395-in

12.4 Drilling Operations Procedure

Parameter	Guideline
ROP	Rate of Penetration will be controlled based on directional requirements
Pump Rate	550 gpm (0.1224 bbl/stk with 6-in liners x 2 pumps at 54 spm each)
SPP	4,500 psi
WOB	10-30 klbs
RPM	550 gpm and 0.29 revs/gal =160 RPM at the bit . Drill String RPM of 30-50. (Monitor and keep track of KREVS on the bit)
Torque	Monitor difference between on and off bottom torque. Do not exceed makeup torque of weakest connection in hole.
SMW DMW ECD FIT	Surface Mud Weight (SMW) = 14.0 ppg Downhole Mud Weight (DMW) = 14.3 ppge Equivalent Circulating Density (ECD) = 14.7 ppge max Formation Integrity Test (FIT) = 14.94 ppg Downhole Equivalent Mud Weight
Hole Deviation	Through drill pipe, and open hole ranging will dictate directional work for intercept. A mud motor with 1.15° bent housing will be used for directional work.
Section TD	Planned Intersection with the MC252#1, Target Well, is projected to be 17,969-ft MD (17,212-ft TVD). **(see Relief Wellbore Sketch, Attachment 14)**

12.4.1 8½-in Intercept Interval

1. This "Revision 1" procedure replaces "Revision 0" with the Drill and Range BHA already positioned at the 9⅞-in shoe, ready to finish tripping to bottom to begin drilling and ranging to intercept point with MC252#1.
   - The MC252#3, 9⅞-in shoe is at 17,856-ft MD (17,099-ft TVD) with 14.9 ppge downhole FIT.
   - Current total depth is 17,909-ft MD (17,152-ft TVD).
   - The MC252#1, 9⅞-in shoe may be as shallow as 17,914-ft MD.
   - BOPs have been tested per **Attachment 7** on 5⅞-in drill pipe (8/31/2010).
     - BOP test must be started before midnight on Tuesday Sept 14th as per BOEM Regulations. Do not start any operations that may preclude testing BOPs on the required date.
   - Halliburton CAST F has been run and results filed with the BOEM, which satisfies casing testing requirements (8/28/2010).
   - BSRs and CSRs have been tested to 2600 psi with 13.8 ppg SMW (8/31/2010).
   - Diverter has been functioned (9/7/2010).
   - Well control and emergency disconnect drills have been conducted.
   - All personnel are confirmed to be in compliance with BOEM Sub Part O, "Well Control and Production Safety Training."
   - 13⅝-in and 9⅞-in Retrievable Test Treat Squeeze (RTTS) packers and Storm Valves, 9⅞-in Fas Drill® Bridge Plugs (rated to 5,000 psi ΔP) prepared for wireline set and drill pipe set, and 9⅞-in EZSVB (rated to 7,500 psi ΔP) are onboard.
   - The Measurement While Drilling tools (MWD) have been shallow tested as per Sperry.
2. Prior to drilling ahead, obtain slow pump rates (SPR) and choke line friction pressures (CLFP) and document.
3. Make final checks prior to drilling into the MC252#1 annulus.
   - Have discussions with all crew members and Halliburton Cementer on DDIII about timing of the upcoming intercept and the potential to have to manage drilling fluids losses while preparing to pump spacer and cement to isolate the MC252#1 annulus.
   - Communicate with the Development Driller II (DDII) on pending intercept. Ensure the DDII has the blind shear rams closed and are monitoring the well.
   - Evaluate the weather window and discuss with Houston based team.
   - Make up a TIW valve one joint up on a full stand of 5⅞-in drill pipe and rack back.

Note 1: Only use a solid body TIW and only use a TIW with a full opening ID of 3-in or greater (record TIW ball valve ID).

4. Determine what the hang-off position on the upper variable bore rams (VBRs) will be after drilling to the Target Well shoe depth, which could be as shallow as 17,914-ft MD, and pulling back into casing at 17,856-ft MD (total of 58-ft), with the bit just outside of the shoe. (This may require using a pup joint).
5. Review line up as specified in "Intercept Preparedness and Response" on page 11 and shown in **Attachment 13**, and in TOI Standing Orders WC023. All four (4) pumps will be required to drill and boost the riser. Drill pipe flowrate range is limited to 10-14 bpm (420-600 gpm) by MWD telemetry and the mud motor.
6. Have the K&B Pump-in sub on the rig floor, cementing hose ready to be tied-in and the DDIII Cementer on alert. It will not be necessary to pre-mix the spacer until it is known whether a cement squeeze or a balanced cement plug will be pumped.
7. Be ready to implement "Intercept Preparedness and Response" procedure and diagnostics on pages 11 and 12.
8. Slide and rotate to RR16, based on previous ranging results (30-ft MD), to approximately 17,939-ft MD or as directed by Well Intercept Team. This is 30-ft above the targeted intercept depth.
   - If ARWD / WSAB ranging data is inconclusive (and hole is stable), POOH with BHA and perform OH range run with Vector Magnetics 2-in RGR Wellspot™ tool and Gyrodata gyro in combination (refer to "Open Hole Wireline Ranging Procedure" on page 10). If necessary RIH with survey BHA.
   - If data is conclusive, or risk is unacceptable to POOH, drill to RR17 / projected intersection depth at 17,969-ft MD.
   - At RR16, the hole depth should be below the depth of the MC252#1 9-$^{7}/_{8}$" casing shoe.
9. Slide and rotate to RR17 / projected intersection depth based on previous ranging results (30-ft MD) to approximately 17,969-ft MD (not accounting for distance uncertainty) or as directed by Well Intercept Team.
   - Intersection could occur at any depth during this section based on the distance uncertainty from the previous range run call.
   - Control drill this section with low WOB, closely monitoring pump pressure, rotary torque, ROP and tool face (if sliding) and mud returns.
   - Intersection with the 7-in casing will be confirmed by:
     - Stalling the rock bit with the motor using a reduced pump rate,
     - RR17 with ARWD / WSAB. If data is inconclusive (and hole is stable), POOH with BHA and perform OH range run with 2-in RGR Combo.
   - Follow mud logging and sampling requirements.

10. Confirm intersection with the MC252#1, 7-in casing. Should losses occur upon intercept of the MC252#1 annulus then refer to "Cement Squeeze Procedure", page 13.

11. Pump slug and POOH to pick-up 3½-in stinger for placing a cement plug.
    - Pump back into 9⅞-in casing, then circulate bottoms up.
    - Flow-check the well for 15 minutes minimum.
    - Pump a slug and continue to POOH. Stop prior to pulling the BHA through the BOP stack.
    - Flow-check the well for 15 minutes minimum.
    - Confirm the riser angle is acceptable prior to pulling the BHA through the stack.

      Note: Follow Transocean's policy for pulling the non-shearable BHA across the BOP stack.
    - Finish POOH

      Note: If intersection with the 7-in casing is not achieved at RR17, drill to RR18 (30-ft MD), to approximately 18,000-ft MD. Follow sequence until intersection is achieved or Target Well bypassed.

12. Pump cement plug and carry out braden-head squeeze, as per the "Balanced Cement Plug and Squeeze Procedure" on page15.

Open Hole Wireline Ranging Procedure

1. Install Halliburton upper wireline sheave wheel with Kevlar slings in derrick for use on main rotary. Inspect sheaves to be certain that they are in proper working condition.
2. Halliburton Wireline Logging Services (HLS) will RU bottom sheave wheel to the pad eye in front of the skate, using chain, and run wireline through lower then upper sheave wheels.

   Note: The use of a chain to secure the lower sheave wheel has been approved by BP and by Transocean.
3. Vector Magnetics and GyroData (if running a gyro in combination) will make sure that the instruments are assembled and that all equipment has been tested. Prepare bridle cable for pick-up.
4. Thread Halliburton wireline (HLS) through the sheave wheels and pass back down to the tool assembly. Connect to the bridle via a clam shell connection. Grease and test same. The wireline will be 0.474-in, the tension rating is 23,600 lbs, the 50% working strength is 11,800 lbs and the weak point will be 5,000 lbs.
5. Lift instrument assembly, maintaining tensions on line to prevent jumping a sheave.
6. Attach the hole finder if required by hole conditions. Zero the tool.
7. RIH with tools to conduct range run in open hole. Reduce wireline running speed as tools pass through BOP stack and 9⅞-in top of liner.

   Note 1: Monitor hole for losses and/or gains.
   Note 2: Monitor cable displacement on the trip tank.
8. Identify the shoe and correct depth, verify radioactive tags located on the box and pin of the 10th joint up from the 11⅞-in liner shoe (these RA tags can be seen through the 9⅞-in liner). There will also be radioactive tags located on the pin of the 3rd and 4th joint up from the 9⅞-in liner shoe.
9. Continue to bottom until tool sets down. Background data and active ranging data will be taken slacked-off on bottom. Using tool moving tests and the tension gauge of the wireline, the depth of pick-up will be compared to the driller's TD.
10. Data will be collected with the tool stationary at intervals determined by the Vector Magnetics Representative.
11. A second run to bottom may be made as determined by the Ranging Engineer to fill in any anomalies encountered on the first pass.
12. Pull out of hole (POOH). Verify shoe depth.
13. When the top clamshell reaches the drill floor, the zero reference should be checked against the starting value.
14. Rig down wireline tools.
15. After rigging down Vector Magnetics, secure the Halliburton wireline to the side of the derrick with a snake and soft line rope. This will enable re-use for further active ranging without having to work in the derrick. Transocean Task Specific Think Plan (TSTP) to ensure that the wireline is secured safely and will not interfere with derrick operations.

Intercept Preparedness and Response

"Base Case" conditions:

1. The Capping Stack and Horizon BOPs have been removed from the Macondo MC252#1 well.
2. The Development Driller II BOPs have been installed and tested on the MC252#1 wellhead.
3. The MC252#1, 9⅞-in casing has been perforated and squeezed with cement or a Dril-Quip lockdown sleeve has been run.
4. There is not an open conduit in the MC252#1 wellbore from the point of intercept to the mudline.
5. There remains potential for there to be communication with the depleted Macondo reservoir upon annulus intercept.
6. The Development Driller III has sufficient mud volume, cement volume and pumping capacity to intercept the MC252#1 annulus without additional marine support (**Attachment 1b**).

