EXHIBIT # 102
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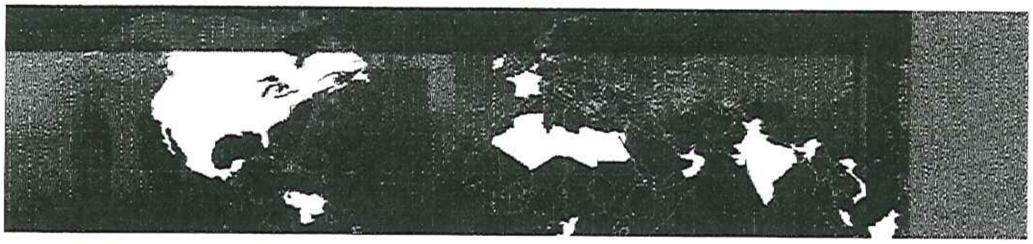

Submitted by:

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Incident Investigation of Well MC252#1
Review of 9-7/8" x 7" Casing Negative Test

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REPORT RELEASE DATA SHEET
Incident Investigation of Well MC252#1
Review of 9-7/8" x 7" Casing Negative Test

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2 EXECUTIVE SUMMARY

I (John Wright) was asked by Kent Corser (the engineering support leader under the Technical and Operations branch of the Horizon Incident Investigation Team) to write an assessment of the negative test performed on the Deepwater Horizon prior to the well blowout on April 20, 2010. My findings are summarized in this document.

I emphasize that these findings are based on my knowledge of the incident provided to me as part of the investigation time up to the date of this writing (May 20, 2010). The information that we have on the incident is not complete and we as a team have to make deductions on the information we have at the time. If more or different information is gained in the future, these findings may change.

2.1 Documented Negative Test Procedure Assessment

1. It appears that there was not a documented engineered procedure on how the negative test was to be performed for the given situation (e.g., deepwater, lock down sleeve not installed, testing seal assembly and

float/cement in shoe track simultaneously, multiple fluid densities in the well, temperature effects, etc.)

2. Performing and correctly interpreting a negative test on a deepwater, high flow potential exploration well from a 5th generation semi-submersible would be considered a safety critical and high significant risk activity. High significant risk activities require a formal risk assessment to be performed. This would include, for example:

   a. Review of negative test procedures and identification of hazards (specifically well control hazards) at each of the steps specific to this rig, well and situation

   b. Identification of top events, e.g., hydrocarbons entering the wellbore below the BOP and hydrocarbons entering the riser above the BOP (either from the shoe track or from behind the seal assembly)

   c. Assessment of the consequences if the top events occur

   d. Evaluation of prevention barriers to prevent occurrence of a top event

   e. Evaluation of mitigation controls to minimize escalation of a top event

3. A detailed written negative test procedure with risk assessment and mitigation decision trees may have:

   a. Prevented the displacement of the Form-A-Set spacer during the negative test which complicated the interpretation of the negative test data.

   b. A list of the risk and consequences may have encouraged a more thorough investigation of, e.g.: the bleed volumes, possible annular leak, build up pressures, differential pressures between the drillpipe and kill line to assure the kill line was not plugged and Form-A-Set was displaced above the BOP.

   c. Since there was well control risk in the interpretation of the negative test and Transocean would have control of well control response, there should have been a bridging document between Transocean and BP to assure conformance to procedure and interpretation of data.

2.2 Assessment of Rig Actions Related to the Negative Test

2.2.1 Operational Issues Prior to the Negative Test

A number of issues were observed that should have increased awareness of a potentially bringing influx into the wellbore during the negative test. They were:

1. Deepwater exploration well
2. Prolific hydrocarbon reservoir sand identified during 4 days of logging
3. Close tolerance between pore pressure and fracture gradient
4. Not placing a mud pill in the rat hole heavier than the tail cement prior to running casing
5. Lower than expected circulation pressure after landing the casing

6. Foamed cement over the reservoir
7. Much higher pressure required to convert the cement float equipment than expected
8. The Lock Down Sleeve is not in place to prevent movement of casing out of seal area
9. Lack of a detailed negative test procedure
10. Lack of a risk assessment related to the negative test procedure
11. Cement integrity on casing not evaluated after cement job with segmented cement bond log

2.2.2 Operational Issues Immediately before and during the Negative Test

1. Displacing Form-A-Set & Form-A-Squeeze spacer with water prior to the negative test
2. Under displacing the Form-A-Set so that it was placed across the BOP stack
3. U-Tube severely unbalanced after displacement (indicating severe swapping and fallout of the Form-A-Set spacer in the seawater)
4. Apparent poor management of tracking volumes bled back to Halliburton from the DP
5. Leaking annular during initial pressure bleed down on the drillpipe and filling up from trip tank after the fact (should have been circulating across riser with trip tank)
6. Multiple pit activities going on simultaneously (transferring to boat, empty sand trap, cleaning trip tanks) making it difficult to manage volumes during a safety critical operation.
7. Bleed back of additional 15 to 23 bbls after the riser was filled. There is no indication from witness statements of where anyone thought this volume was coming from if the annular was no longer leaking.
8. Confusing pressure response on drillpipe when the kill line was opened 17:55
9. Steady pressure increase on the DP up to 1400 psi while the kill line was open
10. Hook load falling 16 kips while the DP pressure stays constant

2.3 Summation

At the time of this writing, it appears that there was not a sense of the significant risk associated with correctly implementing and interpreting the data for the negative test implemented as a step in the temporary abandonment program for the Deepwater Horizon. This is evident from:

1. The engineering staff who wrote and approved the program without a detail procedure and the lack of a formal risk assessment for a safety critical and significant risk activity
2. The BP Sr. WSL and Transocean OIM:

   a.
   Who developed a procedure on the fly with Form-A-Set spacer and multiple activities going on simultaneously that stack the odds against them for interpreting the negative test data correctly

   b.
   Misinterpreting potential well influx indicators as "bladder effect" and proceeding to immediately circulate the well to seawater without performing additional test to confirm their theory (e.g., circulating up the choke line through the mud gas separator) or sending the data to town for the engineering team

to interpret the data before proceeding.

If any person in the command chain had understood the consequence of misinterpreting this critical test, the annular would not have been opened and the riser circulated to seawater which ultimately led to the blowout.

