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From: Wood, Douglas G
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To: Hill, Trevor; Tooms, Paul J
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Trevor, Paul,
My technical note approaching its final draft before I leave.
Doug

<<...>>

Macondo Technical Note

Title:	Well Kill AnalysisTechnical Note
Contributors:	Doug Wood,.......
Issued by:	Paul Tooms
Date:	xxnd May 2010
Version:	A

Purpose of Technical Note
This technical note discusses the results of the well kill attempts and the pressure measurements collated before, during and after these attempts and addresses:
- Evidence to support potential flow paths within the well
- Potential scenarios that match the failure to achieve a successful well kill
- The likelihood that the rupture discs in the B-annulus have been activated

Key Conclusions
The data collected and subsequent modeling does not provide conclusive evidence for the flow path, or why the well kill was unsuccessful. However, it does support the following conclusions:
- The test, upper pipe and lower pipe rams are closed around drill pipe.
- The drill pipe provides a substantial restriction to flow and it is likely that the majority of this drill pipe, including the 3-1/2"section, is present.
- There is some by-pass flow around the pipe rams.
- The by-pass flow is substantially increased when the test rams are opened.

In addition the modeling gives the following results:
- Failure to kill the well can be attributed to an increased by-pass flow following the opening of the test rams.
- Failure to kill the well is not achieved by assuming flow into a fracture at the 18" or 9-7/8" shoe.

These results indicate that it is unlikely that rupture disc activation was the cause of the failed kill attempt. However, they do not provide conclusive evidence that the rupture discs are intact.

Pressure Measurements Prior To (and Post) Top Kill Operations

Intermittent pressure measurements have been made using the existing transmitter on the BOP (below the test rams), a gauge inserted into the mud boost line using an ROV, and acoustic and ROV digital gauges on the choke and kill lines.

Prior to permanent connection of an acoustic transponder to the BOP sensor, measurements were made by directly plugging in an ROV to the sensor electrical connector. Significant step changes were observed between sets of measurements taken by this route. As the electrical connector was being disconnected and reconnected each time a set of measurements were taken, these step changes may not be real changes in pressure. Thus, this data has not been used for the diagnostics.

The pressure sensor upstream of the BOP was shown to have a significant measurement error when compared with the acoustic sensors on the choke and kill line. By comparison with the kill and choke line sensors, during the well kill operations, it has been established that it under-reads by 966 psi. Note that the choke and kill line sensors have been recently calibrated, and that this calibration was independently checked against seawater ambient pressure and the mud hydrostatic head at the BOP depth. The corrected BOP measurements are shown on Figure 1.

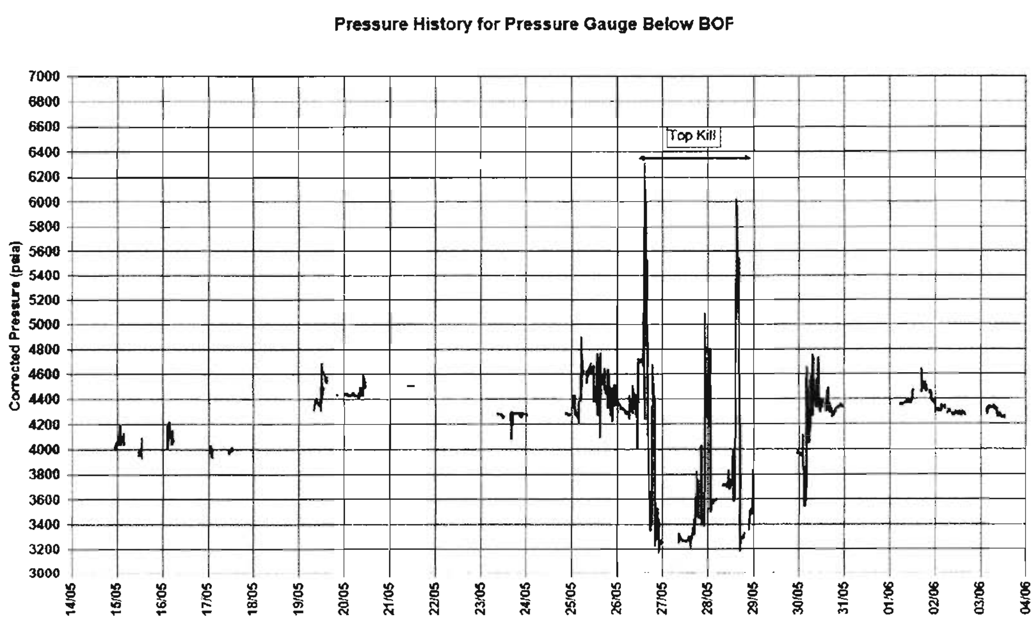
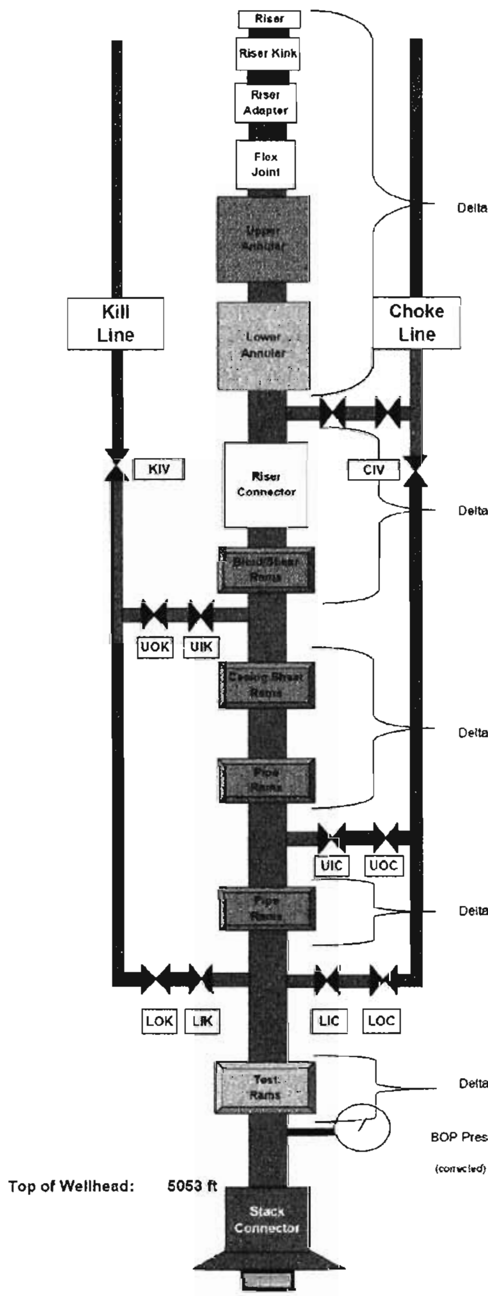


