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DRILL THROUGH EQUIPMENT CONSIDERATIONS FOR DEEPWATER DRILLING

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ABSTRACT

Expanding the drilling envelope into ever-deeper water brings with it numerous technical challenges, both equipment related and operational. While the best of planning minimizes problems, some inevitably arise that no one had previously considered. With improved transfer of knowledge, problems will be avoided, resulting in improved reliability and safer operation.

The knowledge about the effects of deeper water operation on DTE (Drill Through Equipment) is growing daily. This paper reviews some of the more interesting, but less obvious, issues in this area, as well as their solutions.

The material is covered in a case study format. Knowing the right questions to ask about the critical safety equipment you will depend on may well be the margin you need to control your well.

INTRODUCTION

The IADC defines deepwater in their "Deepwater Well Control Guidelines", First Edition issued in October 1998 as greater than 3000 feet. They then define ultra-deepwater as depths above 6500 feet. Rigs are now being built with eventual capability to drill in 12,000 feet. Topics in this paper will tend to have application at the depths over 5000 feet, particularly in light of the relatively limited number of wells drilled beyond this depth.

The obvious deepwater concern of all is the effect of the environment in which the DTE will operate - higher hydrostatic pressure and lower temperatures. The parallel concern is what is required to transport the BOP to these greater depths. This affects riser, tensioners, and so forth. And finally, with such high financial implications of having to pull the stack or the LMRP, what should be done to minimize the prospect of failures that would initiate such an event.

DISCUSSION

"Environmental" Issues

In the context of this paper, the term environmental issues will be limited to those that relate to the environment in which the DTE will operate while in service, not "green" issues concerning spills and the like.

Depth and Pressure. The relationship between depth and hydrostatic pressure is a classic and well-understood one for the drilling professional. At the same time, all the angles relating the application of this principle to DTE need to be thoroughly considered. As problems occur during deepwater drilling, we are learning the extent of either having not covered all the angles, or having not adequately done so.

External Pressure

Effect on Operating Requirements

Let us consider the concept of pressure containment for BOPs as it relates to testing at depth. Normal testing of the BOP when first landed on the wellhead is done with rated pressure, e.g. 15,000 psi at the surface with a column of drill water exerting additional pressure on the ram body. However, the hydrostatic pressure on the outside of the ram is essentially the same as that on the inside. Since pressure vessel calculations are only concerned with the differential pressure between the two sides of the vessel, no additional pressures or forces need to be considered, right? Maybe not. The normal periodic testing mandated by the MMS (Minerals Management Service) in the GOM (Gulf of Mexico) is 14 days. Test pressure is then applied through the choke and kill lines. Some contractors ensure the lines are free of mud; others test with mud in the lines. When testing with mud in the lines, it should be recognized that differential pressure at depth will be higher than rated pressure of the ram, if corrections are not made. Is this significant? Consider the following sample hydrostatic head calculations:

Fluid densities:
Control fluid: 0.445 psi/ft
Mud: 14 ppg
= 14 ppg × 0.0519 psi/ft/ppg = 0.728 psi/ft
Hydrostatic pressure at 7,500 ft. water depth
Control fluid:
0.445 psi/ft × 7,500 ft = 3,338 psi
Mud
0.728 psi/ft × 7,500 ft = 5,460 psi

Pressure differential:
5,460 psi - 3,338 psi = 2,122 psi

Conclusion: For testing with choke and kill lines full of 14 ppg mud at 7,500 feet of water, differential pressure on the ram body will be 2,122 psi higher than surface pressure. If not compensated for, this 14% overpressure reduces the design safety factor. Testing equipment above its MAWP (Maximum Allowable Working Pressure) has liability implications.

Pressure Lock of LMRP Connector

A failure of a LMRP connector to disconnect due to pressure lock has been documented. Upon running the stack to depth, the LMRP connector wouldn't disconnect, yet full stroke of the indicator rod was observed. When the stack was retrieved, this connector unlatched and disconnected without incident. The cause was subsequently attributed to a metal to metal seal affected between the mating surfaces of the mandrel and the connector, see Figure 1. This seal, combined with the seal on the wellbore side due to the gasket, trapped the pressure (atmospheric) of the environment when the connector was latched. Because of these seals and trapped atmospheric pressure, the connector hub could not be separated from the mandrel, even with maximum tensioner overpull. The solution was to modify the connector hub by machining or grinding a groove to prevent the metal to metal seal on the outside surface so pressure in this cavity can be equalized.

