Project Memo #19

Operator:	BP GOM Deepwater Exploration	**Job Number:**	WWCI- 2010-116
Well Name:	Macondo – MC252 #1		
Date:	5-6-10	**Time:**	15:00
To:	Mark Mazzella	**From:**	Dicky Robichaux, Michael Allen
CC:	David Moody, David Barnett, Joe Dean Thompson, Chris Murphy, Rolly Gomez, Kerry Girlinghouse, Bill Burch		
Subject:	Planning Procedure for Junk Shot and Top Kill		

Introduction

This document outlines the assumptions, general procedure, risk assessment for conducting a "junk shot" seal, bullhead kill and cement isolation of the Macondo #1 through the Horizon BOP. Should the junk shot seal be ineffective at sealing the BOP, other methods may be evaluated; however they are not included in this procedure.

The equipment layout will be designed by the Intervention Team to provide adequate fluid storage, pump rate and mixing capabilities as is required in this procedure.

Assumptions and Design Considerations

The basic assumptions for this procedure are listed as follows:

1. The flow path for the blowout is up the annulus.
2. The exit point(s) is sealed by the junk shot pill.
3. The Intervention Team will be providing the rig up plan and the plan for fluid supply vessels.
4. The flow path from the vessel (Q-4000) to the seafloor junk shot manifold consists of the following items:
    a. $6^{5}/_{8}$" drillpipe with an ID of 5.581" – design length is 5000'
    b. Two sections of coflex hose with an ID of 3.0" – design length is 250'-400'
    c. Two sections of coflex hose from the manifold to the gooseneck with an ID of 3.0" – design length is 175'
    d. All equipment in the flow path is rated to 15,000 psi.

This procedure applies to the Junk Shot Pills, Fiber LCM Pill, bullheading operations, and cement isolation.

- LCM pill will be a Fiber LCM pill(s) as per attached mixing procedure.
- Does not include or address operations to rig up to the stack.
- Assumes the zone will take oil back in at same PI as flowing (50 bopd/psi)
- Assumes that the LCM placement is successful and there is no flow out of the BOP stack.

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- Assumes the flow is coming up the annulus.
- Assumes all equipment is rated to 15k from the pump to the BOP.
- Annular volume = 1280 bbl; Casing volume = 744 bbl

Requirements to execute this procedure:

1. A calibrated subsea continuous reading pressure gauge on the stack with 24-7 access to the gauge is desired. This data will be used to make pumping decisions.
    a. Status: In progress
2. The kill will be initiated at low rates - approx 2 bpm. Friction needs to be accounted for using 14.2 ppg brine.
3. The pumping operation requires pumps and piping to deliver 5 to 8 bpm for the cementing operations.
    a. Alex (SLB) to run models for surface pressures 5/3/10 pm.
    b. Alex (SLB) will also confirm the mixing / pumping requirements based on slurry design.
    c. Desired top of cement in the annulus is ~14,000' TVD; however, the design must ensure that the TOC and displacement fluid will be overbalanced to the 14.16 ppge at 17,798' TVD.
    d. Design to be based on 1200 bbls of cement per job. Secure stock for two jobs. Cement storage issues on the Q4000 will be worked by the Intervention team and SLB cementing.

Fluids:

Kill fluid:

14.2 ppg CaBr viscosifed as needed
Volume - 10,000 bbl desired, minimum 6000 bbl – Kill volume is adequate to displace either the annulus, casing or both to well TD.

Cement Displacement fluid:

XX.X ppg brine -- Alex with SLB to model the optimal displacement fluid and spacer(s)
Volume - 3000 bbl min, 5000 desired.

Run Workstring Procedure

1. Make up Franks tong unit for running 6-5/8" FH workstring.
2. PU "Y block" and make up 6-5/8" FH workstring.
3. RIH with 5000' of 6-5/8" S-135, Range-2 FH workstring (placing "Y block" ~50' from mudline)

   Min Make-up Torque = 54,500 ft-lb

   Max Make-up Torque = 56,000 ft-lb
4. PU crossover from 6-5/8" FH to 5-7/8" CTM.
5. Make up Supreme frac head to workstring.

