Macondo MC252
Holistic System Analysis - Initial Report

This report summarises the analysis of the current state of Macondo well and riser utilising the data available to 8th May 2010. The analysis considers the system from the reservoir through the well, BOP and riser to the point of discharge to sea (Figure 1).

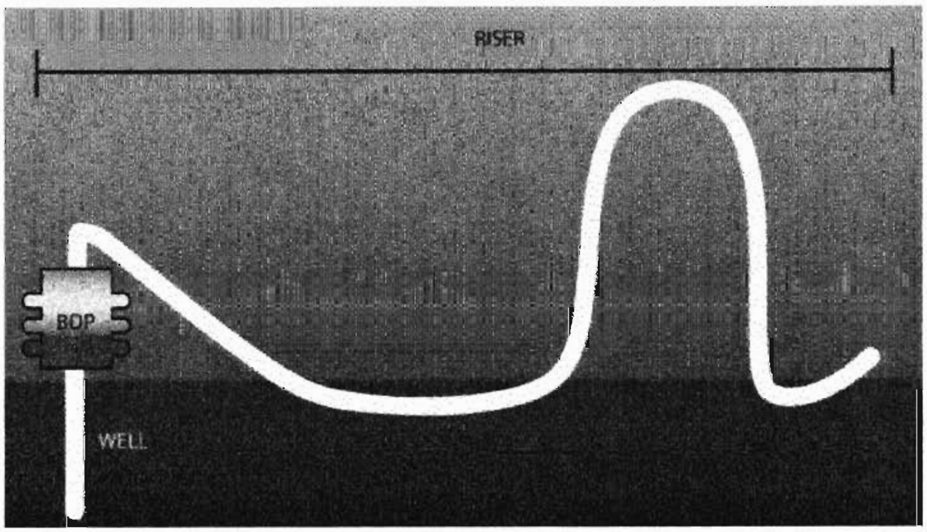


Figure 1. System Overview

Wellbore to Wellhead

There are three scenarios for the wellbore flow paths below the BOP (Figure 2):

- Flow behind production casing string: Reservoir fluids are flowing through the annulus from behind the 9.7/8" production casing.
- Flow inside the production casing string: The float shoe at the end of the 9.7/8" production casing has failed and the well is flowing through the inside of the casing.
- A combination of flow both behind and inside the production casing string: Both seal assembly and float shoe have failed is currently excluded on the basis of being highly improbable (simultaneous failure of two independent barriers).