Figure 1 – Corrected Pressure Measurements From BOP Sensor

Horizon BOP Intervention
Diagnostic Pumping
28-May-2010



Pressures (psi) +/- 50 psi	Pre Kill	Post Kill Attempt 1	Post Kill Attempt 2	Post Kill Attempt 3
	2,260	2,260	2,260	2,260
Delta	310	250	229	
	2,560	2,500	2,479	
Delta	60	120	108	493
	2,620	2,620	2,587	2,743
Delta	620	510	794	410
	3,240	3,130	3,381	3,153
Delta	430	150	234	242
	3,670	3,280	3,665	3,395
Delta	730	40	32	101
BOP Pres (corrected)	4,400 (Test Ram closed)	3,320 (Test Ram open)	3,697 (Test Ram open)	3,496 (Test Ram open)

Figure 2 – BOP Pressure Measured During Diagnostics

Prior to top kill operations and after each top kill attempt pressure measurements were made using the choke and kill line gauges at each inlet to the BOP (between the test ram and lower pipe rams, between the lower and upper pipe rams, between the casing and blind shears and between the blind shears and annulars). These are shown on Figure 2. There was a significant drop measured across the lower pipe rams (430 psi) and across the combination of upper pipe and casing shear rams (620 psi) prior to the initial kill attempt. The pressure drop across the blind shear rams was only 60 psi.

The balance of pressures across these rams changed following each kill attempt and was also affected by the opening of the test rams. Between the kill attempts, when the test rams were opened, the recorded pressure drop across the blind shear approximately doubled, to 120 psi and 108 psi, but remained relatively low.

A more detailed discussion on the pressure measurements, along with the overall top kill data, is included within the technical note, Diagnostics and Top Kill Pressure Measurements.

A summary of the pressure measurements upstream of the BOP and the pressure difference across the BOP rams is shown on Figure 3. The downstream pressure in each case is estimated by utilising the measurements taken on the mud boost line, the gas vent line and seabed ambient pressure following the cutting of the riser, along with the results of the diagnostics which indicated a very limited pressure loss across the BOP annulars.

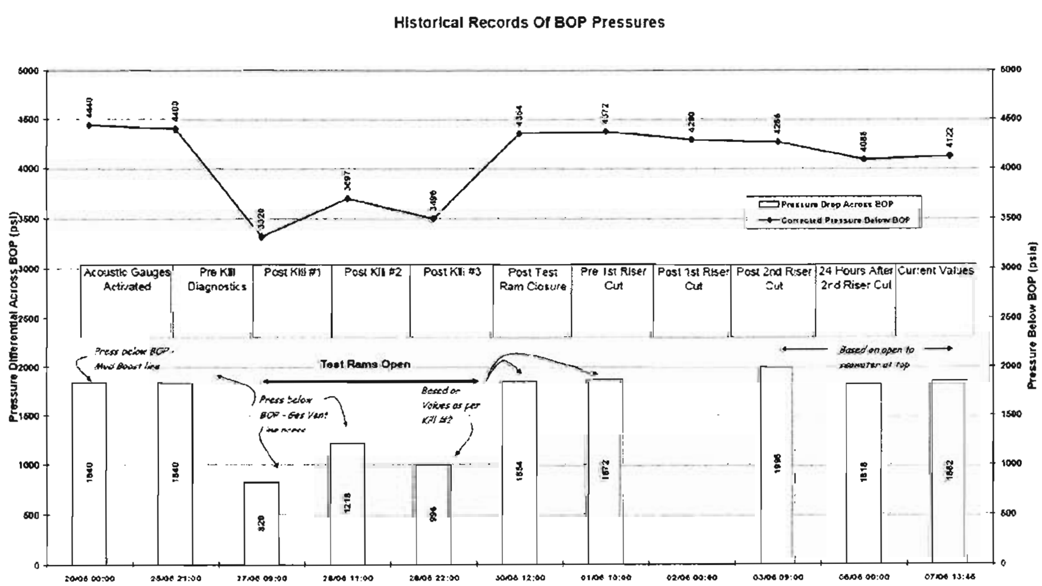


Figure 3 – Historical Records of BOP Pressures

These pressure measurements indicate that the pressure drop across the BOP has not changed significantly (ranging from 1800 psi to 2000 psi) between 20th May and 7th June, except for the period of the three kill attempts when the test rams were open. The three pressure measurements taken during the kill attempts when the test rams were open give a pressure difference of 820 psi, 1218 psi and 966 psi.

Top Kill Operation Data

The top kill operation included 3 separate top kill attempts over 3 consecutive days. In total, 30,000 barrels of heavy mud was pumped at rates up to 80 bpm. This created a peak pressure at the BOP of up to 6300 psi and a surface pressure on the pumping vessel of up to 11000 psi. Sixteen different bridging material shots were fired during the operations including varying sized balls, cubes and miscellaneous objects.