Rig Up Stimulation boats

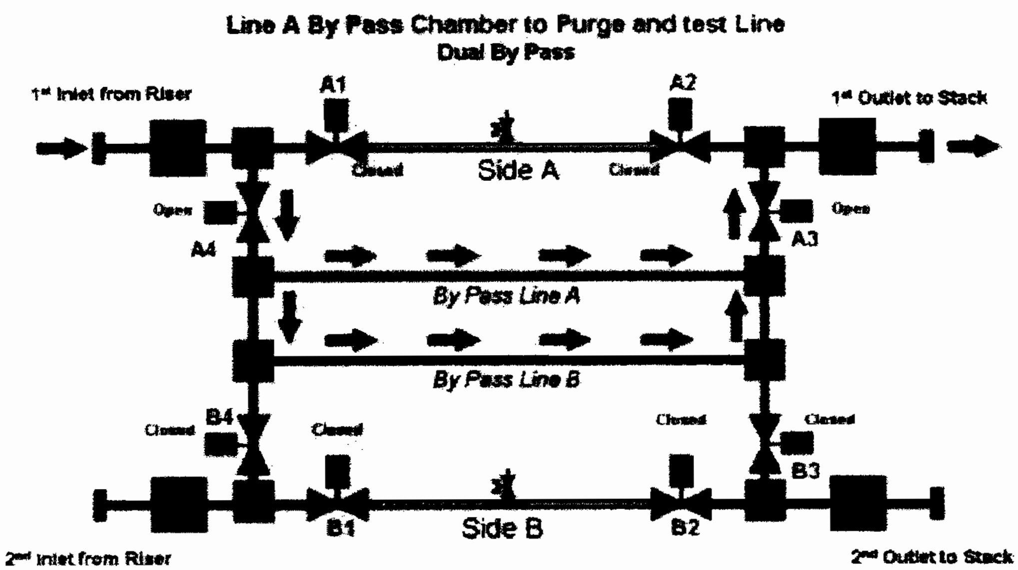
1. RU BJ Services Blue Dolphin to Port Forward corner of Q-4000.
2. Rig up both BJ Blue Dolphin 4" lines as per attached Supreme rig floor layout.
3. Flush each line with seawater for 10 minutes at 25 bbl/min/line overboard.
4. Test lines from boat to frac-head to 15,000 psi and hold for 10 minutes.
5. Flush line with 14.2 ppg $CaBr_2$. Displacing seawater from both lines.
6. RU Halliburton Stimstar III to Port Starboard corner of Q-4000.
7. Rig up both the 3" and the 4" lines as per attached Supreme rig floor layout.
8. Flush each line with seawater for 10 minutes at 25 bbl/min/line overboard.
9. Test lines from boat to frac-head to 15,000 psi and hold for 10 minutes.
10. Flush line with 14.2 ppg $CaBr_2$. Displacing seawater from both lines.

Initiate Well Kill Procedure

1. Pre-mix two 50 bbl pills of "Fiber LCM Pill" (see attached "Fiber LCM Pill recipe) prior to pumping operations
2. Prior to make-up of the coflex lines to BOP stack, secure same and pump with cement unit to displace to end of coflex line hydrate inhibited fluid (215 bbls of MEG). Make up coflex to BOP stack.
3. Pressure test lines to 15,000 psi with BJ frac boat for 10 minutes. Bleed off pressure.
4. Pressure up to 5,000 psi surface pressure to equalize across kill valves. The estimated pressure at the BOP is 4,815 psi with 14.2 ppg to the mudline.
5. Open the fail safe valves on the kill line side on the BOP (Well intervention team to develop plan to open fail safe valves). Record pressure on stack gauge.
6. Establish pump rate with 14.2 ppg $CaBr_2$ at min 2 BPM to ensure line is clear.