3 SUMMARY OF MC252 WELL DATA

3.1 Well Mechanical Configuration

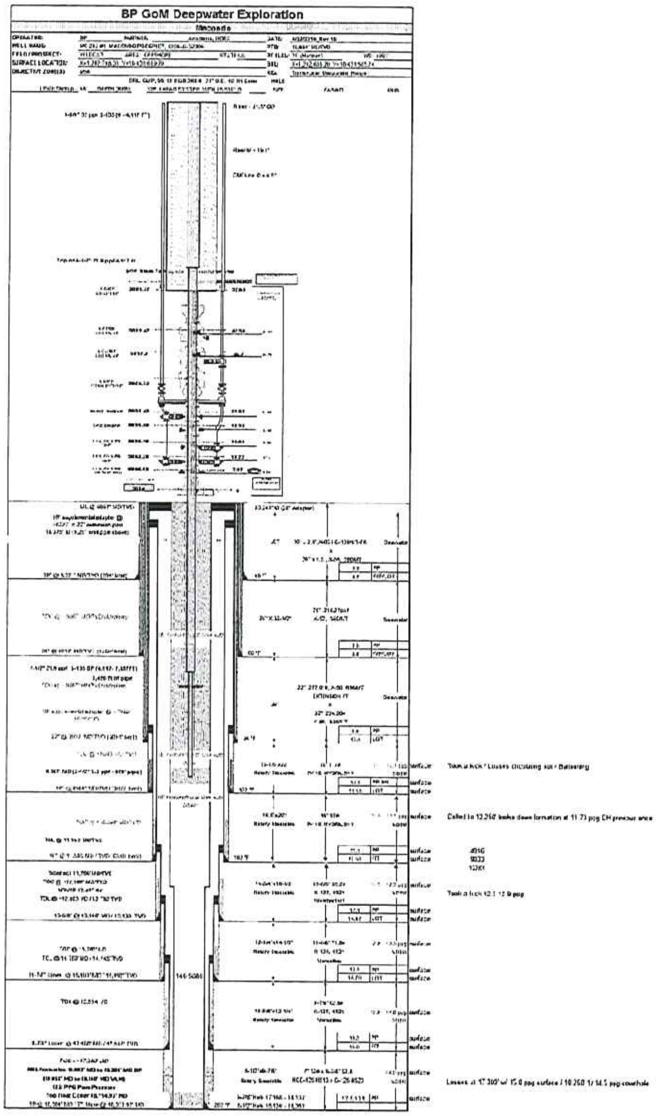

Figure 21: Well Mechanical Schematic

3.2 Well Volumes during Negative Pressure Test

Figure 22: Well Volumes

3.3 Well Pressure Assumptions

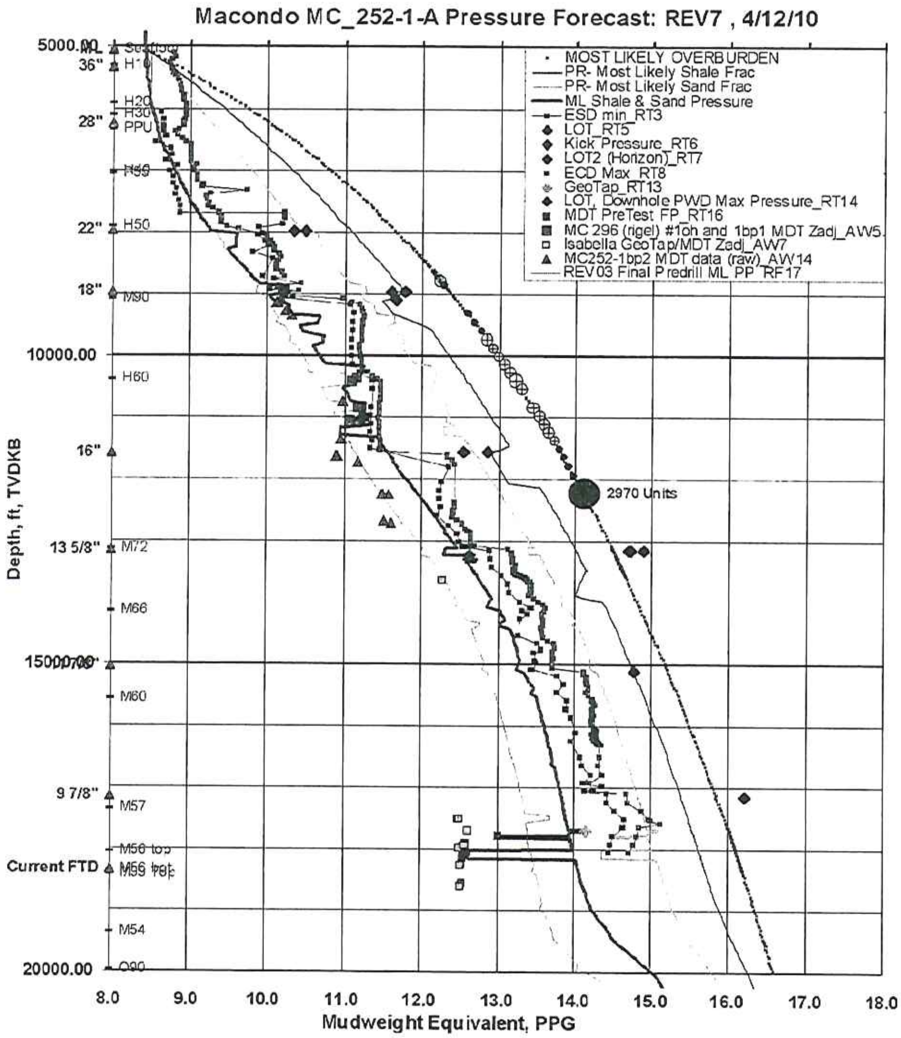

Figure 23: Well Pressure Assumptions

3.4 Mud Log 97/8" x 8-1/2" Hole Section

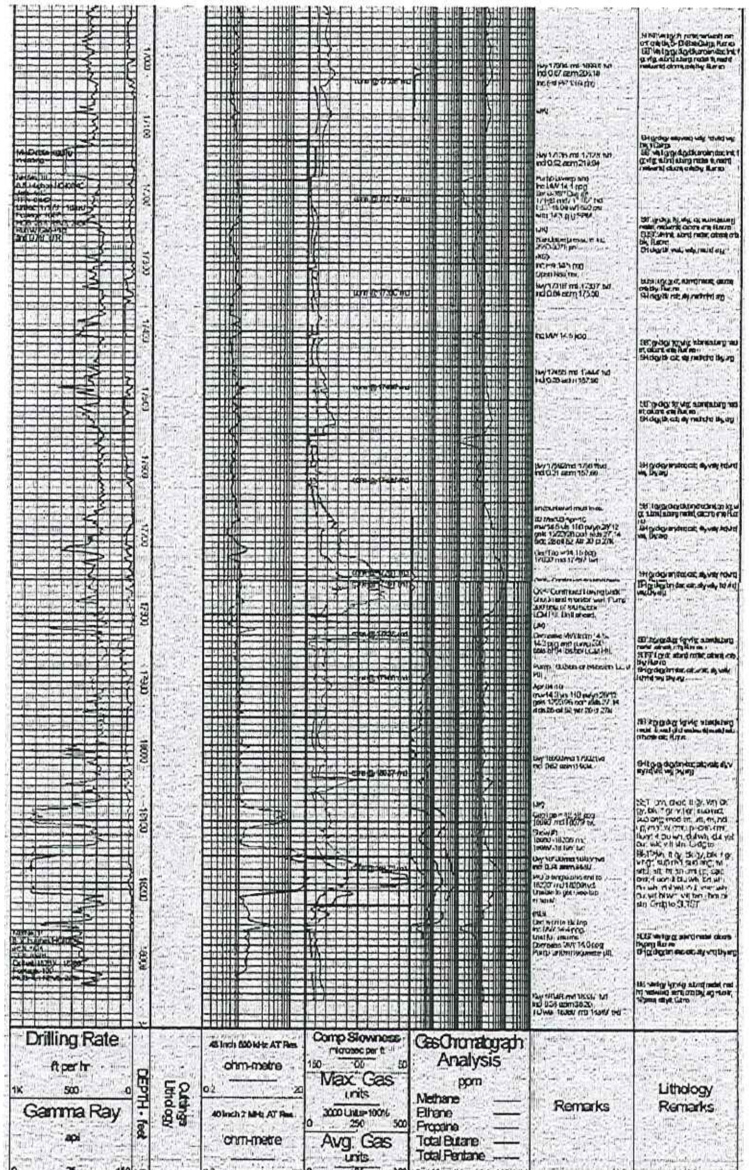

Figure 24: Mud Log

3.5 Composite Well Log in 9-7/8" x 8-1/2" Reservoir Section

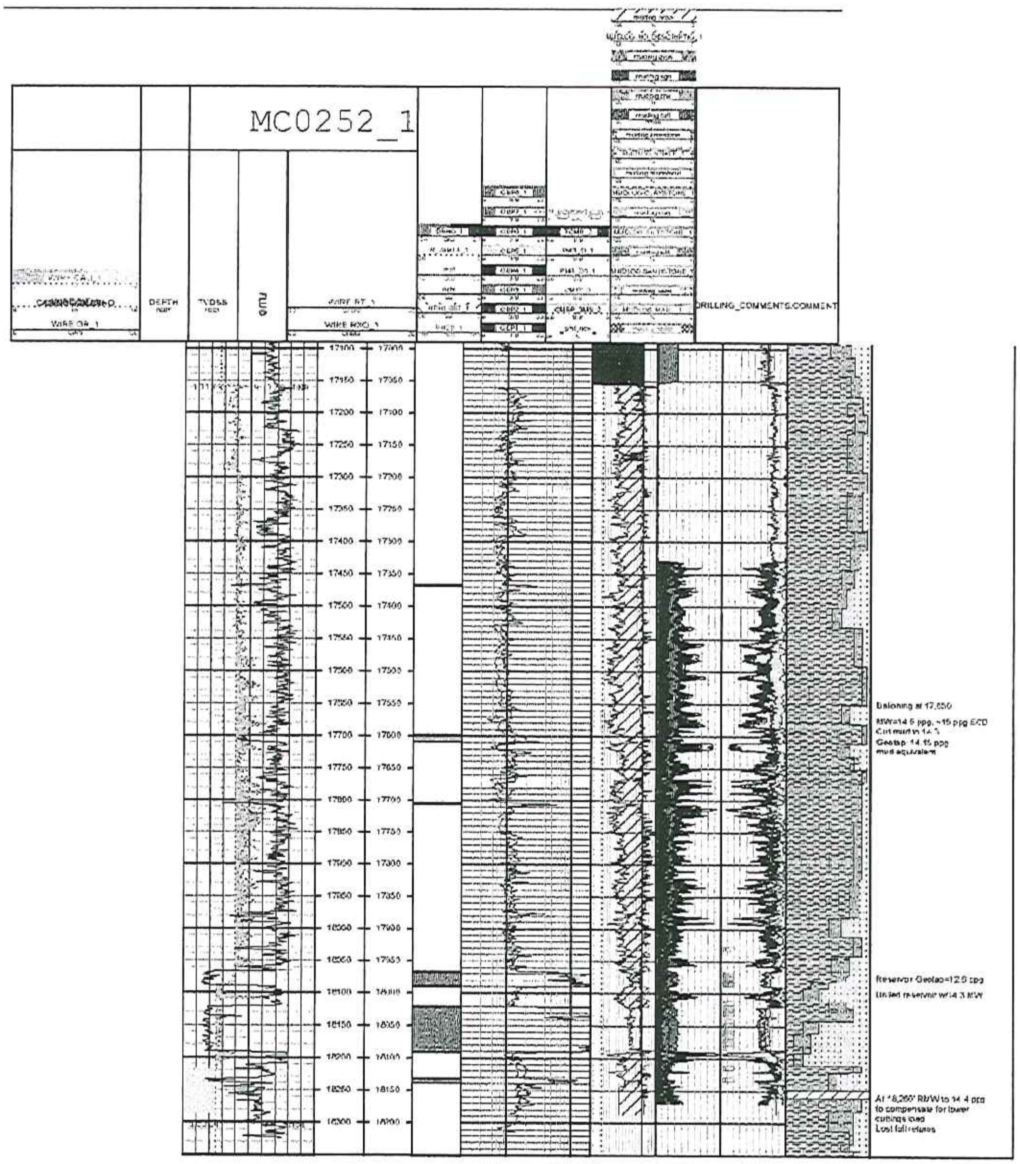

Figure 25: Composite Log

3.6 Well Petrophysical Data

Table 21: Reservoir Petrophysical Data

		Net	Pay	Por	Sw	Perm ar	Perm geo
	TOPS_SAND_LOGS FORMATION_1	S_SAND_L 1_NET_SAN	S_SAND_L 1_PAY_SAN	S_SAND_L G_POR_PA	S_SAND_L G_SW_PAY	S_SAND_L RM_ARITH	S_SAND_L ERM_GEO_
17800.0000	Above_Upper_Lobe	3.00000	1.00000	23.45833	22.52296	155.707	18.1521
18060.0000	M56_Upper	21.50000	21.50000	18.39419	19.06066	36.402	16.8636
18117.0000	M56_Lower	64.50000	64.50000	22.07666	10.37747	525.545	373.7181
18225.0000	Below_Lower_Lobe	5.50000	5.50000	22.23788	19.84553	2046.812	483.5124

	S_SAND_BOTH_L FORMATION_1	AND_BOTI 1_NET_SAN	AND_BOTI 1_PAY_SAN	AND_BOTI G_POR_PA	AND_BOTI G_SW_PAY	AND_BOTI RM_ARITH	AND_BOTI ERM_GEO_
18060.0000	M56	86.00000	86.00000	21.15604	12.26487	397.1442	165.0239

Only 2 main lobes

Parallel flow:
$K_{anthmetic}=(K_1+K_2...+K_n)/n$
Random flow
$K_{geometric}=(K1*K2...*K_n)^{1/n}$

3.7 Well Temperature Gradient

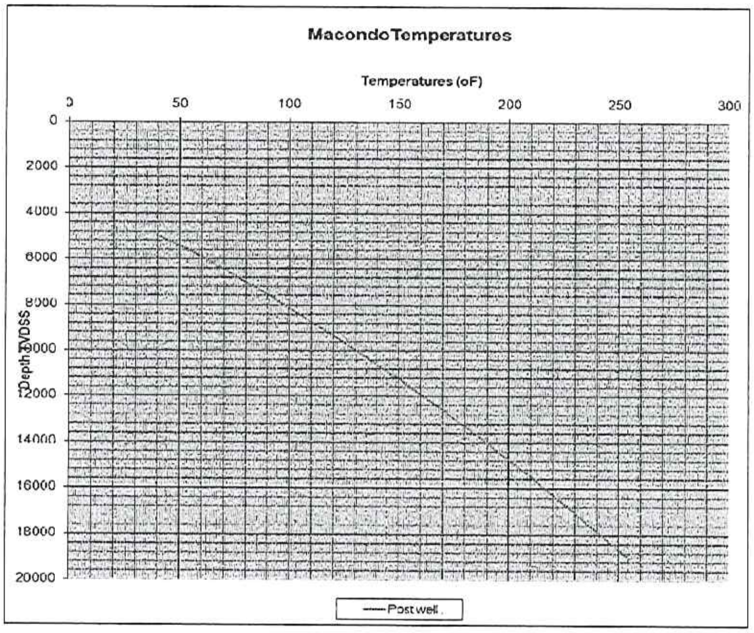

Figure 26: Well Temperature Gradient

3.8 Reservoir Oil Fluid Composition and Phase Envelope

Table 22: Reservoir Oil Composition

Fluid composition

Component	Mole frac	mole wt.	liq. dens
N2	0.624	28.01	
CO2	0.974	44.01	
C1	65.918	16.04	
C2	6.374	30.07	
C3	4.439	44.1	
iC4	0.92	58.12	
nC4	2.083	58.12	
iC5	0.845	72.15	
nC5	1.024	72.15	
C6	1.341	86.18	0.664
C7	1.934	93.26	0.7081
C8	2.092	107.8	0.8675
C9	1.536	120.54	0.852
C10	1.285	134.22	0.7569
C11-13	2.542	159.97	0.9395
C14-19	2.904	222.64	0.9074
C20-28	1.758	321.86	0.9296
C29+	1.407	604.5	0.8165

