MACONDO

Procedure

for

MC252-1

Permanent Abandonment

RPIC APPROVAL:	Jeff Braun	J.M. Braun	9/13/2010	1310
	Print Name above	Sign Above	Date	Time
BOEM APPROVAL:	Michael Prendergast	Michael Prendergast	9/14/10	1510
	Print Name above	Sign Above	Date	Time
CGIC (USCG) APPROVAL:	N/A			
	Print Name above	Sign Above	Date	Time
BOEM (Houston Review)	David J. Trocquet	D.J. Trocquet	9/13/10	1747 hrs
	Print Name above	Sign Above	Date	Time
USCG (Houston Review)	N/A			
	Print Name above	Sign Above	Date	Time

Logged into Sarce William Broman [signature] 9/13/10 1300 hrs

0	9/9/2010	Issued for Use	Don Fryhofer/Mark Heironimus
REV	**DATE**	**DOCUMENT STATUS**	**PREPARED BY**
PRINT DATE	13-Sep-10	**DOCUMENT NUMBER**	2200-T2-DO-PR-4734

Document Authorization Form

This form to be used for authorizing new, revised and obsolete documents, please indicate clearly which category applies

Special Instructions	MC252

Document Details

Document Number	2200-T2-DO-PR-4734	**Revision**	0
Document Title	Permanent Abandonment Procedure		
Next Review Date	N/A		
Reason for Issue (check as applicable)	**New Document**	**Revised Document**	**Obsolete Document**
	x		

Document Sign Off

	Print Name	Signature	Date
Custodian/Owner	Gavin Kidd		9-10-10
	Mark Heironimus	Mark Heironimus	9/10/10
Reviewer(s) (if applicable)	Bruce Rogers		9-10-10
	Don Fryhofer	Donald W Fryhofer	9/10/10
	Theodore Eicks		9-10-10
	Andy Frazelle		9-10-10
	Jon Sprague		9/10/10
	Charles Taylor		9-10-10
Authorizer	Pat O'Bryan		9/10/10
Document Control Use			

AMENDMENT RECORD

Rev	Date	Author	Description	Sec	Page
0	8/28/2010	Mark Heironimus	Issued for Use		
0	9/1/2010	Mark Heironimus	Added HAZOP details to Attachment 12 Added Details of 1st BOP test		
0a	9/4-5/2010	Mark Heironimus	Incorporated BOEM comments		
0b	9/6/2010	Mark Heironimus	Move initial steps to start after "Latch DDII BOP to MC252#1 wellhead" procedure and Ops note. Updated table in 1.2.3 per Kate Baker's data summary		
0c	9/8/2010	Mark Heironimus	Added more detail to table in 1.2.3 to address unknown annular fluids. Added details regarding expected circ pressures.		
0c	9/12/2010	Jeff Hupp	Added LDS retrieval step. Removed Notes. Added Note to consider cement retainer instead of CIBP.	1.2.4 1.2.3 &1.2.4 1.2.7	
0d	9/12/2010	Nicholas Bortka	- Deleted duplicate "in hole" - Hold point before cut and pull 16-in - Test 18-in by 16-in annulus - JIT responsible of evidence - JIT maintain custody and control of evidence - Change preservation contact info - Attached Chain of Custody form	1.2.2 1.2.8 1.2.8 & 1.2.9 Att. 8 Att. 8 Att. 8 Att. 8	
0e	9/13/2010	Mark Heironimus	- Added new perf gun details - Clarified 3rd paragraph of 1.2 regarding zero discharge - Changed sequence & timing of18-in by 16-in annulus test --Changed step 9 from "Repeat steps 9 and 10" to "Repeat steps 8 and 9."	1.2.3 1.2 1.2.8 1.2.6	

TABLE OF CONTENTS

ATTACHMENTS

1 Permanent Abandonment

1.1. Introduction

The following procedure will be used after the Development Driller II (DDII) blowout preventer (BOP) and conventional riser has been installed and tested on the Macondo MC 252 #1 well and the Deepwater Horizon 5 1/2-in x 3 1/2-in drill pipe has been recovered from the well.

1.2. Procedure

Mud weights in this program are surface mud weight (SMW). SMW is approximately 0.15-ppg less than the downhole mud weight (DMW).

Depths specified in this procedure are based on the Deepwater Horizon's 75-ft rig floor elevation. The DDII, rotary kelly bushing (RKB) elevation of 84-ft implies all depths in this procedure will be 9-ft deeper.

Utilize zero discharge protocols for drilling fluids and cuttings throughout this procedure. Subsea discharges of mud, cuttings, other operational well fluids and miscellaneous discharges associated with P&A activities are authorized by the Federal On-Scene Commander (FOSC). Such discharges will be monitored as described in the applicable BP operating procedures and EPA NPDES Permit.

Maintain 2 ea., 9 7/8-in (and 16-in after 9 7/8-in casing is pulled) RTTS storm packers with storm valves on board for hurricane suspension contingencies.

Rig up surface equipment to handle possible hydrocarbons at the surface as detailed in Attachment 6. BOEM inspection is required. Pressure test protocol is as follows:

- Pressure test will be performed with drill water.
- Rig floor piping to choke manifold: 250 psi low for 5 min.; 7,000 psi high for 15 min. after the pressure has stabilized. The acceptance criteria is defined as stable or decreasing pressure fall off less than 10 psi/min.

  Note: Due to current activity on the rig floor, initial pressure test will be performed from SDV-001 to the choke manifold. A final confirmation pressure test will be performed after the rig floor is cleared, and the system can be connected to the rig floor. High pressure test based on pressure limits of chemical injection pump.

- Choke manifold to the LP Surge Tanks, LP Surge Tanks to the rig gas manifold, LP Surge Tanks to the 500 bbl tank and 500 bbl tank to the hose reel will be tested as a system: 50 psi low for 5 min.; 135 psi high for 15 min. after the pressure has stabilized. Acceptance criteria is defined as stable or decreasing pressure fall off less than 10 psi/min.

  Note: High pressure test based on 90% of PSV setting of 150 psi.

1.2.1. *Not used and included to preserve numbering system of previous versions*

1.2.2. *Wellbore Cleanout*

1. Stage in hole with BHA #1 to at least 12,100-ft MD displacing to 13.2-ppg mud.
    - If hard cement is not encountered in the 9 7/8-in production casing, a 6-in bit and 7-in 32-ppf casing scraper will be run until hard cement is encountered or to a maximum depth of 14,488-ft MD. **If hard cement is not encountered above this depth BP is required to contact the BOEM before proceeding.**
    - 2,000-ft of 4-in drill-pipe and BHA will be required on location. BOEM has been consulted and the length was agreed to not require a pipe ram change out from 4 1/2-in to 4-in.
    - Refer to Attachment 3 BHA #9 for detailed contingency 6-in Bottom Hole Assembly (BHA) information.
    - "Hard Cement" is defined throughout the procedure as able to support 15,000 lbs of BHA weight for 5-minutes.
2. Circulate bottoms up with 13.2-ppg SMW SOBM.
3. Flow check and TOOH. Rack back BHA.

Note: If a deep cleanout of the 7-in casing is required, contingency procedures have been prepared to adjust the P&A Plan.

1.2.3. *Isolate 7-in x 9 7/8-in Production Casing Annulus*

Preparation: Make up cementing stand with Blackhawk Cementing head loaded with 2 Halliburton soft foam 6-in drill pipe wiper balls.

1. RIH with combination TCP HSC gun (10-ft loaded 6-spf, 0.22-in holes, 60° phasing, 61 holes) and Halliburton 9 7/8-in EZSV-B retainer dressed for Q-125 casing on 5 7/8-in drill pipe.
    - Refer to Attachment 10A for details of the perforating assembly.
    - The perf gun and charges will be configured to ensure the 13 5/8-in casing is not damaged.
    - A contingency 7-in Dril-Gun combination (EZSV/TCP perf gun) is included in Attachment 10 if cement is tagged lower than the 9 7/8-in x 7-in crossover.
2. Rig up and pressure test cementing equipment and test to 250 psi low and 5,000 psi high for 5 minutes after the pressure has stabilized. The acceptance criteria are defined as stable or decreasing fall off less than 10 psi/min.
3. Circulate 40-bbls prior to setting retainer.
4. Set retainer at 12,025-ft MD, about 75-ft MD above TOC in production casing.
5. Pressure up on drill pipe X production casing annulus to 3,500-psi.
    - Guns hung to perforate at 12,050-ft to 12,054-ft MD, about 46-ft above TOC.

- Keep annular preventer closed and maintain 3,500-psi on the drill pipe X production casing annulus to provide positive differential pressure on 9 7/8-in casing hanger and seal assembly.

6. Pressure up drill string to ~3,550-psi to fire TCP gun. Monitor initial pressure until stabilized.
   - If annulus contains 14.0-ppg SMW SOBM, the U-tube pressure acting against the 13.2-ppg SMW SOBM in the production casing will be approximately 500-psi [(13.2 ppg - 14.0 ppg)*12,050-TVD*.052=501-psi] . If the annulus had been in communication with the reservoir, but is now isolated and contains hydrocarbons, lower pressure is expected.
   - If the annulus is still in communication with the reservoir the pressure in the production casing will increase approximately 500 psi.
   - If rupture discs have failed, be prepared to monitor losses on the drill pipe and fill pipe with base oil. Leak Off Test (LOT) @ 18-in shoe was 11.55 ppg Down Hole Equivalent Mud Weight (DHEMW). The hole will not be capable of holding a full column of 13.2 ppg EMW if the discs have ruptured. Track barrels of base oil pumped to allow estimation of frac gradient. After establishing frac gradient, next contingency step is to un-sting from retainer and circulate to adjust mud weight.
   - Keep annular preventer closed with 3,500-psi on the drill pipe X production casing annulus.
7. Attempt to establish injection rates.
   - Maximum allowable injection pressure at 1/4 to 1/2 bpm is 3,200-psi.
     - This is a 17.1 ppg equivalent at the 9 7/8-in shoe which is 1.0 ppg over the FIT, assuming 14.0 ppg mud is in the annulus.
   - Rupture disks in 16-in casing are rated for 7,000-psi differential pressure at 150°F. Details included in Attachment 7.
   - With 14.0 ppg mud in the annulus and 3,200 psi surface pressure, there is a maximum of 4,300 psi differential across the burst disks.
   - With 7.84 ppg fluid in the annulus and 3,200 psi surface pressure, there is a maximum of 5,500 psi differential across the burst disks.
   - Depleted sand pore pressures below the 9 7/8-in shoe range are estimated to be about 11.1-ppg DHEMW. If the casing annulus contains SOBM and the 9 7/8-in liner shoe is open to depleted sands, the injection pressure will be less than 656-psi.
   - Calculations indicate the 1,064-bbl annulus will require 2.5-bbls to pressure up 1,000-psi if mud filled and if the annulus has become hydrocarbon filled it will require 15-20 bbl to compress the annulus 1,000-psi.
   - If the annulus is full of 7.84 ppg fluid, the 3,200 psi surface pressure is equivalent to 14.3 ppg, which is greater than the 13.5 ppg reservoir frac gradient, but less than the 16.1 ppg 9 7/8-in shoe FIT.

8. If able to inject, bullhead 300 bbls of 13.2 ppg SOBM. Stage up from 2 to 8 bpm, not to exceed the maximum pressure indicated in the table below. Do not exceed a maximum of 4,000 psi. Expected pressures are as follows:

Pump Rate (bpm)	Expected Surface Press (to be added to injection pressure) (psi)	Maximum Injection Pressure with Rate (psi)
4	300	3,500
6	500	3,700
8	1,500	4,700*

**This rate may exceed maximum allowable injection pressure of 4,000 psi. Thus, it may not be achievable.*

Note: A minimum of 2 bpm injection rate is required to proceed with the cement job.

9. Keep annular preventer closed with 3,500-psi on the drill pipe X production casing annulus.

Note: If unable to establish injection with 3,200 psi injection pressure, bleed pressure below retainer back to initial pressure obtained in step 6 above to avoid trapped pressure impacts on future operations. Sting out of retainer as per step 12 below. Circulate bottoms up and TOOH. Skip to Section 1.2.4 to lay a balance cement plug above retainer.

BOEM consultation will be required if injection cannot be established at 3,200 psi, due to oil in the annulus. An Ops Note will be written to attempt a 17.1 ppg equivalent injection pressure after the 9 7/8-in casing is cut and pulled.

10. If injection rate is established, mix and pump 150-bbls of 14.8-ppg spacer, 270-bbls of lead and tail, 16.5-ppg class H cement with 35% BWOC silica flour. Drop 2 each soft foam drill pipe wiper balls from Blackhawk cementing head followed by 40 bbls of 14.8 ppg spacer.
    - Halliburton cement recipes and cement/spacer volumes are included in Attachment 4 and are subject to revision after final lab test results are completed.
11. Displace with 13.2-ppg SMW SOBM to place the wiper balls 5-bbls (221-ft) above the EZSV running tool.
12. Bleed back 1/2 bbl of mud to relieve final squeeze pressure. Shut in drill pipe, bleed pressure from the drill pipe X casing annulus until equalized with the drill pipe pressure. Strip drill pipe through annular and sting out of retainer. Bleed off pressure in drill pipe and drill pipe X production casing annulus. Open annular preventer.
13. Circulate bottoms up immediately above retainer with 13.2-ppg SMW SOBM utilizing pipe wiper balls to clear drill pipe.
14. TOOH.

1.2.4. *Balanced Plug on 9 7/8-in Retainer and 9 7/8-in Casing Log*

Preparation: Make up cementing stand with Blackhawk Cementing head loaded with two (2) Halliburton, Hard, Black 5.5-in drill pipe wiper balls.

1. P/U 2,000-ft of 4-in, XT39 open ended drill pipe stinger and 5 7/8-in drill pipe with 5 1/2-in Halliburton Indicating Ball Catcher positioned ~562-ft above 4-in x 5 7/8-in crossover.
2. TIH to EZSV at 12,025-ft.
3. Rig up cementing stand with swivel to allow rotation while displacing cement and spacer. Rig up and pressure test cementing equipment and test to 250 psi low and 5,000 psi high for 5 minutes after the pressure has stabilized. The acceptance criteria are defined as stable or decreasing fall off less than 10 psi/min.
4. Make-up top-drive. Circulate one bottoms-up volume at 10-bpm to mobilize mud prior to cementing and to ensure a clean hole.
5. Close upper TIW on cementing stand and trap 1,000-psi on Top Drive.
6. Mix and pump 75-bbls of 14.8-ppg spacer. Drop 1st ball from Blackhawk cementing head followed by 50-bbls of 16.4-ppg class H cement with 35% BWOC silica flour. Drop 2nd wiper ball from Blackhawk cementing head and follow with ~10 bbls of 14.8-ppg spacer.
   - Halliburton cement recipes and cement/spacer volumes are included in Attachment 4 and are subject to revision after final lab test results are completed.
7. Displace with 13.2-ppg SMW SOBM @ >10-bpm using the top drive and rig pump.
   - Rotate 25-rpm as cement exits the work string.
   - Utilize IBC to under-displace cement by 15 bbls by pumping 5 additional bbls after ball indication which will position cement 10 bbls short of balance. The cement will be ~350-ft and ~60 psi out of balance at this point.
   - Planned top of cement is at 11,318-ft MD or ~ 700-ft above the 9 7/8-in retainer.
   - Displace using two pit system without returns into the suction pit for positive verification of mud displacement volumes.
   - A pressure "spike" of 3,000 psi is expected as wiper balls enter the indicating ball catcher.
8. Rig down cementing equipment. POOH at 3-min/stand to ~10,818-ft MD (500-ft above top of cement).
9. Circulate bottoms up utilizing free dropped foam wiper balls to clean drill pipe.
10. TOOH while WOC.
11. TIH with 8 1/2-in bit and 9 7/8-in casing scraper.
12. Clean out to 11,875-ft MD after WOC for at least 150% of the time required to build 500-psi compressive strength.

13. Close annular preventer. Pressure test to 1,000-psi for 15-minutes. The pressure test is acceptable where pressure drop is <10% over 15 min.
14. Open annular preventer.
15. Slack off while pumping slowly at 2-bpm. Weight test plug with 15,000-lbs for 5 minutes.

Note: If required, the Surface Mud Weight (SMW) in the production casing may be increased after above plug is in place, to match pressure observed during perforating operations. SMW in the production casing annulus was 14.0-ppg when the production casing was run and cemented.

16. TOOH. Lay down BHA off line.
17. Rig up and run Schlumberger Imaging Behind Casing (IBC)/Isolation Scanner log from PBTD of 11,875-ft to mudline to determine likely fluids behind the production casing and condition of the production casing. POOH.
    - Report results to and confer with BOEM before proceeding with permanent abandonment. Results will include any indication of damage to the casing. The top of cement (TOC) is not expected behind the logged interval, but this log will confirm. Results will also define the nature of the material behind the 9 7/8-in casing (i.e., mud, oil or gas).

Note: Prior to retrieving the 9 7/8-in casing, casing hanger and seal assembly, a video record of the wellhead area may be required if prior information is deemed insufficient. An ops note will be issued with a detailed procedure.

18. RIH with Dril-Quip lock down sleeve (LDS) retrieving tool. Latch and release the LDS.
19. POOH LDS and lay down.

1.2.5. *Cut and Pull 9 7/8-in Production Casing*

Evidence Preservation and Chain of custody requirements must be followed regarding all equipment recovered from the well as per Attachment 8.

Prior to proceeding to the next step BOEM consultation is required.

1. TIH with 9 7/8-in Casing cutter assembly to 11,825-ft and cut casing about 50-ft above the previous plug. Drop ball to activate circulating sub. Monitor for flow or pressure for 30-minutes.
    - Refer to Attachment 3, BHA #2 for detailed Bottom Hole Assembly information.
2. Circulate bottoms up. POOH.
3. RIH with casing spear and pack-off with 6 5/8-in landing string for maximum over-pull.
4. Position 6 5/8-in drill pipe across BOPs. Test pipe rams and annular preventers to 250-psi low and 4,100-psi high.
5. Spear into top of 9 7/8-in casing. Ensure non-shearable BHA components are not positioned across BOP stack. Complete rig up of surface equipment to handle possible hydrocarbons at the surface.

- Refer to Attachment 3, BHA #3 for detailed Bottom Hole Assembly information.

6. Review the process flow diagram (Rev F) with rig personnel and Schlumberger staff and ensure it is understood by all parties involved with the annulus displacement.
7. Install the Schlumberger pressure tanks, choke, pumps, and 500-bbls tank and plumb the lines as shown in Piping and Instrumentation Diagram (Rev E).
8. Contact nearby vessels and inform boat captains of potential flare ignition. Safe distance will be **700-ft away** from DDII (HAZOP action #2).
9. Confirm who will be monitoring for temperatures downstream of the Schlumberger choke and of the LP flare line and who has the action to shut down of the system and rig pumps if temperature approaches -20°F. Temperatures should be monitored downstream of the choke (e.g., via TI-03) and the LP flare line downstream of PCV 2100 and PCV 2200. An infrared gun can be used to monitor temperatures if no TI's are present. The temperature should be monitored initially when the casing seals have been removed from the wellhead as this is when gas is most likely to be removed from the system. Temperature should be monitored throughout the operation (approximately every 30 minutes) to ensure piping and equipment does not operate below carbon steel minimum design temperature limit of -20°F (HAZOP action #3).

Note: The pressure drop will be at the Schlumberger choke manifold.