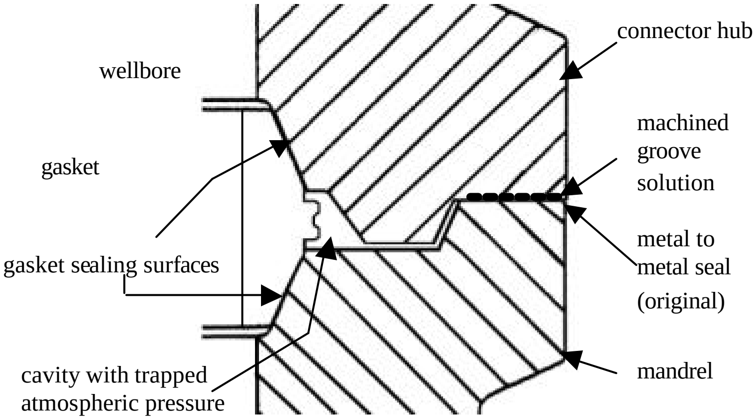

Figure 1 – Detail of LMRP connector showing cause of pressure lock and engineered solution

Internal Pressure. Perhaps a greater concern that has not been widely discussed is the situation where hydrostatic head on the outside of the ram is higher than in the wellbore. How might this happen?

Case 1:
Drilling mud has been replaced with production fluids
Significant foaming of the production fluids has occurred

Case 2:
Massive lost circulation, of the type seen in Southeast Asia, or mud cap drilling where we are potentially drilling into limestone caverns.

Case 3:
Drilling top hole with low mud weight
Gas influx (not recognized)
Wellbore fluids allowed into the riser
Rapid expansion and resulting mud loss from riser

Obviously, pressure vessels anticipate higher internal than external pressure, and are designed accordingly. In the case of BOPs, the design must take into account both the body and sealing areas. Designers realize that seals designed to hold from one direction must be evaluated and tested to determine their capabilities from another direction. Until operating in "deep" water, conditions were such that BOP seals adequately functioned with hydrostatic pressure higher than wellbore pressure. However, recent deepwater operation has resulted in high enough hydrostatic pressure to cause two documented cases of BOP seal failures from this mechanism:

1. Bonnet seal failures from the OD, and
2. Ram shaft packing retainer failure from the weep hole.

Consider these failures illustrated by Figures 2-4.

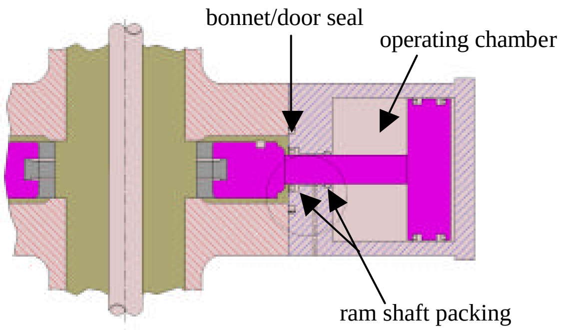

Figure 2 - overall configuration of ram showing operating chambers, bonnet/door seals, and ram shaft packing. Close-ups of the circled area are shown in Figures 3 and 4.