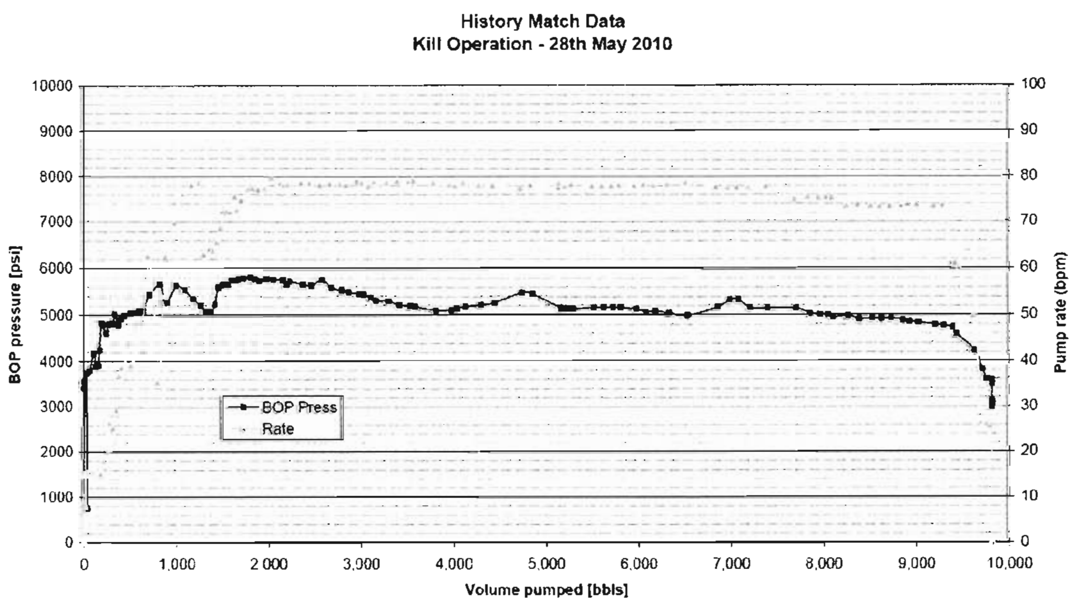


Figure 4 – History Match Data For Top Kill #3

Specifics for each of the 3 top kill operations are discussed in the technical note Diagnostics and Top Kill Pressure Measurements and are summarized as follows:

- Top Kill #1 May 26th
  - 13,100 bbls of 16.4 ppg pumped with a peak pump rate of 53 bpm

- Top Kill #2 May 27th
  - 6,800 bbls of 16.4 ppg pumped with a peak pump rate of 25 bpm and 15 shots of bridging material into the upper kill and lower kill lines
- Top Kill #3 May 28th
  - 9,800 bbls of 16.4 ppg pumped with a peak pump rate above 70 bpm and 2 shots of bridging materials into the lower kill line.

The measured BOP pressures and flowrates used for the Olga modelling of the top kill attempt #3 are shown on Figure 4. This attempt had both the highest and most consistent mud flowrate of the three kill attempts.

During this kill operation the plumes at the riser kink and at the end of the riser were monitored. Figure 5 shows a series of pictures recorded at the end of the kill period showing the plume at the kink during the reduction of pumping rate from over 70 bpm until after the pump was stopped at 16:53.

The appearance of the plume at the kink changed as rate was decreased from above 74bpm (16:18 and 16:33) to the point at which the pump was stopped (16:53). There was negligible change in the plume appearance after the pumping had stopped (17:18). This sequence of pictures is interpreted as showing hydrocarbon flow during the period of pump flowrate reduction and immediately after the pump has stopped.

Scenarios Considered

As the current status of the well following the blow out is unknown, there are a large number of scenarios that could be considered when matching the top kill operation.

The key uncertainties affecting the potential well flow paths are as follows:

Main flow path in wellbore

- Flow up 9-7/8" casing
- Flow up B-annulus
- Flow up both 9-7/8" casing and B-annulus

Communication between casing and B-annulus

- Flow path exists between the casing and B-annulus through the wellhead casing seal
- No flow path exists through wellhead casing seal