10. Confirm who will notify Schlumberger personnel to shut down equipment if the rig floor stops the mud pumps to cease displacing the annulus (HAZOP action #4).
11. BP Well Completion and Intervention Specialist to confirm the safe area overboard from the 500-bbl tank is appropriate for a gas blow-by scenario. <u>Safe area to comply with the following classifications from the vent tip: Zone 0 for the initial 18-inch radius, Zone 1 for a 5-ft radius, and Zone 2 for a 10-ft radius</u> (HAZOP action #6).
12. Purging of well test equipment should be done no greater than 24 hours in advance of starting rig pumps for annulus displacement. Prior to starting rig pumps for annulus displacement, Schlumberger supervisor to confirm all equipment has been purged with nitrogen and have measured no oxygen at high point vents prior to completing purge operations. Purge to include LP flare line, and 500-bbl tank vent line. Have enough nitrogen available to continuously purge the flow back equipment (HAZOP action #7).
13. BP Well Completion and Intervention Specialist to confirm PSV located on the 500-bbl tank and ensure it is relieved to a safe location which meets area classification. <u>Safe area to comply with the following classifications from the vent tip: Zone 0 for the initial 18-inch radius, Zone 1 for a 5-ft radius, and Zone 2 for a 10-ft radius</u> (HAZOP action #9).
14. Install nitrogen purge connection on the vent line of the 500-bbl tank to prevent oxygen ingress (HAZOP action #11). Continuous purge operations to prevent oxygen ingress will occur if hydrocarbons are pumped into 500-bbl tank.

15. Announce to all staff that a single choke manifold and a single choke on that manifold (rig or Schlumberger) will be used at a time (HAZOP action #12).
16. BP Well Completion and Intervention Specialist to confirm the mud pump pressure safety high figure and pop off valve set point prevents premature opening of well burst discs located in 16-in casing (discs will burst at 7,000-psi, see section 1.2.1 of procedure #4734) (LOPA action #1).
17. During annulus displacement, Schlumberger operator in charge of LP surge tanks (MBJ-2100 & 2200) to verify the flow has stopped into entry into initial tank after switching to secondary tank (LOPA #3).
18. SPA to verify all items in checklist above have been performed. **An email will need to be sent to Houston office providing details of each item for documenting closure of HAZOP action items. The engineering and operations managers will need to review the email to give closure to the HAZOP actions PRIOR to annulus displacement. Verify BOEM inspection has been performed and all BOEM actions have been closed out.**

1.2.6. *Schlumberger Pre-Job Checklist*

- Rig up and function ESD system.
- Pressure test from rig floor to choke manifold.
- Pressure test from choke manifold to LP surge tanks (MBJ-2100 & 2200).
- Pressure test from LP suge tanks (MBJ-2100 & 2200) to gas manifold on rig.
- Pressure test from LP surge tanks (MBJ-2100 & 2200) to 500 barrel tank and to hose reel to barge inlet.
- Pump water down to barge to ensure Todo Quick Connect is connected properly and not hydraulical locked.
- Fill LP surge tanks with an initial fluid level and record in reading sheets.
- Light flare pilot on appropriate boom. Ensure LP flare pipe is 4-in.
- Bypass PSL-101 upstream of Choke Manifold and PSHL-301 downstream of Choke Manifold if WHP is around 300 psi.

1. Hold safety meeting with rig crew, Dril-Quip, Schlumberger, Wild Well Control, and all personnel involved with annulus displacement operations. Meeting discussion should include:
   a. Roles and responsibilities of critical personnel involved with the operation.
   b. Communication plan prior to stripping casing hanger from wellhead, during circulation of potential hydrocarbons, and after hydrocarbons are removed from the system.
   c. Flow path from rig floor to Schlumberger equipment in case of hydrocarbon presence.
   d. Flow path from rig floor to rig mud/gas separator system if no hydrocarbons.

e. Safe area overboard on rig from the 500-bbl atmospheric tank.

f. Confirm boat captains have been informed of flare operation and are away from the rig during annulus displacement.

g. Weather conditions for the next 12 hours to determine offloading/transfer of fluid from wellbore to 500-bbl tank or to boat.

h. Verify appropriate valves are open for flow to LP surge tank MBJ-2100 in the case of hydrocarbons are encountered. Ensure valve #10 is closed so initial flow path is directed to the rig mud/gas separator system.

i. Schlumberger to discuss with rig crew the procedure for pressure testing their equipment.

j. Wild Well Control to be on rig floor during circulation of annulus fluids.

k. SPA to verify all items in equipment preparation checklist above have been performed. **Verify engineering and operations managers have given approval for closing HAZOP action items prior to executing next step.**

2. Close annular preventer. Strip 9 7/8-in casing hanger until seal assembly is clear of subsea wellhead and circulation around the casing becomes possible.
   - Dril-Quip Service representative to be present on rig floor.
3. Have SDV-001 upstream of Schlumberger choke manifold open and upstream choke manifold valves closed.
4. Circulate out using 1st step of the "Drillers" well control method at a maximum rate of 2 bpm (this is a max rate and should not be exceeded).
   - Bring pumps up to speed allowing casing pressure to fall by amount of choke line friction. Monitor differential fluid volumes. After pressure and pump rates stabilize, switch to DP pressure gauge and keep constant.
   - Simulations of modeled operations are included in Attachment 5 for two hydrocarbon cases at 1/2-bpm and 2-bpm. Expected choke positions are included.
   - Adjust choke accordingly to maintain back pressure as required by driller to minimize U-tube.
   - Check BSW every 5 minutes to determine annulus fluid and record.
   - Check H_2S and CO_2 with Draeger tubes if gas or oil to surface.
5. Circulate returns to dedicated pit to capture returns from DDII choke/kill line volume. Circulation path will be through the mud gas separator system until gas is observed (if any).

6. If hydrocarbons are observed during the circulation at the mud/gas separator, route the circulation to the Schlumberger system on the main deck. Continue to take samples at Schlumberger choke manifold to determine the nature of the fluid being displaced.
7. Inform driller of fluid recovery volume, contents in each tank every 15 minutes.
8. When LP surge tank MBJ-2100 is full with 70 bbls of fluid, switch the 3 way valve to route returns to LP surge tank MBJ-2200. Pump fluid from MBJ-2100 to the 500-bbl tank or directly to the boat if weather conditions permit.
9. Continue checking BSW and maintaining back pressure until LP surge tank MBJ-2200 has 70 bbls of fluid, switch the 3 way valve to route returns to MBJ-2100. Pump fluid from MBJ-2200 to the 500-bbl tank or directly to the boat if weather conditions permit. Repeat steps 8 and 9 as needed.
10. If 500-bbl tank needs to be unloaded, perform nitrogen surge of tank and vent line while unloading to standby boat.
11. When clean mud is observed at the sample point on the main deck, route the flow path back to the rig mud gas separator system.
12. Continue to circulate the well until clean mud returns with no surface pressure. Sweep BOP Stack.
13. Open annular preventer. Circulate bottoms up. POOH with 9-7/8-in casing while racking back and laying down off-line. Lay down BHA off line.

Note: If casing cannot be pulled, be prepared to re-land hanger and release spear. POOH and initiate contingency 9 7/8-in casing fishing operations.

1.2.7. *Isolate 13 5/8-in Liner Top*

Preparation: Make up cementing stand with Blackhawk Cementing head and 2 each, 5.5-in Halliburton hard, black wiper balls to be used on this job.

1. RIH with 12 1/4-in mill, 13 5/8-in, 88.2-ppf casing scraper and 16-in, 97-ppf casing scraper. Wash as required while RIH. Clean and scrape the 13 5/8-in casing to the 9 7/8-in stub at about 11,825-ft MD and the 16-in casing to ~ 11,100-ft MD. Circulate bottoms up with 13.2-ppg SMW SOBM.
   - Refer to Attachment 3, BHA #4 for detailed Bottom Hole Assembly information.
2. Test casing and primary cement plugs to 1,700-psi over initial injection pressure obtained in Section 1.2.3 Step 7 above to verify burst disc integrity and to confirm lower cement plug integrity. Do not exceed 4,000 psi.
   - Zonal Isolation During Drilling Operations and Well Abandonment and Suspension Section 26.3.3 of the *BP Drilling and Well Operations Practice* states: Weight testing should be up to at least 15K lb. Pressure testing shall be 0.1psi/ft above the leak off test (LOT) (or predicted fracture gradient at the shoe) or 500 psi whichever is the greater. The pressure test is acceptable where pressure drop is <10% over 15 minutes.

- BOEM will require the following for testing of the cement plug: The plug must pass the following tests to verify plug integrity. (1) A pipe weight of at least 15,000-pounds on the plug; and (2) A pump pressure of at least 1,000-pounds per square inch. Ensure that the pressure does not drop more than 10-percent in 15-minutes. The District Manager may require you to test other plug(s).
- Burst Discs located in 16-in casing at 9,560-ft MD, 8,304-ft MD and 6,047-ft MD.
- Deepest burst disc is 591-ft MD below 18-in casing shoe with a 11.55 ppg Surface Mud Weight (SMW) Leak Off Test (LOT).
- 1,700 psi based on 17,157-ft TVD * 0.1 psi/ft= 1,715 psi and frac gradient determined based on initial injection pressure.
- This >1,700 psi test with 13.2 ppg mud will be >2,470 psi over the frac gradient at the 18-in shoe if the burst disc has opened. ((13.2 ppg-11.55 ppg)*8,969-ft*0.052)+>1,700+ psi=2,470 psi.
- Record volume vs. pressure data for comparison with later tests.

3. TOOH. Lay down scraper BHA offline.
4. RU Schlumberger Wireline.
5. RIH with USIT/CBL and log 13 5/8-in and 16-in casing from ~11,800--ft to 16-in Hanger @ 5,227-ft. POOH.
6. RIH with UBI log and log 100' above and below each burst disc sub in 16-in casing. (9,560-ft MD, 8,304-ft MD and 6,047-ft MD).
   - Report results of both logs to BOEM. Results will confirm condition and the Top of Cement (ToC) of the 13 5/8-in and 16-in casing. The cement sheath will be mapped circumferentially by the USIT/CBL log to verify cement isolation up to the 18-in casing shoe at 8,969-ft MD. The UBI log will attempt to confirm the condition of the 16-in rupture discs.
   - If cement was not pumped in section 1.2.3 Step #10, a cement retainer may be substituted for the CIBP in step #7 below to allow pressure testing of the 9 7/8-in casing shoe to 17.1-ppg equivalent.
   - **BOEM approval is required before proceeding with the operation.**
7. TIH with a 13 5/8-in, 88.2-ppf Halliburton EZSV-B bridge plug dressed for Q-125 casing on Schlumberger wireline with Mirage setting tool. POOH.
8. Set bridge plug at 11,800-ft MD, about 25-ft above the 9 7/8-in casing stub. Release from bridge plug.
9. POOH and RD wireline.
10. TIH with 5 7/8-in drill pipe, Halliburton 5 1/2-in Indicating Ball Catcher (IBC) tool and cementing diverter. TIH to EZSV-B bridge plug at 11,800-ft MD.
    - Space out IBC to be at ~10,128-ft MD (15-bbls, 664-ft above expected TOC before pulling stinger out of cement).
11. Tag bridge plug and weight test EZSV-B with 15,000-lbs down for 5-minutes.

12. Make-up cementing head and cementing stand, cementing line and top drive. Rig up and pressure test cementing equipment and test to 250 psi low and 5,000 psi high for 5 minutes after the pressure has stabilized. The acceptance criteria are defined as stable or decreasing fall off less than 10 psi/min.
13. Circulate bottoms up with 13.2-ppg SMW SOBM at >15 bpm with top drive.
14. Close upper TIW on cementing stand and trap 1,000-psi on top drive.
15. Mix and pump 150-bbls of 14.8-ppg spacer. Drop 1st ball followed by 161-bbls of 16.4-ppg class H cement with 35% BWOC silica flour. Drop 2nd ball and pump 19-bbls of 14.8-ppg spacer.
    - Halliburton cement recipes and cement/spacer volumes are included in Attachment 4 and are subject to revision after final lab test results are completed.
16. Displace with 13.2-ppg SMW SOBM @ >15 bpm with rig pump via the top drive. Rotate 25 rpm as cement exits the work string.
    - Displace using two-pit system without returns into the suction pit for positive verification of mud displacement volumes.
    - Slow pump rate to 4-bpm as balls approach the IBC. Shear-out pressures of ~3,000-psi can be expected above circulating rate
    - Under-displace cement balanced plug by 10 bbls. After top ball indicates arrival at IBC pump an additional 5 bbls and allow cement to fall to balance.
    - Calculated top of cement after pulling out the cementing stinger is 10,850-ft MD, 300-ft above the 13 5/8-in liner top.
17. Rig down cementing equipment. POOH at 3-min/stand to 10,350-ft MD (500-ft above top of cement).
18. Circulate bottoms up utilizing wiper balls to clean drill pipe.
19. TOOH while WOC.
20. TIH with 14 5/8-in mill while WOC.
    - Refer to Attachment 3, BHA #5 for detailed Bottom Hole Assembly information.
21. Clean out to 10,903-ft MD or top of hard cement above 10,903-ft after WOC for at least 150% of the time required to build 500-psi compressive strength. If hard cement is not encountered by 11,053-ft an additional plug will be set.
22. Close annular preventer. Pressure test primary cement plug to 1,100-psi for 15 minutes. Open annular preventer.
    - Zonal Isolation during Drilling Operations and Well Abandonment and Suspension Section 26.3.3 of the *BP Drilling and Well Operations Practice* states: Weight testing should be up to at least 15K lb. Pressure testing shall be 0.1psi/ft above the leak off test (LOT) (or predicted fracture gradient at the shoe) or 500 psi, whichever is the greater. The pressure test is acceptable where pressure drop is <10% over 15 minutes.

- BOEM will require the following for testing of the cement plug: The plug must pass the following tests to verify plug integrity. (1) A pipe weight of at least 15,000-pounds on the plug; and (2) A pump pressure of at least 1,000-pounds per square inch. Ensure that the pressure does not drop more than 10-percent in 15-minutes. The District Manager may require you to test other plug(s).
- BP testing requirement is based on 11,585-ft TVD * 0.1 psi/ft= 1,158-psi above calculated frac gradient at 16-in shoe. The 13.1-ppg DHE (downhole equivalent) frac gradient vs 13.35-ppg DHEMW which implies 13.1-13.35*.052*11,585-ft = -151 psi. Therefore test pressure =1,158 psi - 151 psi=1,007 psi (1,100 psi).

23. Slack off while pumping slowly at 2-bpm. Weight test plug with 15,000-lbs for 5 minutes.
24. TOOH. Lay down BHA offline.

1.2.8. *Cut and Pull 16-in Liner above 18-in Liner Top*

Evidence preservation and chain of custody requirements must be followed regarding all equipment recovered from the well. Refer to Attachment 8

Note: Prior to retrieving the 16-in liner, liner hanger, and seal assembly, a video record of the 16-in supplemental wellhead adapter area may be required. Consultation with BOEM will be necessary before proceeding.

1. TIH with a 16-in, 97-ppf Halliburton EZSV-B bridge plug dressed for Q-125 casing on drill pipe.
2. Set bridge plug at 7,589-ft MD, about 150-ft below the planned 16-in casing cut. Release from bridge plug.
3. Close upper GX annular preventer with 3,000-psi applied closing pressure.
4. Pressure test above bridge plug to 1,000-psi.
5. Line cement unit up to pump down standpipe #2.
6. Using the cement unit, pump 70-bbls of base oil (6.8-ppg) down the DP to approximately 3,090-ft, taking returns up the choke-line. Close choke line failsafe valve.
7. DP shut-in pressure with 13.2-ppg SMW in the choke will be approximately 1,030-psi.
8. With cement unit bleed pressure down in ~200-psi steps to 200-psi and monitor on chart.
9. After bleeding down and leaving 200-psi on the DP, the differential pressure above the annular will be approximately 830-psi

Note: After discussion with Hydril Technical Support, the GX annular with 3,000-psi applied closing pressure can support up to 2,000-psi from the top side.

10. Monitor the pressure for 15-minutes. Monitor riser on trip tank. Monitor pressure reading on HPHT sensor on BOP stack.

11. Bleed DP to zero and record the volume bled back. Open and monitor for flow back to the cement unit for 60 minutes. Monitor riser on trip tank. Monitor pressure reading on HPHT sensor on BOP stack.

Note: Differential below the annular will be approximately 1,030 psi.

12. If flow observed, shut in and record pressures while determining forward plan.
13. After a successful negative test, pressure up on the DP to the initial pressure of approximately 1,030-psi. A successful negative test is defined as a no-flow condition for 60 minutes as required by step 11 above.
14. Line up to route returns through the mud gas separator. Open kill line failsafe and reverse out the base oil.
15. Open annular preventer. Observe well for flow for 15-minutes. Circulate bottoms up at bridge plug with 13.2-ppg SMW SOBM.
16. Displace cased hole with 11.1-ppg SMW SOBM. TOOH.
    - 16-in casing was run in 11.1-ppg SMW SOBM.
17. RIH and mechanically cut 16-in casing at 7,439-ft MD with casing cutter assembly Monitor well for 30-minutes.
    - Refer to Attachment 3, BHA #6 for detailed Bottom Hole Assembly information.
18. RIH with spear/pack-off assembly on 6 5/8-in landing string. Engage spear in top of 16-in casing.
    - Refer to Attachment 3, BHA #7 for detailed Bottom Hole Assembly information.
    - 22-in x 16-in supplemental adapter at 5,227-ft MD.
    - Shearable 6 5/8-in drill pipe will be spaced out across the shear rams.
19. Close annular preventer with minimal operating pressure to prepare for stripping drill pipe. Line up to circulate up choke and kill lines simultaneously.
20. Pull 16-in hanger above 22-in supplemental adapter (stripping drill pipe through annular). Attempt to circulate bottoms up via choke/kill lines. Monitor returns until clean mud has been circulated around.
    - Per Dril-Quip, the 16-in casing hanger is predicted to pull free of the 22-in adapter with the seal assembly in place at ~20,000-lbs of over-pull.
    - Dril-Quip Service representative to be present on rig floor.
21. Open annular preventer. Monitor well. POOH and lay down 16-in casing.

1.2.9. *Isolate 16-in Casing Stub and 18-in Liner Top*

Preparation: Make up cementing stand with Blackhawk Cementing head (loaded with 2 each, Halliburton 5 1/2-in hard black wiper balls to be used on this job.

1. TIH with 5 7/8-in drill pipe, Halliburton 5 1/2-in Indicating Ball Catcher (IBC) tool, and cementing diverter.
   - Spaceout IBC to be at ~ 6,082-ft (15-bbls, 664-ft above expected TOC of 6,746-ft with DP still in cement)
2. Cautiously re-enter 16-in casing stub. RIH to bridge plug at 7,589-ft MD. Tag-up with 5,000-lbs to verify bridge plug location and space-out.
3. Make-up cementing head and cementing stand, cementing line and top drive. Rig up and pressure test cementing equipment and test to 250 psi low and 5,000 psi high for 5 minutes after the pressure has stabilized. The acceptance criteria is defined as stable or decreasing fall off less than 10 psi/min.
4. Circulate bottoms up with 11.1-ppg SMW SOBM at >15-bpm with top drive.
5. Close annular and pressure test casing to 1,150-psi.
   - BP testing requirement is based on 8,969-ft TVD * 0.1 psi/ft= 897-psi above calculated frac gradient at 18-in shoe.
   - The 11.6-ppg DHE (downhole equivalent) frac gradient vs 11.1-ppg DHEMW which implies (11.6-11.1)*.052*8,969-ft = 233-psi. Therefore test pressure = 897 psi + 233-psi=1,130-psi. Equivalent shoe pressure at 18-in shoe is 13.5 ppg or 1.9 ppg over frac gradient.
   - 11.1+(1,130 psi / (8,969*.052))= 13.5 ppg
   - If casing test fails due to pressure communication with 18-in shoe, establish an injection rate for cementing of at least 2 bpm.
6. Close upper TIW on cementing stand and trap 1,000-psi on top drive.
7. Mix and pump 150-bbls of 13.8-ppg spacer. Drop 1st ball and follow with 304-bbls of 16.4-ppg class H cement with 35% BWOC silica flour. Drop 2nd wiper ball and follow with 10-bbls of 13.8-ppg spacer.
   - Halliburton cement recipes and cement/spacer volumes are included in Attachment 4 and are subject to revision after final lab test results are completed.
8. Displace cement at >15-bpm rate using the mud pump via the top drive. Rotate at 25-rpm as cement exits the drill string.
   - Displace using two-pit system without returns into the suction pit for positive verification of displacement volumes.
   - Slow pump rate to 4-bpm as balls approach the IBC. Shear-out pressures of ~3,000-psi can be expected above circulating rate.
   - Under-displace cement balanced plug by 10-bbls. After top ball indicates arrival at IBC pump an additional 5-bbls and allow cement to fall to balance.
   - Planned top of cement is at 6,790-ft MD, 650-ft above the 16-in stub.