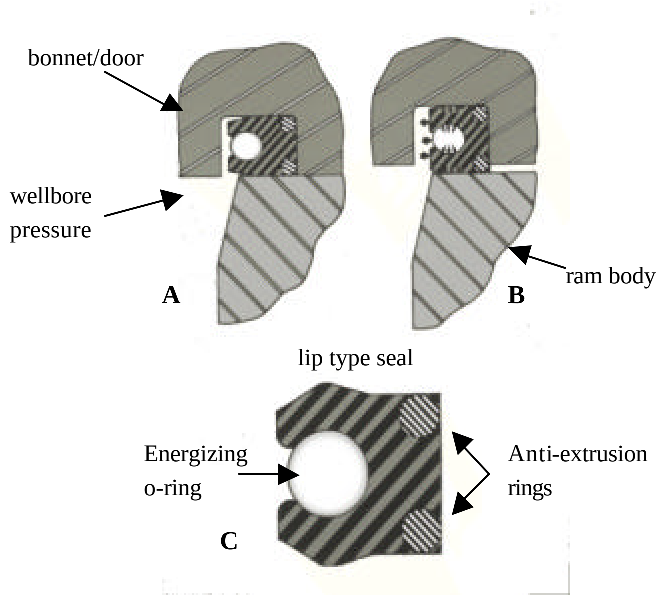

Figure 3 - bonnet/door seal and gasket details

Figure 2 shows an overall cross section with the ram body, operating chamber, and the seals of interest. Figure 3 shows a close-up of the bonnet/door seal configuration in various situations. Note that these details are rotated 90° from Figure 2. These seal details were provided by a ram manufacturer. Detail A shows the installed gasket with no applied wellbore pressures, detail B energized with wellbore pressure, and detail C a cross section of the gasket in the shelf position. For wellbore testing at high pressures, the lip seal is energized by the wellbore pressure to form the seal. To achieve a leak free low pressure test, an energizing o-ring can be used to expand the gasket against the bonnet/door and the ram body, assisting the rubber compression (detail B). The steel anti-extrusion rings prevent rubber extrusion.

However, when hydrostatic pressure on the outside of the ram is higher than wellbore pressure, this external pressure is transmitted to the back side of the gasket. Not having been designed to withstand force in this direction, it is easy to understand why a leak occurs. Without any support in the wellbore direction, the gasket is subject to deflecting inward, allowing a leak. This deflection has been seen to cause permanent gasket deformation, necessitating pulling the stack due to loss of wellbore integrity.

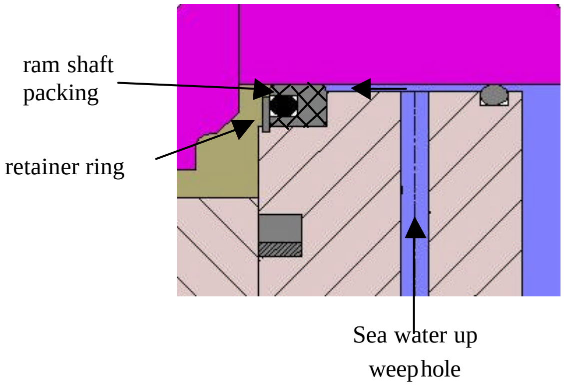

Figure 4 - Ram shaft packing detail

Figure 4 details the ram shaft packing configuration. The discussion of this packing failure is parallel to that discussed in the paragraphs above.

The industry standard for BOP design, API Specification 16A, does not require any external pressure testing in the design verification, section 4.7. Certain manufacturers of specific BOP equipment have recognized the known failures mentioned above. It is not unreasonable to expect other difficulties with the other makes and models of this equipment. Downtime can be avoided from this cause only to the extent that this potential failure mode is discussed and manufacturers test their equipment to ensure fitness for purpose.

Other potential failures from higher external than internal pressures are collapse of riser or flexible choke and kill lines. Additionally, although annulars seal failures have not been documented as with the ram seal failures described above, the potential exists. Ring joint gaskets should also be evaluated from this perspective. The commentary on pressure vessel design applies in all these situations.

API RP16Q, Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems covers collapse by stating the main riser tube design and flexible choke and kill lines should be designed with collapse in mind (Sections 2.7.3.1.a and 2.10.3.d respectively). For riser main tubes, this results in thicker walled main tubes for riser destined for deeper water service.

Another precaution to avoid riser collapse is the installation of a riser fillup valve. This valve is a sliding sleeve and is activated by differential pressure between inside and outside the riser.

Proponents of these valves feel additional security from knowing they have provided for automatically filling the riser with sea water rather than having the riser collapse. Others feel like the risk of failure is not substantial enough to install this equipment, and that the time lost due to maintenance and/or failures override the prospective benefits. Expected failure modes include seal failure with loss of riser pressure integrity, costing a day of downtime to pull riser and LMRP, not to mention the cost of lost mud. Some have experienced such a low reliability, at least with earlier models, that they concluded an additional sense of security would only be false. Based on the testing and maintenance, or lack thereof, historically performed on these valves, one might not be surprised about reports of low reliability. On the other hand, with improvements in these areas, reliability can only be expected to increase. With all this in mind, it is interesting to note that some recently built deepwater rigs have installed riser fillup valves.