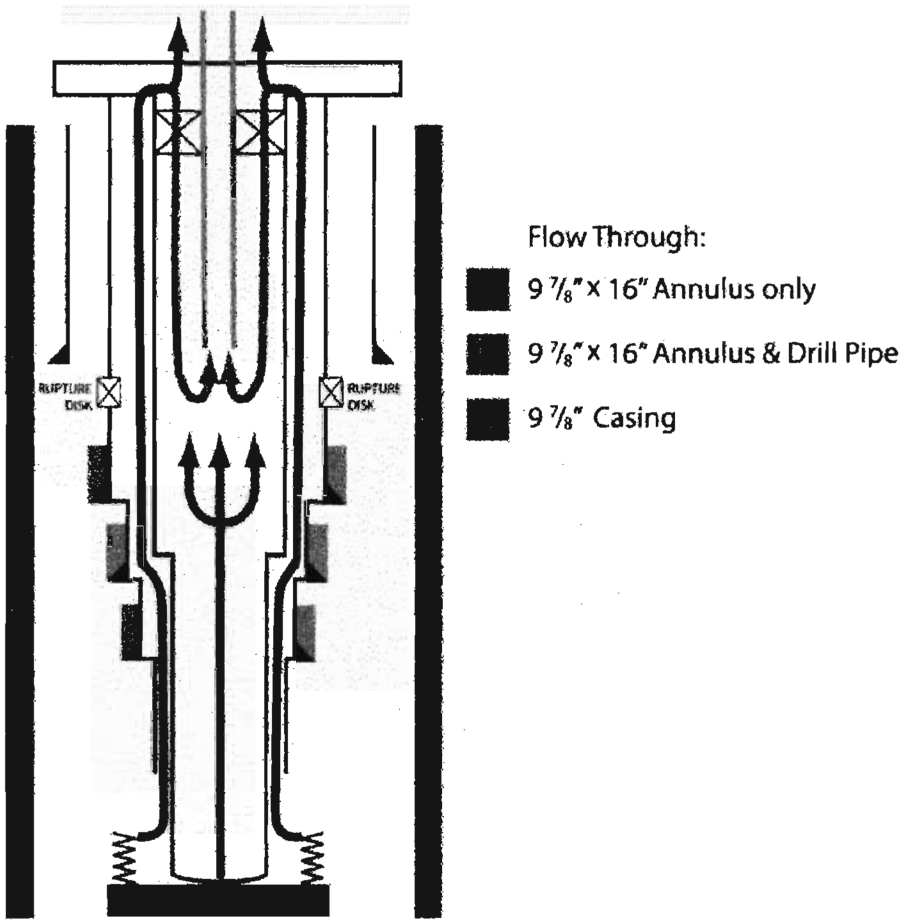


Figure 2. Potential well bore flow paths

Data does not indicate which of these conditions has occurred (but judgment is that the most likely flow-path is behind the production casing. Note that, in this case, the flow path exposes the 16" casing, seal assembly and rupture discs to flowing and shut-in pressure.

Preliminary fluids analysis has been developed. Initial lab test results indicate unusual phase behaviour of the reservoir fluid, but this has only limited effect on modelling. The agreed interpretation of this fluid behaviour is that it has a bubble point of ca. 6,500 psi and Gas Oil Ratio (GOR) of ca. 3,000 scf/bbl. Asphaltene deposition is considered likely but, further testing is ongoing.

The reservoir pressure has been measured as ~12,000 psi when the well was logged. Wellhead shut in pressure at the mud line has been calculated to 8,900 psi.

Inflow performance modelling considered combinations from two lengths of open reservoir section, a range of total skin from 0 to 50, possible flow paths up the well and 3 conditions for choking. The choking conditions considered were open pipe, equivalent 1/2" and equivalent 1/4" diameter orifices at the wellhead. Actual choke locations at, or downstream, of the wellhead could include the following:

- Rams and/or pipe in the BOP stack
- Kink in the riser and collapsed first riser joint, as well as, any pipe and debris within it
- Hydraulic pressure loss through to discharge
- Other unknown obstructions in the riser.

This modelling indicates a wide range of potential flow-rates. Flow behind casing (currently considered most likely) yields a feasible range of 2,000-47,000 stbpd, with a worst case of 52,000 stbpd.

Unconstrained flow (no restriction through reservoir, well bore or downstream of well head) through the inside of the production casing string shows a theoretical value exceeding 60,000 stbpd.

At present it is not possible to measure the hydrocarbon flow-rate as it leaves the system. The consequences of reducing or eliminating chokes can therefore be expressed in terms of a proportional rather than absolute change in flow-rate. For a given wellhead pressure this proportional change shows only slight variation, regardless of the assumptions used, for inflow performance modelling.

Ratio increase of flow-rate (as function of pressure drop to 2,300 psi):

Table 1. Flow through Annulus / Casing (0-50 skin)

Measured Pressure at location	2,300 psi	3,000 psi	4,000 psi
Proportional change multipliers	1	1.09-1.13	1.24-1.35

Reducing the unknown wellhead pressure to ambient (ca. 2,250 psi) would increase the flow-rate by ~10% for an assumed wellhead pressure of 3,000 psi, and by ~30% for an assumed wellhead pressure of 4,000 psi.

Pressure measurements taken below the middle variable bore rams, on 08May2010, indicate a flowing pressure at that point of 3,700-4,000 psi.