9. Rig down cementing equipment. POOH at 3-min/stand to 6,290-ft (~500-ft above top of cement).
   - If injection was established in step #5 above, close annular and squeeze 50-bbls of cement into 18-in x 16-in casing annulus and 50-ft above 22-in x 18-in adapter.
   - Do not exceed 750-psi injection pressure as pipe could be forced through the BOP by the pressure.
   - Hold final squeeze pressure for at least 150% of the time required to build 500-psi compressive strength.
   - 50-bbls of cement will decrease top of cement in the 22-in by ~100-ft which will be made up by increasing the volume on the next jobs by 50-bbls.
10. Circulate bottoms up utilizing wiper balls to clean drill pipe.
11. TOOH while WOC.
12. TIH with 18 1/8-in bit and brush assemblies while WOC. Clean out to 6,790-ft MD or top of hard cement-after WOC for at least 150% of the time required to build 500-psi compressive strength.
    - Refer to Attachment 3, BHA #8 for detailed Bottom Hole Assembly information.
13. Close annular preventer. Pressure test primary cement plug to 1,100-psi for 15-minutes. Open annular preventer.
    - Zonal Isolation during Drilling Operations and Well Abandonment and Suspension Section 26.3.3 of the *BP Drilling and Well Operations Practice* states: Weight testing should be up to at least 15K lb. Pressure testing shall be 0.1-psi/ft above the leak off test (LOT) (or predicted fracture gradient at the shoe) or 500-psi whichever is the greater. The pressure test is acceptable where pressure drop is <10% over 15-minutes.
    - BOEM will require the following for testing of the cement plug: The plug must pass the following tests to verify plug integrity. (1) A pipe weight of at least 15,000-pounds on the plug; and (2) A pump pressure of at least 1,000-pounds per square inch. Ensure that the pressure does not drop more than 10-percent in 15-minutes. The District Manager may require you to test other plug(s).
    - 1,100 psi based on 8,969-ft TVD * 0.1 psi/ft= 897-psi and frac gradient at 18-in shoe =11.55-ppg DHEMW or (11.55-11.1)*8,969-ft TVD*.052 = 210-psi. Test pressure = 897-psi+210-psi =1,107-psi.
14. Slack off while pumping slowly at 2-bpm. Weight test plug with 15,000-lbs for 5 minutes.
15. TOOH.

1.2.10. *Isolate 22-in Casing*

Preparation: Make up cementing stand with Blackhawk Cementing head (loaded with 2 each, Halliburton, 5 1/2-in hard black wiper balls to be used on this job.

1. TIH with 5 7/8-in drill pipe, Halliburton 5 1/2-in Indicating Ball Catcher (IBC) tool and cementing diverter to 6790-ft MD or cleanout depth per Step 11 in section 1.2.9 above.
   - Spaceout IBC to be at ~ 5,292-ft (15-bbls, 664-ft above expected TOC of 5,956-ft with DP still in cement)
2. Make-up cementing head and cementing stand, cementing line and top drive. Rig up and pressure test cementing equipment and test to 250 psi low and 5,000 psi high for 5 minutes after the pressure has stabilized. The acceptance criteria are defined as stable or decreasing fall off less than 10 psi/min.
3. Circulate bottoms up with 11.1-ppg SMW SOBM at >15-bpm with top drive.
4. Close upper TIW on cementing stand and trap 1,000-psi on top drive.
5. Pump 150-bbls of 13.8-ppg spacer. Drop 1st wiper ball followed by 330-bbls of 16.4-ppg class H cement with 35% BWOC silica flour. Drop 2nd wiper ball followed by 10-bbls of 13.8-ppg spacer.
   - Halliburton cement recipes and cement/spacer volumes are included in Attachment 4 and are subject to revision after final lab test results are completed.
6. Displace cement at >15-bpm rate using rig mud pump via the top drive. Rotate 25-rpm as cement exits the drill string.
   - Displace using two-pit system without returns into the suction pit for positive verification of displacement volumes.
   - Slow pump rate to 4-bpm as balls approach the IBC. Shear-out pressures of ~3,000-psi can be expected above circulating rate.
   - Under-displace cement balanced plug by 10-bbls. After top ball indicates arrival at IBC pump an additional 5-bbls and allow cement to fall to balance.
   - Planned top of cement is at 5,991-ft MD (799-ft plug, TOC = 924-ft BML).
7. Rig down cementing equipment. POOH at 3-min/stand to 200-ft above top of cement.
8. Circulate bottoms up utilizing wiper balls to clean drill pipe.
9. TOOH while WOC.
10. TIH with 18 1/8-in bit and BHA #8 while WOC. Clean out to 5,991-ft MD or top of hard cement–after WOC for at least 150% of the time required to build 500-psi compressive strength.
11. Close annular preventer. Pressure test secondary cement plug to 1,000-psi for 15-minutes. Open annular preventer.

- Zonal Isolation during Drilling Operations and Well Abandonment and Suspension Section 26.3.3 of the *BP Drilling and Well Operations Practice* states: Weight testing should be up to at least 15K-lb.
- BOEM will require the following for testing of the cement plug: The plug must pass the following tests to verify plug integrity. (1) A pipe weight of at least 15,000-pounds on the plug; and (2) A pump pressure of at least 1,000-pounds per square inch. Ensure that the pressure does not drop more than 10-percent in 15-minutes. The District Manager may require you to test other plug(s).

12. Slack off while pumping slowly at 2-bpm. Weight test plug with 15,000-lbs for 5 minutes.
13. Close upper GX annular preventer with 3,000-psi applied closing pressure.
14. Line cement unit up to pump down standpipe #2.
15. Using the cement unit, pump 103-bbls of base oil (6.8-ppg) down the DP to approximately 4,650-ft, taking returns up the choke-line. Close choke line failsafe valve.
16. DP shut-in pressure with 11.1-ppg SMW in the choke line will be approximately 1,030-psi.
17. Confirm system is lined-up to take returns from the standpipe to cement unit where cementer can bleed pressure and chart results.
18. With cement unit bleed pressure down in ~200-psi steps to 200-psi and monitor on chart.
19. After bleeding down and leaving 200-psi on the DP, the differential pressure above the annular will be approximately 830-psi

Note: After discussion with Hydril Technical Support, the GX annular with 3,000-psi applied closing pressure can support up to 2,000-psi from the top side.

20. Monitor the pressure for 15-minutes. Monitor riser on trip tank. Monitor pressure reading on HPHT sensor on BOP stack.
21. Bleed DP to zero and record the volume bled back. Open and monitor for flow back to the cement unit for 60-minutes. Monitor riser on trip tank. Monitor pressure reading on HPHT sensor on BOP stack.

Note 1: Differential below the annular will be approximately 1,030-psi.

Note 2: The pressure inside the BOP will be approximately 360-psi lower than the SW gradient on the outside.

22. If flow observed, shut in and monitor pressure while determining forward plan.
23. After a successful negative test, pressure up on the DP to the initial pressure of approximately 1,030-psi. A successful negative test is defined as a no-flow condition for 60 minutes as required by step 21 above.
24. Line up to route returns through the mud gas separator. Open kill line failsafe and reverse out the base oil.

25. Open upper annular and monitor wellbore for flow for 15-minutes.
26. Displace well and riser to seawater.
27. TOOH and rack back BHA.

1.2.11. *Set Surface Plug in 22-in Casing*

Preparation: Make up cementing stand with Blackhawk Cementing head (loaded with 2 each, Halliburton, 5 1/2-in, hard, black, wiper balls to be used on this job).

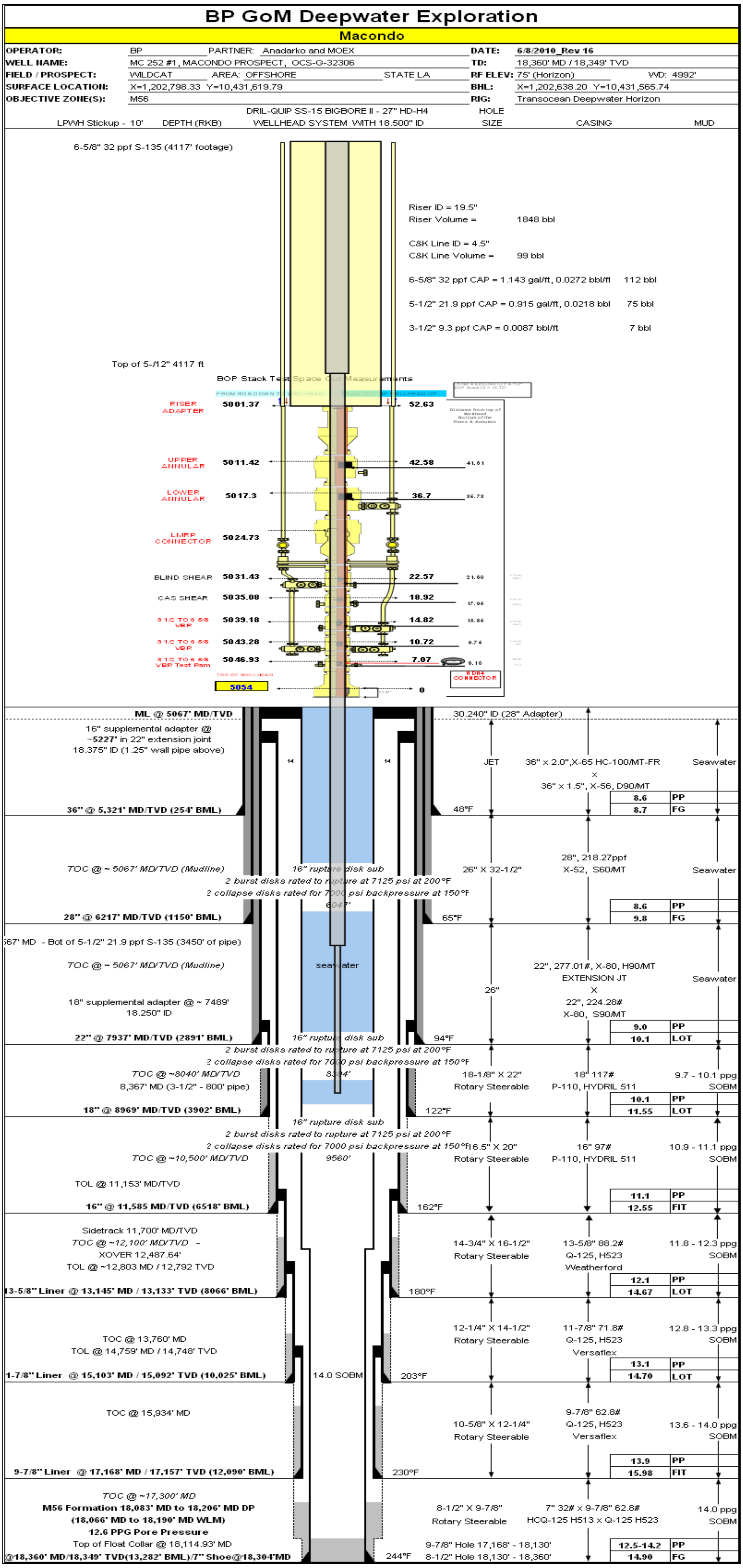
1. TIH with 5 7/8-in drill pipe, Halliburton 5 1/2-in Indicating Ball Catcher (IBC) tool and cementing diverter to 5,991-ft MD or cleanout depth as per step 9 in section 1.2.9 above.
   - Space out IBC to be at ~ 4,523-ft (15-bbls, 664-ft above expected ToC of 5,187-ft with DP still in cement)
2. Make-up cementing head and cementing stand, cementing line and top drive. Rig up and pressure test cementing equipment and test to 250 psi low and 5,000 psi high for 5 minutes after the pressure has stabilized. Acceptance criteria are defined as stable or decreasing fall off less than 10 psi/min.
3. Circulate bottoms up with seawater at >15 bpm with top drive.
4. Close upper TIW on cementing stand and trap 1,000-psi on top drive.
5. Mix and pump 150-bbls of 12.5-ppg spacer and drop 1st ball followed by 300-bbls of 16.4-ppg class H cement with 35% BWOC silica flour. Drop 2nd ball and pump 10-bbls of 12.5-ppg spacer.
   - Halliburton cement recipes and cement/spacer volumes are included in Attachment 4 and are subject to revision after final lab test results are completed.
6. Displace cement at >15-bpm rate with rig pump. Rotate at 25 rpm as cement exits the drill string.
   - Displace using two-pit system without returns into the suction pit for positive verification of displacement volumes.
   - Slow pump rate to 4-bpm as balls approach the IBC. Shear-out pressures of ~3,000-psi can be expected above circulating rate.
   - Under-displace cement balanced plug by 10-bbls. After top ball indicates arrival at IBC pump an additional 5-bbls and allow cement to fall to balance.
   - Planned top of cement is at 5,192-ft MD (799-ft plug, 125-ft BML).
7. Rig down cementing equipment. POOH at 3-min/stand to 100-ft above top of cement.
8. Circulate bottoms up utilizing wiper balls to clean drill pipe.
9. TOOH while WOC.
10. TIH with 18 1/8-in bit and BHA while WOC. Clean out to 5,192-ft MD after WOC for at least 150% of the time required to build 500-psi compressive strength.

11. Close annular preventer. Pressure test secondary cement plug to 1,000-psi for 15 minutes. Open annular preventer.
    - Zonal Isolation during Drilling Operations and Well Abandonment and Suspension Section 26.3.3 of the *BP Drilling and Well Operations Practice* states: Weight testing should be up to at least 15K-lb.
    - BOEM will require the following for testing of the cement plug: The plug must pass the following tests to verify plug integrity. (1) A pipe weight of at least 15,000-pounds on the plug; and (2) A pump pressure of at least 1,000-pounds per square inch. Ensure that the pressure does not drop more than 10-percent in 15-minutes. The District Manager may require you to test other plug(s).
12. Slack off while pumping slowly at 2-bpm. Weight test plug with 15,000-lbs for 5 minutes.
    - Top of surface cement plug to be no deeper than 150-ft MD BML.
13. Trip out of hole.

1.2.12. *Pull Riser and Release Rig*

1. Release SHD-H4 wellhead connector. Have ROV inject methanol into SHD-H4 wellhead connector as necessary to remove hydrates. Pull riser and BOP stack.
2. Perform an ROV survey of the top and the inner surfaces of the HP housing. Note any scratches, dents, galls or other damage. Record the survey on high resolution video.
3. Install TA cap on wellhead. Have ROV inject MacDermid wellhead preservation fluid into TA cap.
4. Site clearance survey work, seafloor debris recovery and debris mapping work are ongoing. This work is not within the scope of this procedure.
5. Offload equipment. Release rig.

Attachment 1: Current Conditions Schematic



Note: Add 9-ft to MD/TVD for Development Driller II

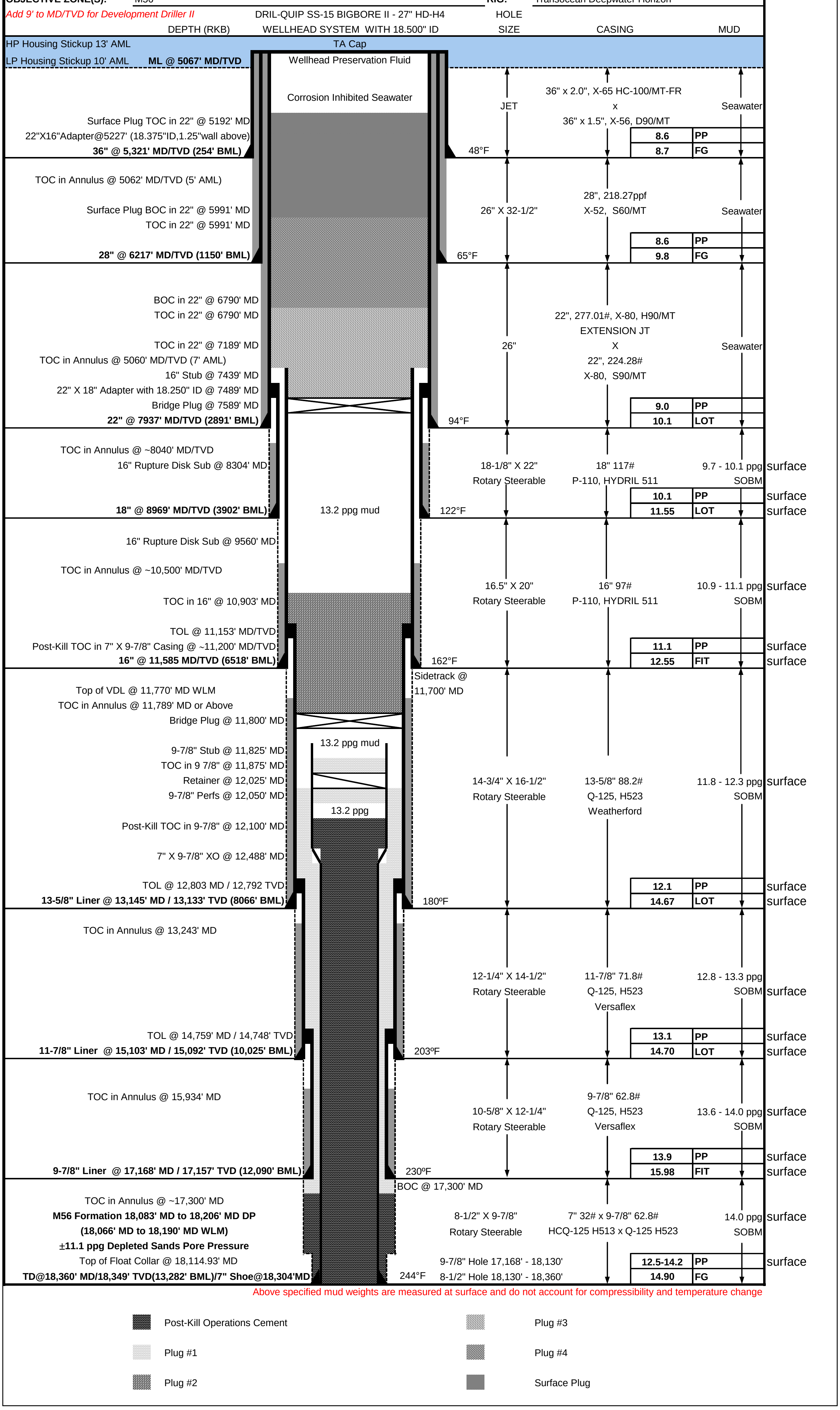
Attachment 2: Proposed Conditions Schematic