Procedure

1. Line Up: Ensure the following drilling configuration is lined up prior to drilling beneath the Blowout Well 9⅞-in shoe (see C&K Manifold Layout diagram **Attachment 13**).
   - Two (2) pumps to be lined up on Standpipe #1 (on the hole) to maintain 420 - 540 gpm (82 spm - 105 spm). Need 420 gpm for MWD Telemetry. Max flow rate for the Sperry mud motor is 600 gpm.
   - The remaining two (2) pumps will be lined up on the boost line, on Standpipe #2 through the C&K crossover valve, and on the HP Cement Unit line up the C&K Test Line. The boost line valves will be in the open position to boost the riser while drilling. The C&K Manifold will be lined up to allow both the crossover line and the test line to be pumped down the C&K lines, dead heading against the UIK and LIC failsafe valves.
   - While boosting the riser, pump pressure should be able to be seen on the C&K manifold.
   - Both trip tanks to remain full at all times, and a trip tank pump circulating to keep barite from settling.
2. Initial Response: When intercept occurs, and should losses occur, keep the hole full until cementing operations commence. The initial response does not include closing the annular. **The annular preventers are open**.
   - Maintain pumps going down the drill string and notify Mud Logger to zero the stroke counters.
   - Open UIK and LIC failsafe valves on the BOP while continuing to boost the riser.
   - Keep pumps running on boost lines (two pumps at reduced rate will ensure that both pumps are operational, and eliminates risk of rupturing a burst disk as a pump is brought on line).

Intercept Preparedness and Response

- Pick-up and space out tool joint above the hang-off rams (the bit should be just outside of the 9⅞-in shoe and the TIW should also be at the rig floor).
- Well head pressure on the BOP and returns to be monitored.

Note : If massive losses occur and if the fluid level in the riser cannot be kept at the surface, follow TOI Standard Operating Procedure WC023. Line up preparations for Macondo "Drill to Kill Transition (Transition Sequence) - Rev 4, to open UIK and LIC failsafe valves and close the lower annular preventer.

3. Communicate handover and accountabilities from Intersect Operations Team to Kill and Cement Team **(Attachment 11 and 12)**. *Note: this only applies to kill and cementing operations.*
4. Notify the DDIII Cementer of operational status and have all personnel at their stations ready to commence cementing operations.
5. Start mixing the cement spacer.
6. Inform the Bridge/Control Room of present situation and station keeping requirements. Bridge will contact all other required personnel including: BP Wellsite Leader, Senior Toolpusher, OIM, and SIMOPS Coordinator on DDIII. Bridge will also contact all other support vessels and installations in the field.
7. Immediately record the following data each minute:
   - Time
   - Pressures (to include drill pipe, wellhead, C&K)
   - Volume pumped and rates
8. Delegate the monitoring responsibility to Auxiliary Assistant Driller, and record each minute until pressure stabilizes. Wellhead pressure to be charted continuously.

Diagnostics

- **In Communication with the Reservoir: If losses occur then cement as per "Cement Squeeze Procedure" on page 13.** The reservoir fracture pressure is ~13.5 ppge and the Relief Well ECD will be ~14.7 ppge. Expect losses should the Macondo reservoir be in communication via the MC252#1 annulus back to the MC252#3 intercept point.
- **In Communication with Failed Burst Disks: If losses occur then cement as per "Cement Squeeze Procedure" on page 13.** If burst disks in the 16-in casing have failed, creating communication to the 18-in shoe (11.55 ppge LOT), expect losses.
- **Annulus is Isolated: If no losses occur then cement as per "Balanced Cement Plug and Squeeze Procedure" on page 15.** The conclusion will be that cement isolates the annulus from the reservoir and the burst disks in the 16-in casing are intact, or isolated.

Cement Squeeze Procedure

Squeeze Objective: Squeeze a 100 bbl cement pill through the BHA and motor into the MC252 #1, 9⅞-in open hole x 7-in casing annulus to establish a reliable barrier to pressure.

Bullhead Squeeze Procedure:

1. From projected intersection depth of 17,969-ft MD, pull bit back to the 9⅞-in casing shoe at 17,856-ft MD.
2. Open LIC failsafe and pump 50 bbls of base oil down the choke line (choke line volume is 81 bbls).
3. Space out and close the lower annular preventer.
4. Make up TIW, K&B Pump-in Sub **(Attachment 10)** with Weco 1502 union, Lo-Torq valve, and Cementing Hose from cementing manifold. Test surface lines to 250 psi low for 5 minutes and 5,000 psi high for 5 minutes. Verify that TIW on top drive is closed.
5. Mix 50 bbls (pumpable volume) of 15.2 ppg spacer.
6. Verify that required volume of 14.0 ppg SMW for displacement is ready.
7. Verify final displacement volume and compressibility assumptions (estimate 6 bbls of compression).
8. Be prepared and lined up to deliver ~70 bbls of base oil to the cement unit.
9. Squeeze cement job to be pumped by the DDIII.
   - DD3 Cement Tank #1: 3,195 sacks 35% Silica Flour (16.5 ppg @ 1.39 cuft/sack)
   - DD3 Cement Tank #3: 1,361 sacks 35% Silica Flour (16.5 ppg @ 1.39 cuft/sack)
10. Bullhead **45 bbls of 15.2 ppg spacer** at 12 bpm with DDIII rig pumps.
11. Bullhead **100 bbls of 16.5 ppg cement** at +/- 4 bpm with DDIII cement unit.
12. Bullhead **5 bbls of 15.2 ppg spacer** at 12 bpm with DDIII rig pumps.
13. Bullhead 345 bbls of 14.0 ppg SOBM at 12 bpm with DDIII rig pumps.
14. Bullhead 50 bbls of 6.5 ppg base oil at 5 bpm down the drill pipe (this is 2,232 -ft inside the drill pipe) with DDIII cement unit, displacing the TOC to the bit. (This is to better assure positive pressure during squeeze.)
    - Estimated drill pipe volume to the bit = 400 bbls
    - 100-ft of 8½-in hole to the Intersection = 7 bbls
    - Over displacement beyond point of intercept = 5 bbls
    - Estimated TOTAL = 412 bbls
15. If positive pressure on the standpipe is not achieved at this stage then continue to fill the drill pipe with base oil. If 12 bbls of base oil, or more, is required to achieve static fluid levels and a positive pressure on the standpipe then revert to step 17 and Wait

on Cement (WOC).

16. Begin squeeze cementing down the drill pipe utilizing a hesitation technique with 6.5 ppg base oil as follows:
    - After bullheading cement into position, the total squeeze volume is 7 bbls open hole volume plus 5 bbls over displacement.
    - Pump at 1/2 bpm for 3 bbls then shutdown for 10 minutes. Report pressure response, and repeat same for 2 more hesitations, for a total of 9 bbls.
    - On last 3 bbls, slow down pump rate to 1/4 bpm. Report pressure response.
    - Total squeeze volume is to equal 12 bbls.
17. Monitor the choke line surface pressure.
18. WOC as per lab report until cement reaches 1,000 psi compressive strength, while maintaining final squeeze pressure.
19. Bleed-off drill pipe pressure and monitor returns to verify that the drill pipe float is holding.
20. Do not bleed-off final cement squeeze pressure on the choke line as this will severely under-balance the open hole interval (12.4 ppge) to intercept point and may result in wellbore collapse or a potential problem with the 14.15 ppg M57C sand.
21. Open UIK failsafe valve and allow well to see full column of 14.0 ppg and monitor for losses for 10 minutes.
22. If the well is static, close the lower VBRs and displace the base oil out of the choke line with 14.0 ppg SMW.

    Note: If well is not static, close UIK failsafe, re-apply original squeeze pressure with base oil down the choke line and open LIC failsafe valve. Contact Houston based team for direction.
23. Open the lower VBRs and circulate out the base oil pumping the long way with 14.0 ppg SMW taking returns up the choke line and maintaining constant bottomhole pressure.
24. Open the lower annular preventer.
25. Wash down to intercept point.
26. If there are no mud losses then the MC252#1 annulus is isolated.
27. Pull one stand, circulate bottoms up to surface.
28. Proceed to "Balanced Cement Plug and Squeeze Procedure" on page 15.

Balanced Cement Plug and Squeeze Procedure

Cement Information:

- Cement: 16.5 ppg Premium Cement with Silica Flour
- Spacer Ahead: 80 bbls Tuned Spacer III – 15.2 ppg
- Spacer Behind: 10 bbls Tuned Spacer III – 15.2 ppg

Note: Verify below volumes and displacements based on actual hole conditions.

Procedure:

1. Make up 48 joints of 3½-in drill pipe (~1,400-ft) for cementing stinger assembly **(Attachment 6b)** with diverter.
2. Transition and cross over to the 5 ⅞-in, XT57 drill pipe.
3. MU one joint of 5 ⅞-in, XT57 drill pipe.
4. MU a Halliburton 5 ½-in Indicating Ball Catcher sub (7.25-in OD), with crossovers to the 5 ⅞-in, XT57 drill pipe.
5. RIH with the cementing stinger on the 5 ⅞-in, XT57 drill pipe to the shoe depth at 17,856-ft MD.
6. Wash down to intersection depth. Circulate bottoms up to above the stack and boost the riser. Pull up to the 9⅞-in shoe.
7. Conduct a pre-job safety meeting with all personnel involved in the job.
8. Run in the hole, make up Blackhawk cement head and continue in hole to intersection depth.
9. Rig up the cement lines and pressure test to 250 psi low for 5 minutes and 5,000 psi high for 5 minutes.
10. Pump a total of 80 bbls of 15.2 ppg Tuned Spacer III with DDIII rig pump ahead of the cement.
11. Drop one 5.5-in hard rubber ball from the Blackhawk head ahead of the cement.
12. Mix and pump 70 bbls of 16.5 ppg cement slurry at +/- 4 bpm (1,000-ft plug length inside of an 8½-in hole).
13. Pump 10 bbls Tuned Spacer III behind cement slurry to balance the plug. Pump at 10 bpm (if possible). The spacer behind is counted in displacement volumes.
14. Adjust displacement volume accordingly when the ball lands in the Ball Catcher Sub. Finish displacing slurry with the 14.0 ppg SOBM at 10 bpm with DDIII rig pump. Slow displacement rate to 2 bpm and leave 18 bbls of cement in the stinger/drill string.
15. Pull out of cement plug at 3-4 min/stand to put the end of the 3½-in stinger at the planned top of spacer (15,768-ft MD, 15,033-ft TVD), which is 2,200-ft off of bottom.
16. After spotting the balanced cement plug the downhole equivalent mud weight will

Balanced Cement Plug and Squeeze Procedure

be 14.4 ppg. Close the annular preventer and pump at 1/4 bpm with Halliburton cementing unit and anticipate pressure to reach 700 psi before injectivity occurs (15.2 ppge is the anticipated fracture pressure). The maximum allowable squeeze pressure is 500 psi over the frac gradient (1200 psi).