Wild Well Control "Junk Shot" Manifold Initial Valve Settings

Figure-1



Wild Well Control "Junk Shot" Procedure:

7. Observe Figure-1 and confirm initial junk shot manifold valve settings.
8. Shut down injection rate.
9. Close valves "A4" and "A3" on side A of junk shot manifold. (All valve operation to be performed by ROV)
10. Pressure up 500 psi higher than stabilized pressure.
11. Open valve "A1" on junk shot manifold and allow pressure to equalize for 1 minute.
12. Maintaining 500psi Open valve "A2" on junk shot manifold and establish injection at min 2 BPM into BOP stack.
13. Pump xx bbls (1.5x's volume though BOP stack) while monitoring flow.
    a. If flow stops go to "Well Kill Procedure"
    b. If flow slows go to "Pill Procedure"
    c. If flow continues, continue with Wild Well Control "Junk Shot" Procedure
14. Shut down pumps.
15. Close valves "A1" and "A2" on side A of junk shot manifold.
16. Pressure up 500 psi higher than stabilized pressure.
17. Open valve "B1" on junk shot manifold and allow pressure to equalize for 1 minute.
18. Maintaining 500psi Open valve "B2" on junk shot manifold and establish injection at 2 BPM into BOP stack.
19. Pump XX bbls (1.5x's volume to BOP stack) while monitoring flow.
    a. If flow stops go to "Well Kill Procedure"
    b. If flow slows go to "Pill Procedure"
    c. If flow continues, Re-load manifold and continue with Wild Well Control "Junk Shot" Procedure
20. Monitor well. Pump additional Junk Shots as required ensuring BOP's are sealed as per WWCI Representative. Record pressure on stack.

Junk Shot Test report

A simulation test was competed on Tuesday May 4, 2010 at Stress Engineering Services, Inc. The following will give the details of this test and the make up of the "Junk Shots". The pressures are listed below as per the rate each shot was pumped at. The shots were loaded in 2-3"ID x 18" tubes.

1st Shot.

- 1- Halliburton Grease disk 3" OD x1/2 thick (wrapped with freezer wrap)
- 1- 2 7/8 cut off wheel
- 6 Soft line rope 6" long with a knot in middle
- 1- Red Super Ball 11/4 O.D.
- 1-27/8 O.D Cut off wheel
- 1 -Halliburton Grease disk 3" OD x1/2 thick (wrapped with freezer wrap)

This shot was pressured up to 3000 psi and pumped at 2 bbls per min. A 50 psi burst disk was installed at the end of the 3" line. The red ball was used to indicate position of the shot after the exit point.

2nd Shot

- 1- Halliburton Grease disk 3" OD x1/2 thick (wrapped with freezer wrap)
- 1- 27/8 cut off wheel
- 30 -1" Super Balls
- 10 -Soft line rope 6" long with a knot in middle
- 5-Inner Tube strips ½ inch wide 6" long with knot in the middle.
- 5- 1 5/8 Practice Golf balls
- 8- ½ inch rope 4" long with knot in the middle.
- 1- Red Super Ball 11/4 O.D.
- 1-Halliburton Grease disk 3" OD x1/2 thick (wrapped with freezer wrap)
- 1-27/8 O.D Cut off wheel

This shot was pressured up to 3500 psi and pumped at 3 bbls per min for 2 minutes. Could not see an increase in the pressure when the shot turned the corner of the 90%. A larger 3rd shot was loaded using both the loading tubes.

3rd Shot

Tube #1

- 1- Halliburton Grease disk 3" OD x1/2 thick (wrapped with freezer wrap)
- 1-2 7/8 O.D Cut off wheel
- 10-1 5/8 Practice Golf balls
- 10- Inner Tube strips ½ inch wide 6" long with knot in the middle.
- 10-½ inch rope 4" long with knot in the middle
- 6-1" Super Balls
- 5- 2 " tennis Balls
- 8- Soft line rope 6" long with a knot in middle
- 1-Halliburton Grease disk 3" OD x1/2 thick (wrapped with freezer wrap)
- 1-27/8 O.D Cut off wheel

Tube #2

- 1- Halliburton Grease disk 3" OD x1/2 thick (wrapped with freezer wrap)
- 1-27/8 O.D Cut off wheel
- 9- Inner Tube strips ½ inch wide 6" long with knot in the middle
- 8- Soft line rope 6" long with a knot in middle
- 15- ½ inch rope 4" long with knot in the middle
- 15 - 1" Super Balls
- 8- Inner Tube strips ½ inch wide 6" long with knot in the middle
- 1- Halliburton Grease disk 3" OD x1/2 thick (wrapped with freezer wrap)
- 1-27/8 O.D Cut off wheel
- 2- Tennis Balls 25/8 O.D.
- 2- Dunlop Golf balls 13/4 O.D (Deep Range)

This shot was pressured up to 4000 psi and pumped at 4 bbls per min for 2 minutes. Again not seeing any change in pressure after the valve was opened. Pump pressured remained at 140 psi.