Permanent Abandonment Diagram - Proposed Conditions

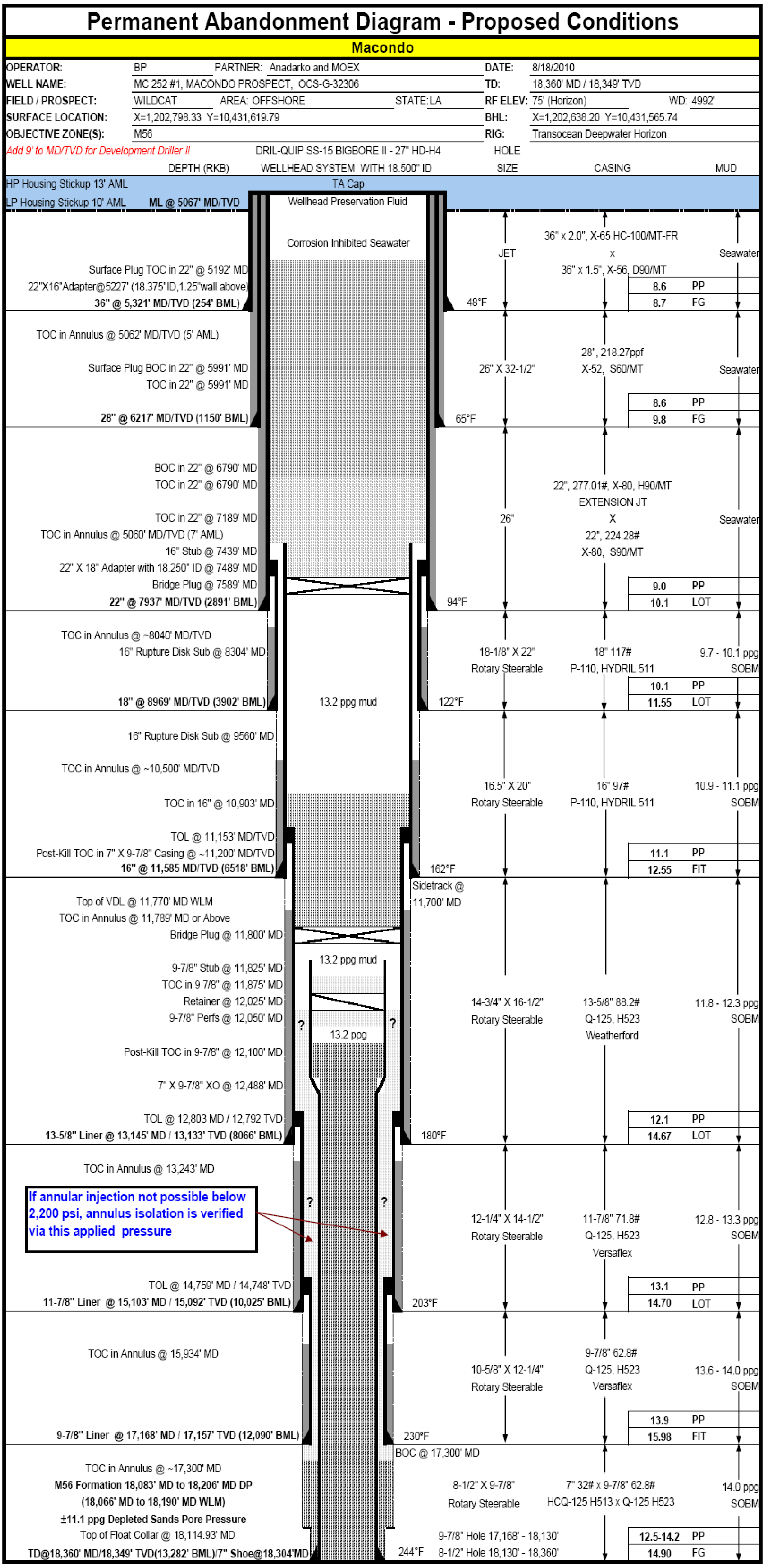
Macondo

OPERATOR:	BP PARTNER: Anadarko and MOEX	**DATE:**	8/19/2010
WELL NAME:	MC 252 #1, MACONDO PROSPECT, OCS-G-32306	**TD:**	18,360' MD / 18,349' 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

Add 9' to MD/TVD for Development Driller II



Attachment 2-A: Proposed Conditions Schematic - Annular Injection Not Possible



Attachment 3: BHA #1

HALLIBURTON

Clean Well™ Technology

Wellbore energy solutions, llc

PREPARED BY	M. Fontenot	REVIEWED BY	
CUSTOMER	BP	DATE REVIEWED	
WELL NAME	Macondo Prospect	SALES CONTACT	S. Squyres
WELL NUMBER	# 1	ENGINEER:	Ted Eicke/ Mark Heironimus
Lease/Parish/County	OCS-G 32306	JOB TYPE	Clean out to set P&A Packer
REVISION	0	MAX DEVIATION	
REVISION DATE		RIG	Transocean DD2
JOB NUMBER	TBD	APPROX. SHIP DATE	TBD
24 HOUR CONTACT NUMBER:		SHOP ADDRESS	6127 Hwy 90 East Broussard, La. 70518

ID Restriction (in.):	ID Restriction Location and Description:	PROJECT NOTES:
Need to Confirm		Run 1 Clean Out to set P&A Packer

Clean Well™ Technology WELLBORE DIAGRAM	DESCRIPTION	Max Extended OD	Max Hard OD	Min ID	Approx. Tool Length	Approx. Depth Top of Tool	Approx. Depth Bottom of Tool
21" Riser 0-5017' 19.75"	5 7/8", 24.2# S-135 Drill Pipe Tube ID: 5.045" XTM-57 Conn (box up)	NA	7.000	4.250	4997.00	0.00	4997.00
BOP Stack 5,017-5,067' Wellhead ID:18.50"	5 7/8", 24.2# S-135 Drill Pipe Tube ID: 5.045" XTM-57 Conn (box up)	NA	7.000	4.250	93.00	4997.00	5090.00
Casing 9 7/8" 62.8# Q-125	5 7/8", 24.2# S-135 Drill Pipe Tube ID: 5.045" XTM-57 Conn (box up)	NA	7.000	4.250	7000.00	5090.00	12090.00
Provided by Rig	Crossover XTM- 57 box x 4 1/2" IF pin	NA	6.625	3.125	3.00	12090.00	12093.00
	6 3/4" 100 ppf Drill Collars w/ 4 1/2" IF (box up)	NA	6.750	2.813	368.00	12093.00	12461.00
Assembly1 Provided by WES 28'	10' Pony Collar w/4 1/2" IF (box up)	NA	6.750	2.500	10.00	12461.00	12471.00
	9 7/8" Drill Tech™ (CWDT 121) **Tapered Mill Sleeve OD: 8.495"**	9.000	8.495	3.000	7.00	12471.00	12478.00
	8.50" Spiral Wrap 360° Mill 41/2" IF box up	NA	8.500	2.813	4.00	12478.00	12482.00
	Crossover 4 1/2" IF box x 4 1/2" Reg box - Bored for Float **Provided by WES Non-Ported Float**	NA	6.625	2.250	3.00	12482.00	12485.00
	8.5" -Smith XR Tri-Cone Rock Bit w/ 4 1/2" Reg (Pin Up) **Provided by bp**	NA	8.500	NA	2.00	12485.00	12487.00
WES will provide all items illustrated in RED					12,487' PBTD	18,380' MD / 18,349' TVD	

Attachment 3: BHA #2

BAKER HUGHES

Baker Oil Tools

bp

BHA #2 - Cut 9-7/8" 62.8# - 8-1/4" MS Cutter, Marine Swivel

CUSTOMER:	BP - Macondo
FIELD:	Mississippi Canyon
LEASE:	OCS-G 32306
WELL #:	#1
BP Rep:	L. Saucier / D. Beynon / M. Heironimus / J. Pusch
BOT Rep:	James A. Sonnier

ITEM NO.	QTY.	DESCRIPTION	MAX OD	MIN ID	CONN DOWN	CONN UP	LENGTH	ACCUM LENGTH	TENSILE STRENGTH	Vendor
			IN.	IN.			FT.	FT.	lbs	
1	1	8 1/4" OD TS MS Cutter f 9 7/8" 62.8, with stop and MM Knives	8.250	0.625	6 5/8" Reg Box	6 5/8" Reg Box	7.0	7.00	1867K	Baker
2	1	X-Over	8.250	3.750	6 5/8" Reg Pin	4 1/2" IF Box	3.0	10.00	944K	Baker
3	1	8.5" SOD Solid Blade Stabilizer	8.500	3.750	4 1/2" IF Pin	4 1/2" IF Box	6.0	16.00	944K	Baker
4	1	Float Sub	6.625	float	4 1/2" IF Pin	4 1/2" IF Box	3.0	19.00	944K	Baker
5	2	Super DownHole String Magnets	6.500	3.000	4 1/2" IF Pin	4 1/2" IF Box	20.0	39.00	826K	Baker
6	1	Circulation Sub - FFV	6.500	1.750	4 1/2" IF Pin	4 1/2" IF Box	3.0	42.00	944K	Baker
7	1	X-Over	8.500	3.750	4 1/2" IF Pin	5 7/8" XTM 57 Box	3.0	45.00	944K	Baker
8		Drill pipe	7.000	4.250	5 7/8" XTM 57 Pin	5 7/8" XTM 57 Box	6000.0	6045.00	1138K	Rig
9	1	X-Over	7.750	3.500	5 7/8" XTM 57 Pin	6 5/8" Reg Box	3.0	6048.00	1138K	Baker
10	1	Marine Swivel	18.550	3.500	6 5/8" Reg Pin	6 5/8" Reg Box	5.0	6053.00	1867K	Baker
11	1	X-Over	8.50	3.50	6 5/8" Reg Pin	6 5/8" FH Box	3.0	6056.00	1867K	Baker
12	1	Drillpipe across stack	8.50	4.0	6 5/8" FH Pin	6 5/8" FH Box	45.0	6101.00	2000K	Rig
13	1	X-Over	8.50	3.50	6 5/8" FH Pin	6 5/8" Reg Box	3.0	6104.00	1867K	Baker
14	1	NOV Lubricated Bumper Jar (18" Stroke)	7.750	3.500	6 5/8" Reg Pin	6 5/8" Reg Box	12.0	6116.00	1270K	Baker
15	1	NOV Fishing Jar	7.750	3.063	6 5/8" Reg Pin	6 5/8" Reg Box	12.0	6128.00	1580K	Baker
16	6	Drill Collars	8.250	2.875	6 5/8" Reg Pin	6 5/8" Reg Box	180.0	6308.00	1867K	Rig
17	1	NOV Iintensifier Jar	7.750	3.063	6 5/8" Reg Pin	6 5/8" Reg Box	12.0	6320.00	1600K	Baker
18	1	X-Over	8.500	3.500	6 5/8" Reg Pin	6 5/8" FH Box	3.0	6323.00	1867K	Baker
19		6 5/8" FH Drillpipe - RIG Supplied- New	8.500	4.000	6 5/8" FH Pin	6 5/8" FH Box	5000.0	11323.00	2000K	Rig
						TOTAL		11323.00		

NOTE: The BHA assumes 5 7/8" XTM 57 below swivel and 6 5/8" FH above swivel
measurements for reference only, actuals will be taken on rig
4 1/2" IF Pup joint(s) may be needed to space out cutter in the middle of the casing jt to be cut - Verify these are on rig
***Do not pump while RIH, or cutter will activate. Fill pipe with fill up line only, do not screw in with Top Drive
***Circulation Sub will require 2.125", and 1.875" OD ball.
NOTE: Must have Drillpipe across stack during cut - Verify.

Note: Add 9-ft to MD/TVD for Development Driller II

Attachment 3: BHA #3

BAKER HUGHES

Baker Oil Tools

bp

BHA #3 - Spear, Circulate, Jar on 9 7/8" 62.8# Hanger, Itco Spear

CUSTOMER:	BP - Macondo
FIELD:	Mississippi Canyon
LEASE:	OCS-G 32306
WELL #:	#1
BP Rep:	L. Saucier / D. Beynon / M. Heironimus / J. Pusch
BOT Rep:	James A. Sonnier

(NOTE: 9 7/8" Hanger is still in place)

NOTE: Casing may be cut with jet cutter.

ITEM NO.	QTY.	DESCRIPTION	MAX OD	MIN ID	CONN DOWN	CONN UP	LENGTH	ACCUM LENGTH	TENSILE STRENGTH	Vendor
			IN.	IN.			FT.	FT.	lbs	
1	1	Spear Packoff	8.625	2.75	4 1/2" IF Pin	4 1/2" IF Box	3	3	944K	Baker
2	1	Itco spear for 9 7/8" 62.8#	8.25	2.75	4 1/2" IF Pin	5 1/2" Reg Box	4.0	7.00	944K	Baker
3	1	Spear Extensions	6.75	2.75	5 1/2" Reg Pin	5 1/2" Reg Box	15.0	22.00	1678K	Baker
4	1	Spear Stop Sub	10.5	3.5	5 1/2" Reg Pin	5 1/2" Reg Box	3.0	25.00	1678K	Baker
5	1	X-Over	8.50	2.75	5 1/2" Reg Pin	6 5/8" FH Box	3.0	28.00	1678K	Baker
6		Drillpipe across stack	8.50	4.0	6 5/8" FH Pin	6 5/8" FH Box	45.0	73.00	2000K	Rig
7	1	X-Over	8.50	3.75	6 5/8" FH Pin	6 5/8" Reg Box	3.0	76.00	1678K	Baker
8	1	NOV Lubricated Bumper Jar (18" Stroke) (optional)	7.75	3.5	6 5/8" Reg Pin	6 5/8" Reg Box	12.0	88.00	1270K	Baker
9	1	X-Over	8.875	3.50	6 5/8" Reg Pin	7 5/8" Reg Box	3.0	91.00	1867K	Baker
10	1	9 1/2" HE Drilling Hydra Jar -500K Max Jar Load	9.50	3.00	7 5/8" Reg Pin	7 5/8" Reg Box	32.00	123.00	2000K	Baker
11	1	X-Over	8.875	3.50	7 5/8" Reg Pin	6 5/8" Reg Box	4.00	127.00	1867K	Baker
12	6	Drill Collars	8.25	2.875	6 5/8" Reg Pin	6 5/8" Reg Box	180.0	307.00	1867K	Rig
13	1	X-Over	8.50	3.50	6 5/8" Reg Pin	6 5/8" FH Box	3.0	310.00	1867K	Baker
14		6 5/8" FH Drillpipe - RIG Supplied- New	8.50	4.0	6 5/8" FH Pin	6 5/8" FH Box	5000.0	5310.00	2000K	Rig
		NOTE: The BHA assumes 6 5/8" FH drill pipe above				TOTAL		5310.00		

measurements for reference only, actuals will be taken on rig

Attachment 3: BHA # 4

HALLIBURTON
Clean Well™ Technology
Wellbore energy solutions, llc

bp

PREPARED BY	M. Fontenot	REVIEWED BY	
CUSTOMER	BP	DATE REVIEWED	
WELL NAME	Macondo Prospect	SALES CONTACT	S. Squyres
WELL NUMBER	# 1	ENGINEER:	Ted Ewicki/Mark Heironimus
Lease/Parish/County	OCS-G 32306	JOB TYPE	Clean out to set P&A Packer
REVISION	2	MAX DEVIATION	
REVISION DATE	8/25/2010	RIG	Transocean DD2
JOB NUMBER	TBD	APPROX. SHIP DATE	9/1/2010
24 HOUR CONTACT NUMBER:	337-839-6911	SHOP ADDRESS	6127 Hwy 90 East Broussard, La. 70518

ID Restriction (in.):	ID Restriction Location and Description:
Need to Confirm	

PROJECT NOTES: Run 3 Clean Out to set P&A Packer

Clean Well™ Technology WELLBORE DIAGRAM	DESCRIPTION	Max Extended OD	Max Hard OD	Min ID	Approx. Tool Length	Approx. Depth Top of Tool	Approx. Depth Bottom of Tool
21" Riser 0-5,017' ID 19.75" WD - 4,992' ML 5,067'	5 7/8", 24.2# S-135 Drill Pipe Tube ID: 5.045" XTM-57 Conn (box up)	NA	7.000	4.250	4974.00	0.00	4974.00
BOP AREA 5,017'-5,067' Wellhead ID 18.50"	5 7/8", 24.2# S-135 Drill Pipe Tube ID: 5.045" XTM-57 Conn (box up)	NA	7.000	4.250	93.00	4974.00	5067.00
Casing 16" 97.0# P-110	5 7/8", 24.2# S-135 Drill Pipe Tube ID: 5.045" XTM-57 Conn (box up)	NA	7.000	4.250	6016.00	5067.00	11083.00
Assembly 2 Provided by WES ~24'	10'-5 7/8" XTM-57 Pup Joint	NA	7.000	4.750	10.00	11083.00	11093.00
	Crossover XTM 57 box x 6 5/8" Reg pin	NA	7.750	3.125	4.00	11093.00	11097.00
	16" Scrapper Tool™ (CSCP) 6 5/8" Reg	15.420	13.500	3.500	6.00	11097.00	11103.00
	Crossover 6 5/8" Reg box x XTM 57 Pin	NA	7.750	4.250	4.00	11103.00	11107.00
Casing 13 5/8" 88.2# Q-125 I.D. 12.375" Drift: 12.250" 11,153' - 11,826'	5 7/8", 24.2# S-135 Drill Pipe Tube ID: 5.045" XTM-57 Conn (box up)	NA	7.000	4.250	328.00	11107.00	11435.00
Provided by rig	Crossover XTM 57 box x 6 5/8" Reg pin	NA	7.750	3.125	4.00	11435.00	11439.00
	8 1/4" 150.4 ppf Drill Collars w/ 6 5/8" Reg (box up)	NA	8.250	2.813	360.00	11439.00	11799.00
Assembly 1 Provided by WES 26'	10' Pony Collar w/6 5/8" Reg (box up)	NA	7.750	3.000	10.00	11799.00	11809.00
	Crossover 6 5/8" Reg box x XTM 57 Pin	NA	7.750	3.000	4.00	11809.00	11813.00
	13 5/8" Drill Tech™ (CWDT 129) **Tapered Mill Sleeve OD: 12.245"**	12.840	7.000	3.000	7.00	11813.00	11820.00
	Crossover XTM 57 box x 6 5/8" Reg box - Bored for Float **Provided by WES Non-Ported Float**	NA	7.000	3.000	3.00	11820.00	11823.00
	12 1/4"" -Cement Mill w/ 6 5/8" Reg (Pin Up) **Provided by WES**	NA	12.250	NA	2.00	11823.00	11825.00
	WES will provide all items illustrated in RED		**11,826' PBTD Top of 9 7/8" Stub**			**18,369' MD / 18,368' TVD**	

Note: Add 9-ft to MD/TVD for Development Driller II

Attachment 3: BHA # 5

HALLIBURTON
Clean Well™ Technology
Wellbore energy solutions, llc

PREPARED BY	M. Fontenot	REVIEWED BY	
CUSTOMER	BP	DATE REVIEWED	
WELL NAME	Macondo Prospect	SALES CONTACT	S. Squyres
WELL NUMBER	# 1	ENGINEER:	
Lease/Parish/County	OCS-G 32306	JOB TYPE	Clean out to set P&A Packer
REVISION	0	MAX DEVIATION	
REVISION DATE		RIG	Transocean DD2
JOB NUMBER	TBD	APPROX. SHIP DATE	TBD
24 HOUR CONTACT NUMBER:		SHOP ADDRESS	6127 Hwy 90 East Broussard, La. 70518

ID Restriction (in.):	ID Restriction Location and Description:
Need to Confirm	

PROJECT NOTES: Run 5 Clean Out to set P&A Packer

Clean Well™ Technology WELLBORE DIAGRAM	DESCRIPTION	Max Extended OD	Max Hard OD	Min ID	Approx. Tool Length	Approx. Depth Top of Tool	Approx. Depth Bottom of Tool
Casing 16" 97.0# P-110	5 7/8", 24.2# S-135 Drill Pipe Tube ID: 5.045" XTM-57 Conn (box up)	NA	7.000	5.875	12401.00	0.00	12401.00
Provided by Rig	Crossover XTN 57 box x 4 1/2" IF pin	NA	6.625	3.125	3.00	12401.00	12404.00
	6 3/4" 100 ppf Drill Collars w/ 4 1/2" IF (box up)	NA	6.750	2.813	368.00	12404.00	12772.00
Assembly 1 Provided by WES 31'	10' Pony Collar w/4 1/2" IF (box up)	NA	6.750	2.500	10.00	12772.00	12782.00
	Crossover 4 1/2" IF box x 6 5/8" Reg pin	NA	6.750	2.500	10.00	12782.00	12792.00
	16" Scrapper Tool™ (CSCP) 6 5/8" Reg	20.750	13.500	3.500	6.00	12792.00	12798.00
	Crossover 6 5/8" box x 4 1/2" Reg box - Bored for Float **Provided by WES Non-Ported Float**	NA	6.625	2.250	3.00	12798.00	12801.00
	14 5/8" -Cement Mill w/ 4 1/2" Reg (Pin Up) **Provided by WES**	NA	14.625	NA	2.00	12801.00	12803.00
WES will provide all items illustrated in RED					**12,803' PBTD**	**18,360' MD / 18,349' TVD**	