Implications

If the flowing pressure is known at a given location the proportional increase in flow rate of removing downstream pressure restrictions can be predicted. This knowledge would also provide insights for managing the pressure/flow related risks associated with remedial actions.

Issues for resolution
Measurement of flowing pressures at key locations through the system reduces the uncertainty in the effect of remedial actions on future potential flow-rates:

- Pressure in the flow-path through the wellhead will result in a definitive value to the proportional increase in current flow-rate that would result from remedial actions.
- Pressure above the BOP to reduce system uncertainty if there is significant flow restriction through the BOP.

In conjunction with these pressures, measurement of flow-rates through the subsea collection and processing systems reduces the uncertainty in the increase in flow-rate during remedial actions.

Blow out Preventers
Upper and lower annular preventers are designed to seal against any pipe size. Closure pressure needs to be maintained for them to remain effective. If seal is obtained the flow-path is through pipe only. Annulars will also close on open hole but with limited pressure containment capacity.

Blind shear rams are designed to sever the body of drill-pipe and seal around the pipe immediately above the severance. If performing correctly, no flow path will exist when activated. Rams will not cut through drill-pipe tool joints and probably not casing larger than ca. 7" diameter. In such situations there are flow-paths through pipe and annulus. To shear the 6 5/8 ram requires at least 4,000 psi pressure to be maintained throughout the shear. Under flowing conditions this may be difficult to achieve.

Casing shear rams (super shears) are designed to sever the body of any pipe but have no sealing elements. Although flow may be stopped through the pipe during cutting, a flow-path through annulus and possibly pipe remains. This flow area is only reduced to 40 sq. in which will have insignificant effect on the flow. They will not cut through drill-pipe tool joints
Insert Cameron diagram.

Variable bore rams (VBR) (upper and middle pipe rams) are designed to seal against the outside of pipe up to a specified diameter (in this case 3 1/2" to 6 5/8"). If seal is obtained the flow path is only through pipe. For an open hole, or pipe outside VBR specifications, the flow will be restricted through the annulus and not the pipe body. Test rams are configured for testing the BOP only.

The experience of well flow control and BOP experts is that the annular elements are very unlikely to have any sealing capability after a prolonged duration at high rate hydrocarbon flow.