17. Squeeze 8 bbls of cement away at 1/4 bpm, hold squeeze pressure and wait for 10 minutes then pump 7 bbls additional cement away at 1/4 bpm. Hold squeeze pressure and WOC as per lab report until cement reaches 1,000 psi compressive strength, while maintaining final squeeze pressure. TOC is at 17,000-ft prior to the squeeze and will be at ~17,210-ft after squeezing 15 bbls.
18. Drop 2 'Nerf' wiper balls and circulate bottoms up.
19. Pump slug and POOH.
20. P&A Procedure to follow

Attachments

No.	Title
1a	Approved MOC to Release HOS Strongline
1b	Approved MOC to Release HOS Centerline and BJ Blue Dolphin
2	Drill and Range BHA Schematic
3	Downhole Devices PBL Sub Spec Sheet
4	MOP for 5 7/8-in Drill Pipe at 8½-in Interval to Total Depth
5	6 3/4-in Sperry Drill Lobe 7/8, 3-Stage Motor Specs
6a	5 7/8-in Drill Pipe Spec Sheet
6b	3 1/2-in Drill Pipe Spec Sheet
7	BOEM Requirements for BOP Testing
8	Original Pore Pressure/Frac Pressure Estimates
9	Macondo Sand Identification Log Section
10	K&B Pump-in Sub
11	Offshore Well Kill, Control and Cementing Team Organization Chart
12	Intercept, Kill, Control & Cement Operations RACIE Chart
13	Rig Choke and Kill Manifold Layout
14	Macondo Relief Wellbore Sketch
15	MC252#1 Wellbore Sketch

Attachment 1a:
Approved MOC to Release HOS Strongline

bp

Drilling & Completions MOC Initiate

MOC #:	**DCMOC-10-0127**
Date Initiated:	**8/27/2010**
Initiator:	**Jacobsen Plutt, Louise A**
Stage:	**Complete**
Status:	

Asset/Project:	GoM	Type of Change:	Technical
Rig:	DDII	Well (i.e., GC 823 #1 or N/A):	MC252 #3
Verifier:	Jacobsen Plutt, Louise A	Priority:	A (High - Immediate)
Coordinator:	Jacobsen Plutt, Louise A		
Desired Completion Date:	08/30/2010		

Proceed with MOC? (•) Yes ( ) No / Cancel ( ) Clarify

Title:

Strongline Support to DDII

Scope:

Because of the success of the Static Kill on the Macondo #1 well, the HOS Strongline will no longer be needed to support the DDII drilling operation on the MC252 #3 Relief Well.

Justification (include financial impact where appropriate):

The plan for the kill operations on the Macondo #1 have changed. The current status of the Macondo #1 is that it is shut in at the capping stack, statically killed with a column of mud, and a successful cement hesitation squeeze was performed leaving the top of cement at approximately 12,000 feet MD. While monitoring the well, no pressure build up has been observed at the stack, indicating the well is statically controlled. Initial pressure tests of the cement indicate isolation to the reservoir.

Justification to go ahead without the Strongline include the following:
- Prior Well Kill Plans and MOC¿s were generated while the possibility of a dynamic kill was still viable. Under the current circumstances, the Macondo #1 well will not be dynamically killed therefore the additional mud on the Strongline is no longer needed.
- Should additional mud be required (other than the +/- 7,500 bbl of mud on the DDII), the Centerline is available in the field as a contingency

Risk/Mitigation (attach risk documentation where appropriate):

The static kill and cement operations on the Macondo #1 have successfully brought the Macondo #1 well into a static condition by pumping mud into the well, followed by cement including a successful hesitation squeeze.

The DDII rig has adequate mud volume to cater to any loss or well control scenarios. Lost circulation material required by the Lost Circulation Decision Tree is available on the DD3. In the event cement is required, cement volumes on the DD3 provide adequate volume to conduct the primary cement job and multiple cement squeezes.

Attachment 1b:
Approved MOC to Release HOS Centerline and BJ Blue Dolphin

bp

Drilling & Completions MOC Initiate

MOC #:	DCMOC-10-0130
Date Initiated:	9/10/2010
Initiator:	Prewett, Harry
Stage:	Complete
Status:	

Asset/Project	GoM	Type of Change	
Rig	DDII	Well (i.e., GC 823 #1 or N/A)	MC252#3 Relief Well
Vender	Prewett, Harry	Priority	
Coordinator	Prewett, Harry		
Desired Completion Date	09/10/2010		
Proceed with MOC?	◉ Yes ○ No / Cancel ○ Clarify		

Title:

HOS Centerline and BJ Blue Dolphin Support to DDII

Scope:

The release of HOS Centerline and BJ Blue Dolphin once DDII BOPs are pressure tested.

Justification (include financial impact where appropriate):

1. The DDIII plan forward is to remain prepared to resume drilling and ranging to intersect the Macondo MC252#1 wellbore (contact the 7 in casing).
2. Once intersect operations are resumed and intersection occurs, a balanced cement plug will be placed in the MC252#3 wellbore from the point of intersection with the MC252#1 and a bradenhead squeeze carried out (8 ½-in Intercept Interval, Revision 1, has been drafted). This scope of work is substantially different compared to the original dynamic kill scenario, which required additional marine support for the DDIII.
3. The present wellbore condition of the Macondo MC252#1 is substantially different compared to its condition which required additional marine support for the DDIII
4. The current total mud volume on the DDIII is 9865 bbls, along with 1180 bbls of base oil and 7447 sacks of barite.
5. The current total cement volume on the DDIII is 10911 sacks, or 1424 bbls when mixed.
6. For perspective, the MC252#1 total hole volume is 1528 bbls and the MC252#3 total annular volume is 1120 bbls; and DDIII available mud plus cement volume is over 4 times the combined volumes for MC252#1 and #3. The scope of work that the 8 ½-in Intercept Interval, Revision 1, addresses requires maximum of 180 bbls of cement and only minor lost circulation, should communication with the depleted reservoir occur upon intersection.
7. The DDII BOPs will be fully tested to assure pressure integrity prior to releasing the HOS Centerline and BJ Blue Dolphin.

Risk/Mitigation (attach risk documentation where appropriate):

The static kill and subsequent cement operations have successfully brought the Macondo MC252#1 well to a static condition that enabled removal of the capping stack and Deepwater Horizon BOP stack and the installation of the DDII BOP stack and riser.

Following successful DDII BOP testing, the Macondo MC252#1 wellbore isolation at the wellhead is assured and the potential for the Macondo well to resume flow, thus requiring the DDIII to intersect and dynamically kill, is considered to be negligible.

From the work documented in the MC252#3 Relief Well Early Intercept Recovery and Well Kill Plan, Appendix H, Dynamic Kill Technical File Note, Table 1.3, a dynamic kill of the Macondo production casing annulus at the deep intercept point would require pumping a total of 2500 bbls of mud at 21 bpm. This scenario has been deemed negligible; however, to support this MOC, it is documented from the high rate circulating test conducted on 08/03/2010, that the DDIII can achieve a 35 bpm rate with 4 pumps, at 3050 psi standpipe pressure, pumping down the choke and kill lines simultaneously (3 pumps would provide a rate >21 bpm).

The cementing requirements have always specified that the well must be static prior to cementing. Based on a static well condition, cementing rate requirements are not critical. The DDIII is fully capable of pumping all of the nearly 11000 sacks of cement onboard at 4 - 5 bpm. Based on the planned scope of work and the negligible risk of the Macondo MC252#1 resuming a flowing condition, the DDIII cementing capability is deemed sufficient.

Attachment 2:
Drill and Range BHA Schematic

sperry-sun DRILLING SERVICES

BHA Report

Customer : BP North America
Well : Relief Well
Field : Mississippi Canyon 252 #3
Lease : OCS-G 32306
Rig : DD 3
Job # : LA-MJ-0007324210

BHA# 24

BHA# 24 : **Date In** 8/28/2010 **MD In (ft)** : 17909 **TVD In (ft)** : 17152 **Date Cur** 8/30/2010 **MD Cur (ft)** : 17909 **TVD Cur (ft)** : 17152

BIT DATA

Bit #	OD (in)	MFR	Style	Serial#	Nozzles (/32's)	TFA (in²)	Dull Condition
14rr2	8.500	Hughes Christensen	MXL1	5178996	3x20, 1x18	1.169	

MOTOR DATA

Run #	OD (in)	MFR	Model	Serial#	Bend	Nzl (/32's)	Avg Dif (psi)	Cum Circ Hrs
	6.750	SSDS	SperryDrill	675557	1.15°			8.00