GOR = 2800 scf/stb
Bubblepoint = 6500 psi @ 237 °F

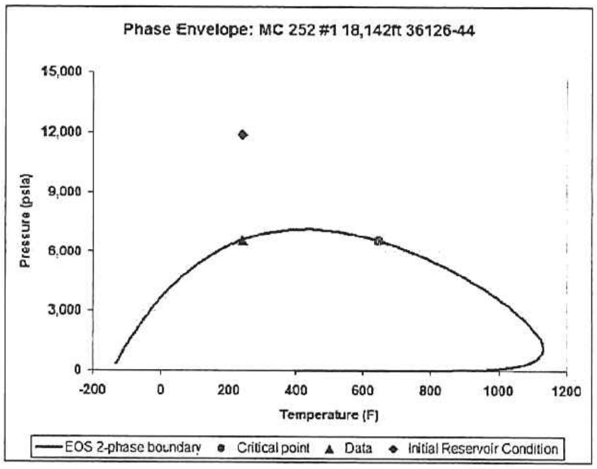

Figure 27: Reservoir Oil Phase Envelope

3.9 Formation Tops

Table 23: Formation Tops

Formation	Pore Pressure EMW (ppg)	LWD Top MD (ft)	LWD Bottom MD (ft)	Fluid
	14.15	17721.5	17725	Brine
	13.01	17821	17822.5	Gas
Upper M56	12.6	18083.4	18104.2	Oil
Lower M56	12.6	18136.6	18201.7	Oil
Lower Lobe	?	18248.5	18254.5	

3.10 Synthetic Oil Base Mud Properties

Synthetic OBM

14.0 PPG

Funnel Visc: 93 s/qt

Pv: 28 cp

Yp: 14.0 lbf/100ft2

10 sec gel: 14.0 lbf/100ft2

10 min gel: 23.0 lbf/100ft2

Solids: 26.06%

Oil 72%

Water 28%

HTHP w/l: 2.4 cc/30min

HGS: 314.3 lbm/bbl

LGS: 42.09 lbm/bbl

4 OPERATIONS TIMELINE SUMMARY

4.1 Drilling 9-7/8" x 8-1/2" Hole Section (4/9/10 to 4/15/10)

i.
9-7/8" casing set at 17,168 ft MD (17,157 ft TVD) with 16.0 ppg FIT

ii.
BOP Test 4/10/10, passed

iii.
Drill 9-7/8" x 8-1/2" hole to TD of 18,360 ft MD (18,349 ft TVD).

a.
See mud and composite logs, Figure 24 and Figure 25 for summary of activities, e.g.: losses, gains, mud density, borehole surveys, LCM pills, pressure readings, hydrocarbon sand locations and characteristics.

b.
Circulate 14.0 ppg SBM, trip out of hole for wireline logging

iv.
Run wireline logs for approximately 4 days, hole reported stable

4.2 Make Wiper Trip prior to running Casing (4/16/10 to 4/17/10)

i.
Run BHA to TD and circulate bottoms up
ii.
Pump high vis sweep
iii.
Monitor for gains or losses – none
iv.
14.0 ppg clean mud throughout before trip out
v.
Pump out from 18360' – 14,759'
vi.
flow checks during trip out – no flow
vii.
Function test BOP and Diverter
viii.
Run in hole to retrieve wear sleeve in subsea wellhead, successful
ix.
Function test blind shear rams

4.3 Running 9-7/8" x 7" Production Casing (00:30, 4/18/10 to 17:30, 4/19/10)

i.
Run 7" x 9-7/8" tapered production casing
a. XO at 12487'
b. FC at 18114'
c. Shoe at 18304'

d. 46' of rat hole

ii.

Laid out three joints of 7" due to damaged threads

iii.

Weatherford bow spring centralizers on joints 1-6 (these cover the M56 reservoir sands up to 17,833 ft MD), slip-on centralizers planned for joints 7-21 were not used.

iv.

Saw 10k weight bobble at 18,218' (only time string took weight during run)

v.

Floats were open during trip in, no losses/gains reported

vi.

Nine attempts to convert float equipment, finally sheared at 3142 psi verses 500-700 psi expected

vii.

Pump 342 bbls prior to starting cement job (100 bbl weighted viscous sweep and 1-1/2 x annular capacity), no losses reported. Circulation pressure was lower than modeled. Observed 350 psi standpipe pressure at 4 bpm pump rate, but expected 570 psi. Switched pumps with same result. Rig called town to discuss and was instructed to continue with cement job. Driller noticed hook load gradually decreased from 450k to 387k (63k). Driller pulled back to initial hook load.

viii.

Purposely did not place a mud pill in the rat hole heavier than the tail cement (e.g. 16.7 ppg which a normal practice to prevent cement swapping with the mud and resulting contamination) due to the small 4 bbl volume in the rat hole below the shoe and concerns with fracturing the formation during pushing the heavy pill behind the casing during cement displacement.

ix.

1377 bbls of mud pumped after converting float equipment, which would place any hydrocarbons in the annulus above the wellhead after cementing operations (shoe to wellhead volume = 1109 bbls)

4.4 Cementing 9-7/8" x 7" Production Casing (17:30, 4/19/10 to 00:30, 4/20/10)

i.
Test Choke and Kill lines. Good test
ii.
Close lower annular and confirm cementing diverter tool not leaking
iii.
Line up to Halliburton cementing unit, pump in the following sequence (Halliburton Post Report):
a. 5 bbls of 14.0 ppg SBM
b. 7 bbl of 6.7 ppg synthetic base oil, 4 bpm
c. 72 bbls of 14.3 ppg TS III (water base lead spacer), 4 bpm
d. 1 bbls 16.7 ppg Class H lead cement (no nitrogen), 4 bpm
e. Drop bottom dart
f. 4 bbls 16.7 ppg Class H lead cement (no nitrogen), 4 bpm
g. 39 surface bbls 16.7 ppg Class H cement base slurry (surface density 14.5 ppg), 4 bpm
h. 7 bbls 16.7 ppg Class H tail cement (no nitrogen), 4 bpm
i. 3 bbls of 14.3 ppg TS III, 4 bpm
j. Drop Top dart
k. 17 bbls of 14.3 ppg TS III, 4 bpm
l. 133 bbls of 14.0 ppg SBM with Halliburton pump
m. 728.5 bbls of 14.0 ppg SBM with rig pumps to top plug
n. Top plug bumped at 1150 psi (approximately 740 psi over circulation pressure)
o. Bleed back 5 bbls to 0 psi to check floats, Floats reported to be holding
p. Minimal U-tube pressure, approximately balanced making it difficult to check float holding
iv.
Summary (Jim McKay report 5/14/10)
a. Cement job appears to have been executed as planned and should have isolated the hydrocarbon sands assuming no channeling or contamination of the cement. 4th foam cementing job over reservoir zone for BP in deepwater GoM.
b. Plug was bumped at the approximately the correct volume accounting for SBM compression
c. No losses were observed from the time the cement left the shoe to bumping the plug based on pit volumes.
d. Total of 61.6 bbls of cement pumped with a 7.0 bbl shoe track
e. Estimated TOC range from 17,260 ft MD (no losses) to 17,450 ft MD (some losses)
    i.
    Shallowest hydrocarbon zone (13.1 ppg gas sand) = 17,821 ft MD
    ii.
    Main pay hydrocarbon zone (12.6 ppg oil sand) = 18,083 ft MD
f. Centralizers were run to 17,857 ft (36 ft above the top of shallowest 13.01 ppg gas sand). Channeling is possible above this depth.
g. WOC time appears adequate. HES lab results in 70 Bc at 7:37 hrs. The negative test was made 21 hrs after cementing.
h. No cement bond logs were run to confirm TOC or cement quality
i. Cementing line volume of 3 bbls has not been confirmed. If this volume is less, the difference would end up in the shoe track
v.
Possible Issues
a. Damage to float equipment during conversion
b. Ability of float to not hold back pressure with small differential pressure, < 100psi
c. Cement channeling due to lack of centralization
d. Swapping of 14.0 ppg SBM with 16.7 ppg cement in shoe track and around shoe.

4.5 Setting and Pressure Test of Seal Assembly (00:30, to 07:00, 4/20/10)

i.
Release running tool
ii.
Set seal assembly at 5059'
iii.
Close Upper Pipe Rams and pressure test seal assembly
a. 4000 psi for 30 sec, 10,000 psi for 10 sec, 6500 psi for 5 minutes
iv.
Shear out of seal assembly with 85k pull
v.
Slack off to 335k hookload, close upper pipe rams and pressure test seal assembly again
a. 4000 psi for 30 sec, 10,000 psi for 10 sec, 6500 psi for 5 minutes
vi.
Begin tripping out

4.6 Preparation for Abandonment and Negative Test (4/20/10)

i.
Run in with tapered string for cement plug (07:00 to 12:00):
a. 6-5/8" x 5-1/2" x 3-1/2" drill pipe
b. Stop at 4700'
c. Close Blind Shear Rams
d. Positive test casing to 250 and 2500 psi through kill line for 30 min
e. Finish RIH to 8367' (Hole appears to have given proper displacement)
ii.
Prepare for negative test (12:00 to 15:04)
a. Mud transfer to boat begins at 13:28 (Unable to monitor pit volumes)
iii.
Displace Choke, Kill and Boost Lines with seawater (15:04 to 15:56)
a. Displaced booster line w/ seawater
    i.
    Pumped 79 bbls
    ii.
    Closed bottom valve
b. Displaced choke line with seawater
    i.
    Pumped 110 bbls
    ii.
    Closed bottom valve
c. Displaced kill line with seawater
    i.
    Pumped 106 bbls
    ii.
    Closed bottom valve
    iii.
    1200 psi trapped in kill line
iv.
Pump 454 bbls Form-A-Set LCM spacer (16.0 ppg) (15;56 to 16:28)
a. The Form-A-Set spacer was used in place of a 16 ppg WBM spacer only because it needed to be removed from the pits before moving the rig off location. Forma-A-Set has high gel strength and high viscosity.

b. Any gas from the cement job should be to surface by this point. No abnormal gas shows seen
c. Begin cleaning trip tank at 16:00, Unable to monitor trip tank volumes

v.
Displace Form-A-Set with Seawater (16:29 to 16:52)
a. Pump 352 bbls seawater (Note: MI procedure called for 775 bbls seawater to put spacer above the BOP stack)
b. 2325 psi static pressure after pumping. Calculated U-tube is 1628 psi (assuming perfect interface between 16 ppg spacer and seawater).
c. Calculated base of spacer at 5235 ft (spacer is across the BOP stack)
d. Still overbalanced at this point both at the shoe and behind the seal assembly.