Note: Add 9-ft to MD/TVD for Development Driller II

Attachment 3: BHA # 6

ITEM NO.	QTY.	DESCRIPTION	MAX OD	MIN ID	CONN DOWN	CONN UP	LENGTH	ACCUM LENGTH	TENSILE STRENGTH	Vendor
			IN.	IN.			FT.	FT.	lbs	
1	1	11 3/4" OD TS MS Cutter f/ 16" 97#, MM Knives, w/ stop	11.75	nozzle	6 5/8" Reg Box	6 5/8" Reg Box	7.0	7.00	1867K	Baker
2	1	Drift OD, SOD Solid Blade Stabilizer	14.75	3.50	6 5/8" Reg Pin	6 5/8" Reg Box	6.0	13.00	1867K	Baker
3	1	Float Sub	7.75	float	6 5/8" Reg Pin	6 5/8" Reg Box	3.0	16.00	1867K	Baker
4	2	8" Super DownHole String Magnets	8	3.50	6 5/8" Reg Pin	6 5/8" Reg Box	20.0	36.00	1711K	Baker
5	1	X-Over	8	3.50	6 5/8" Reg Pin	5 7/8" XTM 57 Box	3.0	39.00	1138K	Baker
6		Drill pipe	7	4.25	5 7/8" XTM 57 Pin	5 7/8" XTM 57 Box	2200.0	2239.00	1138K	Rig
7	1	X-Over	8.5	3.50	5 7/8" XTM 57 Pin	6 5/8" Reg Box	3.0	2242.00	1138K	Baker
8	1	Marine Swivel	18.55	3.50	6 5/8" Reg Pin	6 5/8" Reg Box	5.0	2247.00	1867K	Baker
9	1	NOV Lubricated Bumper Jar (18" Stroke)	7.75	3.5	6 5/8" Reg Pin	6 5/8" Reg Box	12.0	2259.00	1270K	Baker
10	1	NOV Fishing Jar	7.75	3.0625	6 5/8" Reg Pin	6 5/8" Reg Box	12.0	2271.00	1580K	Baker
11	6	Drill Collars	8	2.875	6 5/8" Reg Pin	6 5/8" Reg Box	180.0	2451.00	1867K	Rig
12	1	NOV Iintensifier Jar	7.75	3.0625	6 5/8" Reg Pin	6 5/8" Reg Box	12.0	2463.00	1600K	Baker
13	1	Pump Out Circulation Sub, Ball Drop with 3.25" Ball	8	3.0625	6 5/8" Reg Pin	6 5/8" Reg Box	4.0	2467.00	1867K	Baker
14	1	X-Over	8	3.50	6 5/8" Reg Pin	5 7/8" XTM 57 Box	3.0	2470.00	1138K	Baker
		5 7/8" XTM 57 Drillpipe - RIG Supplied- New	7	4.25	5 7/8" XTM 57 Pin	5 7/8" XTM 57 Box	5500.0	7970.00	1138K	Rig
		NOTE: The BHA assumes 5 7/8" XTM 57 above and below swivel				**TOTAL**		7970.00		

measurements for reference only, actuals will be taken on rig

6 5/8" Reg Pup joint(s) may be needed to space out cutter in the middle of the casing jt to be cut - Verify these are on rig

***Do not pump while RIH, or cutter will activate. Fill pipe with fill up line only, do not screw in with Top Drive

***Pump out Sub will require 3.25" OD ball.

NOTE: 9 7/8" Hanger and casing down to below 16" cut depth has been removed

NOTE: 16" Hanger Seals will be pulled with Hanger, per Dril-Quip

NOTE: Must have Drillpipe across stack during cut - Verify.

NOTE: 16" Supplemental Adapter at 5227ft, in 22" Extension joint

Attachment 3: BHA # 7

BHA #8 - Spear, Circulate, Freepoint, Jar and Pull 16" 97# - Itco Spear, Packoff, Jars

CUSTOMER:	BP - Macondo
FIELD:	Mississippi Canyon
LEASE:	OCS-G 32306
WELL #:	#1
BP Rep:	L. Saucier / D. Beynon / M. Heironimus / J. Pusch
BOT Rep:	James A. Sonnier

(NOTE: 9 7/8" Hanger and casing down to below 16" cut depth has been removed)
NOTE: 16" Hanger Seal can be pulled with the 16" Hanger, per Dril-Quip.

16" 97#: 14.85" ID, Drift: 14.75", wt .575", P-110, Hydril 511

ITEM NO.	QTY.	DESCRIPTION	MAX OD	MIN ID	CONN		LENGTH	ACCUM LENGTH	TENSILE STRENGTH	Vendor
					DOWN	UP				
			IN.	IN.			FT.	FT.	lbs	
1	1	Spear Packoff	14.85	3.5	6 5/8" Reg Pin	6 5/8" Reg Box	4	4	1867K	Baker
2	1	ITCO Spear	11.75	3.50	6 5/8" Reg Pin	6 5/8" Reg Box	5.0	9.00	1867K	Baker
3	1	Spear Extension (to keep spear out of hanger internal profiles)	7.75	3.50	6 5/8" Reg Pin	6 5/8" Reg Box	5.0	14.00	1867K	Baker
4	1	Spear Stop Sub	16.5	3.50	6 5/8" Reg Pin	6 5/8" Reg Box	3.0	17.00	1867K	Baker
6	1	Float Sub	7.75	float	6 5/8" Reg Pin	6 5/8" Reg Box	3.0	20.00	1867K	Baker
7	1	NOV Lubricated Bumper Jar (18" Stroke)	7.75	3.5	6 5/8" Reg Pin	6 5/8" Reg Box	12.0	32.00	1270K	Baker
8	1	NOV Fishing Jar	7.75	3.0625	6 5/8" Reg Pin	6 5/8" Reg Box	12.0	44.00	1580K	Baker
9	6	Drill Collars	8.25	2.875	6 5/8" Reg Pin	6 5/8" Reg Box	180.0	224.00	1867K	Rig
10	1	NOV Iintensifier Jar	7.75	3.0625	6 5/8" Reg Pin	6 5/8" Reg Box	12.0	236.00	1600K	Baker
11	1	X-Over	8.50	3.50	6 5/8" Reg Pin	6 5/8" FH Box	3.0	239.00	1867K	Baker
12		6 5/8" FH Drillpipe - RIG Supplied- New	8.50	4.0	6 5/8" FH Pin	6 5/8" FH Box	5500.0	5739.00	2000K	Rig
		NOTE: The BHA assumes 6 5/8" FH above and below swivel				TOTAL		5739.00		

measurements for reference only, actuals will be taken on rig

Note: Add 9-ft to MD/TVD for Development Driller II

Attachment 3: BHA #8

HALLIBURTON

Clean Well™ Technology

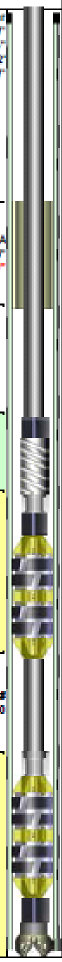
Wellbore energy solutions, llc

bp

PREPARED BY	M. Fontenot	REVIEWED BY	
CUSTOMER	BP	DATE REVIEWED	
WELL NAME	Macondo Prospect	SALES CONTACT	S. Squyres
WELL NUMBER	# 1	ENGINEER:	Ted Eicks/Mark Heironimus
Lease/Parish/County	OCS-G 32306	JOB TYPE	Clean out to set P&A Packer
REVISION	0	MAX DEVIATION	
REVISION DATE	8/25/2010	RIG	Transocean DD2
JOB NUMBER:	TBD	APPROX. SHIP DATE	TBD
24 HOUR CONTACT NUMBER:	337-839-8811	SHOP ADDRESS	6127 Hwy 90 East Broussard, La. 70518

ID Restriction (in.):	ID Restriction Location and Description:
Need to Confirm	18.60" WellHead ID

PROJECT NOTES: Run 4 Clean Out to set P&A Packer



Clean Well™ Technology WELLBORE DIAGRAM	DESCRIPTION	Max Extended OD	Max Hard OD	Min ID	Approx. Tool Length	Approx. Depth Top of Tool	Approx. Depth Bottom of Tool
21" Riser 0-5,017' ID 19.75" WD - 4,992' ML 5,067'	5 7/8", 24.2# S-135 Drill Pipe Tube ID: 5.045" XTM-57 Conn (box up)	NA	7.000	4.250	4973.00	0.00	4973.00
BOB AREA 5,017'-5,067' Wellhead ID:18.60"	5 7/8", 24.2# S-135 Drill Pipe Tube ID: 5.045" XTM-57 Conn (box up)	NA	7.000	4.250	93.00	4973.00	5066.00
	5 7/8", 24.2# S-135 Drill Pipe Tube ID: 5.045" XTM-57 Conn (box up)	NA	7.000	4.250	1871.00	5066.00	6937.00
Provided by Rig	Crossover XTM 57 box X 6 5/8" Reg pin	NA	7.750	3.125	4.00	6937.00	6941.00
	8 3/4" 160.4 ppf Drill Collars 6 5/8" Reg (box up)	NA	8.750	2.813	360.00	6941.00	7301.00
Assembly 2 Provided by WES ~21	Pony Collar 6 5/8" Reg box up	NA	7.750	2.813	10.00	7301.00	7311.00
	Crossover 6 5/8" Reg box x XTM 57pin	NA	7.750	3.000	4.00	7311.00	7315.00
	Riser Bristle Tech™ (CWRBT 102) XTM	20.750	18.250	3.000	8.00	7315.00	7323.00
Casing 22" 224.28# X-80	5 7/8", 24.2# S-135 Drill Pipe Tube ID: 5.045" XTM-57 Conn (box up)	NA	7.000	4.250	93.00	7323.00	7416.00
Assembly 1 Provided by WES 23'	5 7/8" Pup Joint w/ XTM 57 box up	NA	7.000	4.250	10.00	7416.00	7426.00
	Riser Bristle Tech™ (CWRBT 102) XTM 5	20.750	18.250	3.000	8.00	7426.00	7434.00
	Crossover XTM 57 box x 6 5/8" Reg box - Bored for Float Provided by WES Non-Ported Float	NA	7.750	3.000	3.00	7434.00	7437.00
	18.250 -Bit / 6 5/8" Reg (Pin Up) Provided by bp	NA	18.250	NA	2.00	7437.00	7439.00
	WES will provide all items illustrated in RED			7,439' PBTD (Top of 16" Stub)		18,389' MD / 18,358' TVD	

Note: Add 9-ft to MD/TVD for Development Driller II

Attachment 3: BHA # 9

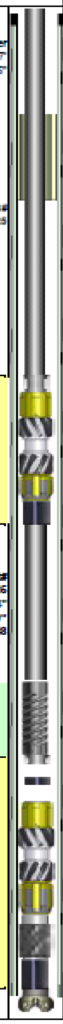
HALLIBURTON
Clean Well™ Technology
Wellbore energy solutions, llc

bp

PREPARED BY	M. Fontenot	REVIEWED BY	
CUSTOMER:	BP	DATE REVIEWED	
WELL NAME	Macondo Prospect	SALES CONTACT	S. Squyres
WELL NUMBER	# 1	ENGINEER:	Ted Eicks/ Mark Heironimus
Lease/Parish/County	OCS-G 32306	JOB TYPE	Clean out to set P&A Packer
REVISION	1	MAX DEVIATION	
REVISION DATE	8/25/2010	RIG	Transocean DD2
JOB NUMBER	TBD	APPROX. SHIP DATE	8/27/2010
24 HOUR CONTACT NUMBER:	337-839-6911	SHOP ADDRESS	6127 Hwy 90 East Broussard, La. 70518

ID Restriction (In.):	ID Restriction Location and Description:
Need to Confirm	

PROJECT NOTES: Run 2 Clean Out to set P&A Packer



Clean Well™ Technology WELLBORE DIAGRAM	DESCRIPTION	Max Extended OD	Max Hard OD	Min ID	Approx. Tool Length	Approx. Depth Top of Tool	Approx. Depth Bottom of Tool
21" Riser 0-5017' 19.75"	5 7/8", 24.2# S-135 Drill Pipe Tube ID: 5.045" XTM-57 Conn (box up)	NA	7.000	4.250	3686.00	1300.00	4986.00
BOP Stack 5,017'-5,067'	5 7/8", 24.2# S-135 Drill Pipe Tube ID: 5.045" XTM-57 Conn (box up)	NA	7.000	4.250	93.00	4986.00	5079.00
Casing 9 7/8" 62.8# Q-125	5 7/8", 24.2# S-135 Drill Pipe Tube ID: 5.045" XTM-57 Conn (box up)	NA	7.000	4.250	7200.00	5079.00	12279.00
Assembly 2 ~37' Provided by WES	10' Poup Joint w/ XTM57 (box up)	NA	7.000	4.250	10.00	12279.00	12289.00
	9 7/8" Drill Tech™ (CWDT 107) **Tapered Mill Sleeve OD: 8.495"**	9.000	8.495	3.000	7.00	12289.00	12296.00
	Crossover w/XTM 57 box x XT 39 pin	NA	7.000	4.250	3.00	12296.00	12299.00
Casing 7" 32# HCQ-125 ID: 6.094" Drift: 5.969" 12,348'-17,168'	4", 14.00# S-135 Drill Pipe Tube ID: 3.340" XT-39 Conn (box up)	NA	4.875	2.750	4390.00	12299.00	16689.00
Furnished by Workstrings	15- 4 3/4" 49.94 ppf Drill Collars w/ XT-39 (box up) Make-up Torque:11,400-22,400 ft/lbs Torsional Yield:37,300 ft/lbs Tensile Strength: 793,700 lbs	NA	4.750	2.250	450.00	16689.00	17139.00
Assembly 1 ~24'	10' Pup Joint W/ XT-39 box up	NA	4.875	2.750	10.00	17139.00	17149.00
	Crossover XT 39 box x 3 1/2" IF pin	NA	4.875	2.750	3.00	17149.00	17152.00
	7" Drill Tech™ (CWDT 104) **Tapered Mill Sleeve OD: 5.870"**	6.375	5.870	2.063	7.00	17152.00	17159.00
	5.969" Spiral Wrap 360° Mill 31/2" IF box up	NA	5.969	2.500	4.00	17159.00	17163.00
	Crossover 3 1/2" IF box x 3 1/2" Reg box - Bored for Float **Provided by WES Non-Ported Float**	NA	4.875	2.563	3.00	17163.00	17166.00
	6" -Reed Tri-Cone Rock Bit w/ 3 1/2" Reg (Pin Up) **Provided by bp**	NA	6.000	NA	2.00	17166.00	17168.00
WES will provide all items illustrated in RED					17,168' PBTD	18,360' MD / 18,349' TVD	

Attachment 4: Detailed Cementing Program

HALLIBURTON

bp America Prod Co-sorac/gom Ebiz
PO Box 22024 - Do Not Mail
Tulsa, Oklahoma 74121-2024

Macondo Prospect 1
MISSISSIPPI CANYON Blk:252

United States of America

Macondo P&A BoD

Prepared for: Macondo Relief Well Team / P&A Team

Version: 7

Submitted by:
Chris Daigle
Halliburton
10200 Bellaire Blvd
Houston, Texas 77072-5299
1.337.849.5861

HALLIBURTON

1 / 8 Proposal MC 252_Macondo BoD_ v.6

HALLIBURTON

Job Information

Note: This recommendation is a preliminary design and is subject to change. This design is intended for job preparedness. Lab testing and engineering software have not been fully completed and will affect the final outcomes.

HALLIBURTON

Isolate 7" x 9 7/8" Production Casing Annulus

Detailed Pumping Schedule

Fluid #	Fluid Type	Fluid Name	Surface Density lbm/gal	Estimated Avg Rate bbl/min	Downhole Volume
1	Spacer	Tuned Spacer III	14.8	8.0	150 bbl
2	Lead Cement	Premium Cement w/Silica	16.5	5.0	92 bbl
3	Tail Cement	Premium Cement w/Silica	16.5	5.0	178 bbl
3	Spacer	Tuned Spacer III	14.8	8.0	40 bbl
4	Mud	Displacement Fluid	13.2	8.0	232 bbl

Job Procedure

1. Perform Bit & Scraper run before setting EZSV-B
2. RIH with EZSV-B with TCP guns to 12025 ft
3. Pressure test cement lines
4. Circulate 40 bbls mud before setting retainer
5. Set EZSV-B at 12025 ft
6. Pressure test drill pipe & 9 7/8" casing annulus.
7. Close annular to keep pressure on annulus
8. Pressure up to fire TCP guns
9. Establish injection rates
10. Bull head 300 bbls 13.2 ppg mud
11. Pump 150 bbls 14.8 ppg Tuned Spacer III
12. Drop foam wiper ball
13. Mix & pump 92 bbls 16.5 ppg Lead Premium Cement with 35% BWOC Silica
14. Mix & pump 178 bbls 16.5 ppg Tail Premium Cement with 35% BWOC Silica
15. Drop foam wiper ball
16. Pump 40 bbls 14.8 ppg Tuned Spacer III
17. Displace with 13.2 ppg mud to place final wiper ball at the EZSV-B
18. Bleed off pressure
19. Sting out if EZSV-B
20. Circulate bottoms up
21. TOOH

HALLIBURTON

Balanced Plug on 9 7/8" Retainer

Detailed Pumping Schedule

Fluid #	Fluid Type	Fluid Name	Surface Density lbm/gal	Estimated Avg Rate bbl/min	Downhole Volume
1	Spacer	Tuned Spacer III	14.8	6.0	75 bbl
2	Cement	Premium Cement w/Silica	16.4	5.0	50 bbl
3	Spacer	Tuned Spacer III	14.8	6.0	13.4 bbl
4	Mud	Displacement Fluid	13.2	8.0	xx bbl

Job Procedure

1. RIH with 2000 ft 4" drill pipe & 5 7/8" drill pipe with 5 ½" IBC to 12025 ft
    a. Space out IBC 15 bbls above TOC (drill pipe in)
2. RU cement head with swivel & two 5 ½" hard rubber drill pipe wiper balls
3. RU cement lines and pressure test
4. Circulate bottoms up
5. Close upper TIW valve & trap 1000 psi with Top Drive
6. Pump 75 bbls 14.8 ppg Tuned Spacer III
7. Drop 1st wiper ball
8. Mix and pump 50 bbls Premium cement with 35% BWOC Silica
9. Drop 2nd wiper ball
10. Pump 13.4 bbls 14.8 ppg Tuned Spacer III
11. Displace 13.2 ppg mud
    a. Rotate while cement exits workstring
12. RD cement head & lines
13. Pull out of cement at 3 minutes per stand.
14. POOH at least 500 ft above cement
15. Circulate using foam wiper balls to clean dp

HALLIBURTON

Plug 1 Isolate 13 5/8-in Liner Top

Detailed Pumping Schedule

Fluid #	Fluid Type	Fluid Name	Surface Density lbm/gal	Estimated Avg Rate bbl/min	Downhole Volume
1	Spacer	Tuned Spacer III	14.8	6.0	150 bbl
2	Cement	Premium Cement w/Silica	16.4	5.0	160.5 bbl
3	Spacer	Tuned Spacer III	14.8	6.0	19 bbl
4	Mud	Drilling Mud	13.2	8.0	xx bbl

Job Procedure

1. Perform Bit & Scraper run before setting EZSV-B
2. RIH with EZSV-B on wire line to 11800 ft
3. Set EZSV-B & POOH with wireline
4. TIH with 5 7/8" workstring with 5 ½" IBC and diverter sub to 11800 ft
    a. Space out IBC 15 bbl above TOC (drill pipe in).
5. Tag EZSV-B with 15000 lbs down
6. RU cementing head with swivel & two 5 ½" rubber wiper balls
7. RU cement lines and pressure test
8. Circulate bottoms up
9. Close upper TIW valve & trap 1000 psi with Top Drive
10. Pump 150 bbls 14.8 ppg Tuned Spacer III
11. Drop 1st wiper ball
12. Mix and pump 160.5 bbls Premium cement with 35% BWOC silica
13. Drop 2nd wiper ball
14. Pump 19 bbls 14.8 ppg Tuned Spacer III
15. Displace with 13.2 ppg mud
    a. Slow down to 4 bpm as wiper balls approach IBC
    b. Rotate while cement exits workstring
16. RD cement head & lines
17. Pull out of cement at 3 minutes per stand.
18. POOH at least 500 ft above cement
19. Circulate using foam wiper balls to clean dp