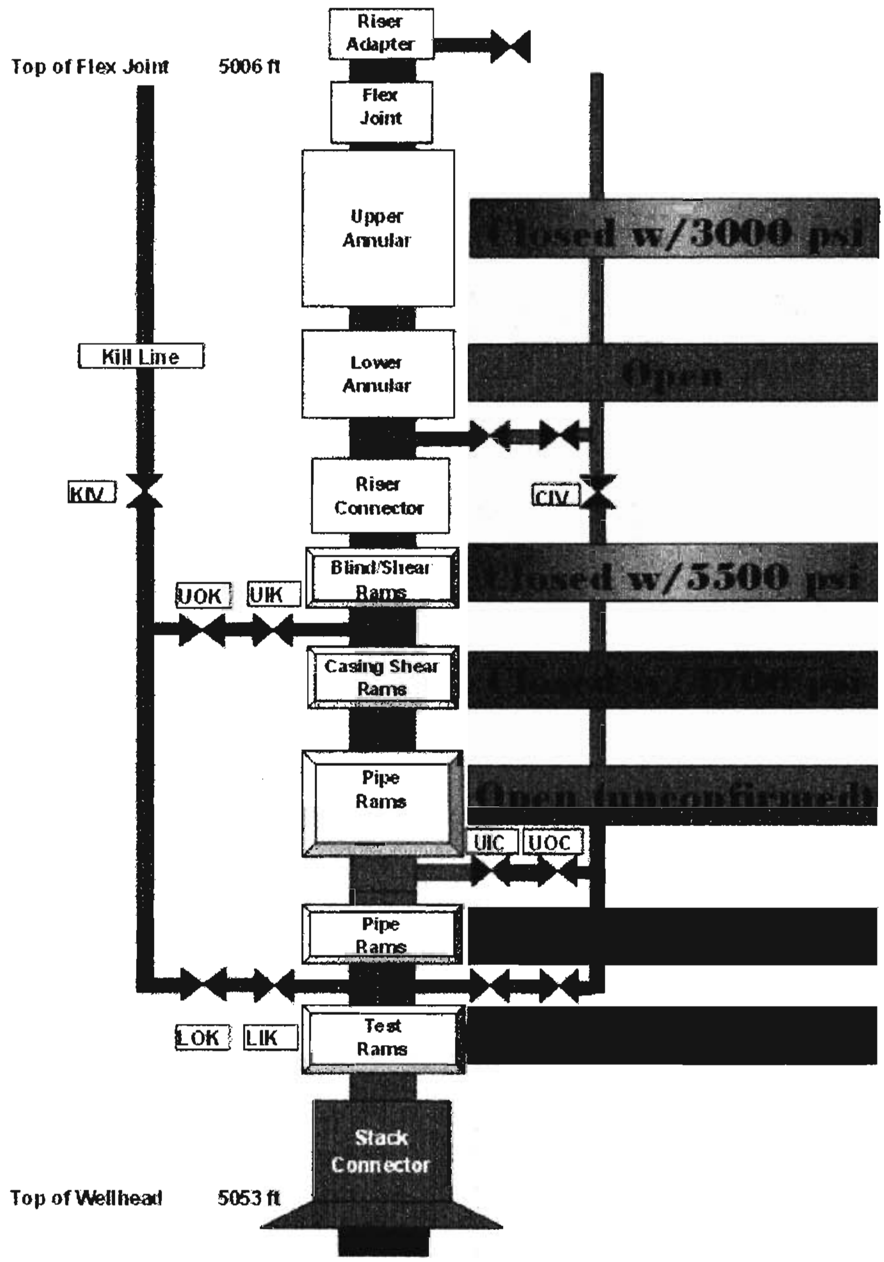


Figure 3. BOP Status

The BP response team has functioned, by ROV, all BOP annulars and rams (except for upper pipe rams and lower annular) without significant flow reduction. However, the annulars and rams had been exposed to well-flow for several days before ROV access.

Rams have either been unable to close and seal or the sealing elements have been washed out.

- It is not plausible that the annulars remain sealed .
- Blind shear rams are not sealing and it is not known whether they are closed and passing or have been prevented from full closure.
- Indications are that casing shear rams closed across the full bore although this is not certain. One of the leaks at the riser kink was interrupted during ram function.
- Upper pipe rams status is not known as they have not been functioned since the incident.
- Middle pipe rams have been functioned and could be sealing on drill pipe, as they took no additional volume to pressure up when activated by the ROV.
- Test rams have been closed but, are not designed to seal from below.

Casing integrity modelling indicates that the 9 7/8" casing would not fail due to pressure alone and that the casing is therefore unlikely to be through the BOP and riser kink. However, the scenario of casing through the BOP and/or kink is still being considered possible as this could explain ineffective BOP function.

As it is not known whether there is casing, drill-pipe, both or neither across the BOP; potential flow paths have been identified for all combinations of BOP and pipe. Only flow restrictions of less than ca. 3" equivalent diameter have any material effect on flow.

The identified flow path scenarios are as follows:

- VBRs have sealed around the drill-pipe and the blind shears rams have not sealed providing a fluid path through the drill-pipe to failure location downstream.
- The casing shear rams have severed the pipe(s) and the blind shear rams have not sealed, thus allowing pressure communication between the annulus and pipe(s) immediately above the casing shears.
- No pipe across the BOP and the blind shear rams have not sealed.

Diagrams

The pressure measurements identified in the Wellbore "Issues for Resolution" would also be used in the analysis of the above scenarios.

Implications

Restriction to flow through BOP is unknown and could be established from the recommended pressure measurements. Understanding these pressures is crucial for planning of remedial actions.