4.7 Negative Test (4/20/10)

i.
Close Annular to start Negative Test (16:53)

ii.
Bleed DP pressure from 2325 psi to 1220 psi (16:55 to 16:57)

iii.
Reported 25 bbl returned through drillpipe during this bleed down (assume to Halliburton tanks)
a. This is a very high flow rate back to Halliburton 12.5 bpm through 2" lines
b. BP Trainee WSL (Lambert) on floor. No Sr. WSL on floor
c. Could be that no substantial flowback occurred beyond SBM expansion during this period

iv.
Open kill line valve at BOP stack (16:57:15)
a. DP pressure builds to 1400 psi
b. Kill line pressure drops from trapped 1200 psi to 645 psi
c. Equalizing U-tube pressure between DP and Kill Line.
d. Note: This observation cannot occur if there is a perfect interface between the seawater and the 16.0 ppg Form-A-Set spacer. This can occur if the spacer is strung out in the seawater below the interface, giving an average density of 12.7 ppg from the BOP to the bottom of the drill pipe.

v.
Bleed DP pressure from 1220 psi to 273 psi (16:58:10 to 16:58:50) did not drop to zero psi. Kill line drops to zero psi
a. DP pressure varies from 241 psi to 420 psi from (16:59 to 17:05). Kill line remains zero.
b. Report 40 bbls seawater bled back (assume through DP to HES). This rate seems excessive during the initial 40 sec (60 bpm) of bleed down. Indicating either the volume may have been less or the time period longer covering the 6 minutes the DP pressure varied from 241 to 420 psi.

vi.
The total volume bled back at this time is 65 bbls (as per WSL Trainee Lambert witness statement) and .60 bbls as per (Sr, WSL Vidrine witness statement).

vii.
DP pressure begins to climb from 420 psi to 1250 psi from 17:05 to 17:09. All lines reported closed at during this time.
a. Kaluza arrives on rig floor. Statement indicates that rig crew was filling riser with a "few barrels" and then static. Possible leak in annular from riser to DP?
b. Review of the pit tank volumes 9 & 10 (pumping to the trip tank) and the trip tank volumes (assumed filling the annulus) from 17:10 to 17:30 it appears a total of approximately 50 bbls of 14.0 ppg SBM was filled in the annulus.

viii.
DP pressure slowly drops from 1250 psi to 1200 psi from 17:09 to 17:26
a. Mud transfer from the rig to M/V Bankston ceased at 17:17 (mud loggers not informed)
b. Discussion on rig floor between Kaluza and Transocean crew about DP pressure anomaly. Decide to conduct negative test on kill line. Witness statements from Vidrine, Kaluza and Lambert.

ix.
Bleed DP pressure to zero from 17:26 to 17:27 to Halliburton
a. Monitor pressure on kill line from 17:27 to 17:52

b. BP WSL (Kaluza) on rig floor during this test. He indicated 15 bbls flowed back.
c. Haire (cementer statement - Opened up DP and flowed back 23 bbls to Halliburton cement unit over 26 minute period. Fluid was sheen tested and discharged overboard bypassing pits being monitored.
d. Tabler (Cementer) witness statement - 15 bbls returned during this period
e. Volume bled during this period: 15 to 23 bbls
f. Suspect IBOP closed at 17:32 - Discovery Wells data and Kaluza witness statement.

x.

Pressure builds (17:52 to 18:40)

a. Cement Unit Pressure shows 700 psi on Halliburton gauge and volume of 3 to 15 bbls is bled off to Halliburton cement unit.
   i.
   Kaluza witness statement 3-4 bbls.
   ii.
   Vidrine witness statement 3-4 bbls
   iii.
   Tabler (Cementer) witness statement - 3-4 bbls.
   iv.
   Haire (cementer) - witness statement - bled back 15 bbls, sheen tested, and dumped. Continuous flow that spurted and was still flowing when instructed to shut-in.
b. Supposition is this pressure is could be from the kill line and the bleed back is from the kill line, but not confirmed at this time. It is not likely that the cement unit pressure would switch between kill line and drillpipe.
c. Kaluza leaves rig floor at approximately 1805 to meet with Vidrine in WSL office. (Kaluza statement that he left rig floor just after bleeding to Halliburton).
d. DP (cement unit) pressure increases in a linear fashion to 1200 psi, (from 18:01 to 18:32)
e. Kill line pressure increase from zero to 80 psi (18:32). Filling kill line with rig pump as per witness statements, approximately 0.25 bbls total (from data). The kill valve at the BOP is reported closed during this top up
f. DP (cement unit) increases and stabilizes at 1400 psi, coincide with increase on kill line (18:34). It appears the DP (cement unit) is isolated and trapped after this period from 18:32 until 20:01
g. Kill line fills up and pressure increases to 450 psi and rig pumps stopped 18:41 to 18:43.
h. Kaluza and Vidrine arrive at rig floor together at approximately 1910 and witness 0.2 bbl bleed to mini trip tank followed by no flow.Bleed 0.2 bbls from kill line into mini trip tank (witness statement)
i. Preparation for 2nd negative test (18:45 to 19:12)
   i.
   DP pressure (cement unit) constant at 1400 psi,
j. 2nd Negative Test on kill line (19:12 to 19:48)
   i.
   Kill line BOP valve opened
   ii.
   DP constant at 1400 psi
   iii.
   No flow observed from kill line
   iv.
   Discussion again about DP pressure anomaly. Explained by TO personnel as "bladder effect" or "annular compression". Kaluza, Vidrine and Lambert witness statement confirm this discussion. Lee Lambert leaves rig floor between 19:00 – 19:20.
   v.
   Hook load decreases from 390k lbs to 340k lbs (50k lbs) from 18:00 to 20:00
k. End 2nd Negative Test Prepare for Circulation to Seawater (19:48 to 20:02)
   i.
   Kill line BOP valve closed
   ii.

Pressure up to 1400 psi with rig pumps to open IBOP (19:54 to 19:56)
iii.
Open annular preventer at 20:01
iv.
Cement unit pressure falls to zero
v.
IBOP open at 20:02
vi.
Standpipe pressure falls to zero.
vii.
Start circulation with seawater at 20:02

5 DISCUSSION OF EVENTS DURING NEGATIVE TEST

This chapter will describe the events that occurred immediately before and during the negative test as we understand them at the time of this writing. Specifically, based on the information available from the data logs and from witness statements, the possible causes of the abnormal observations that occurred will be discussed and possibly eliminated as more data became available. All events listed in this section occurred on April 20, 2010.

5.1 15:56 – Prepare for Displacement

Observation :	Displace boost, choke and kill lines with seawater.
Reference/Confirmation :	Discovery Wells Data
Abnormal :	No
Standpipe Pressure (psig) :	0
Kill Line Pressure (psig) :	1200
Reported Gain (bbl)	0

An expected density profile for the 14 ppg mud can be calculated based on static pressure and temperature as seen in Figure 41. The average density from surface down to the mudline is in this case is 14.15 ppg, which gives an expected u-tube pressure between the kill line and drillpipe of:

$$0.052 \times 504314.15-8.52=1473 \text{ psig}$$

The recorded stabilized pressure after displacing both the kill and choke line was 1450-1500 psig, which agrees with the expected pressure. After the lines were displaced the valves at the BOP were closed and a 1200 psig pressure was trapped inside the kill line.

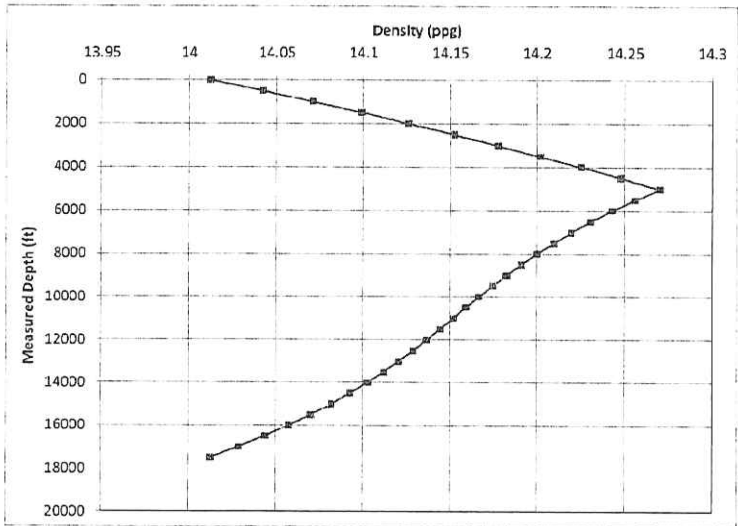

Figure 41: Synthetic Oil Mud density with measured depth based on static temperature and pressure

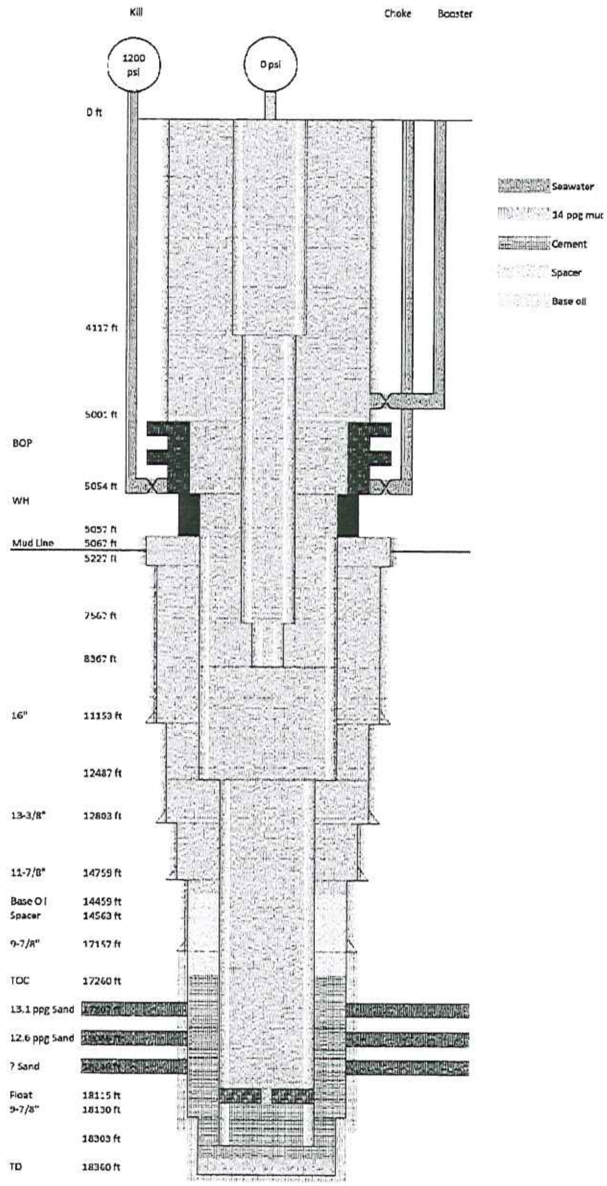

Figure 42: Displaced choke and kill line with seawater

5.2 16:53 – Pump Form-A-Set and Displaced with Seawater

Observation :	Pumped 454 bbl 16 ppg Form-A-Set and Form-A-Squeeze spacer followed by 352 bbl seawater. Unable to monitor pit volumes during displacement. Incorrect seawater volume was pumped, leaving spacer across and below the BOP. After pumping, SPP was 2324 psig, which was higher than the expected 1663 psi based on u-tube.
Reference/Confirmation :	Discovery Wells Data. Willis statement.
Abnormal :	YES
Description of Abnormality :	High u-tube pressure
Standpipe Pressure (psig) :	2324

Kill Line Pressure (psig) :	1200
Reported Gain(bbl)	0

Form-A-Set is a water based MI fluid loss control plug that had been mixed during the drilling of the previous hole section. Form-A-Squeeze is an Alpine high fluid loss fine granular LCM. It was desired to discard this volume of fluid, so it was weighted up to 16 ppg and was used a spacer to push the 14.0 ppg SBM out of the well ahead of the seawater. The final mix was composed of 210 bbls of 41.0 ppg Form-A-Set and 180 bbls of 14.0 ppg Form-A-Squeeze mixed in the same pit then weighted up to 16 ppg with barite. Rheology tests performed using a rotational viscometer after the incident indicated that all the rpm readings except 1 was off the scale, indicated a very viscous spacer with high fluid loss solids. The original plan was to move the bottom of the spacer above the BOPS stack—the procedure called for 775 bbls of seawater, but only 352 bbls was pumped. Uncertain as to why this did not occur. Hereafter we will refer to this mix as Form-A-Set.