HALLIBURTON

Isolate 16-in Casing Stub and 18-in Liner Top

Detailed Pumping Schedule

Fluid #	Fluid Type	Fluid Name	Surface Density lbm/gal	Estimated Avg Rate bbl/min	Downhole Volume
1	Spacer	Tuned Spacer III	13.8	6.0	150 bbl
2	Cement	Premium Cement	16.4	5.0	291 bbl
3	Spacer	Tuned Spacer III	13.8	6.0	10 bbl
4	Mud	Displacement Fluid	11.1	8.0	xx bbl

Job Procedure

1. Perform Bit & Scraper run before setting EZSV-B
2. RIH with EZSV-B to 7589 ft
3. Circulate 40 bbls mud before setting retainer
4. Set EZSV-B & POOH
5. After 16" casing is cut & pulled TIH with 5 7/8" workstring with 5 ½" IBC and diverter sub to 7589 ft
    a. Space out IBC 15 bbl above TOC (drill pipe in).
6. Tag EZSV-B with 15000 lbs down
7. Pressure test retainer to 1000 psi
8. RU cementing head with swivel & two 5 ½" rubber wiper balls
9. RU cement lines and pressure test
10. Circulate bottoms up
11. Close upper TIW valve & trap 1000 psi with Top Drive
12. Pump 150 bbls 13.8 ppg Tuned Spacer III
13. Drop 1st wiper ball
14. Mix and pump 291 bbls Premium cement
15. Drop 2nd wiper ball
16. Pump 10 bbls 13.8 ppg Tuned Spacer III
17. Displace with 11.1 ppg mud
    a. Slow down to 4 bpm as wiper balls approach IBC
    b. Rotate while cement exits workstring
18. RD cement head & lines
19. Pull out of cement at 3 minutes per stand.
20. POOH at least 500 ft above cement
21. Circulate using foam wiper balls to clean dp

6 / 8 Proposal MC 252_Macondo BoD_ v.7

HALLIBURTON

Plug 3 Surface Plug

Detailed Pumping Schedule

Fluid #	Fluid Type	Fluid Name	Surface Density lbm/gal	Estimated Avg Rate bbl/min	Downhole Volume
1	Spacer	Tuned Spacer III	13.8	6.0	150 bbl
2	Cement	Premium Cement	16.4 to 17.0	5.0	314 bbl
3	Spacer	Tuned Spacer III	13.8	6.0	10 bbl
4	Mud	Displacement Fluid	11.1	8.0	xx bbl

Job Procedure

1. TIH with 5 7/8" workstring with 5 ½" IBC and diverter sub to 6790 ft
    a. Space out IBC 15 bbl above TOC (drill pipe in).
2. RU cementing head with swivel & two 5 ½" rubber wiper balls
3. RU cement lines and pressure test
4. Circulate bottoms up
5. Close upper TIW valve & trap 1000 psi with Top Drive
6. Pump 150 bbls 13.8 ppg Tuned Spacer III
7. Drop 1st wiper ball
8. Mix and pump 314 bbls (16.4 to 17.0) ppg Premium cement
9. Drop 2nd wiper ball
10. Pump 10 bbls 13.8 ppg Tuned Spacer III
11. Displace with 11.1 ppg mud
    a. Slow down to 4 bpm as wiper balls approach IBC
    b. Rotate while cement exits workstring
12. RD cement head & lines
13. Pull out of cement at 3 minutes per stand.
14. POOH at least 500 ft above cement
15. Circulate using foam wiper balls to clean dp

HALLIBURTON

Plug 4 Surface Plug

Detailed Pumping Schedule

Fluid #	Fluid Type	Fluid Name	Surface Density lbm/gal	Estimated Avg Rate bbl/min	Downhole Volume
1	Spacer	Tuned Spacer III	12.5	6.0	150 bbl
2	Cement	Premium Cement w/ KCl	16.4 to 17.0	5.0	192 bbl
3	Cement	Premium Cement	16.4 to 17.0	5.0	108 bbl
3	Spacer	Tuned Spacer III	12.5	6.0	10 bbl
4	Sea Water	Sea Water	8.54	8.0	xx bbl

Job Procedure

1. TIH with 5 7/8" workstring with 5 ½" IBC and diverter sub to 5990 ft
   a. Space out IBC 15 bbl above TOC (drill pipe in).
2. RU cementing head with swivel & two 5 ½" rubber wiper balls
3. RU cement lines and pressure test
4. Circulate bottoms up
5. Close upper TIW valve & trap 1000 psi with Top Drive
6. Pump 150 bbls 12.5 ppg Tuned Spacer III
7. Drop 1st wiper ball
8. Mix & pump 192 bbls (16.4 to 17.0) ppg Lead Premium Cement KCl
9. Mix & pump 108 bbls (16.4 to 17.0) ppg Tail Premium Cement
10. Drop 2nd wiper ball
11. Pump 10 bbls 12.5 ppg Tuned Spacer III
12. Displace with sea water
    a. Slow down to 4 bpm as wiper balls approach IBC
    b. Rotate while cement exits workstring
13. RD cement head & lines
14. Pull out of cement at 3 minutes per stand.
15. POOH at least 100 ft above cement
16. Circulate using foam wiper balls to clean dp

Attachment 5: Well Control Model Simulation of Circulating Out Behind 9 7/8-in Casing

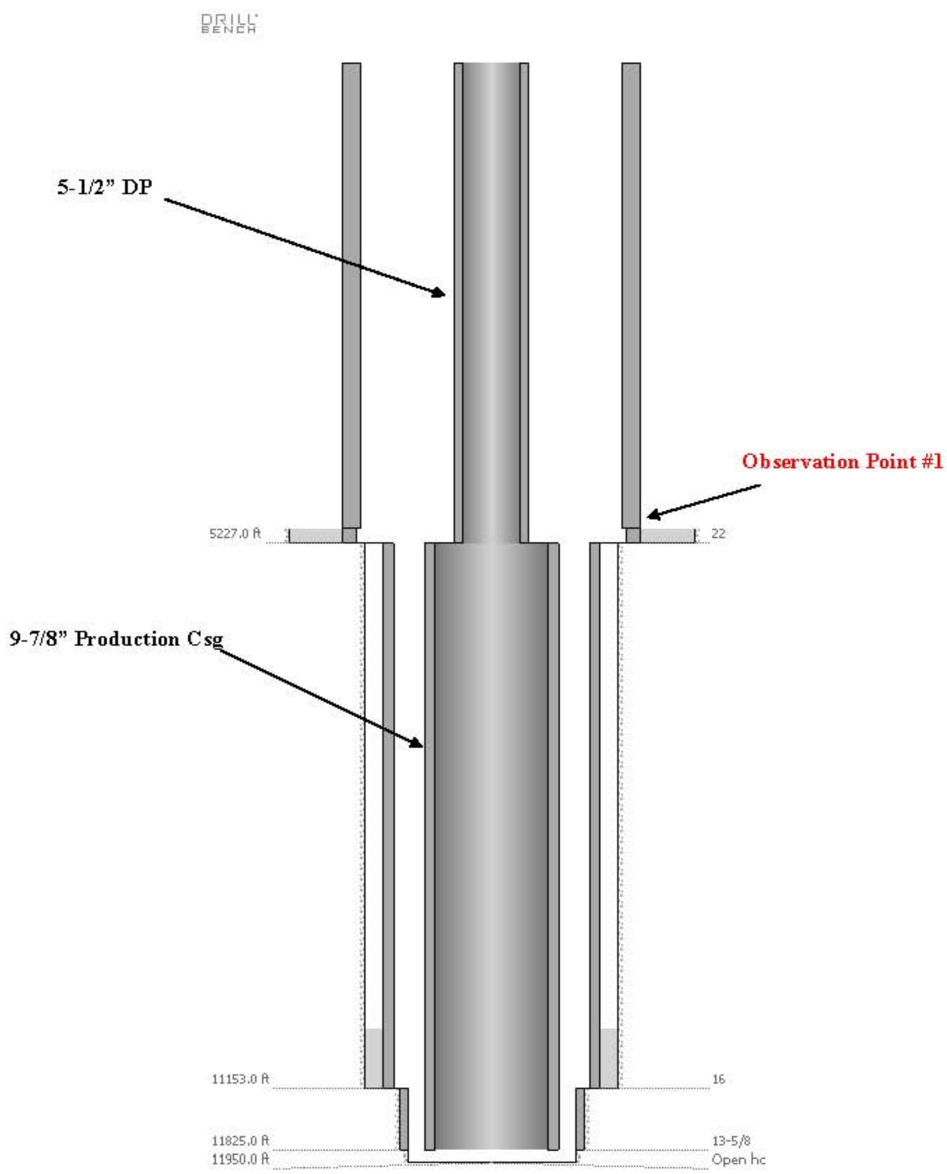


Figure 1 – Wellbore Schematic and Observation Point

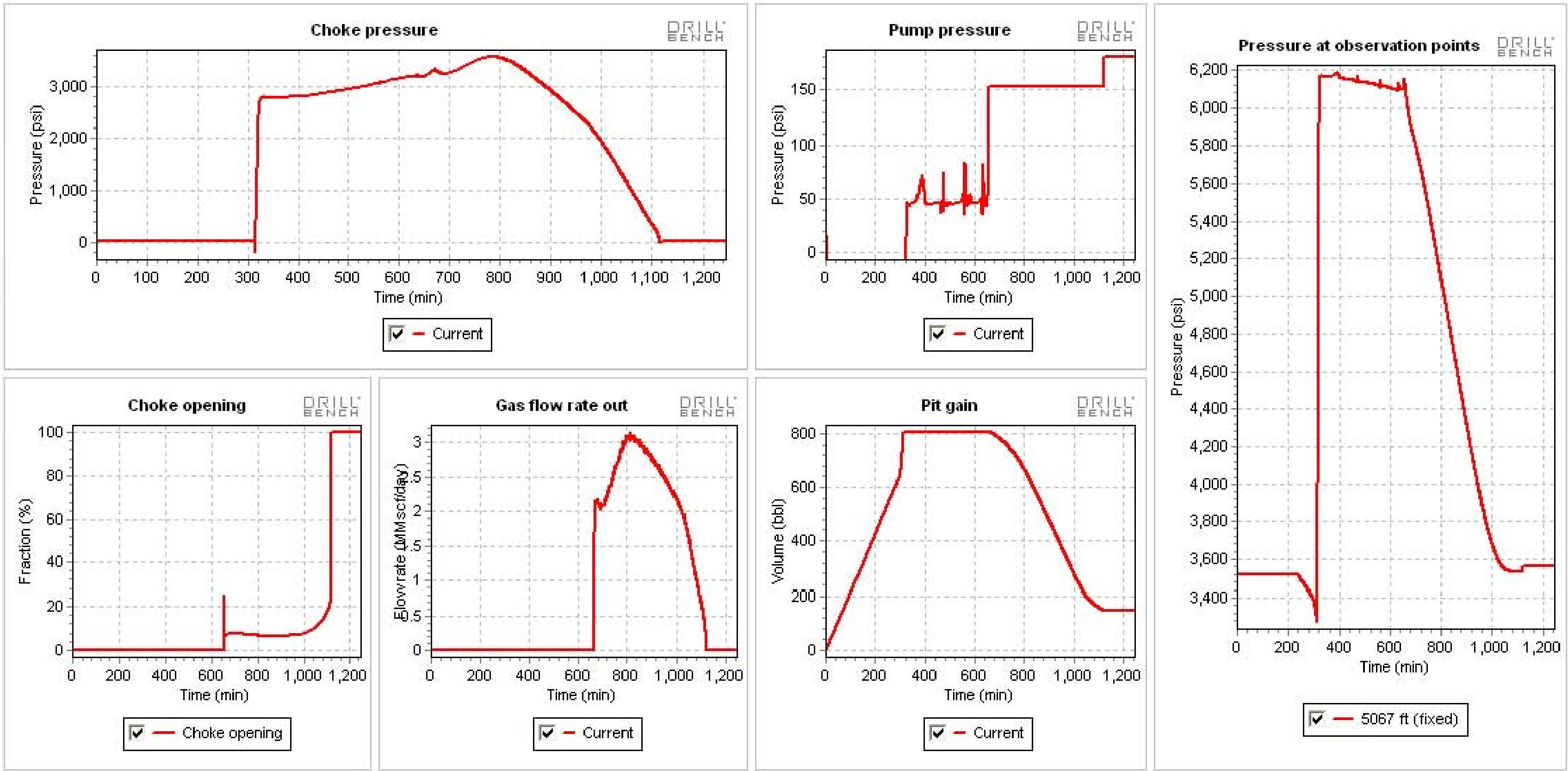


Figure 2 – Scenario #1, Circulating Macando Fluid from 9-7/8" Casing Annulus. 2 bpm circulating rate, constant drill pipe pressure

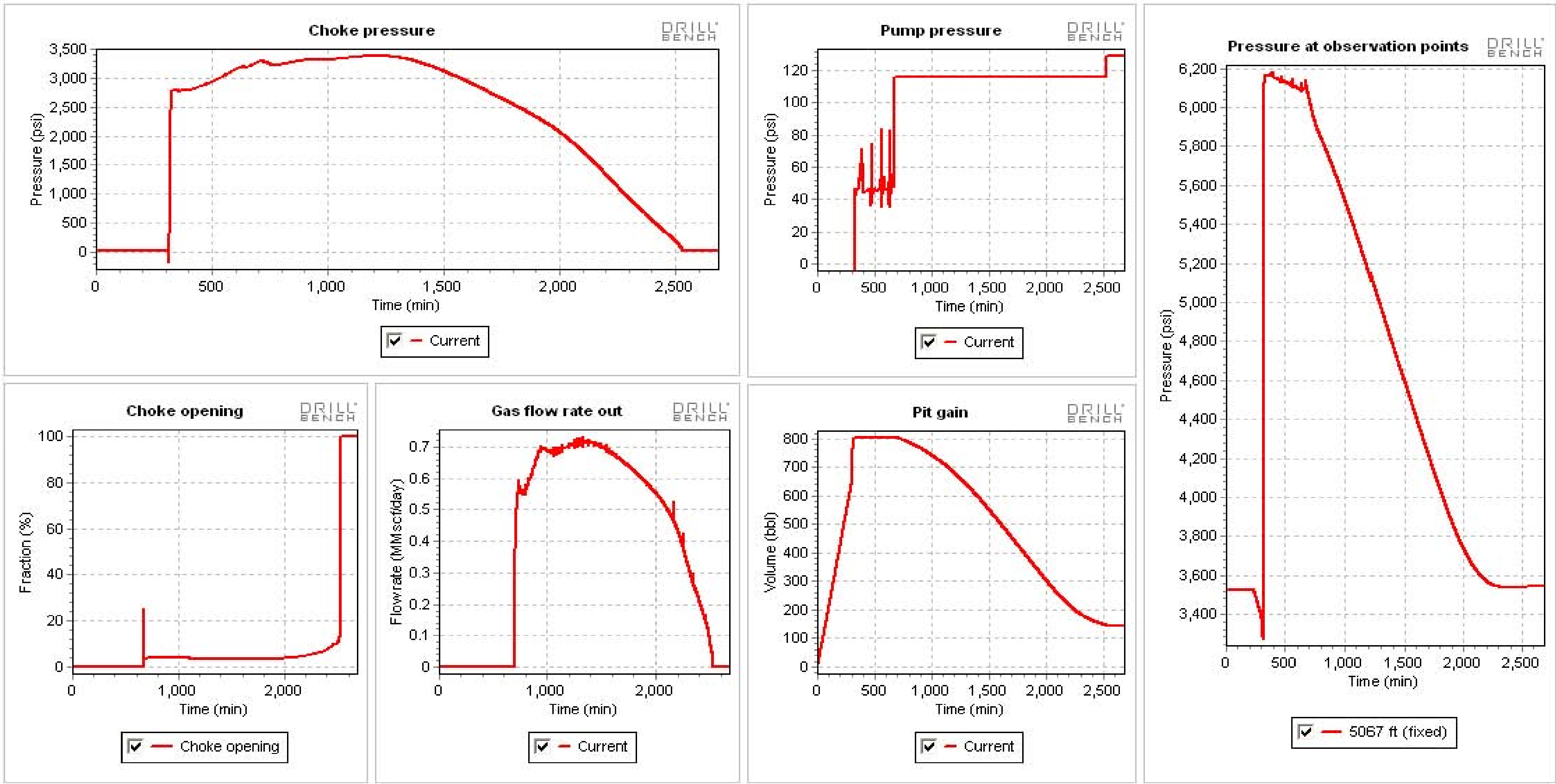
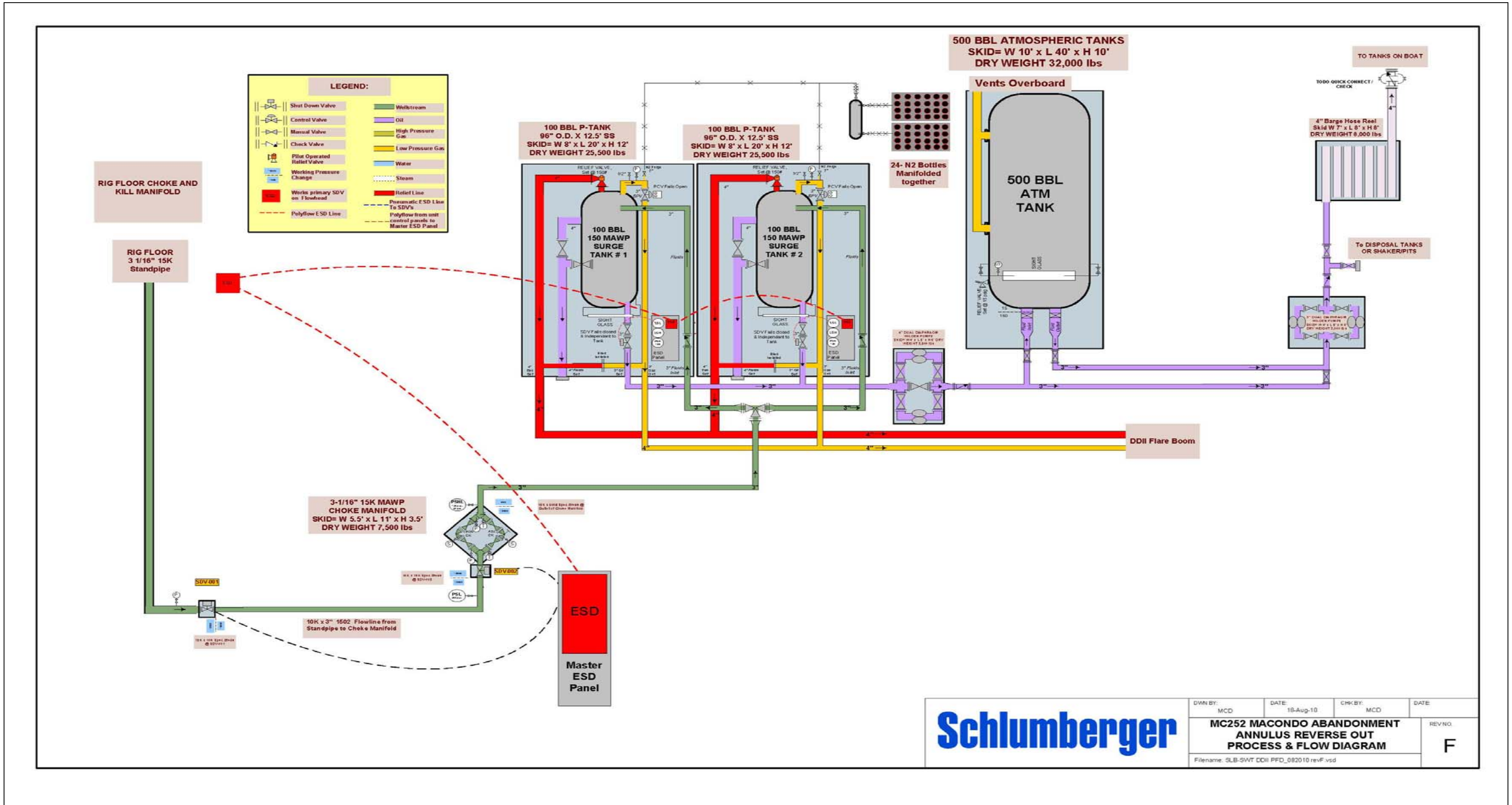
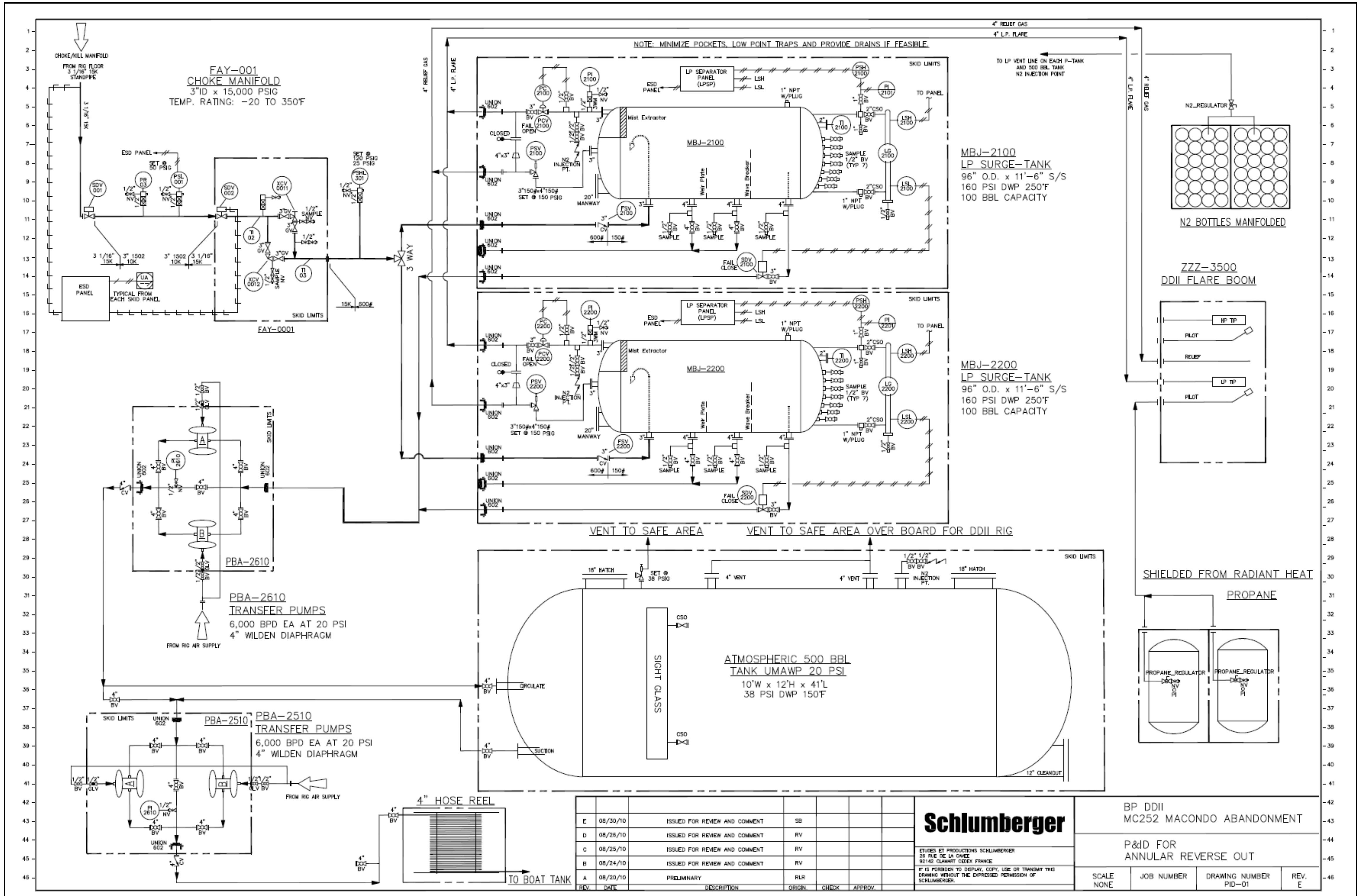