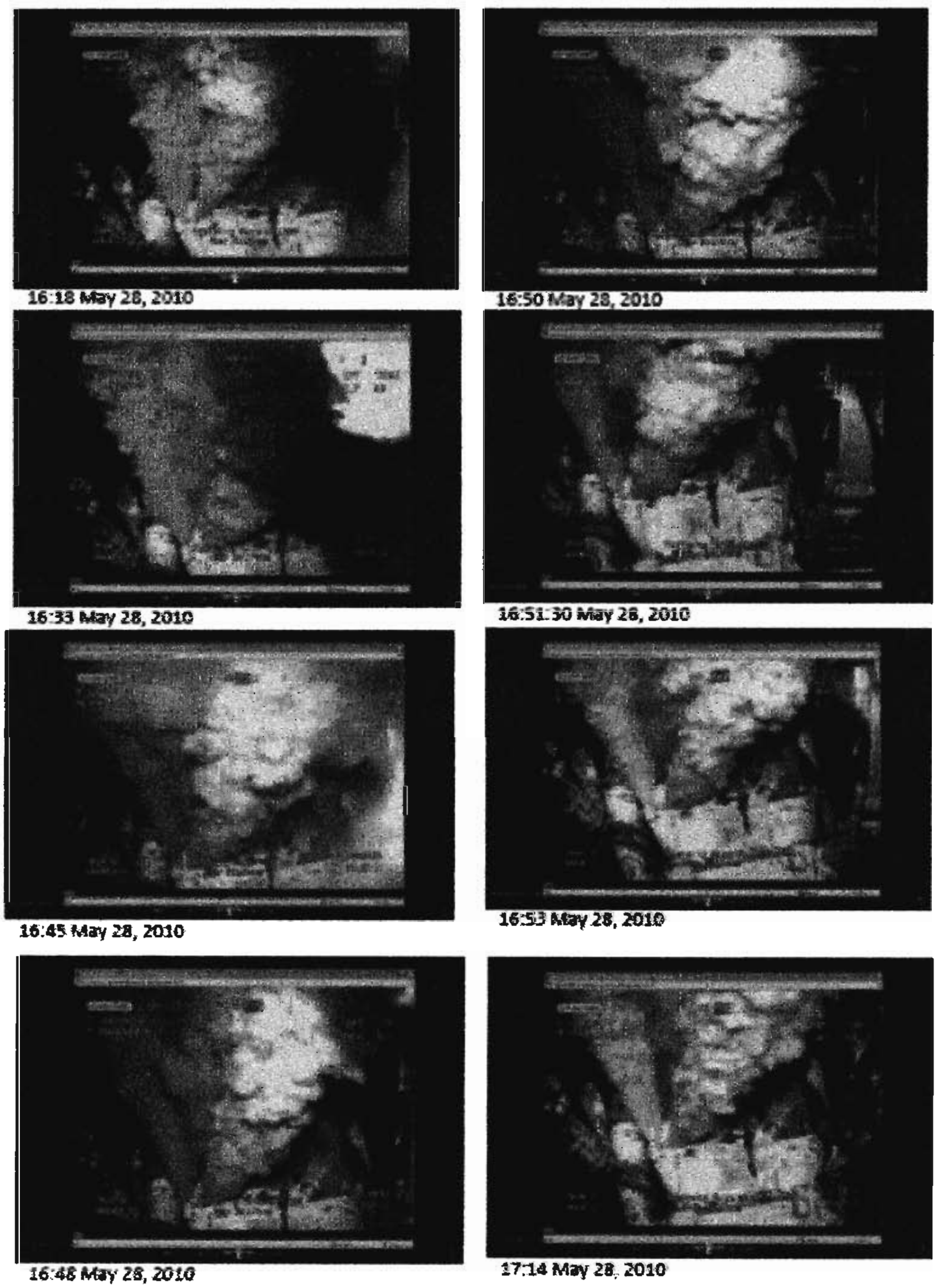


Figure 5: Flow through the riser kink during and immediately post top kill attempt #3. Pumping ceased at 16:53.

Presence of drill string

- All 2500 feet of 5-1/2" and 800 feet of 3-1/2" drill string is in place in the well
- Drill string has been partially ejected from well and a reduced length of the 5-1/2" section remains in the well
- The 3-1/2" section has been severed and no longer is in place
- The drill string has been both partially ejected and the 3-1/2" section has been severed (or the drill string has been washed out below the BOP)
- No drill string is present
- Full string is present but there is communication between the drill string and the surrounding annulus within the casing.

By-pass flow around pipe rams

- Drill string is in place. No flow by-pass around the pipe rams
- Drill string is in place. Small flow by-pass around the pipe rams
- Drill string is in place. Significant flow by-pass around the pipe rams

Shear rams, annulars and riser kink restriction

- Significant flow restriction downstream of pipe rams
- Limited or no flow restriction downstream of pipe rams

Bottom hole restrictions

- Significant deep choke in the well due to, for instance, flow through cement.
- No, or a limited, deep choke in the well

16" casing bursting disc status

- The bursting discs between the B-annulus and C-annulus are intact
- One or more of the six bursting discs between the B-annulus and C-annulus have activated enabling flow via a fracture at 18" shoe (flow area depends on number of bursting discs activated and the level of wash out)

Immediately following the top kill operations, a number of scenarios were considered when reviewing the measured data from the top kill operation. These are summarized below. An initial assessment of their likelihood was made and is included in Appendix 1.

- *Scenario #1: Hydrocarbon flow is up either the casing or the B-annulus with the hydrocarbon and dominant mud flow up the drill string during the kill operation. Ram by-pass and a severed drill pipe were considered as sub-scenarios.*

- *Scenario #2: Hydrocarbon flow is up the B-annulus and the dominant mud flow is down the 9 7/8" casing and into the reservoir.*

- *Scenario #3: Hydrocarbon flow is up the 9-7/8" casing and the dominant mud flow is down the B-annulus, through the activated discs in 16" casing and into fractures at the 18" shoe.*

- *Scenario #4: Hydrocarbon flow is up the 9-7/8" casing and the dominant mud flow is down the B-annulus and into fractures at the 9-7/8" shoe.*

Since these four scenarios were identified, the possibility for counter-current flow in the top of the section of the B-annulus has been reviewed (ref: Sandia presentation "Mud Flow During Kill"). This indicates that counter-current hydrocarbon/mud flow may be possible above the 9-7/8" liner leading to a further scenario that could be considered.

- *Scenario #5: Hydrocarbon flow and dominant mud flow are both in the B annulus (counter-current) with mud flow through the activated discs in 16" casing and into fractures at the 18" shoe.*

Relevant Information Required For Scenario Assessment

Fracture Gradient

To assess Scenarios 3 and 4, a value for the fracture gradients at the 18" and 9-7/8" shoe is required.

The predicted sand and shale fracture gradients at the 18" shoe were 11.2 ppg and 11.8 ppg giving fracture pressures at this location of 5235 psia and 5503 psia. A Leak Off Test at 11.55 ppg has been conducted at this location. A fracture pressure of 5235 psia for any scenario assessment is proposed for this depth (Conditions Required to Shut down a Broach to the Sea Bed, Tony Liao, 26th May 2010)

The predicted sand and shale fracture gradients at the 9-7/8" shoe were 14.7 ppg and 15.2 ppg (Ref: e-mail from Martin Albertin). A Formation Integrity Test of 16.0 ppg has been conducted at this location but there is some uncertainty on the validity of this test due the extent of exposed formation. A fracture pressure between 13560 psi (15.2 ppg) and 14270 psi (16.0 ppg) is proposed for this depth.