The predicted u-tube pressure after displacing the Form-A-Set spacer, calculated based on the volumes pumped, was 1663 psig. After displacement, the actual pressure was recorded at 2324 psig, which is 661 psig higher than expected. Some possible explanation for the high u-tube pressure includes:

- A kick was taken
- Form-A-Set density was higher than 16 ppg
- The slug of Form-A-Set was trapping pressure
- Form-A-Set strung out throughout the annulus (falling through the seawater due to density swapping)

Up until this point the bottom-hole pressure should have been higher than the permeable formations encountered in the 8.5" hole interval and the well appeared to be static. Even if we assume a cement mix water gradient over the cemented interval, the well should not have fallen underbalanced (below 13 ppg emw). Table 4 and Table 5 shows that the pressure exerted on the sands was likely higher than the pore-pressure. Additionally, if a kick was taken, returns would have been observed after stopping the pumps.

Table 4: Pressure exerted on the sands through a potentially failed float at 16:53

Formation	Depth to Top	Pressure	EMW
	ft	psi	ppg
Float		13173	
Tight Sand (13.1 ppg)	17821	13043	14.10
Upper M56 (12.62 ppg)	18083	13159	14.02
Below Lower Lobe (? ppg)	18249	13232	13.97

Table 5: Pressure exerted on the sands through a potentially failed seal assembly at 16:53

Formation	Depth to Top	WITHOUT LOSSES		WITH LOSSES	
	ft	Pressure (psi)	EMW (ppg)	Pressure (psi)	EMW (ppg)
Tight Sand (13.1 ppg)	17821	13009	14.06	13074	14.14
Upper M56 (12.62 ppg)	18083	13125	13.98	13190	14.05
Below Lower Lobe (? ppg)	18249	13198	13.93	13264	14.00

The common practice for mixing a spacer is to weigh it up 2 ppg heavier than the mud it is designed to displace, which in this case was 14 ppg. Although the rheology of the Form-A-Set was not measured, the density was measured at 16 ppg.

The Form-A-Set spacer was described as very viscous and there is some reason to believing that it was displaced similarly to that of a slug of gelatin with flat fronts as seen in Figure 43. If this was true, the slug could have trapped pressure (661 psi) below which caused the u-tube pressure to be higher than expected.

However, it may be more plausible that the Form-A-Set spacer did not have a flat front since it was displaced with lighter seawater not containing any viscosifier. If mixing between the two fluids occurred as seen in Figure 44 the Form-A-Set could be left in the narrow annulus below the wellhead, where a given volume would cause a higher hydrostatic than if it was located in the large riser. After pumping 352 bbl of seawater down the drillpipe (which has a volume of 207 bbl), 145 bbl would enter the annulus. Assuming that 60% of the Form-A-Set mixed with the seawater in the annulus, the average density of the fluid mixture would be:

$$8.52ppg\times145bbl+16ppg\times454bbl\times0.6145bbl+0.6\times454bbl=13.4\text{ ppg}$$

With the volumes pumped, the top of the Form-A-Set would be located at 3717 ft and the top of the Form-A-Set /Seawater mixture would be located at 4270 ft. Using this data, the calculated u-tube imbalance is:

$$0.052\times14\times3717+0.052\times16\times4270-3717+0.052\times13.4\times8367-4270-0.052\times8.52\times8367=2314\text{ psig}$$

which matches the observed u-tube pressure.

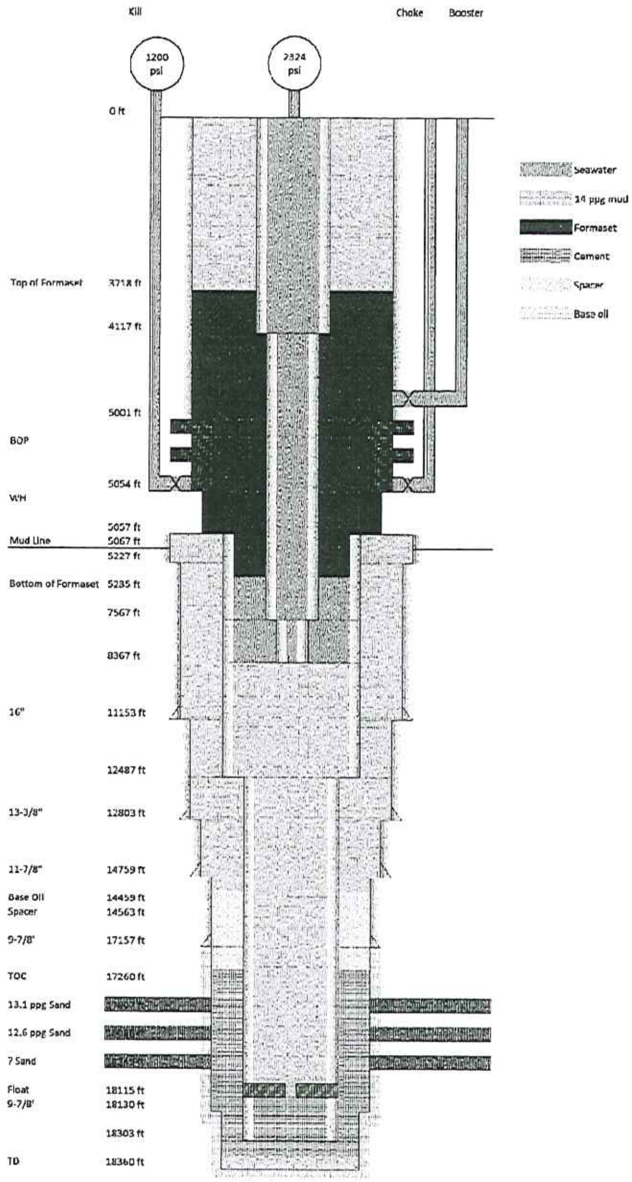

Figure 43: After Pumping Form-A-Set and Displaced with Seawater (assuming flat fronts)

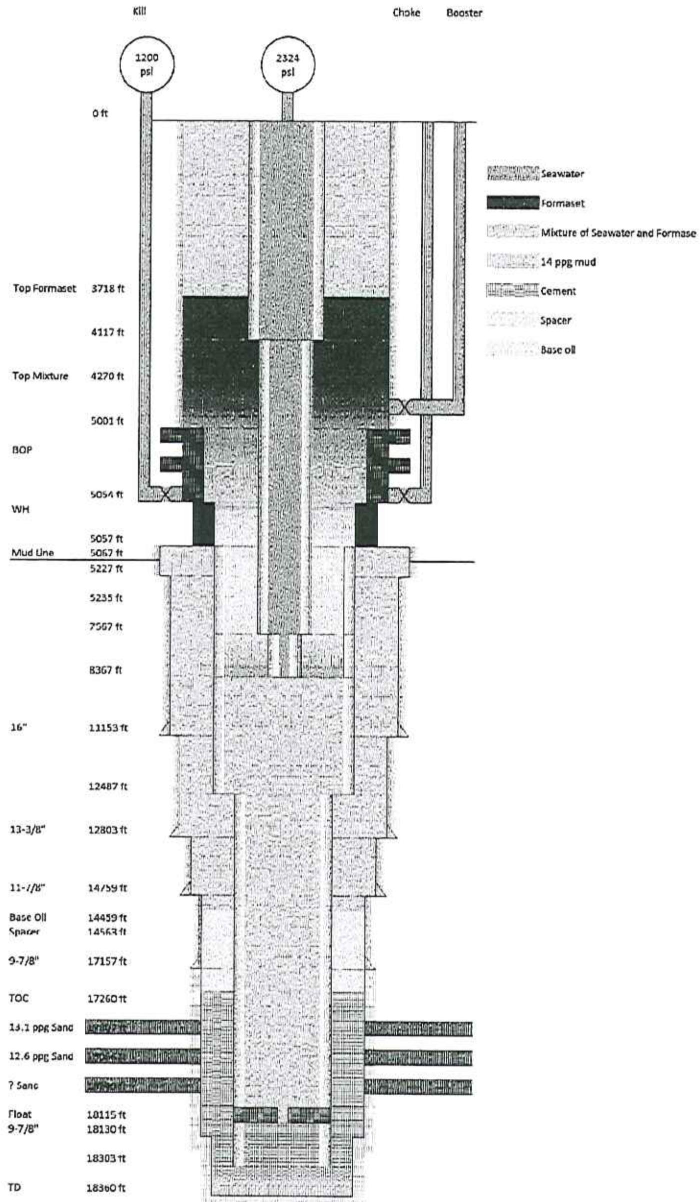

Figure 44: After Pumping Form-A-Set and Displaced with Seawater (assuming mixing)

5.3 16:54 – Close Annular

Observation :	Unknown whether upper or lower annular was closed, normally would use the upper annular, with lower reserved for backup.
Reference/Confirmation :	Discovery Wells Data. Willis statement.
Abnormal :	No
Description of Abnormality :	
Standpipe Pressure (psig) :	2324

Kill Line Pressure (psig) :	1200 (trapped)
Reported Gain(bbl):	0

One of the annular preventers was reported to have a lower pressure rubber and used for stripping operations.