COMPONENT DATA

Item #	Description	Serial #	OD (in)	ID (in)	Gauge (in)	Weight (lbs/ft)	Top Con	Length (ft)	Bit - Center Blade (ft)
1	8-1/2" Rock Bit	5178996	8.500	1.750	8.500	185.19	P 4-1/2" IF	0.80	
2	Non-Mag W.S.A.B. sub	7-019	6.875	1.750		118.32	P 4-1/2" IF	1.82	
3	6-3/4" SperryDrill Lobe 7/8 - 3.0 stg	675557	6.750	4.469	8.375	68.50	B 4-1/2" IF	24.35	5.47
4	Pressure Drop Sub	6725P	6.813	0.875		122.19	B 4-1/2" IF	3.13	
5	Non-Mag Gap Sub	11457884	6.500	3.250		84.82	B 4-1/2" IF	3.32	
6	8-3/8" IB Stabilizer	0675-0095	6.813	2.813	8.375	103.06	B 4-1/2" IF	5.55	35.84
7	6-3/4" ARWD	90253831	6.750	1.920		112.09	B 4-1/2" IF	31.48	
8	6-3/4" ABI Receiver	90232824	6.750	1.920		112.09	B 4-1/2" IF	8.74	
9	6-3/4" HOC w/Gyro Insert	11443741	6.750	1.920		112.09	B 4-1/2" IF	25.62	
10	6-3/4" RLL DM+PWD+DGR+HCIM	90253827	6.750	1.920		112.09	B 4-1/2" IF	26.59	
11	6-3/4" Pulser	90253833	6.750	1.920		112.09	B 4-1/2" IF	11.14	
12	8-3/8" IB Stabilizer w/ plunger	6737	6.750	2.813	8.375	100.77	B 4-1/2" IF	4.42	146.79
13	PBL Sub	6755BP449	6.750	1.500		115.93	B 4-1/2" IF	9.27	
14	Cross Over Sub	0725-0006	7.250	2.813		119.51	B XT57	5.11	
15	12x 5-7/8" HWDP		5.875	4.000		49.56	B XT57	370.00	
16	Drilling Jars	05529D	7.000	4.250		82.81	B XT57	30.96	
17	3x HWDP		5.875	4.000		49.56	BXT 57	92.48	
18	Cross Over Sub	0725-0009	7.313	2.813		121.97	B 4-1/2" IF	4.19	
19	Non-Mag Gap Sub	11423568	6.500	3.250		84.82	B 4-1/2" IF	3.32	
20	Cross Over Sub	0725-0005	7.313	2.750		122.90	B XT57	5.10	
21	16x 5-7/8" HWDP		5.875	4.000		49.56	B XT57	493.36	
								1162.75	

Parameter	Min	Max	Ave
WOB (lbs) :			
RPM (rpm) :			
Flow (gpm) :			
SPP (psi) :			

Activity	Hrs
Drilling :	0.00
Reaming :	1.50
Circ-Other :	6.50
Total :	8.00

BHA Weight	(lb)
in Air (Total) :	68586
in Mud (Total) :	54159
in Air (Bel Jars) :	35568
in Mud (Bel Jars :	28087

Drill String	OD(in)	Len(ft)

PERFORMANCE

	In	Out
Inclination (deg)	3.23	3.23
Azimuth (deg)	199.04	199.04

	Distance(ft)	ROP (ft/hr)	Build (°/100')	Turn (°/100')	DLS (°/100')
Oriented :					
Rotated :					
Total :					

Attachment 3:
Downhole Devices PBL Sub Spec Sheet

DOWNHOLE DEVICES

6 3/4" PBL BALL LOCK BYPASS SYSTEM
TECHNICAL SHEET

SERIAL #	NOR675SBP415
A-TOOL O.D.	6.75"
B-TOOL I.D. (DRIFT)	1.50"
FLOW AREA THROUGH TOOL	2.92 sq/in
C-BOX CONNECTION	4 1/2 IF
D-PIN CONNECTION	4 1/2 IF
E-ACTIVATION BALL/# TO ACTIVATE:	1
DIAMETER	2"
MATERIAL	Ertalyte
SHEARING PRESSURE	3,600 psi
F-DEACTIVATION BALL/# TO DEACT.:	2
DIAMETER	1 3/8"
MATERIAL	Steel
G-LOCKING BALL/# TO LOCK OPEN:	1
DIAMETER	1 1/8"
MATERIAL	Ertalyte
SHEARING PRESSURE	2,200 psi
H-SIZE OF PORT	1.1"
NUMBER OF PORTS	2
TFA WHEN TOOL IS OPEN	1.901 sq/in
NUMBER OF CYCLES	5
OVERALL LENGTH	9.63 ft
WEIGHT	850 lbs
TENSILE STRENGTH	3,100,00 lbs
TORSIONAL STRENGTH	190,000 ft/lbs
MAKE UP TORQUE	34,840 ft/lbs

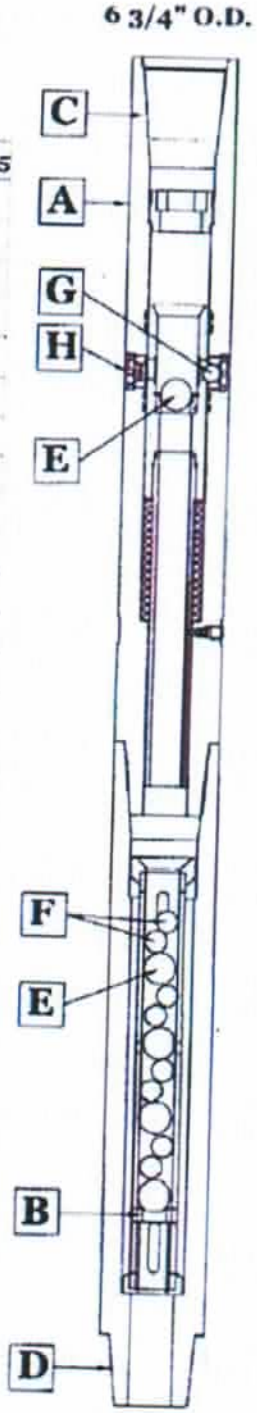
NOTES:

NO DRIFT WHEN BALLS ARE IN TOOL.

* Tool is rated to operate in temp. up to 420 degrees Fahrenheit.

* Ball Trap Installed: YES (NO)

Completed By/Date: JD / 7-21-10



Attachment 4:
MOP for 5⅞-in Drill Pipe at 8½-in Interval to Total Depth

Drill String Design - Margin of Overpull

This worksheet calculates ***Margin of Overpull (MOP)*** for pipe configurations with up to 5 different sizes of drill pipe and 3 different sizes of drill collars plus hevi-wate dp. It can also incorporate a safety factor.

Well: MC252-3 **Description:** 8 ½-in Drilling assembly

Drill Pipe Data

Bottommost Section Pipe #1		Pipe #2	Pipe #3	Pipe #4	Uppermost Section Pipe #5
5.875	OD		OD	OD	OD
4.875	ID		ID	ID	ID
34.03	Nominal Wt		Nominal Wt	Nominal Wt	Nominal Wt
34.03	Adjusted Wt		Adjusted Wt	Adjusted Wt	Adjusted Wt
135,000	Yield strength, psi		Yield strength, psi	Yield strength, psi	Yield strength, psi
90	% rem wall		% rem wall	% rem wall	% rem wall
Tensile strengths from the pipe drill pipe data entered above					
1,205,617	Tensile Strength		Tensile Strength	Tensile Strength	Tensile Strength

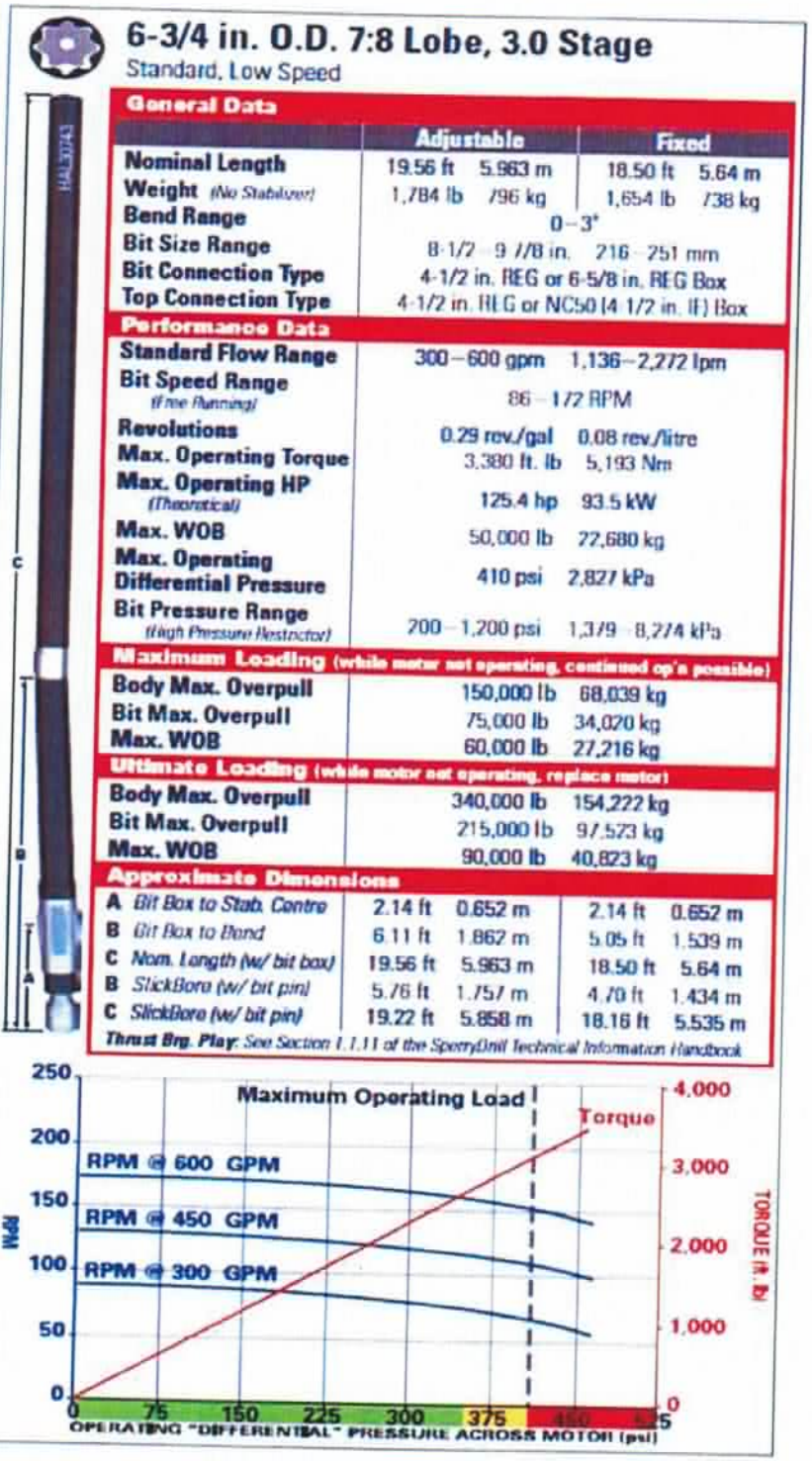
BHA Data

6.750	⇐ DC #1 OD		⇐ DC #2 OD		⇐ DC #3 OD	5.875	⇐ HWDP OD
2.813	⇐ DC #1 ID		⇐ DC #2 ID		⇐ DC #3 ID	4	⇐ HWDP ID
250	⇐ DC #1 Length		⇐ DC #2 Length		⇐ DC #3 Length	870	⇐ HWDP Length
☐ Spiraled	⇐ Spiraled (√)	☐ Spiraled	⇐ Spiraled (√)	☐ Spiraled	⇐ Spiraled (√)	☑ Spiraled	⇐ Spiraled (√)
101	Wt/ft DC #1		Wt/ft DC #2		Wt/ft DC #3	Buoyancy Factor	0.7861
25,194	Wt. DC #1		Wt. DC #2		Wt. DC #3	Air weight of BHA	72,524
			Wt WH equip			Buoyed weight of BHA	57,013
Depth of Interest ⇒ ⇒ ⇒ ⇒			18,100	Safety Factor	80 %	Total length of BHA	1,120'
Anticipated Mud weight			14.00	Block Wt.	120,000	**Total depth**	18,100