Issues for resolution:

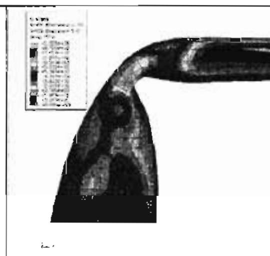
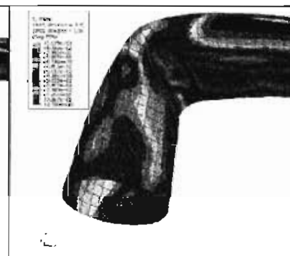
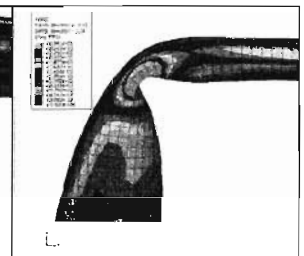
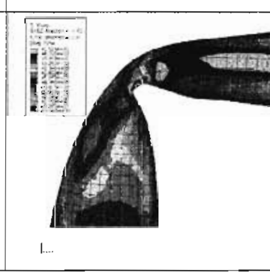
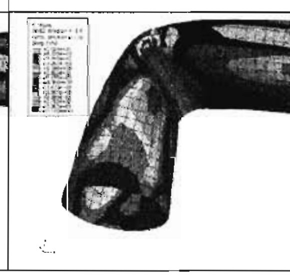
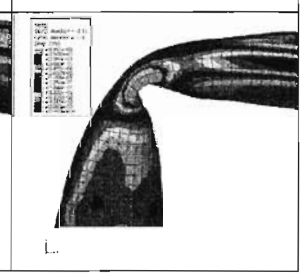
- Position of blind and casing shear rams, to infer their effectiveness in cutting pipe through use of gamma ray attenuation and ultra sonic techniques on ram cylinders.

- Flow path areas for the verified ram positions and assumed pipe positions.
- Pressure in annulus at top of BOP allows for understanding of the ram and annulus impact on system flow.
- Determine presence of pipe inside the riser kink through use of gamma ray attenuation.

Riser Kink

The riser is kinked above the Lower Marine Riser Package (LMRP) at an angle of ca. 80 degrees (Picture 1) and has two leaks at the kink just downstream of maximum bend.

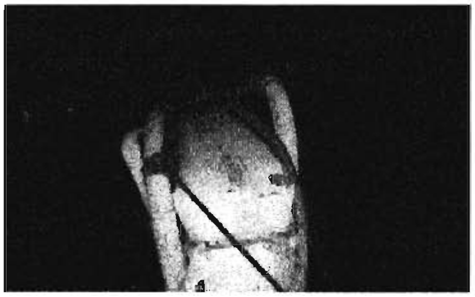
The kink in the riser is a weak point that modelling shows is robust to back pressures of up to ca. 3500 psi (Picture 2). The diagrams below show that re-circularisation would start to occur by the time the pressure reaches 4000 psi on the downstream side of the kink. This is predicted to cause failure at the kink unless it is reinforced.

3000psi internal			
4000psi internal			

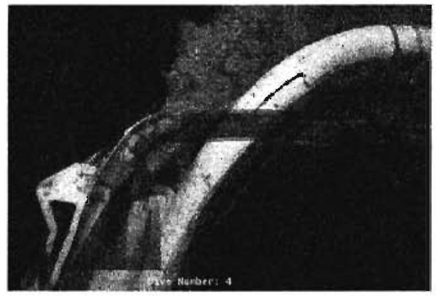
Variations in characteristics of flow through the leaks have been observed. Flow out of one leak was interrupted during operation of the casing shear rams implying two flow paths through the kink at the time the casing shears were activated. It is not known whether the two flow paths remain. As there was drill-pipe through this location at the time of the incident, it is likely that drill-pipe is now trapped in the kink. This provides a second flow path in addition to the riser pipe annulus.

Finite element modelling of the kink indicates the flow path area should not be small enough to restrict the flow through either drill-pipe or annulus.