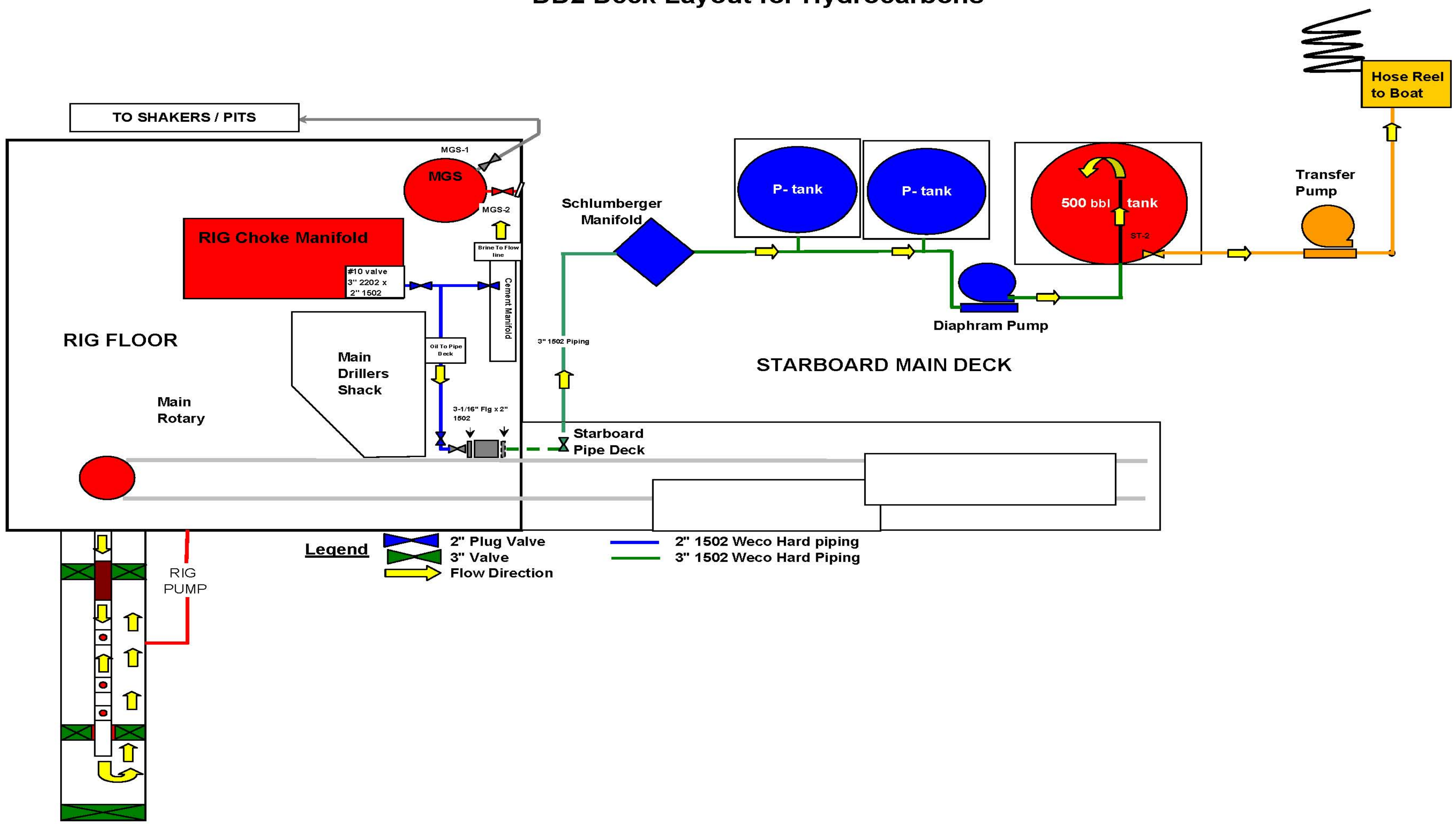
Figure 3 – Scenario #1b, Circulating Macando Fluid from 9-7/8" Casing Annulus. 0.5 bpm circulating rate, constant drill pipe pressure.

Attachment 6: Surface Rig-Up for Hydrocarbon Handling




FAY-001
CHOKE MANIFOLD
3"ID x 15,000 PSIG
TEMP. RATING: -20 TO 350°F
MBJ-2100
LP SURGE-TANK
96" O.D. x 11'-6" S/S
160 PSI DWP 250°F
100 BBL CAPACITY
MBJ-2200
LP SURGE-TANK
96" O.D. x 11'-6" S/S
160 PSI DWP 250°F
100 BBL CAPACITY
N2 BOTTLES MANIFOLDED
ZZZ-3500
DDII FLARE BOOM
PBA-2610
TRANSFER PUMPS
6,000 BPD EA AT 20 PSI
4" WILDEN DIAPHRAGM
PBA-2510
TRANSFER PUMPS
6,000 BPD EA AT 20 PSI
4" WILDEN DIAPHRAGM
VENT TO SAFE AREA
VENT TO SAFE AREA OVER BOARD FOR DDII RIG
ATMOSPHERIC 500 BBL
TANK UMAWP 20 PSI
10'W x 12'H x 41'L
38 PSI DWP 150°F
SIGHT GLASS
SHIELDED FROM RADIANT HEAT
PROPANE
4" HOSE REEL
TO BOAT TANK
NOTE: MINIMIZE POCKETS, LOW POINT TRAPS AND PROVIDE DRAINS IF FEASIBLE.
Schlumberger
BP DDII
MC252 MACONDO ABANDONMENT
P&ID FOR
ANNULAR REVERSE OUT
SCALE NONE
DRAWING NUMBER PID-01
REV. E
E 08/30/10 ISSUED FOR REVIEW AND COMMENT
D 08/26/10 ISSUED FOR REVIEW AND COMMENT
C 08/25/10 ISSUED FOR REVIEW AND COMMENT
B 08/24/10 ISSUED FOR REVIEW AND COMMENT
A 08/20/10 PRELIMINARY

DD2 Deck Layout for Hydrocarbons

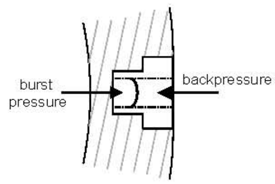
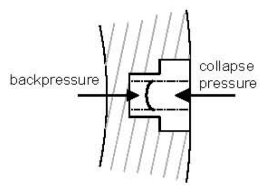


Attachment 7: Burst/Collapse Disc Sub Specifications

Rupture Disk Sub Worksheet – Statement of Requirements

Business Unit		Well Charge		Date	
Purchase Number		Item Number		Material Number	
Description	**16" Burst & Collapse subs** **3 subs plus 1 back-up for a total of 4 subs**			Drawing Number	

Casing String Designation *Description of string that will include burst disk sub*	*OD, Weight / Wall, Grade, Connection, Special Drift Requirements* **16" 97.0 (0.575" wall) P-110 Hydril 511**	
	Burst (MIYP) Rating **6,920 psi**	*Collapse Rating* **2,340 psi**

Burst Disk Description *Typical tolerance is ± 5%* *Rating is at 150°F unless noted otherwise* *Disks should be installed 2 per sub, 180° apart*		*Burst Disks per Sub* **2 at 180°; HES AO6239-3** *Burst Pressure (e.g. 5,000 psi ± 5%)* **7,500 psi ± 5% at 200°F** *Minimum Backpressure* **5,250 psi**
Collapse Disk Description *Typical tolerance is ± 5%* *Rating is at 150°F unless noted otherwise* *Disks should be installed 2 per sub, 180° apart*		*Collapse Disks per Sub* **2 at 180°; new disk item** *Collapse Pressure (e.g. 2,000 psi ± 5%)* **1,600 psi ± 5% at 150°F** *Minimum Backpressure* **7,000 psi**

O-Ring Material *Verify compatibility with mud http://ut.bpweb.bp.com/elastomers/*	*O-Ring Material (e.g. Viton or Buna-N)* **Viton**	
Sub Geometry *Vendor to supply drawing* *All disks shall be installed with thread lock compound*	☐ Pin x Pin ⊗ Pin x Box ☐ Box x Box	*Additional Requirements (e.g. minimum tong area, number of recuts, minimum length requirements)*
Pressure Test Parameters *Hunting's tester allows for different burst disk and collapse disk test values*	*Test Pressure – Specify the minimum of:* *- Casing test pressure* *- 85% of nominal rupture pressure for burst disks* *- 90% of minimum backpressure for collapse disks* **6,300 psi**	*Hold Time (e.g. 10 minutes)* **10 minutes**
Number of Additional Disks *For reworking field returns*	*Total Additional Burst Disks* **2 additional disks**	*Total Additional Collapse Disks* **2 additional disks**
Special Marking or Identification Requirements		

Attachment 8: Evidence Handling and Chain of Custody Protocols for Casing Recovery

References

a) USCG-BOEMRE Joint Investigation Protocols for Physical Collection of Evidence
b) Procedure for permanent abandonment, 2200-T2-DO-PR-4734.

Purpose

Per the subpoenas issued by the USCG-BOEMRE Joint Investigation, all equipment and materials recovered from the MC252 #1 well and the MODU DEEPWATER HORIZON shall be considered evidence. Recognizing this fact, the purpose of this document is to further amplify the procedures in references (a) and (b).

Recovery and Preservation of Evidence

Recognizing that the procedures for the recovery of evidence are developed by ICP Houston, a member of the USCG-BOEMRE Joint Investigation Team (JIT member) shall be embedded with the planning groups at ICP Houston to ensure that recovery procedures ensure the integrity and preservation of evidence in as much as possible.

The U.S. Navy, Supervisor of Salvage & Diving (SUPSALV) has been designated by the Department of Justice to provide technical oversight on evidence preservation procedures on behalf of the U.S. Government.

During evidence recovery planning, the ICP planning group will ensure that the JIT is aware of any plans to change the condition of evidence during recovery (i.e. cutting, cleaning, decontamination and disassembly of equipment before shipping). Any plans to change the condition of evidence must be bought to the attention of and approved by the JIT member assigned to the ICP Houston planning group.

Identification and Documentation of Evidence

Per the subpoenas issued by the JIT, all equipment and materials recovered from the MC252 #1 well and the MODU DEEPWATER HORIZON shall be considered evidence.

The FBI Evidence Recovery Team (ERT) has been designated by the JIT to document evidence on behalf of the U.S. Government, including the JIT. As such, ERT procedures will be followed for documentation of evidence.

The ERT will begin documentation as soon as the procedure for recovery of evidence has commenced. As such, members of the JIT and the ERT must be on scene during recovery efforts. The ERT will rely on ROV footage to document sub-sea efforts. As such, ERT members must be in a position to monitor recovery efforts via ROV. ROV footage will be recorded and, upon completion of operations, ROV footage will be turned over to the JIT/ERT as evidence.

Once evidence has been recovered and is at the water's surface, the ERT must be on scene to witness and document the evidence that has been raised.

Custody and Tagging of Evidence

The JIT will take custody of the evidence from the time it is removed from the well, and will maintain custody through the lifting and transport process. As such, a member of the JIT must be on scene during recovery efforts.

As part of the ERT documentation process, the ERT will tag the evidence and document transfer of evidence from BP to the JIT on a Chain of Custody form (attached).

Delivery and Storage

Unless otherwise agreed to, BP will arrange for safe transport of evidence from the recovery site to the evidence storage site at USCG Base Support Unit, which is on the NASA Michoud facility in New Orleans, LA.

During transport of evidence, the JIT and BP will ensure that precautions are taken to ensure that evidence is secure and safe for transport and storage. Cradles for lift, transport and storage shall be used as much as possible to preserve the evidence. Furthermore, BP shall ensure that the JIT is aware of such specifications and requirements to facilitate movement of evidence on land.

During the delivery of evidence from the recovery site to shore, members of the JIT and/or the FBI or other federal agents must be onboard the transport vessel or on a supporting escort vessel to maintain custody and control of the evidence.

The USCG will be responsible for arranging and providing a safety zone around the transporting vessel if required by the JIT.

Primary Points of Contact for Evidence Matters

Phase	JIT POC
Recovery Preservation	Michael Saucier michael.saucier@boemre.gov 985-856-5703 Dave Williams David_williams@doioig.gov 504-593-1800
Identification & Documentation	Howard Stewart howard.stewart@usdoj.gov 504-593-1800
Tagging & Custody	Howard Stewart howard.stewart@usdoj.gov 504-593-1800
Delivery & Storage	CAPT Suzanne Englebert, USCG Suzanne.e.englebert@uscg.mil 202-604-1230

U.S. Department of Homeland Security
U.S. Coast Guard
CG-6000 (6-04)

COAST GUARD INVESTIGATIVE SERVICE EVIDENCE CUSTODY FORM

1. Receiving Office	2. Case Control Number (CCN)	3. Evidence Log Type and Number
4. Case Title/Subject		
5. Name/ Grade / Title of Person From Whom Seized/Received Owner ☐ Other ☐	6. Address (include ZIP)	
	7. Work Phone	8. Home Phone
9. Location Where Property Seized/Received		
10. Reason Obtained ☐ Found ☐ Impounded ☐ Other ______ ☐ Evidence	11. Time/Date Seized/Received	12. Seized/Received By (Printed Name)

13. Item	14. Quantity	15. Disposal Action	16. Description of Article/Make, Model, Serial Number, Identifying Marks, Condition, Value, Weight, and Evidence Tag Number

17. Name and Signature of Witness	18. Name and Signature of Evidence Custodian

19. CHAIN OF CUSTODY

Items	Date/Time	Released By	Received By	Purpose
		Name	Name	
		Organization	Organization	
		Signature	Signature	
		Name	Name	
		Organization	Organization	
		Signature	Signature	

Page 1 of 2 Pages

Reset

Note: Add 9-ft to MD/TVD for Development Driller II

19. CHAIN OF CUSTODY (CONT'D)

Items	Date/Time	Released By	Received By	Purpose
		Name Organization Signature	Name Organization Signature	
		Name Organization Signature	Name Organization Signature	
		Name Organization Signature	Name Organization Signature	
		Name Organization Signature	Name Organization Signature	
		Name Organization Signature	Name Organization Signature	
		Name Organization Signature	Name Organization Signature	
		Name Organization Signature	Name Organization Signature	

20. FINAL DISPOSITION

Final Disposition Authority

Name (Printed)	Grade/Rank	Organization

Persons Witnessing Destruction (Print)	Organization	Signature and Date
1.		
2.		

NOTE: You MUST indicate in Disposal Action Column (on front) by two number or letter code, persons receiving or witnessing action and the type of action.