		Buoyed Wt	Section MOP		
Enter Length DP #1 ⇒	16,980	454,248	453,232 #	Pipe needed on last sec.	0'
Enter Length DP #2 ⇒	0			Weak point in string	453,232
Enter Length DP #3 ⇒	0			Total weight of string	511,262
Enter Length DP #4 ⇒	0			Total weight BLK & string	631,262
Enter Length DP #5 ⇒	0			Total weight Indicator Reading With over pull.	1,084,494

NOTE: The air weight of spiraled hevi-wate drill pipe is calculated as 96% of non-spiraled HWDP.
Assumes lowest planned mud weight of 14.0 ppg for section
All pipe shall be inspected to 90% of rem wall.
BHA per SperrySun proposed BHA #12 (8 ½-in Ranging PDM BHA)

Attachment 5:
6¾-in Sperry Drill Lobe 7/8, 3-Stage Motor Specs



6-3/4 in. O.D. 7:8 Lobe, 3.0 Stage
Standard, Low Speed

General Data	Adjustable	Fixed
Nominal Length	19.56 ft 5.963 m	18.50 ft 5.64 m
Weight (No Stabilizer)	1,784 lb 796 kg	1,654 lb 738 kg
Bend Range	0 – 3°	
Bit Size Range	8-1/2 – 9 7/8 in. 216 – 251 mm	
Bit Connection Type	4-1/2 in. REG or 6-5/8 in. REG Box	
Top Connection Type	4-1/2 in. REG or NC50 (4 1/2 in. IF) Box	

Performance Data	
Standard Flow Range	300 – 600 gpm 1,136 – 2,272 lpm
Bit Speed Range (Free Running)	86 – 172 RPM
Revolutions	0.29 rev./gal 0.08 rev./litre
Max. Operating Torque	3,380 ft. lb 5,193 Nm
Max. Operating HP (Theoretical)	125.4 hp 93.5 kW
Max. WOB	50,000 lb 22,680 kg
Max. Operating Differential Pressure	410 psi 2,827 kPa
Bit Pressure Range (High Pressure Restrictor)	200 – 1,200 psi 1,379 – 8,274 kPa

Maximum Loading (while motor not operating, continued op's possible)	
Body Max. Overpull	150,000 lb 68,039 kg
Bit Max. Overpull	75,000 lb 34,020 kg
Max. WOB	60,000 lb 27,216 kg

Ultimate Loading (while motor not operating, replace motor)	
Body Max. Overpull	340,000 lb 154,222 kg
Bit Max. Overpull	215,000 lb 97,523 kg
Max. WOB	90,000 lb 40,823 kg

Approximate Dimensions				
A Bit Box to Stab. Centre	2.14 ft	0.652 m	2.14 ft	0.652 m
B Bit Box to Bend	6.11 ft	1.862 m	5.05 ft	1.539 m
C Nom. Length (w/ bit box)	19.56 ft	5.963 m	18.50 ft	5.64 m
B SlickBore (w/ bit pin)	5.76 ft	1.757 m	4.70 ft	1.434 m
C SlickBore (w/ bit pin)	19.22 ft	5.858 m	18.16 ft	5.535 m

Thrust Brg. Play: *See Section 1.1.11 of the SperryDrill Technical Information Handbook*

Attachment 6a: 5⁷/₈-in Drill Pipe Spec Sheet

FOR REFERENCE ONLY

GRANT

1450 Lake Robbins Drive
Suite 600
The Woodlands, TX 77380 U.S.A.
Phone: 281-297-8500
Fax: 281-297-4525
Toll Free: 800-231-0283

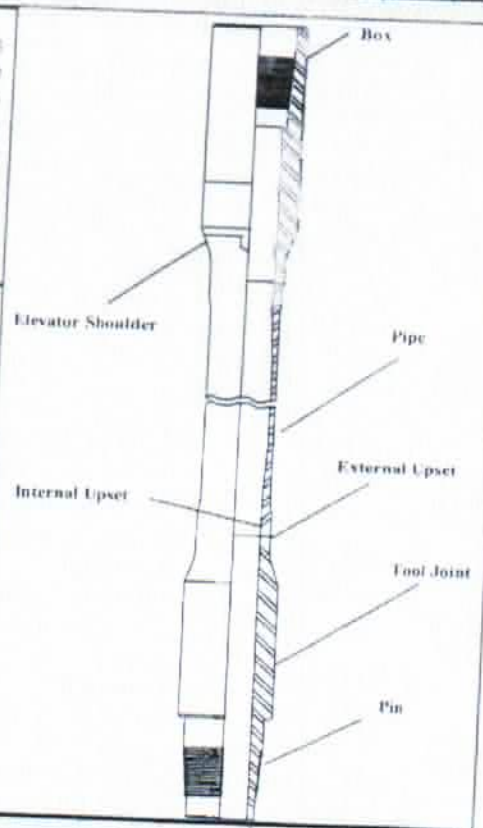
Drill Pipe Performance Characteristics Sheet ©

Minimum make-up is based on shoulder separation caused by bending

Pipe Size and Weight: 5-7/8" 0.500"wt XR™ IEU
Pipe Grade: S-135
Range: 2
Tool Joint: 7.000 X 4.250 XT57

Pipe	5-7/8" 0.500"wt XR™ IEU	
Dimensional Data	**New**	**Premium**
OD (in)	5.875	5.675
Wall thickness (in)	0.500	0.400
ID (in)	4.875	4.875
Cross sectiona	8.443	6.629
Cross sectiona	27.109	25.294
Cross sectiona	18.665	18.665
Section modul	10.470	8.172
Polar section m	20.939	16.344
Performance Data	**New**	**Premium**
Torsional strength (ft-lbs)	135,900	106,100
Tensile strength (lbs)	1,139,800	894,900
80% Torsional strength (ft-lbs)	108,700	84,900
Pressure capacity (psi)	20,106	18,383
Collapse capacity (psi)	21,023	14,824

Tool Joint	7.000 X 4.250 XT57
Dimensional Data	
OD (in)	7.000
ID (in)	4.250
Pin tong length (in)	16.0
Box tong length (in)	17.0
Performance Data	
Torsional Strength (ft-lbs)	94,300
Max Recommended Make-up Torque (ft-lbs)	56,600
Min Recommended Make-up Torque (ft-lbs)	33,800
Balance OD (in)	6.93
Tensile strength (lbs)	1,208,700
Tool joint/Drill pipe torsional ratio (New pipe)	0.69
Tool joint/Drill pipe torsional ratio (Prem pipe)	0.89
Min OD for premium class (in)	6.781



Drill pipe assembly with eXtreme™ Torque tool joint	
Adjusted weight (lbs/ft)	34.03
Approximate length (ft)	32.35
Fluid displacement (gal/ft)	0.521
Fluid capacity (gal/ft)	0.941
Drift size (in)	4.125

Attachment 6b: 3½-in Drill Pipe Spec Sheet

Allis-Chalmers Rental Services, LLC.

208 Bon Crest
Broussard, LA 70518
337-387-3396

P. O. Drawer 2367
Morgan City, LA 70381
800-631-2573

6101 U S Highway 59 North
Victoria, TX 77905
361-572-4007

Product Specifications

3-1/2" 13.3# S-135 3-1/2" IF

Product:	Drill Pipe (PIP-504)		
Tube Size:		3-1/2	In.
Nominal Weight/Ft:		13.30	Lbs./Ft.
Tube Grade:		S-135	
Connection:		3-1/2" IF	
Hardbanding/Coating	ARMACOR-M/TK-34XT		
Tube Specifications			
Inside Diameter:		2.764	In.
Wall Thickness:		0.368	In.
Tensile Yield New:		489,000	Lbs.**
Premium:		382,000	Lbs.
Torsional Yield New:		33,400	Ft.-Lbs.**
Premium:		25,900	Ft.-Lbs.
Test Pres(New/Prem):	22,700	17,300	PSI**
Burst(New/Prem)	24,800	22,700	PSI**
Collapse(New/Prem):	25,400	21,600	PSI**
Engineering Data			
Drift Diameter:		2.438	In.
Adj. Weight/Foot:		14.72	Lbs./Ft.
Avg JtLength/JtWeight:	31.00	456	Feet | Lbs.
Displacement (Open):		0.2240	Gal./Ft.
		0.5333	Bbl./100 Ft.
Capacity:		0.3080	Gal./Ft.
		0.7333	Bbl./100 Ft.
Connection Specifications			
Outside Diameter:		4-7/8	In.
Inside Diameter:		2-9/16	In.
Tensile Yield New:		551,700	Lbs.**
Premium:		408,000	Lbs.
Torsional Yield New:		20,200	Ft.-Lbs.**
Premium:		17,300	Ft.-Lbs.
Make Up New Min:		10,100	Ft.-Lbs.**
New Max:		12,000	Ft.-Lbs.**
Premium Min:		10,000	Ft.-Lbs.
Premium Max:		10,500	Ft.-Lbs.
Recommended:		10,500	Ft.-Lbs.
Special Note:			

** The new data is for information only and is not to be used. These Product Specifications are based on AICH Premium Class 1 minimums. Refer to manufacturer for performance at specific specifications. Tension capacity at yield torque is zero. You must consider all dynamic and combined loads and include factors of safety in the final string design used in the field. All data is subject to change without notice. Please contact us with any changes or recommendations.