The formation process of holes at the kink is still under investigation. Current pressure drop across the kink and the modelled flow-path area appear to be incompatible with the erosion necessary to cause holes at the kink. There was no significant change in the leak when the riser elevation reduced substantially, dropping the back-pressure by 150 psi. This indicates that the pressure driving the leaks is substantially greater than 150 psi.



Picture 1. Kink at Riser before leak



Picture 2. Kink at Riser with leak

<u>Implications:</u>
Pressure integrity may be lost at the kink during some remedial actions whether upstream or downstream.

The design criterion for remedial actions is that pressure immediately downstream of the kink must not exceed 3500 psi.

The effect of remedial actions on the back pressure in the collapsed pipe needs to be assessed.

Flow modelling shows that it is not plausible for the leaks at the kink to have resulted from linear flow with or without drill-pipe inside. A dilemma here is finding a plausible way to have a pipe within the riser that has caused a jetting action (requiring differential pressure) and yet to have sheared pipe within the BOP.

Flow modelling has not been able to replicate a scenario that produces the leaks at their pint of origin. Some possible explanations of this are as follows:

- Flow was through drill pipe that was cracked at kink and jetted holes in riser. Drill pipe has been subsequently cut by shear ram. This would require that the VBRs are sealing.
- There is a greater restriction at the kink than modelled.
- There are two separate flow paths through the kink – considered unlikely due to shear rams being functioned.
- The modelling is wrong.

The big issue here is whether there is more than one flow path through the kink (i.e. is the pipe inside the kink at a higher pressure than the riser?) The riser pressure can be measured through the mud boost line. This has major implications in understanding the choke location(s).

Issues for resolution:

- Specific modelling of pressure integrity at the kink is required for each remedial action.
- Gamma attenuation measurements through the riser kink required to establish the presence of pipe and flow-path dimensions.

Riser

During the Deepwater Horizon incident, the riser parted underneath the vessel. Although partially fitted with buoyancy modules the riser dropped towards the seabed. The kink at the top of BOP was formed, and the first joint collapsed. The configuration of the riser downstream of the kink at that time included some buried sections, some suspended sections, with a vertical loop up to 1,500 feet above seabed and then a buried section to the plume. Over a subsequent period the vertical loop has slowly fallen to the seabed and is lying close to the seabed and over the sunken rig.