5.4 16:58 – Prepare for negative test

Observation :	Bleed surface pressure from 2324 to 1200 psig. Volume is bled back to the Halliburton unit so there is not an electron record. Witness statements is approximately 25 bbl. Opened the kill line valve at BOP and the standpipe pressure increased for a short duration (up to 1400 psig).
Reference/Confirmation :	Discovery Wells Data. Willis statement.
Abnormal :	YES
Description of Abnormality :	High bleed back volume and drillpipe pressure increase.
Standpipe Pressure (psig) :	1400
Kill Line Pressure (psig) :	670
Reported Gain(bbl)	25 to unknown

The rise in drillpipe pressure can possibly be explained by:

- A kick was taken,
- Form-A-Set inside BOP and wellhead settling into annulus
- The annular BOP is leaking fluid from the riser into the annulus.
- The pressure increase is caused by u-tube effect after opening the kill line valve.

According to the hydrostatic calculations, the well should not have fallen underbalanced, thus an influx is still not likely at this point (Table 6 and Table 7).

It is likely that after pumping was stopped the Form-A-Set would start to settle down the annulus, which may cause some increase in the u-tube imbalance. The most extreme case would be where Form-A-Set is filling the large volume inside the BOP and wellhead, while seawater is filling the narrow annulus below. If the Form-A-Set and seawater swapped place a theoretical pressure increase of 120 psig could be accounted for, which is less than the observed 200 psig increase,

Assuming that fluid was bled off from the drillpipe, the pressure under the BOP would decrease while pressure above would remain the same. If the BOP was leaking, fluid would flow from the riser and into the wellbore, which may explain the large volume bled off and the drillpipe pressure increase.

Table 6: Pressure exerted on the sands through a potentially failed float at 16:58

Formation	Depth to Top	Pressure	EMW
	ft	psi	ppg
Float		12249	
Tight Sand (13.1 ppg)	17821	12119	13.10
Upper M56 (12.62 ppg)	18083	12235	13.04
Below Lower Lobe (? ppg)	18249	12308	13.00

Table 7: Pressure exerted on the sands through a potentially failed seal assembly at 16:58

Formation	Depth to Top	WITHOUT LOSSES		WITH LOSSES	
	ft	Pressure (psi)	EMW (ppg)	Pressure (psi)	EMW (ppg)
Tight Sand (13.1 ppg)	17821	12085	13.07	12150	13.14
Upper M56 (12.62 ppg)	18083	12201	13.00	12266	13.07
Below Lower Lobe (? ppg)	18249	12274	12.96	12340	13.03

As seen in Figure 45, the relative small rise in drillpipe pressure coincide with the drop in kill line pressure, which occurred after opening the kill line valve at the BOP. After the pressures stabilize the difference between the two gauges is approximately 730 psig. If the Form-A-Set spacer was displaced with a flat front (no mixing or viscous fingering) the bottom of the pill would be located at 5235 ft, which is approximately 180 ft below the kill line. The maximum u-tube imbalance between drillpipe and kill line is thus:

$$0.052 \times 180\text{ft} \times 16\text{ppg} - 8.52\text{ppg} = 70 \text{ psig}$$

This cannot explain the observed 200 psig increase on the drillpipe side or the 730 psig difference to the kill line. However, if we consider that the annulus below the kill line to the tip of the drillpipe is a mixture of Form-A-Set and seawater, with an average density of 12.7 ppg the u-tube imbalance would be:

$$0.052 \times 8367\text{ft} - 5054\text{ft} \times 12.7\text{ppg} - 8.52\text{ppg} = 720 \text{ psig}$$

This matches well with the observed u-tube imbalance from drillpipe to kill line

The average density of the mixture (12.7 ppg) is less than 13.4 ppg which was calculated to match the initial u-tube imbalance of 2324 psig. However, the earlier volume of the mixture was larger (extending above the BOP) and it is likely that the average density of the mixture decreases with depth. If we assume that the entire mixture has a linear density with depth, with a density of 8.54 ppg at 8367 ft and an average density of 13.4 ppg at 4270 ft, then the average density for the volume below the wellhead is

8.52ppg+8367ft-5054ft8367ft-4270ft×13.4ppg-8.54ppg=12.5 ppg

which is a reasonable match. Based on this, it is likely that the Form-A-Set was not displaced with a flat front, but instead strung in the annulus.

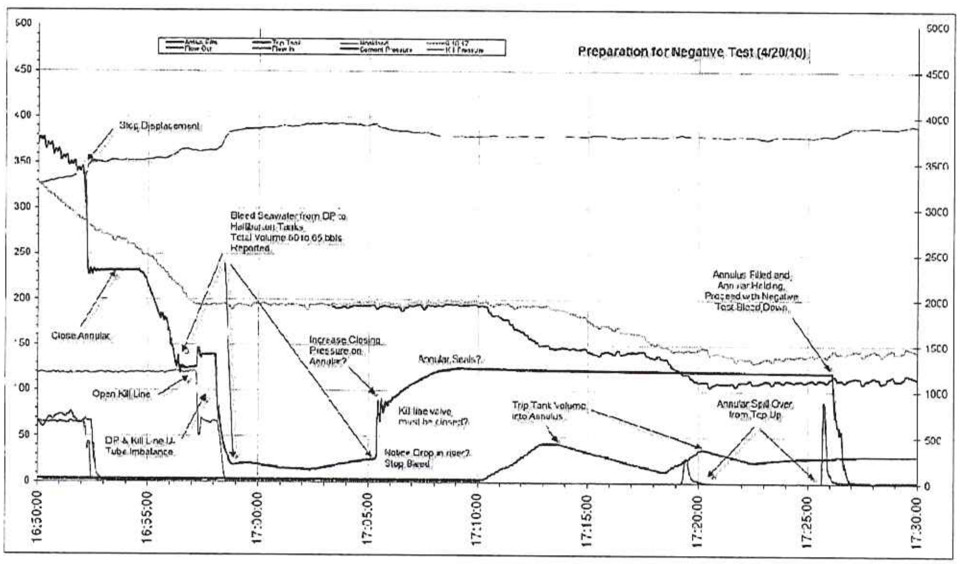

Figure 45: Time Data during Preparation for Negative Test

5.5 16:59 to 17:05 – Continue to prepare for negative test

Observation :	Continue to bleed surface pressure, from 1200 psig to 273 psig. Based on witness statements another 40 bbls was bled to Halliburton. Total amount of volume bled off through DP is 60 - 65 bbls.
Reference/Confirmation :	Discovery Wells Data. Willis statement.
Abnormal :	YES
Description of Abnormality :	High bleed back volume that did not stop
Standpipe Pressure (psig) :	273
Kill Line Pressure (psig) :	0
Total Reported Gain (bbl):	60 to 65 total from beginning

Some possible explanations for the abnormal bleed-off volume include

- The reported bleed-off volume is simply incorrect (exaggerated)
- An influx was taken
- Wellbore fluid expanded as pressure was lowered
- The BOP annular was leaking

Bleed-off volumes are based on witness statements bled to the Halliburton unit and dumped overboard. The wellsite leaders reported total bleed volume as follows;

- Vidrine - 60 bbl
- Kaluza - 18 bbl
- Lambert 65 bbl

While the cementers reported;

- Tabler- 18 bbl
- Haire - 38 bbl

The total volumes bled reported range from 18 bbls to 65 bbls.

Based on hydrostatic pressure, the well is likely underbalanced at this time (Table 8 and Table 9). If the cement and casing integrity failed—i.e. casing float or seal assembly failure—an influx could occur at this time. However, a kick would not explain the large reported bleed off volume since much of it occurred before the well fell underbalanced.

Table 8: Pressure exerted on the sands through a potentially failed float at 16:59

Formation	Depth to Top	Pressure	EMW
	ft	psi	ppg
Float		11122	
Tight Sand (13.1 ppg)	17821	10992	11.88
Upper M56 (12.62 ppg)	18083	11108	11.84
Below Lower Lobe (? ppg)	18249	11181	11.81

Table 9: Pressure exerted on the sands through a potentially failed float at 16:59

Formation	Depth to Top	WITHOUT LOSSES		WITH LOSSES	
	ft	Pressure (psi)	EMW (ppg)	Pressure (psi)	EMW (ppg)
Tight Sand (13.1 ppg)	17821	10958	11.85	11023	11.92
Upper M56 (12.62 ppg)	18083	11074	11.80	11139	11.87
Below Lower Lobe (? ppg)	18249	11147	11.77	11213	11.84

There were several earlier occasions where the rig crew had the opportunity to record the compressibility of the wellbore system, which included while converting the float, bumping the plug and testing the casing. The volumes pumped and corresponding surface pressure while attempting to convert the float and when testing the casing is seen in Table 10. The results show that 6-8 bbl may be required to change the pressure 2000 psig. If the seal assembly was leaking and there was communication with the outer annulus the volume could be as much as 20 bbl, which is still also too small to explain a 65 bbl bleed-off volume.

Table 10: Compressibility of wellbore system based on data recorded while converting float and testing casing

		Total Fluid Volume bbl	From psig	To psig	Diff psig	Pumped Volume bbl	Comp 1/psi
Converting Float	Fourth attempt	886	0	2000	2000	6.7	3.78E-06
	Fifth attempt	886	0	2000	2000	6.6	3.72E-06
	Seventh attempt	886	0	2250	2250	7.3	3.66E-06
	Eight attempt	886	0	2500	2500	7.8	3.52E-06
Casing Test	Casing incl. kill-line	846	314	2617	2303	6.1	3.13E-06

Kaluza reported that the crew was filling up the annulus with a few barrels and the data seems to match this report. It appears the rig crew was bleeding fluid back to the cement unit until 17:05 when the drillpipe was shut in. It was probably observed at this time that the fluid level in the annulus was too low. The pressure blips during the buildup is probably due to increasing the closing pressure on the annular, where it finally closes and the DP pressures stabilizes at approximately 1250 psi. If the annular did not seal at this point, the pressure should have continued to rise to above 2400 psi due to U-tube imbalance.

Review of the trip tank data shows approximately 50 bbls appear to have been filled in the annulus, see Figure 46 from 17:10 to 17:25. Based on this data it appears the most likely scenario is the annular was leaking and U-tubing seawater back up the drillpipe. If the 65 bbl bleed back is correct there may be an additional 15 bbls of influx or the bleed back volume may only be 50 bbls to match the annulus fill up volume.