B-Annulus Fluids

At the end of the drilling operations the B-annulus fluids were 14.0 ppg mud

Prior to top kill attempt 3, this annulus could be in one of several potential conditions.

1. Annulus hydrocarbon flow scenarios – Annulus is hydrocarbon fluid filled

2. Casing hydrocarbon flow scenarios, no communication to annulus – Annulus remains filled with 14.0 ppg mud
3. Casing hydrocarbon flow scenarios, communication to annulus, bursting discs activated – Annulus remains filled with 14.0 ppg mud up to bursting discs and 16.4 ppg mud and hydrocarbons above this location. The 18" fracture pressure and the measured upstream BOP pressure prior to top kill attempt 3 (3600 psia) determines the location of the mud/hydrocarbon interface in this case. This assumes that mud had flowed out through the activated bursting disc during top kill attempt 1.
4. Casing hydrocarbon flow scenarios, communication to annulus, no bursting disc – Annulus is filled with 16.4 ppg mud and hydrocarbons. The 9-7/8" fracture pressure and the measured upstream BOP pressure prior to top kill attempt 3 (3600 psia) determines the location of the mud/hydrocarbon interface in this case. This assumes that mud had flowed out below the 9-7/8" liner during top kill attempt 1. Note that, for a 15.6 ppg fracture gradient, a full column of 16.4 ppg above the fracture pressure would give a below BOP pressure equal to the measured value of 3600 psia.

Casing to B-Annulus Flow Area

The maximum potential flow area between the casing and the B-annulus, in the event that there is communication across the casing hanger, has been estimated as a total of 14 sq in (combined flow area of the casing hanger ports) (Ref: e-mail from Kim Phan).

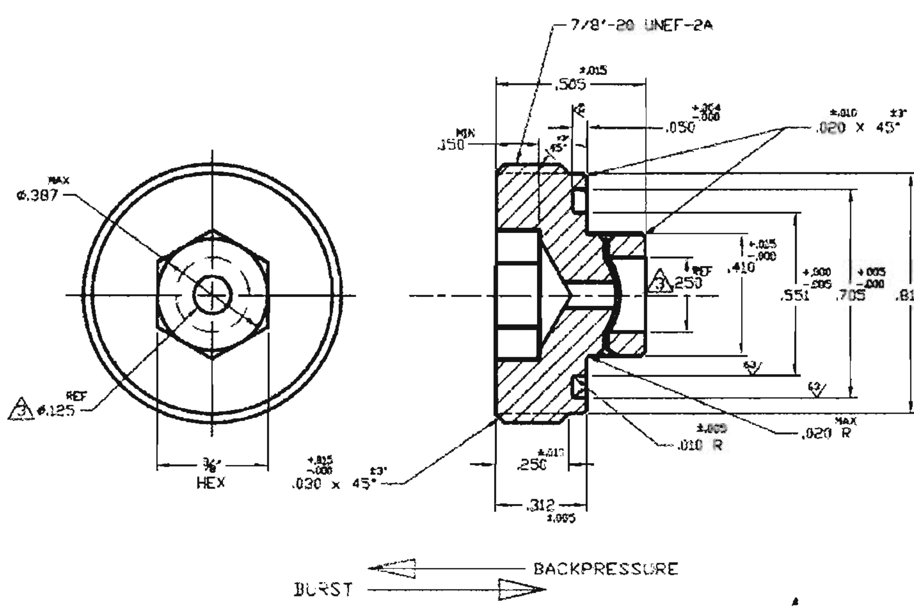


Figure 6 – Rupture Disc Design

Rupture Disc Flow Area

The rupture disc design is shown in Figure 6. There are 6 rupture discs in the 16" casing string each of which as a 0.125" hole diameter. These are set at depths of 6047, 8304 and 9560 feet with 2 at each location. For the purposes of modeling, it is assumed that all 6 rupture discs have failed and have been washed out to a maximum diameter of 0.433".

Scenario Modeling

The evidence obtained in the flowing condition, during the kill diagnostics and during the kill attempts has been used to compare the potential flow paths and scenarios. These comparisons have utilized qualitative assessment along with modeling of the full system or part system using multiphase flow tools, specifically Prosper/GAP for steady state analysis and Olga for transient analysis.

The Prosper model has been utilized to review the pressure drop across the drill string in steady state flowing conditions to determine the feasibility of wellbore paths and the impact of the different drill string scenarios. It can also be used to assess the effect of chokes in the system. GAP system models have been developed to match the steady state flowing conditions and presumed steady state conditions at the end of the well kill, and can be used to compare the different scenarios under these steady state conditions.

The GAP modelling results, Appendix 2, requires high ram by-pass or a reduction in drill string length to match the system pressures under the flowing and mud injection conditions. In addition none of the annular flow cases modeled with GAP could match the combination of data for the flowing and well kill cases.

The Olga model, using the well kill module, has been utilized to conduct transient analysis of kill attempt 3. Transient models have been run for a number of the potential scenarios as follows:

- Scenario #1 with casing flow and the drill string in place and with the drill string severed 300 feet below the BOP.
- Scenarios #3 and #4 with a variety of initial conditions. In some of these scenarios ram by-pass was also considered. The final model runs with these scenarios utilized the most appropriate starting conditions for kill attempt #3 as described above, but did not include ram by-pass.

For each scenario the flowrates through the system were adjusted to match the measured pressures across the drill string.

The history matches from some of these runs are shown below (Figure 7 and 8) (Ref: e-mails from Thomas Selbeck). These plots are typical of all the cases run and show two distinctive shapes of curve. Figure 7 demonstrates a good match with the measured pressures and does not lead to a successful well kill. Figure 8 shows a significant pressure peak, reaching approximately 8000 psia, that is not consistent with the highest measured pressure. This pressure peak is sufficient to overcome the hydrocarbon flow and for these cases the well is killed.