If the flexible kill line were to collapse as a result of a significant displacement of the mud with a kick, control problems would be exacerbated. In the case of either collapse situation, without testing, the risk of failure remains unknown, and subsequently a concern.

Operational. As water depth increases, the effects of hydrostatic pressure on ram BOPs become more pronounced. As noted above, since both wellbore (mud) and control fluid have different densities, the differential pressure between the two systems increases with depth. The net effect of the forces generated by this differential pressure is an opening force on the BOP. When one also adds wellbore pressure to the picture, opening forces are increased even further. Increased closing control system pressure is required to overcome these opening forces.

To calculate the increased closing control pressure required, consider Figure 5. This schematic shows the forces developed by each component of the system. Note that the figure shows only the operating piston and ram shaft - to see this component in the context of the full ram cross section, reference Figure 2.

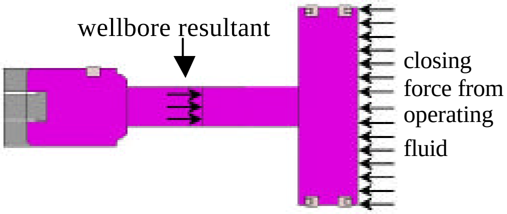

Figure 5 - Forces on ram operating piston and block

A sample calculation of the effect of just hydrostatic pressure on closing force required is as follows:

Equipment: 18 ¾" 15K Generic Ram BOP
Operators:
Operator close piston area: 250 in^2
Ram shaft diameter: 35 in^2

Hydrostatic Calculations:
See above, conclusion of Pressure differential:
5,460 psi - 3,338 psi = 2,122 psi

Opening force against the ram shaft at 2,122 psi:
$2{,}122 \text{ psi} \times 35 \text{ in}^2 = 74{,}270 \text{ lb}_f$

Operating pressure increase required to overcome opening force:
$74{,}270 \text{ lb}_f \div 250 \text{ in}^2 = 297 \text{ psi}$

In this specific example, in order to exert the same force on the shear blades at 7,500 feet subsea as on the surface, control system operating pressure must be 300 psi higher. In the context of 3000 psi hydraulic operating systems, this may not seem a significant factor. On the other hand, it is a factor to be taken into account in conjunction with the thoughts on shearing pressures required based on ram design and drill pipe metallurgy noted in "Deepwater Drilling Risk Analyses Considering Drill Through Equipment Reliability" presented at this conference by Raleigh Williamson.

Finally, an extremely brief mention of the pressure effects on stack valves is appropriate. There are distinct possibilities that the valves you expect to fail in the closed position may or may not have the ability to do that in a well control situation where closing pressure is not available. Additional details can be found in another paper presented at the Offshore Technology Conference last year.

Depth and Temperature. Deeper water environments include colder water. Temperature difficulties may be experienced in two areas, the capability of ram and annular elastomers to seal and dealing with hydrates.

Elastomer Sealing. The fact that special elastomers need to be used for temperatures above 200°F has become more commonly known with the drilling of HTHP (High Temperature, High Pressure) wells. One of the next facts quickly realized as a result of HTHP drilling in the North Sea was that achieving a successful pressure test with these elastomers was more difficult when cold. The rubber experiences a glass transition stage at which it does not flow. Of course, this same principle applies to standard rubber goods, albeit at a lower temperature. Accordingly, you can expect operating temperature ranges of 0°F minimum to 200°F maximum for standard ram elastomers compared to 50°F minimum to 350°F maximum for HTHP goods.

However, this problem is normally not an operating safety issue. In the North Sea, surface tests were accomplished by internally heating the BOP prior to testing. In normal operation, you would expect the mud to be the primary influence on elastomer operating temperature. Thus, with the advent of a well control event, temperatures of the rubber goods only slightly cooler than ambient would be expected.

Hydrates. Hydrates are a different problem. Hydrates occur external to the wellbore because of the shallow gas trapped in the seabed in the deepwater environment of higher pressure and lower temperature. Hydrate formation curves are available that plot temperature versus pressure (or water depth), for different gas compositions. These should be referenced to see if hydrates are a possible concern for drilling programs in water deeper than 2000 feet.