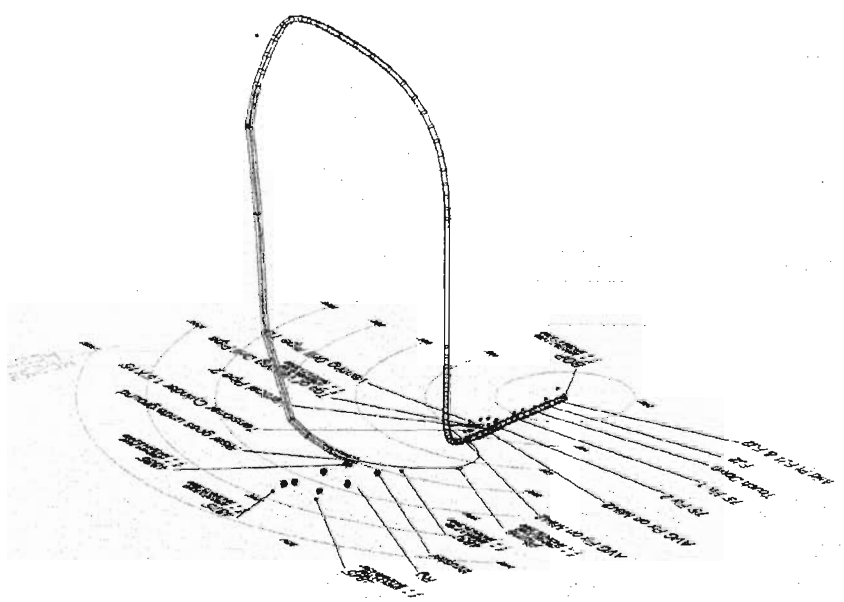


Figure 4. Isometric View of Riser Survey

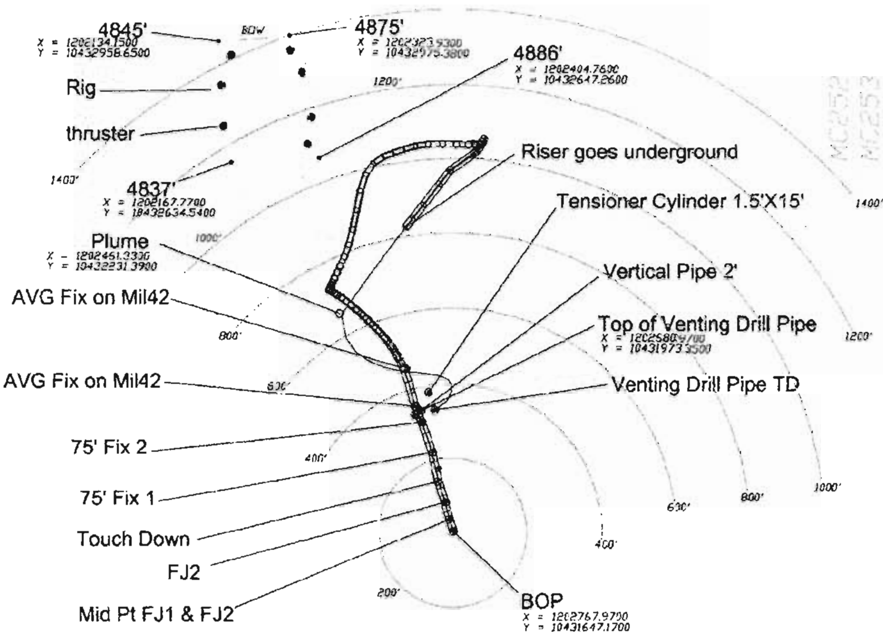
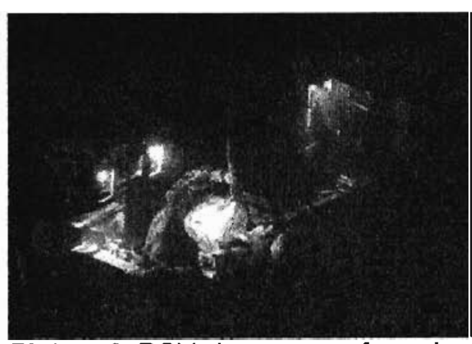


Figure 5. Plan View of Riser Survey

Oil and associated gas is being discharged out of the open end after flowing through ca. 4400 feet of riser. The open end is ca. 680 feet from the wellhead.

Drill-pipe protruding from the open end of the riser was passing a low flow-rate of hydrocarbons. This has been capped, and is reading zero pressure, indicating that there is no continuous flow path back to the well bore. The location of this discontinuity in the drill-pipe flow path is not known.

Picture 5. Leak at drill-pipe before capping leak



Picture 6. ROVs in process of capping leak at drill-pipe

Structural modelling of the riser shows it remains sound downstream of the first joint.

At seabed conditions ca. 40% of the total volume of fluids leaving the riser is gas. In the riser pipe, when near horizontal, the oil moves slowly and fills 60-90% of the pipe area; gas moves more quickly at the top of the pipe.
The gas can occasionally form large bubbles which cause variations in the appearance of the plume – the whiteness is caused as the gas combines with seawater and forms hydrates.

At the kink the jets tend to be higher velocity, mixing well with seawater and rapidly forming hydrates – sometimes a 'snow' effect can be seen – centre jet velocity, and colour, does change – this is still being analysed.

Hydrates can only form inside the riser pipe if formation water is being produced – this is felt to be unlikely. At the open end of the riser pipe, there is likely to be some seawater ingress by back flow under the oil and gas stream. There may be some hydrate formation at this location but, the flowing streams show no indications of restriction.