Thursday, May 7, 2009 - 10:09:52 AM *Page 1 of 1* *Chris P. Bourgeois*

Attachment 7:
BOEM Requirements for BOP Testing

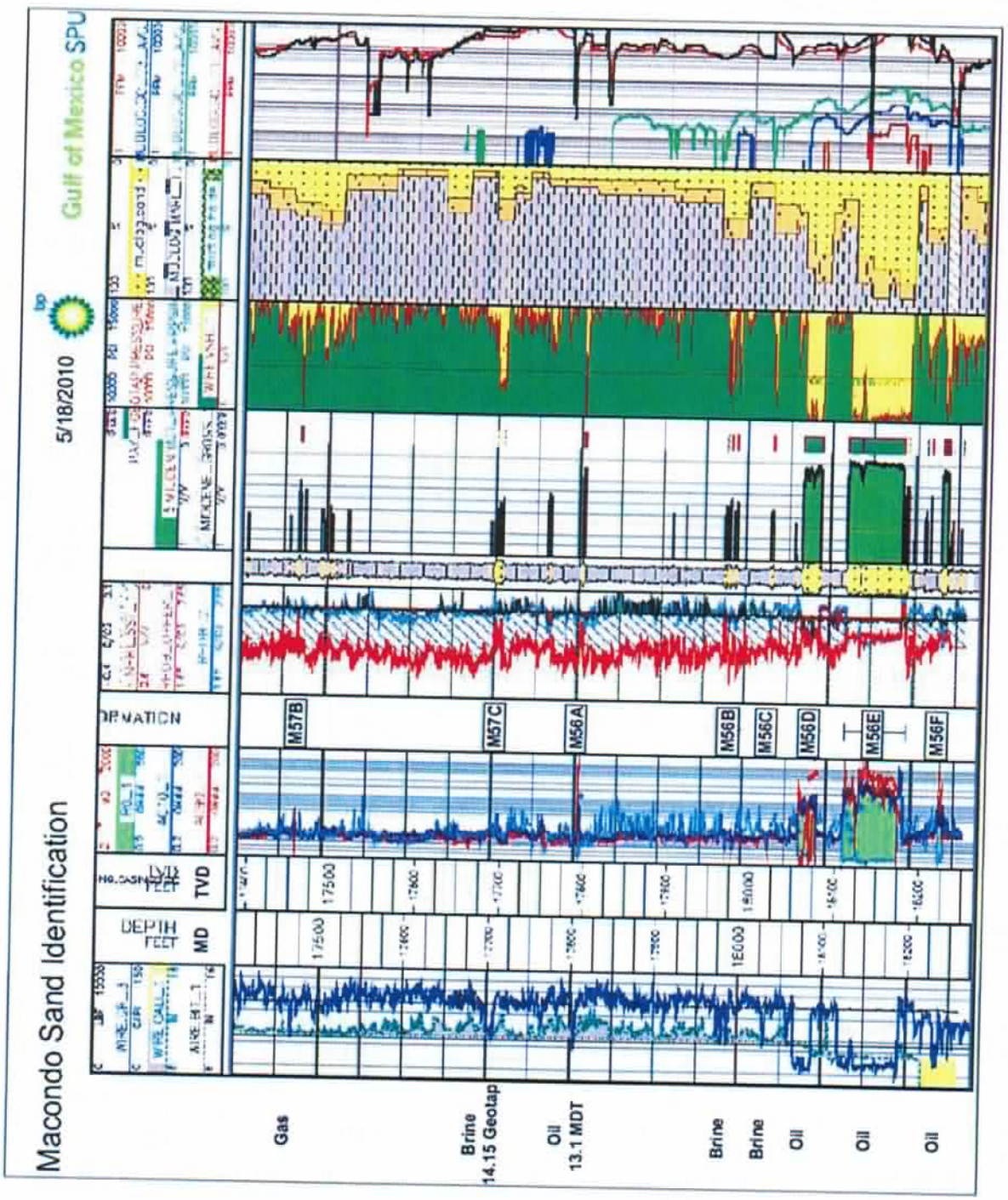
BOEM requires a Full Function and Pressure Test of all Blow Out Preventer (BOP) components, including choke and kill lines and valves and choke manifold.

- Diverter Function Test
  - Make sure mud level in riser is below diverter vent line outlets. Close diverter in "Normal" Divert mode on Diverter panel MMI. Time packer closure and verify by viewing through rotary. Observe the overboard valves opening.
  - Do not pump through vent/overboard lines. Open the diverter packer and close overboard valves and verify by visual observation.
  - This test will be performed weekly rotating between the Driller's panel and the Toolpusher's panel on the bridge and in conjunction with BOP test and weekly function test.
- After running isolation test tool or having used inverted test rams
  - Using $5^{7}/_{8}$-in drill pipe
  - Pipe rams tested to 250 psi (low) and 6,500 psi (high)
  - Annulars to 250 psi (low) and 6,500 psi (high)
- After retrieving isolation test tool or without pipe across stack
  - Test Blind Shear Ram (BSR) and casing to 250 psi (low) for 5 minutes and Application for Permit to Drill (APD) psi for 30 minutes.
  - Test second BSR to APD psi for 5 minutes.
  - Function casing shear rams.

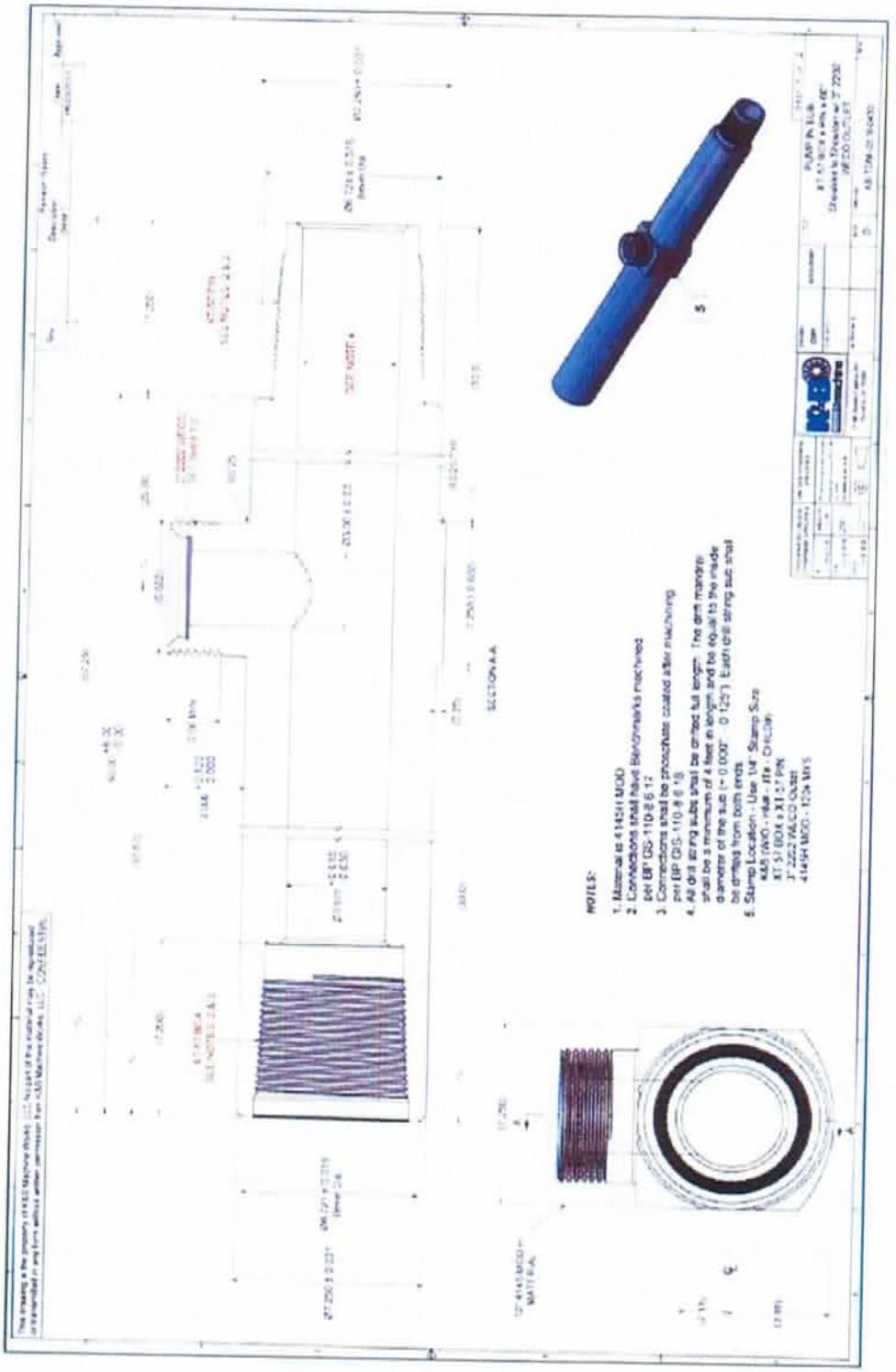
Attachment 8:
Original Pore Pressure/Frac Pressure Estimates