4th Shot

The next shot was as per BP rep request. It was felt at this time that enough was pumped to establish the goal of pumping past the 90 degree turn. As per BP rep a jell vis was located and brought to location. In an attempt to plug off the 3" 90 degree turn. A spacer was put between the loads. With 36 inches of material with a 3 ft spacer of jell.

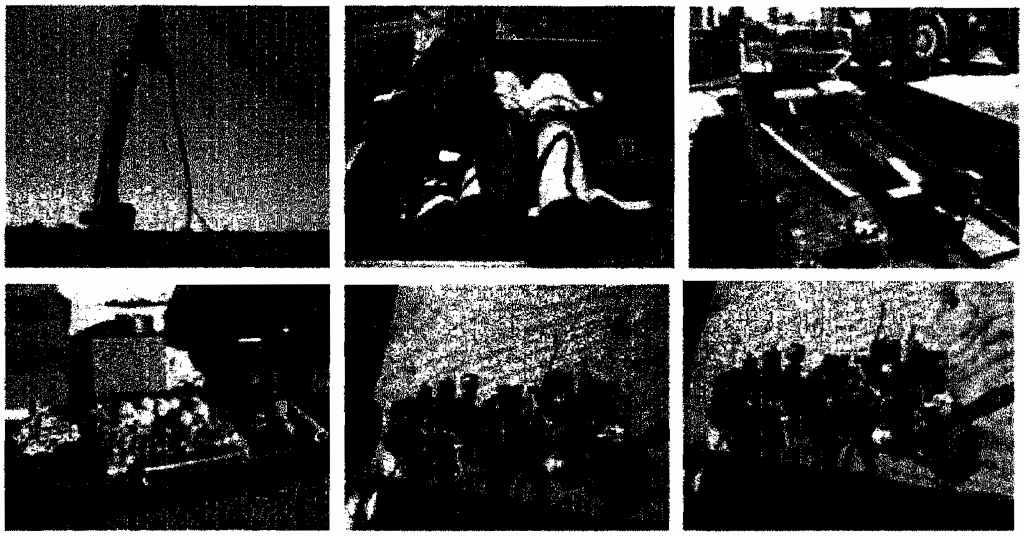
Tube #1

- 1- Halliburton Grease disk 3" OD x1/2 thick (wrapped with freezer wrap)
- 1-2 7/8 O.D Cut off wheel
- 15-Inner Tube strips ½ inch wide 6" long with knot in the middle
- 10-½ inch rope 4" long with knot in the middle
- 10- Soft line rope 6" long with a knot in middle
- 6-1 5/8 Practice Golf balls
- 8-½ inch rope 4" long with knot in the middle
- 1-Halliburton Grease disk 3" OD x1/2 thick (wrapped with freezer wrap)
- 1-27/8 O.D Cut off wheel

Tube #2

- 1-Halliburton Grease disk 3" OD x1/2 thick (wrapped with freezer wrap)
- 1-2 7/8 O.D Cut off wheel
- 30- Soft line rope 6" long with a knot in middle
- 7-2 " tennis Balls
- 6-1 5/8 Tennis balls
- 1-Halliburton Grease disk 3" OD x1/2 thick (wrapped with freezer wrap)
- 1-27/8 O.D Cut off wheel
- 2- Tennis Balls 2 5/8 O.D
- 2- Dunlop Golf balls 1 3/4 O.D (Deep Range)

This shot was pressured up to 4600 psi and pumped at a rate of 4.5 bbls per min. Again no change in pump pressure after Shot reached the turn. In all the shot two 2-5/8 O.D tennis balls were pumped for verification of shot. They also acted as a wiper for the following shots.