In order to monitor changes in the behaviour of the flow either at the kink or the open end of the riser, it is important that stills and video are taken consistently (i.e. location, perspective and equipment). This is because the appearance of the plume changes as a function of ROV location, extent of zoom, camera, lighting, direction of thrusters.

Hydraulic modelling for drill-pipe and riser flow paths shows up to 200 psi pressure loss from kink to end for the original downed riser pipe configuration.

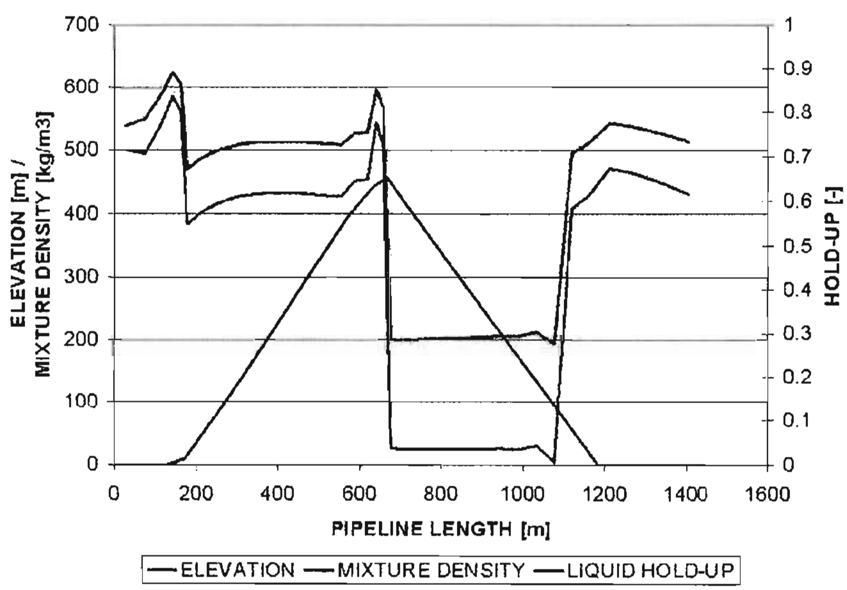


Figure 6. TITLE

Now that the riser lies close to the seabed for its entire length, the majority of this back pressure has been released. It is noted that this reduction in back pressure (~150 psi) did not change the appearance of the leaks at the kink. This implies that the pressure above ambient, upstream of the kink driving the leaks, is significantly greater than the estimated 150 psi reduction.

<u>Implications:</u>
Cutting the riser during the course of remedial actions carry risks, as pressures in the riser and drill-pipe at any cross section are not certain.

<u>Issues for resolution:</u>

- Continue to monitor for riser movement. If further movement occurs, confirm through modelling that the riser will remain structurally sound.
- Location of drill-pipe to a) infer where drill-pipe has parted, b) determine where clamp could best be placed.

Conclusions

- Without measurement of current flow rate it is not possible to estimate the absolute increase in flow that would arise from removal of constraints but the relative increase in flowrate is shown to be of the order of 30% for cases modelled.

- If there is flow via the casing annulus, the 16" casing and rupture discs are exposed to potential transient pressures that must be considered when planning shut-in and well kill interventions.

- Current flow-rate from the well remains unknown - pressure data enables understanding of proportional change with release of choking mechanisms downstream of these measurements and potential impacts to system of interventions.

- Wellbore flow-path could be through annulus or casing - if casing is found to be in the BOP annular flow must have occurred to fail the casing.

- Pressure drop across the BOP will enable determination of ram/annular sealing around drill-pipe.

- Rupture discs/16" casing shoe is a weakness that could compromise well integrity in the case of high pressure annular flow. Current integrity is not known.

- BOP pressure reading indicates that well is choked upstream of the BOP or flowing into 16" annulus via burst rupture disc

- The kink in the riser is a weak point that modelling shows is robust to back pressures of up to ca. 3500 psi.

Remedial Action Design Criteria

- The design criterion for remedial actions is that pressure immediately downstream of the kink must not exceed 3500psi.