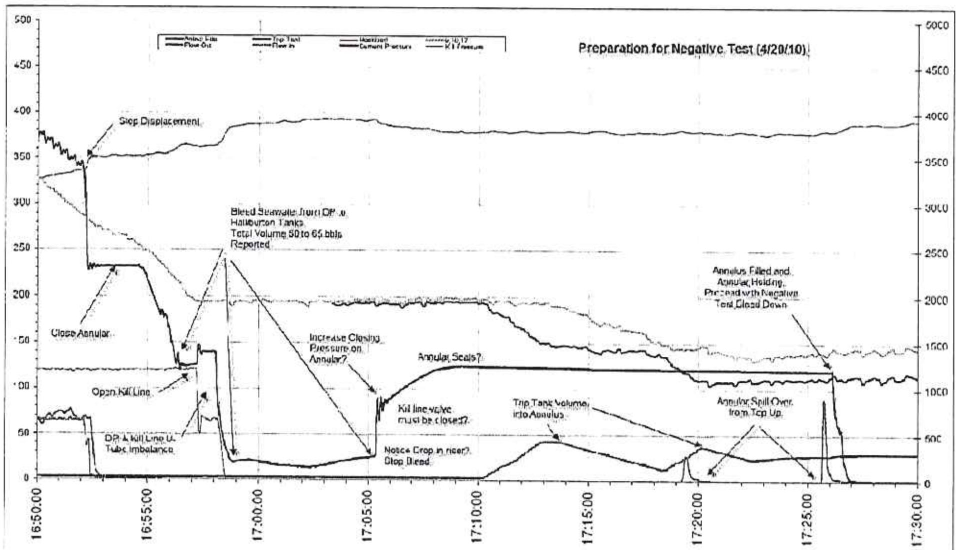

Figure 46: Pressure build up to 1200 psig

5.6 17:27 to 18:00 – Continue Negative Test

Observation:	Once riser is full and annular sealed, continue with negative test. Bleed surface pressure from drillpipe. This time the pressure went all the way to 0 psig after

	bleeding off additional 15 - 23 bbls over 26 min. Fluid was sheen tested and discharged bypassing pits being monitored.
Reference/Confirmation :	Discovery Wells Data. Kaluza and Haire statement.
Abnormal :	YES
Description of Abnormality :	High bleed-back volume
Standpipe Pressure (psig) :	0
Kill Line Pressure (psig) :	0
Total Reported Gain (bbl)	Approximately 80 to 88 (-50 bbls from riser) 30 to 38

Possible explanations for abnormal behavior include:

1. The reported bleed-off volume is incorrect
2. The BOP annular was leaking
3. A kick was taken
4. U-tube down kill line

The fluid bled off was again reportedly sent to the Halliburton tanks and not measured electronically; the volumes are based on witness statements.

- Kaluza witness statement - 15 bbls.
- Tabler (Cementer) witness statement - 15 bbls.
- Haire (Cementer) witness statement - 23 bbls.

It appears from consistent statements that at least 15 bbls was bled off during this time period.

As discussed earlier, if the annular was leaking at 17:00 it appears based on the pressure-buildup that the leak sealed up at 17:07. To explain the additional reported gains based on a leaking annular alone would mean that the leak now has opened itself up again at 17:26. There are no statements of filling the riser after this time nor are there any electronic records from the trip tanks showing the riser was filled. So we will assume the annular is holding and the bleed off is not from U-tube from the riser.

It was reported that the IBOP was closed, probably around 17:32. It is reported the 15 to 23 bbls was bled continuously over 26 minutes through the DP. At 17:52 we assume the kill line valve on the BOP is opened (witness statements) and the DP is closed in (data interpretation), resulting in sharp build up to 750 psi. This appears to match a calculated U-tube pressure between the kill line and the DP if the kill line were opened.

From 17:54 to 18:00 it was reported that the kill line was bled back to Halliburton as follows: Kaluza witness statement 3-4 bbls, Vidrine witness statement 3-4 bbls, Tabler (Cementer) witness statement - 3-4 bbls, Haire (cementer) - witness statement - bled back 15 bbls, sheen tested, and dumped. Continuous flow that spurted and was still flowing when instructed to shut-in, see Figure 47.

U-Tube calculations indicate it is not possible to bleed off the kill line (they are in U-tube balance with the drillpipe closed) and the DP pressure fall as shown in the chart. If hydrocarbon are coming into the wellbore (the well is underbalanced at this point) then the kill line could flow, but the DP pressure would not drop. We have assumed the cement unit pressure is still measuring the DP and not the kill line as there is no kill pressure recorded from the mud logging transducer. Also if the kill line pressure was reading 700 psi, the DP pressure would have to read 1400 psi.

This is not consistent with the pressure at 18:00 which is back at zero.

It appears from the pressure data that the drillpipe would have to be bleed off and not the kill line to match the pressure response.

See Figure 48, which illustrates the movement of fluid if the influx is coming through the seal assembly or through the casing shoe and failed float and cement.

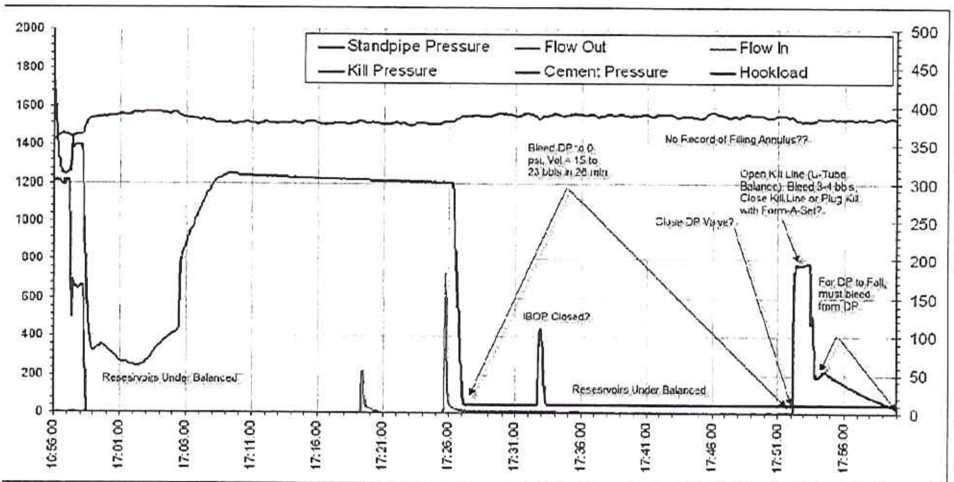

Figure 47: Preparation for Negative Test

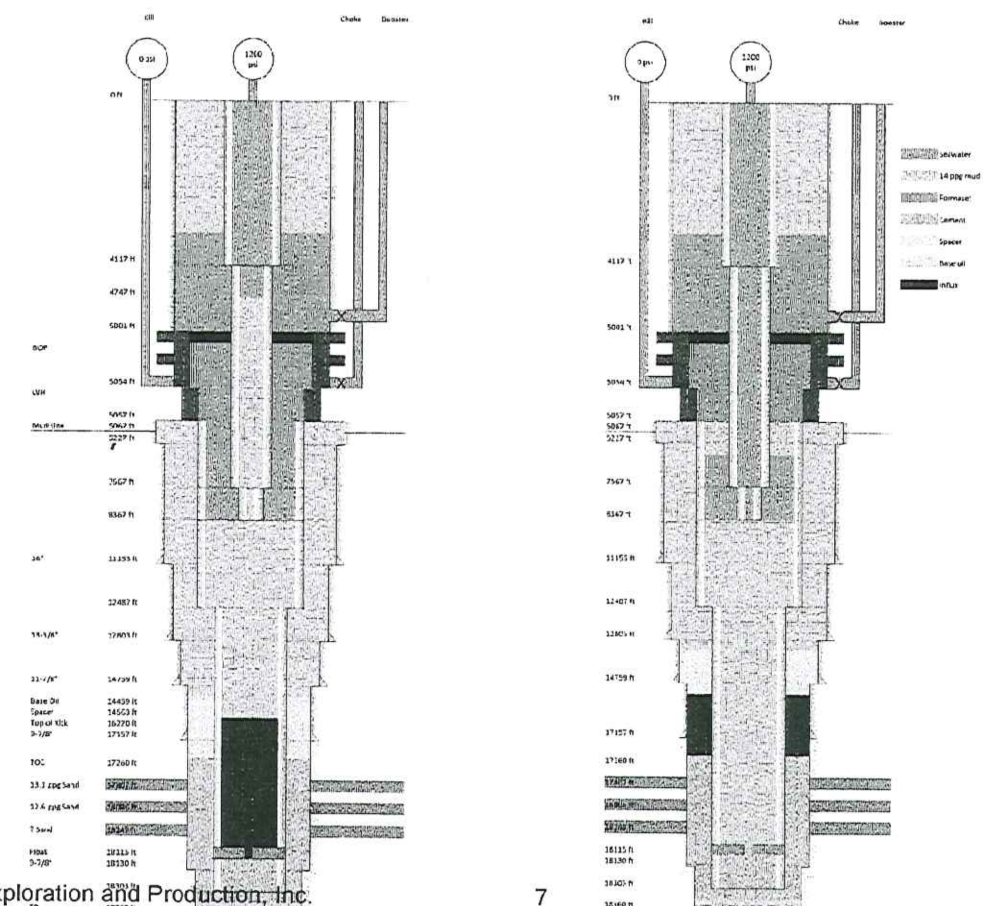

Figure 48: A Potential influx is taken either inside of casing through the float or on the backside with a failed seal assembly.

5.7 18:00 to 18:40 – DP Shut in, Continue to Prepare for Negative Test

Observation :	Drillpipe pressure builds linear to 1200 psi measured on cement unit, then quickly builds to 1400 psi at 18:32 and levels off. At 18:32 kill line pressure is observed for the first time since 17:00. See Figure 48
Reference/Confirmation :	Discovery Wells Data. Witness statement.
Abnormal :	YES
Description of Abnormality :	Pressure build-up on drillpipe
Standpipe Pressure (psig) :	1400
Kill Line Pressure (psig) :	0
Reported Gain (bbl) :	Approximately 78 to 92 (-50 bbls from riser) 28 to 42

Again, possible explanations for abnormal behavior include:

- The BOP annular was leaking
- Hydrocarbon Influx is coming into the wellbore

If the annular where leaking the pressure increase would have to be do a slow steady leak across the element and then seal at DP pressure at 1400 psi. If the annular continued to leak the pressure would increase up to approximately 2300 psi. There are no apparent witness statements or data indication of fill-up in the riser after 17:27. It is logical to assume that the crew would have been looking for a leaking riser after the earlier leak was detected. The fact that this was not mentioned and there is not data to support it, the leaking annular is a low probability.

If we discount an annular leak the pressure increase is possibly due to an influx of formation fluid. The linear build up however does not match a normal reservoir pressure build up. Two of several theories at the time of this writing include: 1) Possible choke effect on the movement of the influx into the wellbore or 2) Influx possibly pushing a Form-A-Set high gel strength slug into the kill line. This theory assumes the fail safe valve on the kill line is open during this build up and the kill line level dropped during the bleed off of the drillpipe 17:54 to 18:00. The sharp rise observed at 18:33 could be the kill line filling up back to surface causing the rapid pressure increase.

Following this theory, the Form-A-Set slug must effectively plug the kill line or the U-tube pressure on the kill line should increase back to approximately 800 psi as seen at 17:53 when the kill line was opened.