Recommended Junk Shot Load

These loads should consist of the above tested material with 4 X 18" segments per barrel, each segment being more aggressive than the previous. Spacers fluid in-between each segment will consist of motor oil. The Junk Shot segments them self will consist of various amounts of Halliburton Grease disk 3" OD x1/2" thick (wrapped with freezer wrap), 2 7/8" O.D Cut off wheel, Inner Tube strips ½ inch wide 6" long with knot in the middle, Soft line rope 6" long with a knot in middle, hemp rope 4" long with knot in the middle, 1 5/8" Tennis balls, 2 7/8" O.D Cut off wheel, Tennis Balls 2 5/8 O.D, Dunlop Golf balls 1 3/4 O.D (Deep Range) and 1" Super Balls. Paint balls will be loaded in front and behind junk shots in different colors.

Well Pill Procedure

1. Begin pumping 10 bbl Fiber LCM pill at 2-5 bpm or as dictated by pressure limitations.

2. Displace with 215 bbls of 14.2 ppg $CaBr_2$ brine (10 bbls past BOP stack).

3. Monitor well. Pump additional pills as required to ensure BOP's are sealed as per WWCI Representative. Record pressure on BOP stack.

4. Go to Well Kill Procedure.

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Next steps assume the BOPs are sealed up and flow has stopped.

Well Kill Procedure:

1. Line up Wild Well Control manifold so that pumping is straight thru either side A or side B of manifold. Do NOT go thru **"by-pass area"** of Wild Well Control Junk Shot manifold.
2. Initiate pumping at ~2 bpm with 150 barrels of 80 ppt viscosified 14.2 ppg $CaBr_2$ kill fluid. Displace viscosified bromide pill with non-viscous 14.2 ppg $CaBr_2$. Max injection pressure will be established based on shut in pressures. Track fluid and pressures that should follow the pump schedules (attached).
    a. Monitor gauge for movement indicating underground flow.
    b. Pumping schedules will be revised based on actual pressures.
3. Adjust injection pressure and rate as necessary to fill hole with kill fluid. Pressure indicators to stop pumping and revising the program include:
    a. Pressure spike indicating lockup. Max injection pressure will be established prior to initiating kill operations.
    b. Pressure reaches a steady point with significant pressure still on stack. This may indicate underground flow. Action to be reviewed.
4. Inject approximately 2,000 bbls of 14.2 $CaBr_2$ adjust rates as per pressure indicates. Hole volumes are as follows:

a. Injection line to BOP stack	210 bbls
b. Annular (suspected leak path)	1,050 bbls
c. Casing Volume	660 bbls
d. Workstring Volume	80 bbls

5. It is not expected that the well will be dead with 14.2 ppg brine to TD. Due to temperature effects, the overall fluid column is estimated to be 14.17 ppg. While this is overbalanced to the 12.6 ppg geotapped formation at 18,078' TVD, there are two sands above (17,712' and 17,798' TVD) that were geotapped at 14.15/14.16 ppg.
6. Once the 14.2 ppg brine has reached well TD, sufficient cement will be pumped to hydrostatically kill the well.
7. Go to cementing procedure.

Cementing Procedure:

1. Pump cement as per SLB cementing plan (Alex)
2. Shut in and observe pressure until cement has set up. Cement will be designed to set in 1 hour after circulating. Bleed off slowly and observe.

Risks:

- Shut-in pressures could create failure at casing shoes or liner top packers
- Injection into the zone or within acceptable pressure limits may not be possible.
- Injected fluid could create leak at 16" liner top. Lead to underground flow transfer to 18" liner top or the 16" or 18" shoe.
- Oil brine compatibility is not expected to be an issue, but no way to test.
- Compatibility testing of fluid and cement needs to be done.
- Bridges and solids are possible - watch for packoffs, especially at increasing rates.
- It is not expected that the well will be dead with 14.2 ppg brine to TD. Due to temperature effects, the overall fluid column is estimated to be 13.6 ppge. While this is overbalanced to the 12.6 ppg geotapped formation at 18,078' TVD, there are two sands above (17,712' and 17,798' TVD) that were geotapped at 14.15/14.16 ppge. Once the 14.2 ppg brine has reached well TD, sufficient cement will be pumped to hydrostatically kill the well.
- Shut in conditions will continue to increase following pressure buildup from the main zone and the zone at 17712' begins/continues flowing into the wellbore. CEMENTING OPERATION SHOULD BE STARTED AS SOON AS POSSIBLE AFTER SHUT IN. PROMPTLY ADDING HYDROSTATIC REDUCES THE DANGER TO THE LINER TOP AND OTHER WEAK POINTS.
- Cement could lock up in the string; need to ensure proper testing and design.