	Depth		Most Likely Pressure Gradient Curves, PPG			
	TVDKB, ft	MD, ft	Pore Pressure	Sand Frac	Shale Frac	Overburden
INTERCEPT PT	17120	17874	13.83	14.68	15.18	15.55
	17188	17942	13.84	14.69	15.20	15.57
	17220	**17974**	**13.85**	**14.69**	**15.21**	**15.57**
	17238		13.85	14.70	15.21	15.58
	17288		13.86	14.71	15.22	15.59
	17338		13.86	14.72	15.24	15.61
	17388		13.87	14.73	15.25	15.62
	17438		13.88	14.75	15.26	15.64
	17455		14.15	14.88	15.27	15.64
	17457		14.15	14.88	15.27	15.64
	17488		13.89	14.76	15.28	15.65
	17538		13.90	14.77	15.29	15.67
	17588		13.91	14.78	15.30	15.68
	17638		13.91	14.79	15.32	15.69
	17687		14.17	14.93	15.33	15.71
	17688		14.17	14.93	15.33	15.71
	17697		14.17	14.93	15.33	15.71
	17738		13.93	14.81	15.34	15.72
	17788		13.94	14.82	15.36	15.73
	17792		13.01	14.35	15.36	15.73
	17794		13.01	14.35	15.36	15.73
	17838		13.95	14.84	15.37	15.75
	17888		13.96	14.85	15.38	15.76
	17938		13.97	14.86	15.40	15.77
	17988		13.98	14.87	15.41	15.79
	18038		13.99	14.88	15.42	15.80
	18055		12.61	14.18	15.43	15.81
	18078		12.60	14.18	15.43	15.81
	18088		14.00	14.89	15.44	15.81
	18108		12.58	14.18	15.44	15.82
	18138		12.57	14.18	15.45	15.83
	18179		12.57	14.18	15.46	15.84
	18188		14.02	14.92	15.46	15.84
	18220		12.50	14.15	15.47	15.85
	18227		12.50	14.15	15.47	15.85
	18238		14.03	14.93	15.48	15.85
	18288		14.04	14.94	15.49	15.87
	18338		14.05	14.95	15.50	15.88
	18388		14.07	14.97	15.52	15.89

Attachment 9:
Macondo Sand Identification Log Section

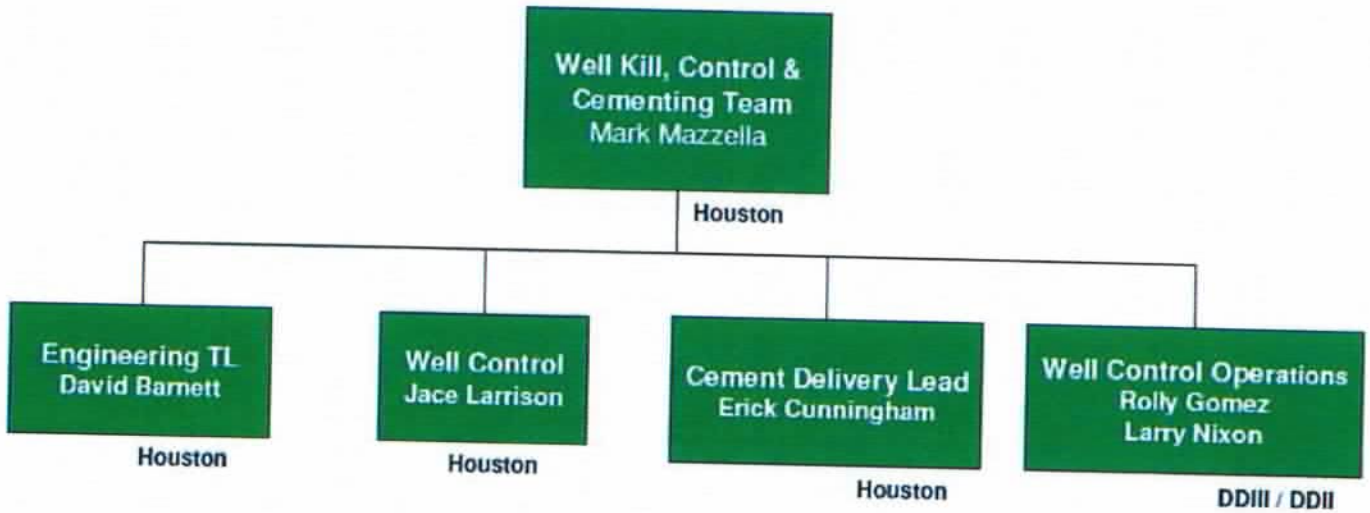


Attachment 10:
K&B Pump-in Sub



Attachment 11:
Well Kill, Control and Cementing Team Organization Chart

Well Kill, Control & Cementing Organization



Attachment 12: Intercept, Kill & Cement Operations RACIE Chart

	Pat O'Bryan	David Sims	Mark Mazzella	Jon Sprague	Robert Sanders	Doug Chestor	Bruce Rogers	Kurt Mix	David Barnett	Erick Cunningham
RIG OPERATIONS:	E									
1 Logistics		A	I		R	R				
2 Station Keeping		A	I		R	R				
3 Stability		A	I		R					
4 Equipment Maintenance		A			R					
5 Communications		A	C		R	R				
6 SIMOPS		A	C		R	R				
7 HSE		A	E	E	R	R			R	R
DOWN HOLE ACTIVITIES:	E									
1 Drillout/Perform FIT		A	C		R	R	I	I	I	I
2 Range & Intercept		A	C	C	R	R	I	R	I	
3 Commence Kill Procedures, including diagnostics		C	A	C	R	R	I	R	C	R
4 Cement & Isolate		C	A	C	R	R	I	R	C	
5 P&A		A	C	C	R	R	I	I	I	
HOUSTON SUPPORT:	E									
1 Modeling		C	C	A	C	R	C	R		
2 Cement Design		C	C	A	C	R	C	R		
3 Contingency Planning		C	C	A	C	R	R	R		
4 Well Planning Procedure Development		A	C	C	R	R	R	C		
5 Daily Engineering & Operational Planning		A	C	C	R	R	R	C		

R - **Responsible** - Bold "R" indicates primary person to work issues, other R's implement the assurance. (Person doing the work)

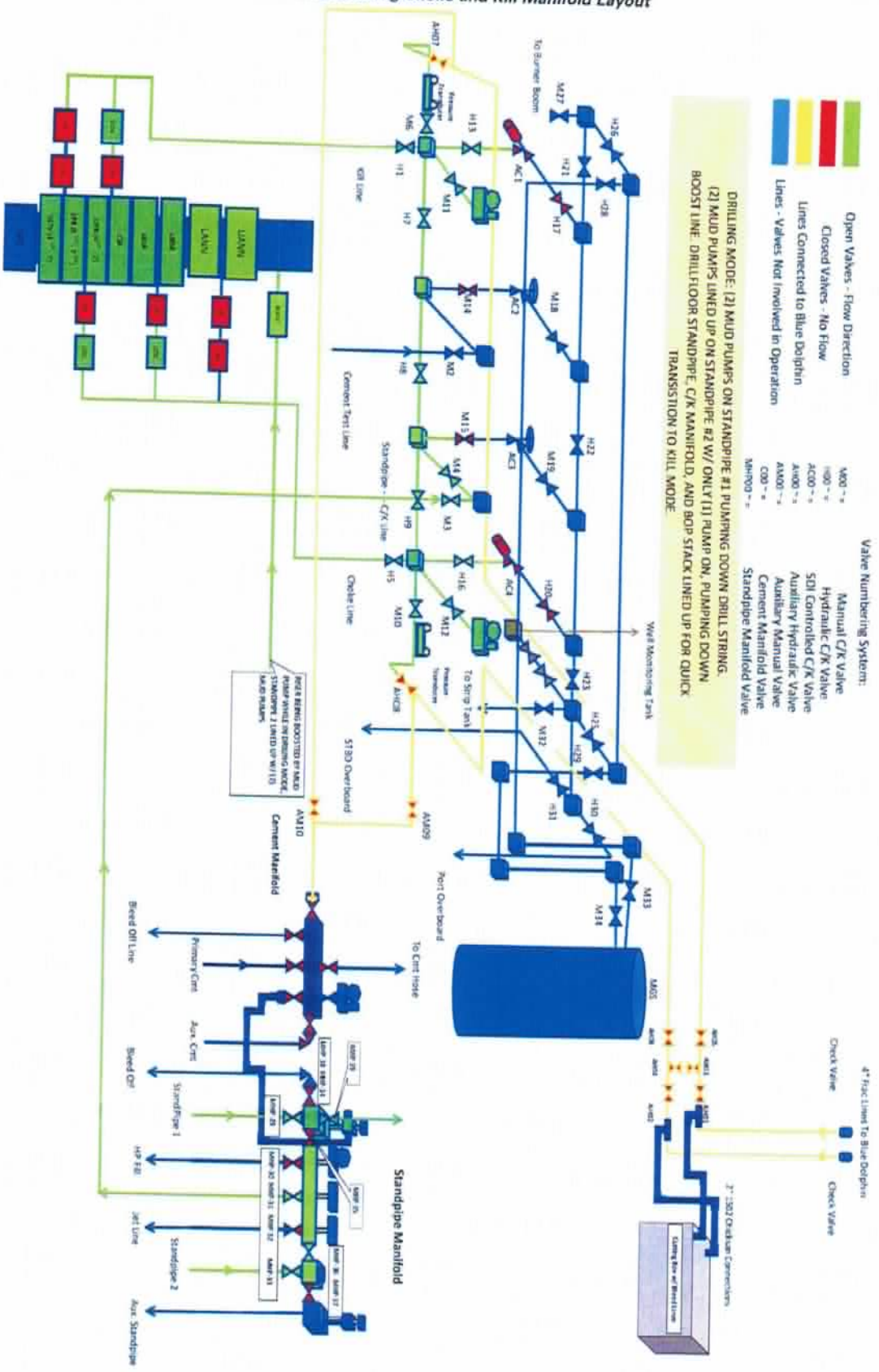
A - **Accountable** - Accepts accountability for decision (there can only be one accountable Party). ("Buck

C - **Consulted** - Individual required to be in the decision making process. (Consulted and Provides advice)

I - **Informed** - Individual is to be informed of the decision within an appropriate time. (Post)

E - **Endorses** - Endorses and has power to veto.