The Olga modeling only predicts an unsuccessful well kill when the majority of the mud flow is routed through to the riser. This requires a reduced length of drill pipe remaining, removing its restriction to the mud flow, or the majority of the mud flow by-passing the rams. Without significant ram by-pass or a severed drill pipe, it does not predict a successful kill for Scenarios #3 or #4.

However, the model results for the Scenarios shown on Figure 8 (no ram by-pass) appear to show inconsistencies with the expected behaviour of system. In particular, the model appears to require a much higher pressure during the pressure build-up period to drive the same flowrate of mud through the 18" or 9-7/8" fracture than it does after the well has been killed. Given this inconsistency, the results of the Olga modeling are not deemed as conclusive evidence that Scenarios 3 and 4 should be discounted.

Results Interpretation

Pressure loss across the shear rams, annulars and riser kink restriction

The diagnostic pressure measurements at the choke vent indicate a relatively constant pressure loss of between 229 psi and 310 psi. In addition the pressure loss across the blind shear rams was relatively small; between 60 and 120 psi. This indicates that the pressure loss across the blind shear rams, annulars, riser kink and riser was not a significant component of the pressure loss between the below BOP sensor and the riser outlet. This indication is supported by the limited decrease in pressure below the BOP following the riser removal.

Casing vs Annular Flow

Steady state analysis has been matched against the pressure measurements obtained during the pre-kill diagnostics assuming the full drill string is present. This has been conducted for both the B-annulus and casing flow scenarios. The difference in the flow route between the below BOP pressure sensor, and the kill or choke line sensor connected to a BOP inlet above the pipe rams, is as follows:

- Casing flow - Pressure drop of full flow through drill string minus gas hydrostatic head in drill string/casing annulus
- B-annulus flow – Pressure drop of full flow through both the drill string/casing annulus and the drill string.