When the initial hole is drilled and cased, a flow path is created for shallow gas up the outside of the casing, allowing hydrate formation if the environmental conditions are right. The biggest concern about hydrates is their mechanically obstructing the unlocking mechanism of the wellhead connector. Some have said there is nothing worse than having completed drilling the well and being unable to get off the wellhead and leave.

Four different prevention/mitigation techniques exist to avoid this situation:

1. Exclusion seals fitted onto specially machined area on the connector,
2. Glycol injection ports drilled through the connector,

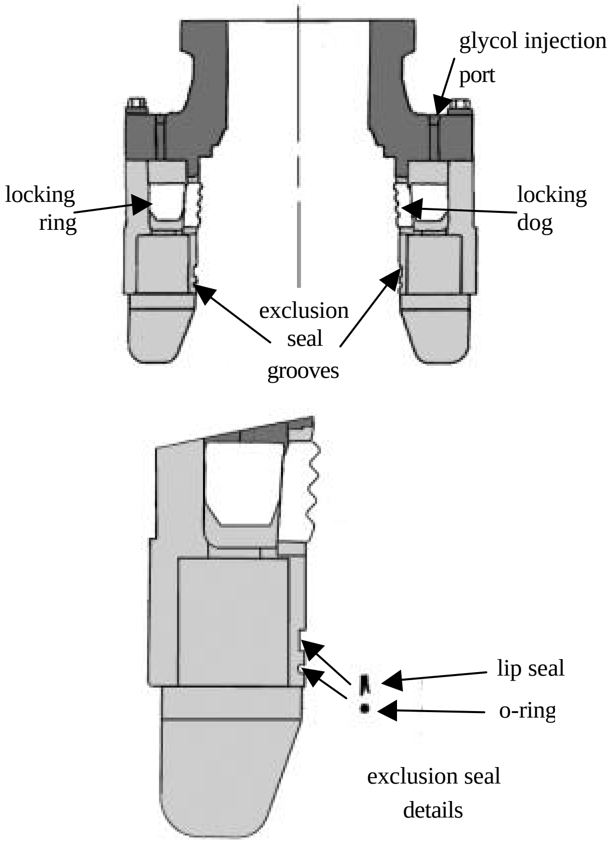

Figure 6 - connector hydrate exclusion ring and glycol injection port schematics

3. Exclusion funnel connected to the 30", and
4. Mud mat.

Although connector modifications have been commercially available from the wellhead connector vendors for some time, they may not be well known because of their specialized application. Once installed, the existence may not be known to the operator. A schematic of one exclusion seal design, as well as a glycol injection port installation can be found as Figure 6.

Exclusion funnels are very effective, but more expensive than the modified connector solutions. The mud mat is also a simple design. In it, the clearance between the mat and the 30" is tight, effectively routing gas bubbles under the mat and released where they cannot end up in the connector locking systems.

Obviously, each of these techniques has strengths and weaknesses. They can be used individually or in combination to reduce risks.

Transportation Issues

Once again, most of the issues associated with transporting the stack to the wellhead installed over a mile below have been adequately addressed. Riser tensioners have been upgraded in load capacity, classes of riser have been added to provide the required mechanical stress, and buoyancy mechanical strength has been increased to withstand the additional hydrostatic head.

One area that different operational philosophies have resulted in different equipment purchases is the debate over the need for a hot line. A hot line provides continuous hydraulic pressure to the pod while running the stack, ensuring full operability during that operation. The major concern is that the LMRP connector stays latched. It provides a measure of safety against leaks or physical damage of the control system piping that might allow backdriving of the LMRP connector. Backdriving has been a topic of other papers, and is defined as the release of preload, which has resulted in unlatching of the connector when latching pressure is vented.

Proponents of the hot line offer that full functionality of the stack is maintained at all times. At the same time, they realize the validity of other's point that, if all the equipment works as designed, it is not necessary. However, because of its simplicity, they feel the measure of redundancy is worth the cost.

Conclusion

As the number of wells drilled in "deep" water increases, the body of knowledge will begin to increase exponentially. To the extent that we distribute that knowledge well as a learning industry, we can quickly move past initial problems, drastically reducing risk, downtime, and regulatory intervention. This is particularly true in the rather specialized area of Drill Through Equipment. However, significant improvements are possible in both the distribution and application of that knowledge when considering historical activity.

References

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