Well Failure / Pressure Limitation Discussion:

Evaluate initial stack shut-in pressures when gauge first installed on the stack, which could be prior to an earlier shut-in operation or just prior to the kill outlined in this procedure.

Shut in pressures for failure of critical equipment require adequate margin. The stack pressures are estimated to be in the range of 8900 psi, but could vary based on uncertainty about the fluid gradient

Pressures from 7100 - 9000 psi is the expected range if the stack is communicating ONLY with the 7" casing drilling section and the main flowing interval. Pumping against a stack shut-in pressure > 8550 requires a check with engineering prior to pumping UNLESS the pressure is observed to be rising. If the pressure is rising, commence pumping immediately to get hydrostatic into the well.

Pressures that are < 7100, down to 3000 psi stack pressure would indicate a leak to the outside (possibly deep) or possibly a bridge. In either case, commence pumping operations to find the problem point.

Stack pressures indicating underground flow would be high and steady. Pressures indicating flow to the 18" shoe would be expected to be ~ 4-5000 psi. For a flow into the section below the 22" shoe we would expect ~ 3-4000 psi stack pressures. In either case, proceed with pumping kill fluid in order to find the leak depth from the annulus. See attached Stack Pressure vs Depth of Casing Exit graph for approximate pressures - uncorrected for friction and restriction complications that may exist.

Stack pressures just above SW gradient indicate a very shallow blowout, which should be visible nearby with ROV.

It is not expected that the shut in pressures will exceed casing design burst load cases; however, there are four potential failure points identified. The four most likely failure points were identified and evaluated by Rich Miller, BP EPT Integrity Management and Phil Pattillo BP EPT Distinguished Advisor. A comprehensive discussion can be provided upon request. Below is a summary of results. Actual pressures and failure potential will vary; this was provided as a discussion point to bring to light the potential failure points of the well.

Hanger Loads

- Differential pressure at the 16" hanger is 7,615 psi for the more severe external pressure of 11.1 ppg balancing the minimum pore pressure at the 18" shoe. It is 6,890 psi with hydrostatic 11.1 ppg mud behind pipe.

Top Rupture Disk

- Differential pressure at the top rupture disk sub at 6,047 feet is 7,885 psi if external pressure is mud balancing minimum pore pressure. It is 7,160 psi if external pressure is 11.1 ppg mud. Although injection will cool the disks, reducing the adverse impact of thermal yield derating, the burst disk has a low tolerance of 7,125 psi at 200°F. Since the internal gradient exceeds the external gradient, the lowest disk will have a more severe differential pressure. 9,812 psi mudline pressure on 16.4 ppg mud will likely rupture a disk. From a kill perspective, most of the flow would still go down the casing, but the 16" would no longer have pressure integrity.

16" casing at 8,969' (18" shoe depth)

- Differential pressure across the 16" casing at the 18" shoe is 8,689 psi if external pressure is the minimum pore pressure of 9.35 ppg. This would decrease to 8,387 psi if external pressure is the mean pore pressure of 10.0 ppg. The 16" MIYP (minimum internal yield pressure) is 6,920 psi. The ISO 10400 rupture pressure is 7,830 psi, while a Klever-Stewart rupture pressure with nominal dimensions is 9,560 psi.

16" casing at 11,153'

Differential pressure across the 16" casing at the 13-5/8" TOL is 9,077 psi if external pressure is the minimum pore pressure of 10.2 ppg. This would decrease to 8,435 psi if external pressure is the mean pore pressure of 11.3 ppg. The 16" MIYP (minimum internal yield pressure) is 6,920 psi. The ISO 10400 rupture pressure is 7,830 psi, while a Klever-Stewart rupture pressure with nominal dimensions is 9,560 psi.