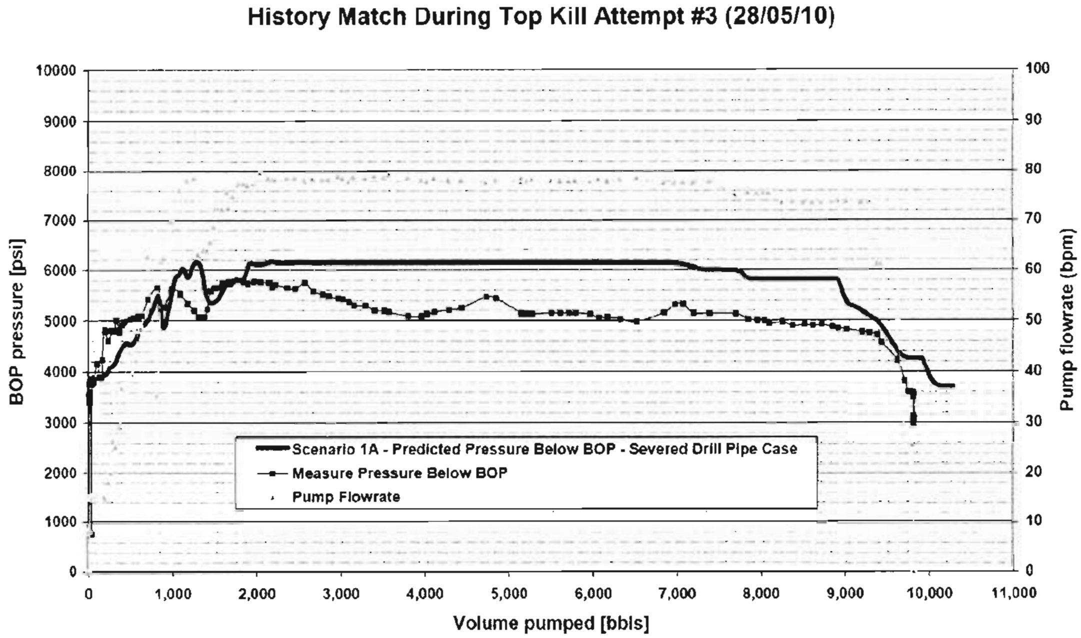


Figure 7 – Olga History Match for Scenario #1

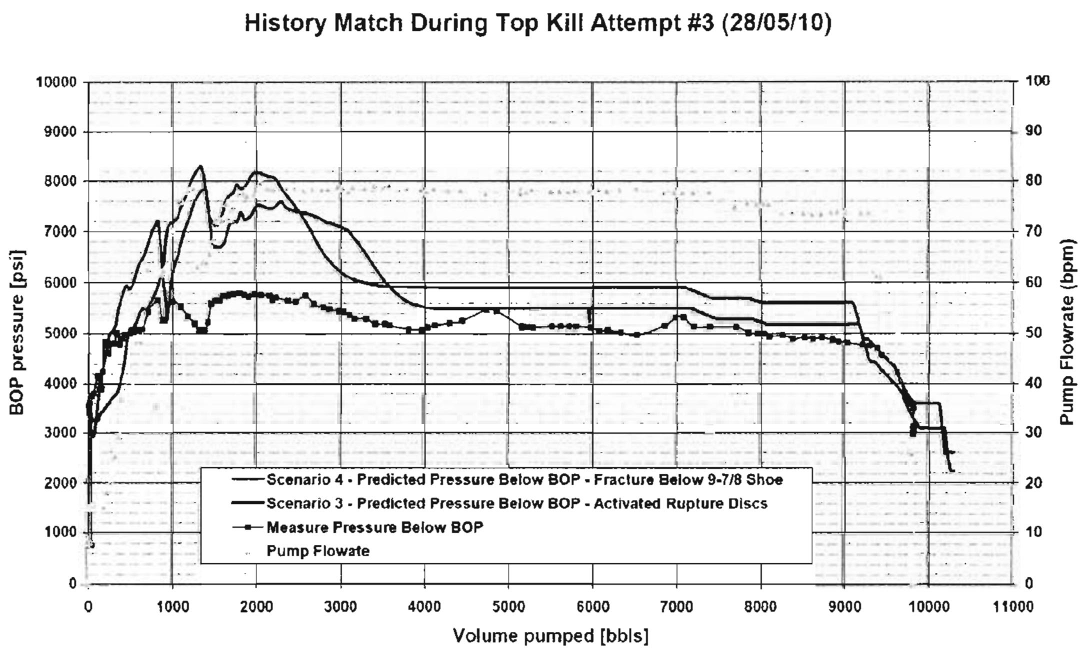


Figure 7 – Olga History Match for Scenarios #3 and #4

For the same flowrate the drill string component of pressure drop is the same. The model predicts that the drill string annulus component (gas head vs full stream downflow) for the two cases is not significantly different and cannot therefore distinguish between the two cases. Hence, the diagnostics have not provided evidence to enable the main flow path in the wellbore to be established. Note that if a reduced length of drill string was assumed the predicted pressure difference between these two routes would be even smaller.
The pressure drop across the system assuming a full drill string is in place, and no other restrictions, is matched by a production rate of approximately 20 mbd (+/- 15%).

Ram By-pass and Drill String Presence

Figure 2 shows a significant decrease in pressure drop across the BOP when the test rams were opened which was subsequently recovered once they were closed after kill attempt #3. The test rams are therefore either sealing or providing a significant choking effect when closed.

The pressure drop across the test and pipe rams during the pre-kill diagnostics was as follows:

- Test rams – 730 psi
- Lower pipe rams – 430 psi
- Upper pipe rams and casing shear rams – 620 psi

If there is a significant by-pass flow through the test rams when closed, opening the rams should lead to an increase in flow past the lower and upper pipe rams. This should, in turn, lead to an increase in pressure drop across these pipe rams. However, a decrease in pressure drop was observed.

- Test rams – 0 psi
- Lower pipe rams – 150 psi
- Upper pipe rams and casing shear rams – 510 psi

As well as the opening of the test rams, two further events occurred between these measurements.

- Actuating the upper pipe rams which led to an observed increase in pressure above the test rams
- The first kill attempt

These two activities could have reduced the by-pass flow (operating the upper pipe rams) and subsequently increased the by-pass flow (erosion due the kill attempt) potentially masking the impact of opening the test rams.

A high ram by-pass case would also expect to lead to erosion of this flow route through time and a measurable decrease in pressure across the BOP. However, no change in pressure drop has been observed.

Although this evidence suggests a low probability of high ram by-pass, it does not preclude this scenario.

For the scenarios with a reduced length of drill string, the pressure loss across the BOP can only be explained by a high hydrocarbon flowrate. Although this scenario is consistent with the failure to kill the well, it cannot explain the substantial reduction in pressure below the BOP when the test rams were opened, as there would be no change in flow path. Note that a severed and crimped drill string could replicate the behaviour of the full drill string but still cannot explain the impact of opening the test rams.

In summary, the evidence supports the presence of the full drill string and some pipe ram by-pass that is substantially increased when the test rams are opened. The extent of pipe ram by-pass cannot be concluded from the diagnostic data. A large ram by-pass, with the test rams open, is required for modeling to predict an unsuccessful well kill. However, this ram by-pass can be reduced if combined with another effect such as loss of mud through fractures at the 18" or 9-7/8" shoe. Note that the observed pressure behaviour, and failure of the top kill, could be explained by the test rams covering a hole in the drill string at the test ram location that is exposed when the test rams are opened.

General BOP Pressure Trends

The pressure measurements made upstream of the BOP sensor, excluding the period when the test rams were opened show the following characteristics:

- Pressure measurements lie within a range of 4100 psia and 4600 psia.
- No obvious long term trend
- Occasional increases in pressure of up to 200 psi followed by a period of fluctuations during which the pressure drops.

The maximum pressure observed is only slightly below that required to overcome the fracture pressure at the 18" shoe assuming a hydrocarbon gradient in the B-annulus and C-annulus. Thus, if the rupture discs had been activated, occasional flow into a fracture at this location cannot be discounted.

No explanation has been developed for the occasional increases in pressure. Longer term monitoring may be required to understand this behaviour.

Summary and Conclusions

The pressure measurements and pump flowrate data collated before, during and after the top kill attempts do not provide conclusive evidence for the flow path, the hydrocarbon flowrate or why the kill was unsuccessful.

However, the data collected and associated modeling work supports the following conclusions:

- The test rams, upper pipe rams and lower pipe rams are closed around drill pipe.
- The drill pipe provides a substantial restriction to flow and it is likely that the majority of this drill pipe including the 3-1/2" section is present.
- There is some by-pass flow around the pipe rams.
- The by-pass flow is substantially increased when the test rams are opened. This increase in by-pass flow can also be explained by the test rams covering a hole in drill pipe that is open only when the test rams are in the open position.
- Modeling cannot distinguish between casing and annular flow.
- Modeling of well kill attempt 3 with mud flowing through the B-annulus to fractures, either via the rupture discs or through the 9-7/8" shoe, predicts that the well will be killed due the frictional losses in these routes. However, modeling cannot determine whether the rupture discs have activated.
- The evidence suggests that the most likely cause reason that the well was not killed was due a proportion of the mud flow by-passing directly through the BOP. This may be combined with losses via the B-annulus into the 18" or 9-7/8" shoe.