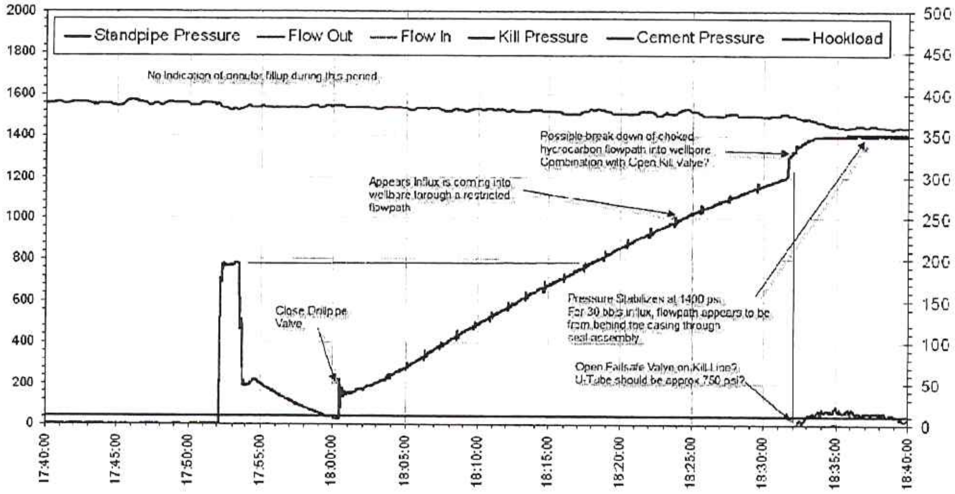

Figure 49: Continue Preparation for Negative Test

5.8 19:48 – Negative test on kill line

Observation :	Open kill line and bleed 0.2 bbls followed by no flow. DP pressure at 1400 psi and stable, kill line open with no flow. Monitor flow on kill line for 30+ minutes with no flow.
Reference/Confirmation :	Kaluza and Vidrine witness statement
Abnormal :	YES
Description of Abnormality :	1400 psi pressure on drillpipe, no flow from kill line; and 16 kip drop in hook load with no increase on DP pressure. See Figure 49
Standpipe Pressure (psig) :	1400
Kill Line Pressure (psig) :	0
Reported Gain (bbl)	Approximately 78 to 92 (-50 bbls from riser) 28 to 42

It appears from this data that there is no longer hydraulic communication between the DP and kill line pressure. The hydrostatic between the DP pressure of 1400 psi and the kill line pressure should be approximately 800 psi, which means the kill line should be flowing. If the fail safe valve is open, you would conclude based on these observations that the kill line may be plugged (possibly from the Form-A-Set).

If the 16 kip drop in hook load from 18:33 to 20:00 if caused by pressure below, the annular should have seen an increase of approximately 700 psi over the initial 1400 psi for a total of 2100 psi on the drillpipe by 20:00. It is not clear to the authors why the cementing unit pressure which is apparently monitoring the drillpipe stays constant during this time. Speculation could be the pressure is trapped from 18:33 onwards (closed valve on the rig floor) and not actually connected to the drillpipe or the drillpipe has also become plugged with Form-A-Set.

The rig crew did not recognize a potential well control situation after this test and the well was opened and circulated to seawater. There was a discussion reported on the rig floor about the abnormal DP pressure and was assumed to be a "bladder effect" or "annular compression" and not well control related. The results were not sent to the office for review circulation to seawater.

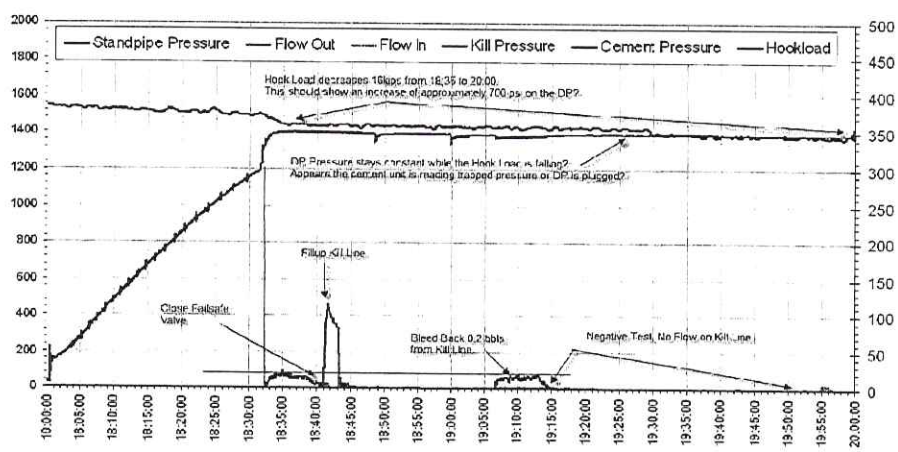

Figure 410: Negative Test

6 CONCLUSIONS

6.1 Documented Negative Test Procedure Assessment

A brief temporary abandonment procedure was submitted to the MMS on April 16, 2010 as follows:

1. Negative test casing to seawater gradient equivalent for 30 min with kill line.
2. TIH with 3-1/2" stinger to 8367 ft
3. Displace to seawater. Monitor well for 30 min
4. Set a 300 ft cement plug from 8367 to 8067 ft

    a.
    The requested surface plug deviation is for minimizing the chance for damaging the LDS sealing area for future completion operations.

    b.
    This is for temporary abandonment only

    c.
    The cement plug length has been extended to compensate for added setting depth
5. POOH
6. Set 9-7/8" LDS (Lock down sleeve)
7. Clean and pull riser
8. Install TA cap on wellhead and inject wellhead preservation fluid below TA cap

A modified temporary abandonment procedure emailed on April 20, 2010 at 10:43 hrs, by Brian Morel (drilling engineer assigned to this well). Note: Brian was reported to be on the rig when this modification was made.

Quick ops note for the next few days:

1. Test casing per APD to 250 / 2500 psi
2. RIH to 8367'
3. Displace to seawater from there to above the wellhead
4. With seawater in the kill close annular and do a negative test -2350 psi differential
5. Open annular and continue displacement
6. Set a 300' balanced cement plug w/5 bbls in DP
7. POOH -100-200' above top of cement and drop neft ball / circulate DS volume
8. Spot corrosion inhibitor in the open hole
9. POOH to just below the wellhead or above with the 3-1/2" stinger (if desired wash with the 3-1/2" / do not rotate / a separate run will not be made to wash as the displacement will clean up the wellhead)
10. POOH and make LIT / LDS runs
11. Test casing to 1000 psi with seawater (non MMS test / BP DWOP) - surface plug
    a. Confirm bbls to pressure up on original casing test vs bbls to test surface plug (should be less due to volume
    b. differences and fluid compressibility -seawater vs sobm)
    c. Plot on chart / send to Houston for confirmation

The actual procedure performed at the rig site, up to the time of the incident, is as follows:

1. TIH with 3-1/2" stinger to 8367 ft
2. Displace choke, kill and booster lines with seawater
3. Partially displace to seawater using a Form-A-Set spacer between seawater and SBM
4. Close annular when Form-A-Set across BOP and attempt negative test down drillpipe.
5. Confusing data, so 2nd negative test performed down kill line. Crew assumes test is good.
6. Open annular and continue to displace to seawater
7. Well under balance, failure of shoe track and/or seal assembly, hydrocarbons in wellbore/riser, followed by well blowout

Findings:

1. It appears that there was not a documented engineered procedure on how the negative test was to be performed for the given situation (e.g., deepwater, lock down sleeve not installed, testing seal assembly and float/cement in shoe track simultaneously, multiple fluid densities in the well, temperature effects, etc.)
2. Performing and correctly interpreting a negative test on a deepwater, high flow potential exploration well from a 5th generation semi-submersible would be considered a safety critical and high significant risk activity. High significant risk activities require a formal risk assessment to be performed. This would include, for example:

   a.
   Review of negative test procedures and identification of hazards (specifically well control hazards) at each of the steps specific to this rig, well and situation

   b.
   Identification of top events, e.g., hydrocarbons entering the wellbore below the BOP and hydrocarbons entering the riser above the BOP (either from the shoe track or from behind the seal assembly)

   c.
   Assessment of the consequences if the top events occur

   d.
   Evaluation of prevention barriers to prevent occurrence of a top event

   e.
   Evaluation of mitigation controls to minimize escalation of a top event

3. A detailed written negative test procedure with risk assessment and mitigation decision trees may have:

   a.
   Prevented the displacement of the Form-A-Set spacer during the negative test which complicated the interpretation of the negative test data.

   b.
   A list of the risk and consequences may have encouraged a more thorough investigation of, e.g.: the bleed volumes, possible annular leak, build up pressures, differential pressures between the drillpipe and kill line to assure the kill line was not plugged and Form-A-Set was displaced above the BOP.

c.

Since there was well control risk in the interpretation of the negative test and Transocean would have control of well control response there should have been a bridging document between Transocean and BP to assure conformance to procedure and interpretation of data.

6.2 Assessment of Rig Actions Related to the Negative Test

6.2.1 Operational Issues Prior to the Negative Test

A number of issues were observed that should have increased awareness of a potentially bringing influx into the wellbore during the negative test. They were:

1. Deepwater exploration well
2. Prolific hydrocarbon reservoir sand identified during 4 days of logging
3. Close tolerance between pore pressure and fracture gradient
4. Not placing a mud pill in the rat hole heavier than the tail cement prior to running casing
5. Lower than expected circulation pressure after landing the casing
6. Foamed cement over the reservoir
7. Much higher pressure required to convert the cement float equipment than expected
8. The Lock Down Sleeve is not in place to prevent movement of casing out of seal area
9. Lack of a detailed negative test procedure
10. Lack of a risk assessment related to the negative test procedure
11. Cement integrity on casing not evaluated after cement job with segmented cement bond log

6.2.2 Operational Issues Immediately before and during the Negative Test

1. Displacing Form-A-Set & Form-A-Squeeze spacer with water prior to the negative test
2. Under displacing the Form-A-Set so that it was placed across the BOP stack
3. U-Tube severely unbalanced after displacement (indicating severe swapping and fallout of the Form-A-Set spacer in the seawater)
4. Apparent poor management of tracking volumes bled back to Halliburton from the DP
5. Leaking annular during initial pressure bleed down on the drillpipe and filling up from trip tank after the fact (should have been circulating across riser with trip tank)
6. Multiple pit activities going on simultaneously (transferring to boat, empty sand trap, cleaning trip tanks) making it difficult to manage volumes during a safety critical operation.
7. Bleed back of additional 15 to 23 bbls after the riser was filled. There is no indication from witness statements of where anyone thought this volume was coming from if the annular was no longer leaking.
8. Confusing pressure response on drillpipe when the kill line was opened 17:55
9. Steady pressure increase on the DP up to 1400 psi while the kill line was open
10. Hook load falling 16 kips while the DP pressure stays constant

6.3 Summation

At the time of this writing, it appears that there was not a sense of the significant risk associated with correctly implementing and interpreting the data for the negative test implemented as a step in the temporary abandonment program for the Deepwater Horizon. This is evident from:

1. The engineering staff who wrote the program without a detail procedure and the lack of a formal risk assessment for a safety critical and significant risk activity

2. The BP WSL and Transocean OIM:

    a.
    Who developed a procedure on the fly with Form-A-Set spacer and multiple activities going on simultaneously that stack the odds against them for interpreting the data correctly

    b.
    Misinterpreting potential well influx indicators as "bladder effect" and proceeding to immediately circulate the well to seawater without performing additional test to confirm their theory (e.g., circulating up the choke line through the mud gas separator) or sending the data to town for the engineering team to interpret the data before proceeding.

If any person in the command chain had understood the consequence of misinterpreting this critical test, the annular would not have been opened and the riser circulated to seawater which ultimately led to the blowout.