Contingency Fiber LCM Pill Formulation

10 bbl pill Formulation	
8 bbls of 14.2 ppg $CaBr_2$	
3 ppb Biopolymer	
15 ppb Magma Fiber	3 sacks
15 ppb Vinseal C	3 sacks
10 ppb Super sweep	2 sacks

Figure 1

Kill Line Surface Pressure Using 14.2 ppg Brine Corrected for Temperature

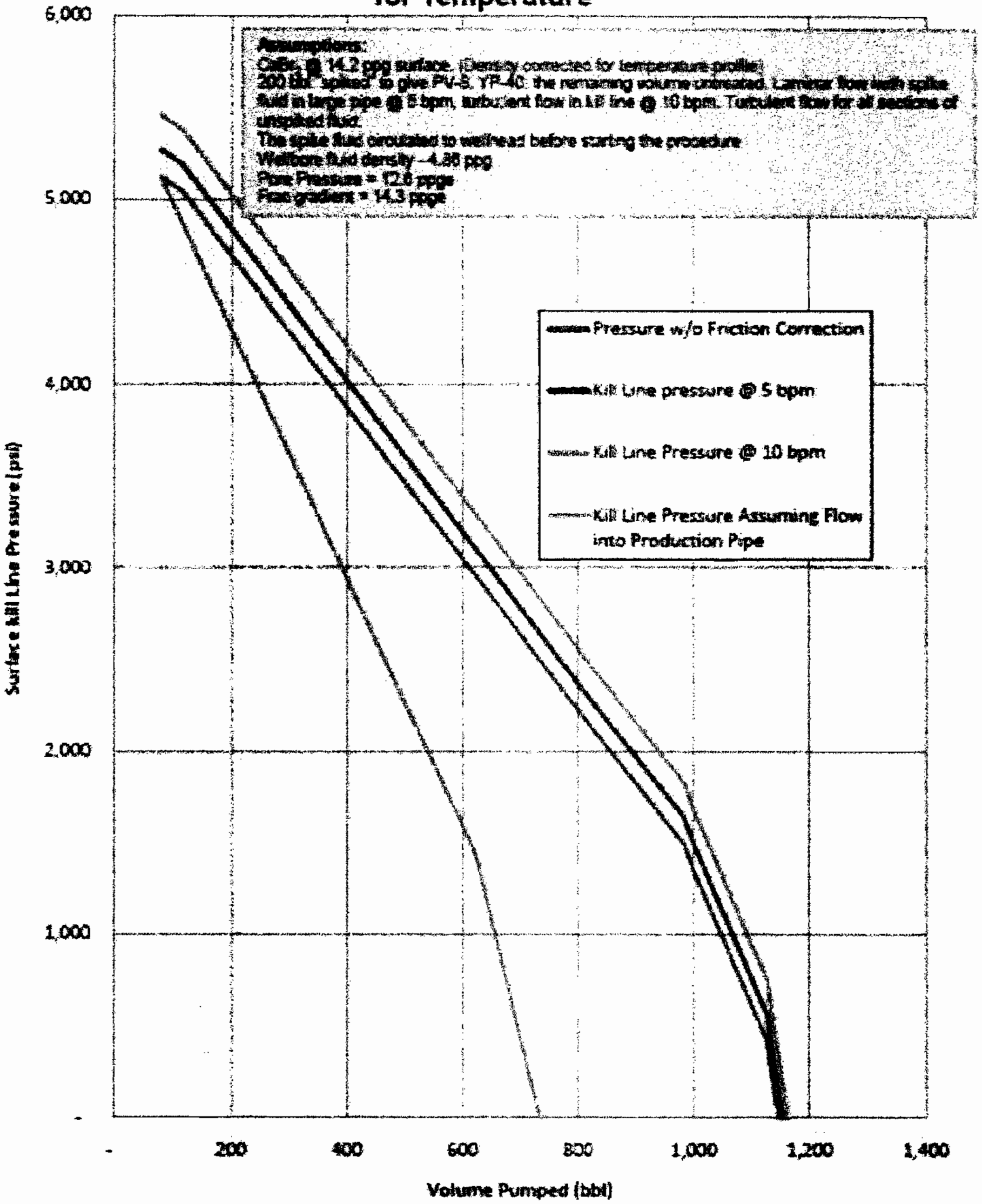