Appendix 1 - Top Kill Scenarios

Scenario	Description	Mud									Supports Scenario	Disputes Scenario	Comments
		Drill pipe	Rams bypass	9 7/8" casing	Annulus 9.7/8"x16" to 18" shoe	Annulus 9.7/8"x16" to bottom hole	9 7/8" casing	Annulus 9.7/8" x 16"	Drill pipe	Rams bypass			
1	HC and dominant mud flow up drill pipe and bypass through rams HC flow is up annulus and/or casing	Up	Up				Up	Up	Up	Up	1, 4	2, 3	Need 78 bpm to flow up combination of drill pipe and ram bypass. Pressure drop indicates max flow up drill pipe ca. 25 bpm, therefore, ca. 50 bpm bypass at rams. Massive flow past rams would expect significant erosion. Plausible, but not credible
1A	HC and dominant mud flow up drill pipe. HC flow is up annulus and/or casing Drill pipe severed close to BOP due to erosion by mud	Up (severed close to BOP)	Up				Up	Up	Up (severed close to BOP)		1, 2, 4, 5	HC flow rate	Allows 78 bpm mud to flow through drill pipe. However, inconsistent with 1000 psi dp across drill pipe for HC flow after end of kill attempts. Would require 70 mbd HC to generate this back pressure. Not credible
1B	HC and dominant mud flow up drill pipe with no bypass through rams HC flow is up annulus and/or casing	Up					Up	Up	Up				Would generate very high pressure loss through drill pipe Not credible
2	HC flow is up annulus and possibly casing as well. Dominant mud flow into casing			Down			Possibly	Up	Up		1, 4, 5; 2 possible	3	Need tight restriction through BOP providing a high choke in the annulus. Would need combined HC and mud flow down casing/drill pipe annulus (high dP), with HC/mud separation in casing and HC going up through drill pipe with some mud, and most mud going down into casing Volumes pumped would have filled casing volume many times. Initial photographs of incident indicated focused vertical jet fire consistent with casing/drill pipe flow Dominant mud flow in casing would kill casing production. Mud could be injected into formation below 7" shoe, but not connecting with producing HCs No real variation from 1st to 3rd Kill attempts (kill graph doesn't fit model). Would expect different pressure fall off for different pump rates. Plausible, suggest reconciliation with investigation report to check credibility.
3	HC flow is up 9.7/8" casing and possibly annulus as well. Dominant mud flow though failed 16" rupture discs				Down		Up	Possibly	Up		1, 2, 3, 4, 5		Max flow rate up drill pipe < 25 bpm. Would need mud to prefer to go through restriction around casing hanger/seal assembly rather than down casing/drill pipe annulus Max flow rate through 7/8" rupture disc openings ca. 60 bpm (six discs failed). Need to confirm flow area through the rupture disks and subsequent effect of mud erosion. Smaller orifice size being used by DoE. HC flow continues up drill pipe throughout killing operations. Pressure during remedial activities have been insufficient to fail discs. Disc(s) would need to have failed during the initial event. Coincident with initial WHFP of ca. 4 400 psi and fracture closure pressure calculated at ca. 4,700 psi. BOP pressure reduction measured during kill is approximately equal to replacing a gas column with 16 4ppg mud down to first rupture disc. Need to check against volume pumped "Flatline" profile has same character as a leak off test. Consistent with modeling of HC flow through drill pipe only (small bypass of rams). There are plausible explanations for annulus exposure and disc rupture either inward or outward. Plausible, and credible

Scenario	Description	Mud									Supports Scenario	Disputes Scenario	Comments
		Drill pipe	Rams bypass	9 7/8" casing	Annulus 9.7/8"x16" to 18" shoe	Annulus 9.7/8"x16" to bottom hole	9 7/8" casing	Annulus 9.7/8" x 16"	Drill pipe	Rams bypass			
4	HC flow is up 9.7/8" casing and possibly annulus as well. Dominant mud flow down annulus to a lower zone					Down	Up	Possibly	Up		1, 2, 4, 5	3	Zone would be between the top of cement for the 7" line (17300 ft mdrkb) and 9.7/8" liner shoe at 17163 ft mdrkb. Would need mud to prefer to go through restriction around casing hanger/seal assembly rather than down casing/drill pipe annulus May be able to pick out changes in friction pressure on passing casing chances Rupture discs remain intact. If HC flow in annulus as well as casing, then HC flow in annulus would be reduced or stopped. Possible to have mud entering into formation below 9.7/8" shoe, but there is little sand in this section, meaning that breakdown requires a shale frac gradient. Would expect a rising pressure as fracture propogates. Plausibe, and credible
4A	HC flow is up 9.7/8" casing and possibly annulus as well. Dominant mud flow down annulus to oil production zone					Down	Up	Possibly			1, 2, 4, 5	3	Would need mud to prefer to go through restriction around casing hanger/seal assembly rather than down casing/drill pipe annulus May be able to pick out changes in friction pressure on passing casing changes Rupture discs remain intact. HC flow in annulus would be killed. No apparent change in HC flowrate, though annulus flow could be significantly less than casing. Plausibe, and credible
4B	HC flow is up 9.7/8" casing and possibly annulus as well. Dominant mud flow down annulus to higher pressure gas zone.					Down	Up	Possibly			1, 2, 4, 5	3	Frac pressure too high, with modelling showing peak pressures in excess of observations. Not credible

HC returns — 1. Immediately after pumping ceased hydrocarbons were seen venting at the kink (plume color at the kinks quickly reverted to brown as previously observed for oil/gas).
Continuous Gas — 2. During the kills, always appeared to have gas entrained at the vents in the kink (similar energy/velocity as oil/gas only, but with a grey color due to mud).
700 psi bump — 3. During Kills, pressures reduced for a while by a maximum of ca.700 psi (for a fixed rate) independent of the rate though "Flat-Lined".
Pressure return quickly — 4. Pressure below BOP recovered back to near starting pressure very rapidly as pumping ceased
Only minor ram erosion — 5. Pressure drops across rams in BOP have remained, although they have reduced somewhat.