CODES: (R) Person receiving (W) Witness to Action (A) Turned over to another Agency
(1) Returned to Individual Owner (C) Returned to Command (S) Turned into Supply
(D) Destroyed (M) Another method (explain in Remarks section)

EXAMPLE: Code R1 = person receiving the item was the owner;
WD = person witnessed the destruction of the item;
RC = person receiving item returned it to the command

21. REMARKS

Page 2 of 2 Pages

Reset

Attachment 9: DD2 Drill Pipe Sheet

Drill Pipe & Collars Reference Chart

	String	Grade	Body ID	Lengths: Range	Lengths: Ave Jt	Lengths: Ave Std	Weights: Nominal	Weights: Adjusted	Body Tensile Premium	Connection: Type	Connection: OD	Connection: ID	Torsional Strength	Make Up Torque: Min	Make Up Torque: Max
Drill String	5 7/8 Drill Pipe 0.5 wt	S-135T	4 7/8	R2	32.22ft	128.91ft	28.67#	**34.01#**	894,900	XTM57	7	4¼	84,000	33,800	50,400
	5 7/8 HWDP	Std HW	4	R2	30.85ft	123.33ft	49.385#	**64.88#**	627,843	XTM57	7	4		48,900	58,700
Landing Strings	6 5/8 FH 0.813 wt	S-135	5	R3	42.18ft	126.56ft	50.39#	**56.63#**	1,557,600	FH	8½	4	119,400	55,800	55,800
	6 5/8 XTM 0.415 wt	S-135T	5.795	R3	42.11ft	126.34ft	27.50#	**34.23#**	862,700	XTM69	8½	5¼	100,600	50,300	60,400
Drill Collars	9 ½	-	3	R2	30.92ft	123.70ft	**216.71#**	-	-	7 5/8 Reg	9 ½	3		88,500	97,500
	8 ¼	-	2 7/8	R2	30.95ft	123.80ft	**159.49#**	-	-	6 5/8 Reg	8 ¼	2 7/8		52,500	58,000

Casing Reference Chart

Casing Size	Grade	Nom. ID	Drift Ø	Casing Properties: Weight	Burst	Collapse	Tensile Strength	Connection: Type	OD	ID	Opt MU Torque ft lbs	Volumes: Capacity	Metal Disp	Closed-End
20 in	X56	18.376"	-	166.4#	3980 psi	2510 psi	2,741,000	XLW	20	18.376	-	0.3280	0.0606	0.3886
20 in	X56	18.73"	-	131.3#	3060 psi	1500 psi	2,125,000	XLW	20	18.730	-	0.3408	0.0478	0.3886
16 in	N80	15.01"	14.822	84#	4330 psi	1480 psi	1,929,000	HYDRIL 521	16.257	14.935	43,000	0.2188	0.0306	0.2494
13 5/8 in	HCQ125	12.375"	12.250	88.2#	10,030 psi	4,800 psi	2,393,000	SLIJ II	13.875	12.317	34,400	0.1488	0.0321	0.1809
10 3/4 in	C110	9.45"	9.294	71.1#	11,640 psi	9,300 psi	1,778,000	SLIJ II	11.045	9.370	30,700	0.0868	0.0259	0.1127
9 7/8 in	C110	8.625"	8.500	62.8#	12,180 psi	10,290 psi	1,551,000	SLIJ II	10.151	8.559	28,900	0.0723	0.0229	0.0952
5 1/2 in	13Cr-85	4.67"	4.545	23#	11,220 psi	11,810 psi	564,000	VAM TOP HC	6.156	4.607	10,850	0.0212	0.0084	0.0296

Annular Capacities

	String	Riser	Inside: 20" hole	20"166#	20"131#	16½" hole	16"	14½" hole	13 5/8"	12¼" hole	10¾"	9 7/8"
Drill String	5 7/8 Drill Pipe	0.3284	0.3537	0.2932	0.3059	0.2296	0.1840	0.1694	0.1139	0.1109	0.0519	0.0374
	5 7/8 HWDP	0.3242	0.3495	0.2890	0.3017	0.2254	0.1798	0.1652	0.1097	0.1067	0.0477	0.0332
Landing Strings	6 5/8 Casing LS	0.3190	-	-	-	-	-	-	-	-	-	-
	6 5/8 Completion LS	0.3183	-	-	-	-	-	-	-	-	-	-
Drill Collars	9 ½	0.2757	0.3010	0.2405	0.2532	0.1769	-	0.1167	-	-	-	-
	8 ¼	0.2973	0.3225	0.2620	0.2747	0.1984	-	0.1382	-	0.0797	-	-

Pipe Volumes

	Volumes: Capacity	Metal Disp	MD /5 stds	Closed-End	CE /5 stds	Drift Ø
5 7/8 Drill pipe	**0.0226**	0.0124	8.0	0.0350	22.5	4 1/8
5 7/8 HWDP	**0.0156**	0.0236	14.5	0.0391	24.1	3 7/8
6 5/8 FH	**0.0238**	0.0206	13.0	0.0444	28.1	3 7/8
6 5/8 XTM	**0.0326**	0.0125	7.9	0.0451	28.5	5 5/8
9 ½ DC	**0.0087**	0.0789	-	0.0876	-	2 7/8
8 ¼ DC	**0.0080**	0.0581	-	0.0661	-	2 ¾

Capacities

		Capacity
Open holes	20 in	0.3886
	17 in	0.2807
	16½ in	0.2645
	14½ in	0.2043
	12¼ in	0.1458

		Capacity	ID
Riser	21", 0.813wt, X80, 72lb	0.3647	19.374"
	21", 0.875wt, X80, 28lb	0.3600	19.25"
	Average	0.3834	19.34"
Outlets	C & K lines, 5.905"	0.0156	4"
	Boost line, 7"	0.0350	6"

Pipe		External Upsets: Pin-end	Box-end	Tong Lengths: Pin	Box
5 7/8 XTM57		6.000"	6.000"	16"	17"
5 7/8 HWDP XTM57		-	-	24"	24"
6 5/8 FH		6.906"	6.906"	12"	15"
6 5/8 XTM69		7.125"	7.031"	14"	15"

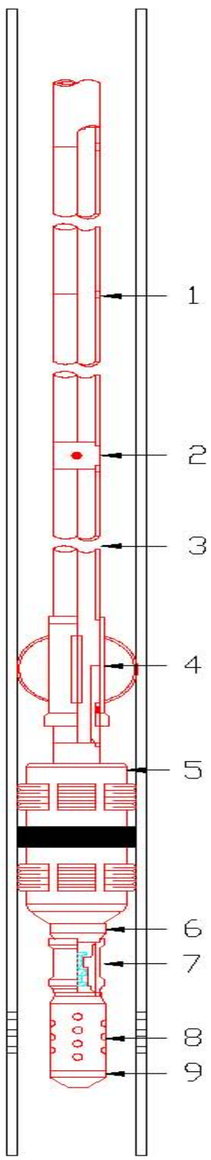
Mud Pumps: National 14-P-220 (14" Stroke)

Liner	bbls/stk	gal/stk	MAX psi
5 1/2"	0.1029	4.32	7475
6"	0.1223	5.14	6285
6 1/2"	0.1436	6.03	5360
7"	0.1666	7.00	4615

REV O - Dec

Attachment 10-A: 9 7/8-in Dril-Gun Data

HALLIBURTON



Date: *August 27, 2010*

Prepared For: *Bp*
Attention Of: *Mr. Mark Heironimus*

Stage I of I

Field Name: *Macondo*
Lease: *OCS-G-32306*
Well : *#1*
Location: *Offshore, La.*

Casing: **9 7/8" 62.80lb. HCQ-125**
Workstring: **5 7/8" XTM-57**

247738v2

Description:	*I.D.*	*O.D.*	*Length*	*Depth*
1. Workstring to surface				
2. Ball Catcher	2.500"	7.250"	6.15'	11,939.65
3. Workstring Drill Pipe (1 Stand)	4.875"	7.000"	93.00'	11,945.80
4. Retainer Setting Tool	1.620"	6.870"	5.49'	12,038.80
5. 9 7/8" 62.80lb. EZSVB Retainer	-	6.875"	3.01'	12,044.29
6. Drill Gun Adapter	-	6.000"	0.70'	12,047.30
7. Firing Head - Inside 2ft 2 7/8" pup	-	2 7/8"	2.00'	12,048.00
Top Shot				**12,050.00**
8. 3 3/8" 12 SPF Big Hole 14.7 Gm- 3 ft. loaded	-	7"	3.00'	
Bottom Shot				**12,053.00**
9. Bull Plug	-	7"	1.00'	

Note: Add 9-ft to MD/TVD for Development Driller II

Attachment 10-B: 9 7/8-in Perf Charge Data

TEST LAB REPORT

Test No.________

JRC EXPLOSIVE PRODUCTS ENGINEERING AND TESTING

SINGLE SHOT SCALLOP CARRIER CHARGE IN DUAL STRING CASING

REV: E

DATE: 8-12-10 **SHEET** 1 OF 1 **FILE NAME:** New Attachment 10_8-27-10.xls

REQUESTED BY J. Walker for P. Costlow & BP, Macondo **WITNESS:** ☐ YES ☑ NO **REQ. COMP. DATE** 8-12-10

TEST OBJECTIVE: Determine hole size in first string and penetration if any in second string with 3 3/8" Gun.

This is for one of the BP, Macondo Relief Well

CHG. DESCRIPTION: 2 3/4" 6 SPF BH **GM WT** 14.7

SAP NO. 101206793 **IMS NO.** ________ **TOTAL SHOTS** 6 **GUN SIZE** 3 3/8"

VARIABLE	Minimum H2O CL to String 1						Maximum H2O CL to String 1					
TEST NO.	1	2	3				4	5	6			
MINOR EHD STR 1	0.20	0.23	0.23				0.21	0.19	0.22			
MAJOR EHD STR 1	0.25	0.24	0.24				0.23	0.25	0.24			
AVE. EHD STR 1	0.225	0.235	0.235				0.220	0.220	0.230			
MINOR EHD STR 2												
MAJOR EHD STR 2												
AVE. EHD STR 2	Did Not Penetrate						Did Not Penetrate					
PENETRATION BEYOND STRING 2												
BOOSTER (gms)												
POWDER							(					
MAIN (gms)												
POWDER												
D) CLEARANCE (in.)	2.680						2.930					
Chg. Mfg. By/Date:	3 June 2010											

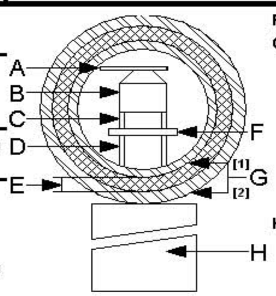
A) DET. CORD
80gr HMX XHV

B) CHARGE

C) STANDOFF (in.)
.582

D) CLEARANCE (in.)
See Above

☐ AIR ☑ WATER



E) CLEARANCE (in.)
1.245

☐ AIR ☑ WATER ☐ Cement ☐ ________

SPECIAL INSTRUCTIONS:

Jim, if shots 1, 2, and 3 go through the second string then don't shoot the last 3 shots.

F) SCALLOP THICKNESS .125

G) TARGET

[1] CASING Ring ☐ Coupon ☑ **O.D.** 9.875 **WT.** 62.8 **THK.** 0.630 **GRD** Q-125 **I.D.** 8.615

[2] CASING Ring ☐ Coupon ☑ **O.D.** 13.625 **WT.** 88.2 **THK.** 0.629 **GRD** Q-125 **I.D.** 12.366

H) PENETR. MEDIUM QC cement **LOT NO.** ________

6" O.D. x 12" lg.

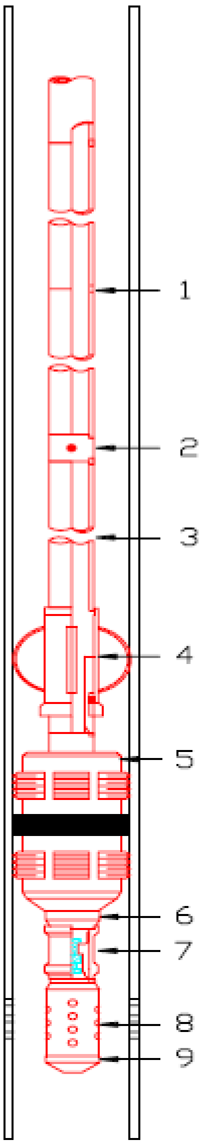
SUMMARY OF RESULTS

VARIABLE	Min CL	Max CL
EHD AVG. IN STR 1	0.23	0.22
EHD STD DEV IN STR 1	0.005	0.005
EHD AVG. IN STR 2		
EHD STD DEV IN STR 2		
PENETRATION BEYOND STRING 2		
PENTR.STD DEV		

PERFORMED BY Roger,Don **DATE COMPLETED:** 8-13-10

556.09/25 REV:00

Attachment 10-C: 7-in Dril-Gun Contingency Data



Date: *August 25, 2010*

Prepared For: *Bp*
Attention Of: *Mr. Mark Heironimus*

Stage I of I

Field Name: *Macondo*
Lease: *OCS-G-32306*
Well : *#1*
Location: *Offshore, La.*

Casing: 7.00" 32.00lb. HCQ-125
Workstring: 4" XT-39

247742v1

Description:	*I.D.*	*O.D.*	*Length*	*Depth*
1. Workstring to surface				
2. RA Bead (Optional)				14,385.80
3. Workstring Drill Pipe (1 Stand)			93.00'	14,385.80
4. Retainer Setting Tool	1.620"	5.650"	5.49'	14,478.80
5. 7" 32.00lb. EZSVB Retainer	-	5.500"	3.01'	14,484.29
6. Drill Gun Adapter	-	5.000"	0.70'	14,487.30
7. Firing Head - Inside Drill Gun Adapter	-	-		
Top Shot				**14,488.00**
8. 3 3/8" 12 SPF Super Hole - 4 ft. loaded	-	7"	4.00'	
Bottom Shot				**14,452.00**
9. Bull Plug	-	7"	1.00'	

Attachment 10-D: 7-in Dril-Gun Perforating Charge Data

TEST LAB REPORT

Test No.________

JRC EXPLOSIVE PRODUCTS ENGINEERING AND TESTING

SINGLE SHOT SCALLOP CARRIER CHARGE IN DUAL STRING CASING — REV: E

DATE: 8-12-10 **SHEET** 1 OF 1 **FILE NAME:** 100813-JLW01-4 in 3.375 Gun in 9.87 in. and 13 in., Dual String for BP Macondo.xls

REQUESTED BY J. Walker for P. Costlow & BP, Macondo **WITNESS:** ☐ YES ☑ NO **REQ. COMP. DATE** 8-12-10

TEST OBJECTIVE: Determine hole size in first string and penetration if any in second string with 3 3/8" Gun.
This is for one of the BP, Macondo Relief Wells

CHG. DESCRIPTION: 3 3/8" 12 SPF BH Stl Case **GM WT** 14

SAP NO. 100008251 **IMS NO.** ________ **TOTAL SHOTS** 6 **GUN SIZE** 3 3/8"

VARIABLE	Minimum H2O CL to String 1						Maximum H2O CL to String 1					
TEST NO.	1	2	3				4	5	6			
MINOR EHD STR 1	0.20	0.20	0.20				0.17	0.22	0.23			
MAJOR EHD STR 1	0.22	0.22	0.23				0.19	0.25	0.24			
AVE. EHD STR 1	0.210	0.210	0.215				0.180	0.235	0.235			
MINOR EHD STR 2												
MAJOR EHD STR 2												
AVE. EHD STR 2												
PENETRATION BEYOND STRING 2												
BOOSTER (gms)												
POWDER												
MAIN (gms)												
POWDER												
D) CLEARANCE (in.)	2.680						2.930					
Chg. Mfg. By/Date:	13 Nov 08											

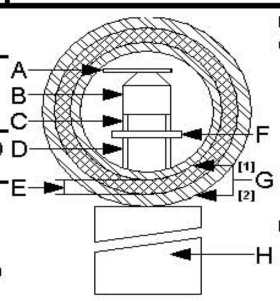
A) DET. CORD
80gr HMX XHV

B) CHARGE

C) STANDOFF (in.)
.256

D) CLEARANCE (in.)
See Above

☐ AIR ☑ WATER



E) CLEARANCE (in.)
1.245

☐ AIR ☑ WATER ☐ Cement ☐ ________

SPECIAL INSTRUCTIONS:
Jim, if shots 1, 2, and 3 go through the second string
then don't shoot the last 3 shots.

F) SCALLOP THICKNESS .125

G) TARGET

[1] CASING — Ring ☐ Coupon ☑ — **O.D.** 9.875 **WT.** 62.8 — **THK.** 0.630 **GRD** Q-125 — **I.D.** 8.615

[2] CASING — Ring ☐ Coupon ☑ — **O.D.** 13.625 **WT.** 88.2 — **THK.** 0.629 **GRD** Q-125 — **I.D.** 12.366

H) PENETR. MEDIUM QC cement **LOT NO.** ________
6" O.D. x 12" lg.

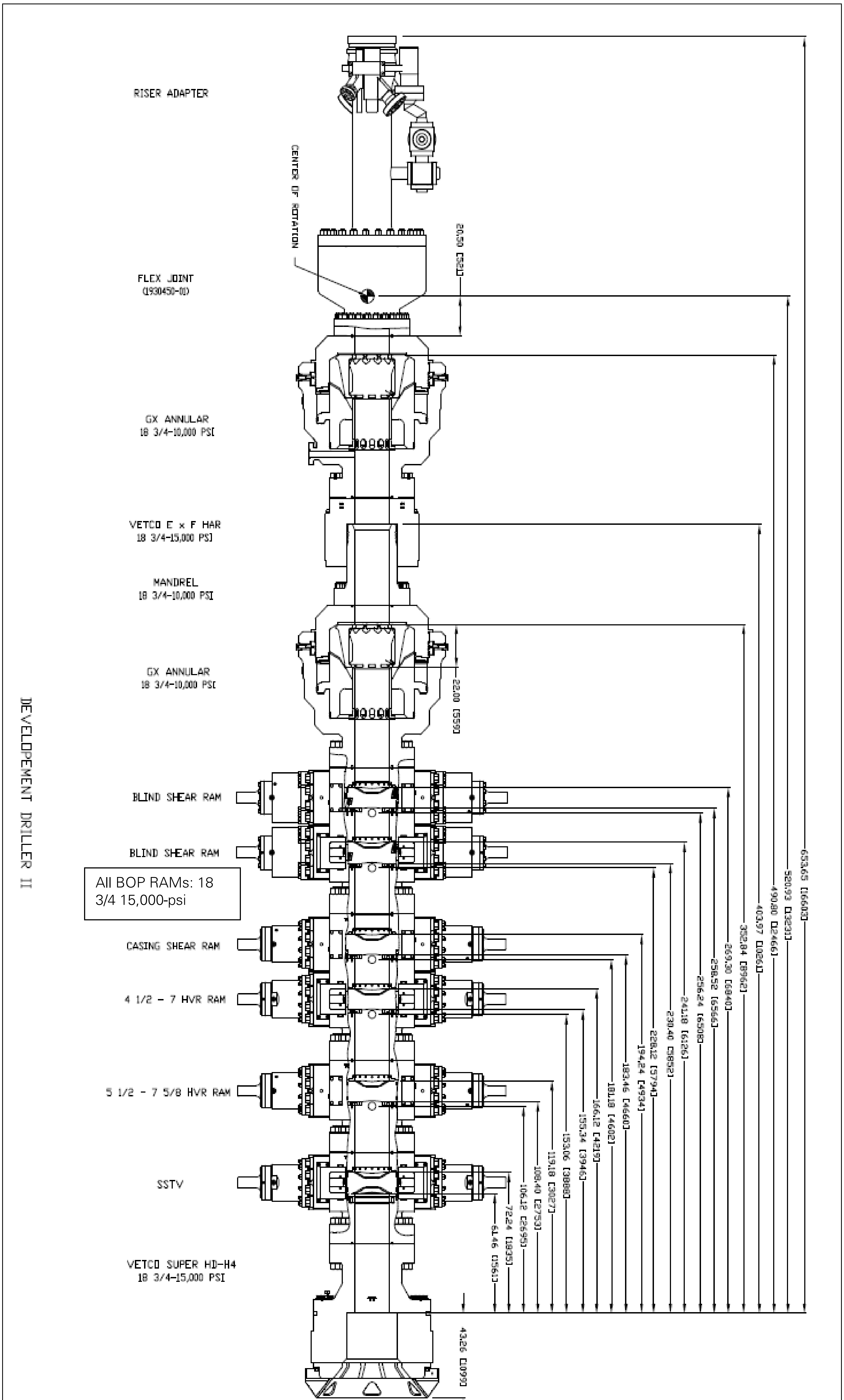
SUMMARY OF RESULTS

VARIABLE	Min CL	Max CL
EHD AVG. IN STR 1	0.21	0.22
EHD STD DEV IN STR 1	0.002	0.026
EHD AVG. IN STR 2		
EHD STD DEV IN STR 2		
PENETRATION BEYOND STRING 2		
PENTR.STD DEV		

PERFORMED BY Roger,Don **DATE COMPLETED:** 8-13-10

556.09/25 REV:00

Attachment 11: DD2 BOP Schematic



Note: Add 9-ft to MD/TVD for Development Driller II