Figure 2

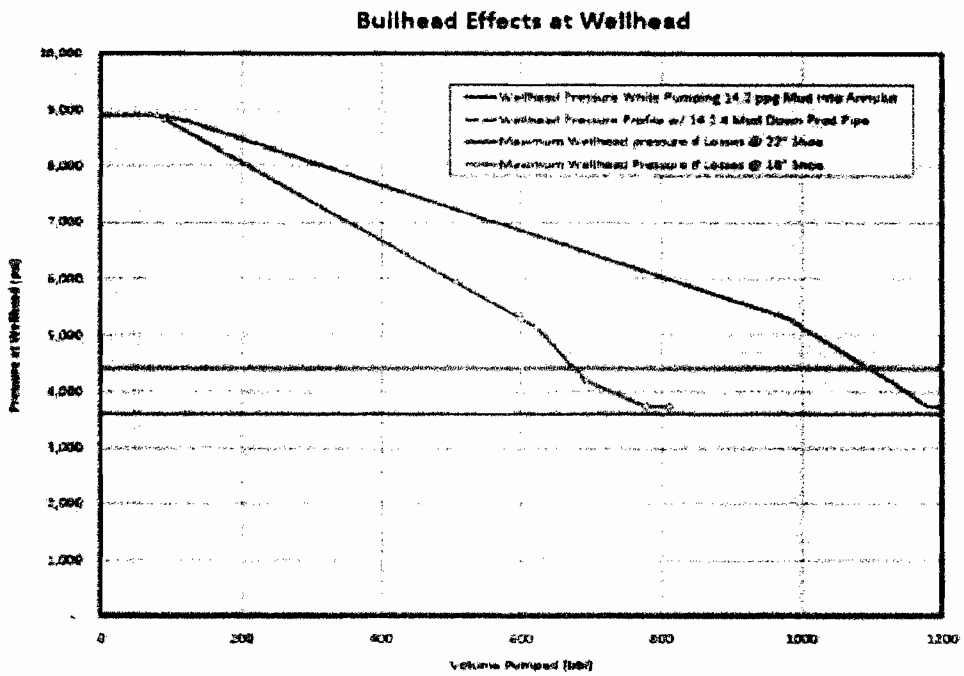
Bullhead Effects at Wellhead
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
200
400
600
800
1000
1200

Figure 3 -- Flow area of the Casing/shear through Mud Slot is 1" X 8"

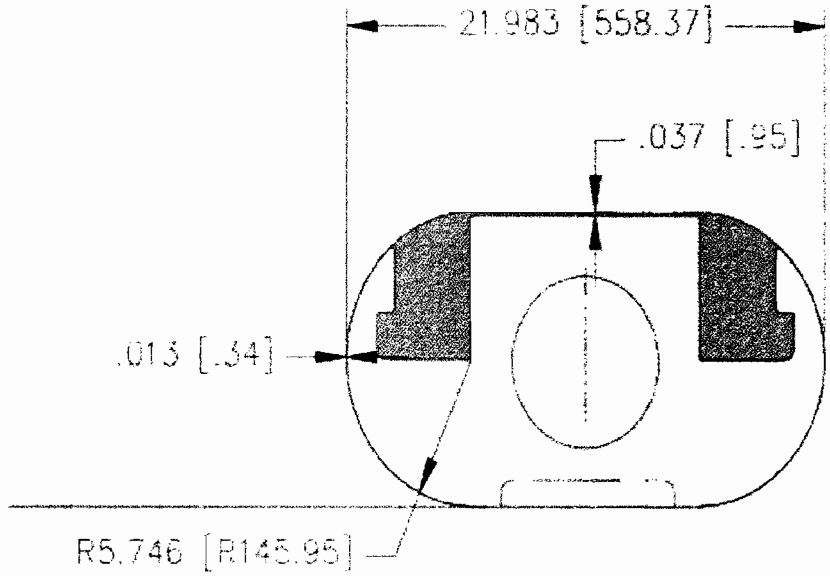

Figure 4 -- Flow area of the Casing/shear