Attachment 13: Rig Choke and Kill Manifold Layout



Attachment 14: Macondo Relief Wellbore Sketch

BP GoM Deepwater Exploration

Macondo Relief Well (Rev 4.2_BOD)

OPERATOR:	BP	PARTNER:	Anadarko / MOEX	DATE:	9/9/2010
WELL NAME:	OCS-G-32306	MC 252#3		PTD:	18,360' TVD
FIELD / PROSPECT:	WILDCAT	AREA: OFFSHORE	STATE LA	RF ELEV:	~88' WD: 5,161'
SURFACE LOCATION:	X=1,203,820.00	Y = 10,429,008.00		PBHL:	X=1,202,674.43 Y=10,431,614.69
OBJECTIVE ZONE(S):	Macondo#1 9-7/8" shoe (M56 sand)			RIG:	DDIII

Top of LP Housing 5,238'
11' Stick up

DEPTH (RKB)

DRIL-QUIP SS-15ES BIGBORE II - Hi4
WELLHEAD SYSTEM WITH 18.500" ID

HOLE SIZE | CASING | MUD

ML @ 5,249' MD/TVD

NOTE: TOC depths (in red text) are planned tops

36" @ 5,494' MD/TVD

Shoe Depth: 28" @ 6,727' MD/TVD
Drill to depth: 28" @ 6,805' MD/TVD

16" Adapter (18.375" ID) @ 7,587' MD/7,585' TVD

18" Adapter (18.250" ID) @ 8,170' MD/8,168' TVD

Shoe Depth: 22" @ 8,762' MD / 8,751' TVD
Drill to depth: 22" @ 8,788' MD / 8,781' TVD

TOC @ ~8,458' MD

Shoe Depth: 18" @ 9,945'MD/ 9,942' TVD
Drill to depth: 18" @ 10,100' MD/TVD

TOC @ ~11,057' MD

Shoe Depth: 16" @ 12,057'MD/ 11,874' TVD
Drill to Depth: 16" @ 12,090' MD/ 11,901' TVD

TOC @ 12,038' MD (Based on CBL 7/05/10)
9-7/8" TOL @ 13,227' MD
11-7/8" TOL @ 13,552 MD

Shoe Depth: 13-5/8" @ 13,869'MD/ 13,362' TVD
Drill to Depth: 13-5/8" @ 13,978' MD/ 13,453' TVD

Top of 3-1/2" Cement Stinger @ 14,368 ft MD
TOC @ 13,842' MD (Based on CBL 5/26/10)

Before Squeeze
Planned Top Spacer @ 15,768' MD (15,033' TVD)
Shoe Depth: 11-7/8" @ 15,836'MD/ 15,101' TVD
Drill to Depth: 11-7/8" @ 15,938' MD/ 15,200' TVD

TOC @ 13,240' MD (Based on CBL 8/7/10)
Before Squeeze
Planned TOC Plug @ 17,000' MD (~16,250' TVD)
Shoe Depth: 9-7/8" @ 17,866'MD/ 17,099' TVD
Drill to Depth: 9-7/8" @ 17,864' MD/ 17,107' TVD
Current Total Depth 17,909' MD (17,152' TVD)
Planned Intersection Depth 17,969' MD (17,212' TVD)

14.2 ppg DMW

15.2 ppg Spacer 89 bbls

16.5 ppg Premium Cmt 62 bbls

8 bbls

14.4 ppg EMW w/ Cmt Plug

30.24" ID ADAPTER
JET
36" X-80 HC-100DMT
36" X-56 D-90MT
41 °F
NOTE: All fluid weights and pressures are Down hole Mud Weight.
Seawater
8.6 PP
8.7 FIT/LOT

28", 218.27ppf, X-52, D-60MT
ID = 26.50", Drift 26.25", WT 0.75"
26" X 32-1/2"
Seawater
Pad 11.5 PPG
73 °F
8.6 PP
9.9 FIT/LOT

22", 277.01ppf, X-80, H-90
ID 19.50", Drift 19.313", WT 1.25"
22", 224.26ppf, X-80 S-90 MT
ID 20.00", Drift 19.813", WT 1.0"
26"
Seawater or 9.7+/- P&D
Pad 12.7 PPG
104 °F
9.9 PP
11.4 LOT

18", 117ppf, P-110, H511
18-1/8"x22" Rotary Steerable
ID 16.75", Drift 16.563", WT 0.625"
10.1 - 10.9 ppg SOBM (DMW)
128 °F
10.7 PP
12.3 LOT

16", 97ppf, P-110, HS11
16-1/2" x 20" Rotary Steerable
ID 14.85", Drift 14.75", WT 0.575"
10.9 - 11.8 ppg SOBM (DMW)
156 °F
11.6 PP
13.2 LOT

2,000' of 13-5/8", 88.20ppf, Q-125, VAM TOP SB
13-5/8", 88.20ppf, Q-125, SLIJ-II
ID 12.375", Drift 12.25", WT 0.625"
14-3/4"x16-1/2" Rotary Steerable
11.8 - 12.8 ppg SOBM (DMW)
179 °F
12.6 PP
14.0 LOT

11-7/8", 71.8ppf, Q-125, H513
ID 10.711", Drift 10.625", WT 0.582"
12-1/4" x 14-3/4" Rotary Steerable
12.8 - 13.6 SOBM (DMW)
Bottom of 3-1/2" @ 15,768' MD
204 °F
13.4 PP
14.6 LOT

9-5/8", 53.5ppf, SM0242-110, HS13 (9" TD to ~17,744' MD/16,991' TVD)

9-7/8", 62.8ppf, Q-125, H513
ID 8.625", Drift 8.50", WT 0.625"
10-5/8" x 12-1/4"
13.6 -14.0 SOBM (DMW)
Planned TOC After Squeezing 10 bbls 17,138' MD
227 °F
13.8 PP
14.9 FIT

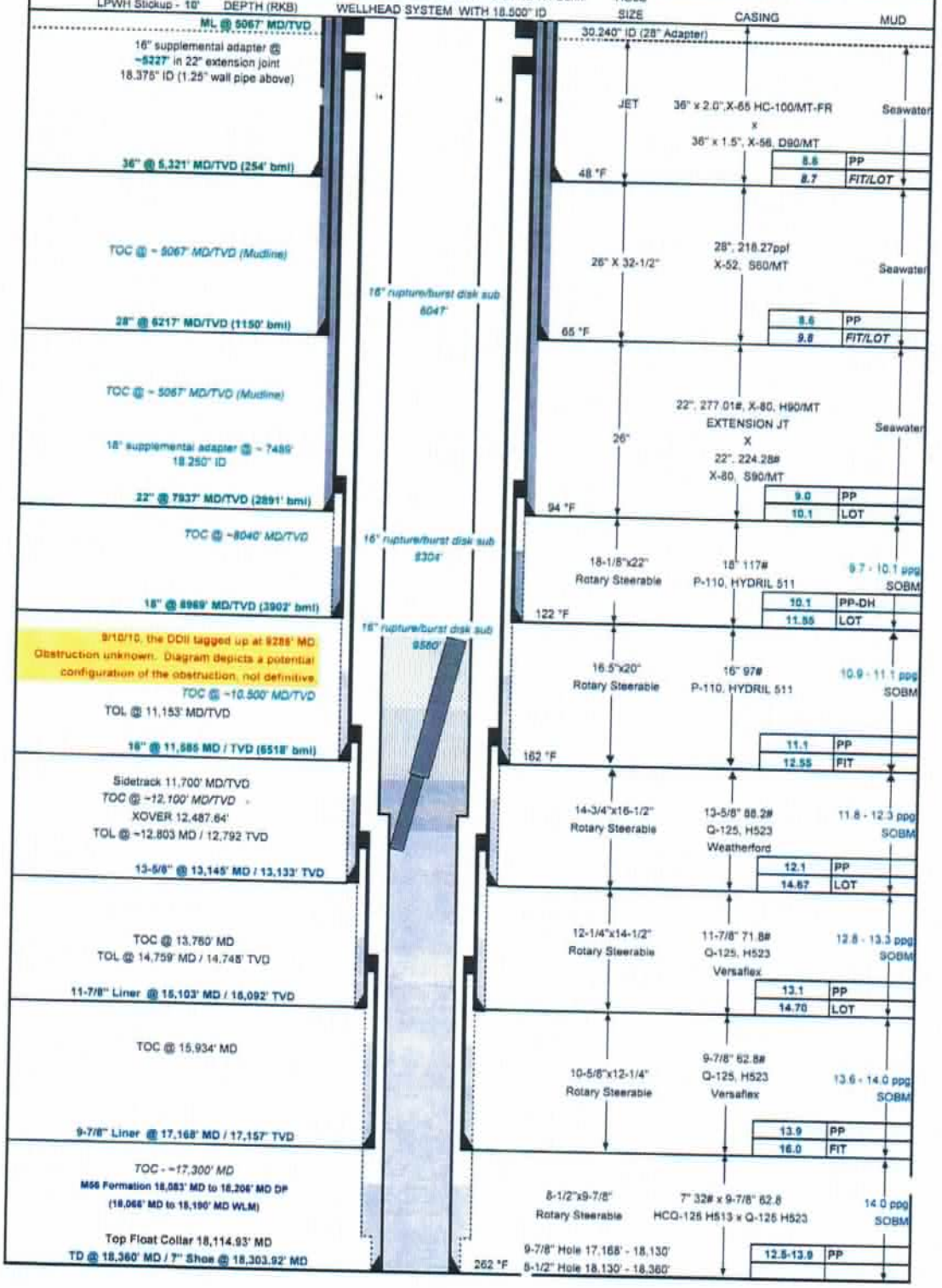
8-1/2"
14.2 ppg SOBM (DMW)
230 °F
13.85 PP
15.21 LOT

Attachment 15: MC252#1 Wellbore Sketch

BP GoM Deepwater Exploration

Macondo

OPERATOR:	BP PARTNER: Anadarko, MOEX	DATE:	4/22/2010 Rev 15 updated 9/11/10 (DDII tag)
WELL NAME:	MC 252 #1, MACONDO PROSPECT, OCS-G-32306	PTD:	19,650' MD/TVD
FIELD / PROSPECT:	WILDCAT AREA: OFFSHORE STATE LA	RF ELEV:	75' (Horizon) WD: 4992'
SURFACE LOCATION:	X=1,202,798.33 Y=10,431,619.79	BHL:	X=1,202,638.20 Y=10,431,565.74
OBJECTIVE ZONE(S):	M56	RIG:	Transocean Deepwater Horizon

DRIL-QUIP, SS-15 BIGBORE II - 27" O.D. HD-H4 Conn.

LPWH Stickup - 10' DEPTH (RKB) WELLHEAD SYSTEM WITH 18.500" ID