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10 October 2006

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Assess the Acceptability and Safety of Using Equipment, Particularly BOP and Wellhead Components, at Pressures in Excess of Rated Working Pressure

Solicitation # 1435-01-05-AN-39253

Dear Ms. Buffington,

The final report can be found following.

In order to safely operate well control equipment at its MWP, a systems approach is critical. The framework to support this systems approach is a quality system. The quality system will improve the reliability of the systems and consequently reduce safety/environmental incidents or downtime.

We look forward to any comments you might have on the technical issues addressed, as well as insight into any assistance you may require in implementing this performance-based system.

Sincerely,

Michael E. Montgomery

CC: Mike Connor

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Section 1: Executive Summary

Objective: Assess the acceptability and safety of using equipment, particularly BOP and wellhead components, at pressures in excess of rated working pressure.

As a result of the offshore oil and gas industry's ongoing expansion of technology frontiers, ever more challenging conditions are being explored, tested, and will hopefully be produced. The parameter of focus in this research project is the high pressure facet of the technology frontier, specifically, the ability of equipment to successfully and reliably operate at or in excess of the manufacturer's (and industry's) stated MWP (Maximum Working Pressure). To that end, this research focused on two areas:

1. Design, manufacture, and initial use, and
2. Capabilities over time, including remanufacture and modification.

With the exception of testing, it is most unusual and considered a poor practice in the industry to use BOP (BlowOut Preventers) and wellhead components in excess of MWP. Industry standards use defined safety factors that are reasonable and not subject to inadvertent escalation or compounding. Historically, occasions of use (outside of subsea testing) in excess of MWP were almost exclusively limited to accidental or emergency use. MASP (Maximum Allowable Surface Pressure) is a separate area where there are no industry standard safety factors; such should be developed and integrated with equipment safety factors for a single, composite factor.

In most cases, API Specifications and Recommended Practices are acceptable relative to defining MWP. The reliability of well control systems are improved if API standards are followed. Two examples of not using the API are:

1. The pressure containing equipment considered in this study is rarely monogrammed, and
2. A quality system, API or similar, does not exist or is poorly implemented on rigs.

There are a few areas where the API Specification 16A standard could be improved:

1. Sealing characteristics tests and current wellbore testing procedures do not address ram sealing capability at elevated wellbore pressures.
2. Capability of subsea equipment for the application of hydrostatic head on the outside of the BOP being greater than the inside of the BOP is not addressed. Failures have occurred and design modifications affected in a number of cases; these failures are mostly a result of deep water drilling.

In contrast to operating equipment in excess of MWP is the ongoing concern about operating above equipment capability in its current condition. BOP equipment pressure de-rating is common in the industry, particularly when equipment fails to pressure test at its rated working pressure or otherwise not conform to API standards. This research identified factors that may compromise equipment pressure ratings so that the risks of exceeding current capabilities can be assessed.

This study has concentrated on the BOP equipment, however, the systems such as the cement pump and shipboard piping must also be considered. Corrosion of shipboard piping systems and the resulting loss in pressure capabilities are discussed in section 8. Once again, a system approach must be taken when considering upgrading the pressure rating.

A performance-based "checklist" is included as a deliverable of this project and should be used to supplement existing MMS requirements to improve reliability and reduce the risk of exceeding equipment current capability. The framework for this performance based system is an industry standard certified quality system.

Section 2: Introduction

As stated in the contract, this research project has the following objectives and scope.

A. Research Objectives:

1. Review standards currently available for the manufacture of BOP and wellhead equipment relative to rated working pressure and evaluate their adequacy.
2. Review current regulations concerning pressure containment issues listed above.
3. Identify areas for clarification and improvement to existing standards compared to current regulations.
4. Review and discuss known occasions of use of equipment in excess of pressure ratings.
5. Review regulatory and current practices for defining MASP (Maximum Allowable Surface Pressure). Include differences due to water depth.
6. Propose performance-based systems that qualify equipment for working above its MAWP (Maximum Allowable Working Pressure), including limitations and applications. This is provided as an attachment in this section.

B. Equipment Covered By This Research

1. Preventers
    a) Ram type
    b) Annular type
2. Connectors
3. Hubs, clamps, and flanges
4. Flexible hose
    a) Choke and kill hose
5. Valves
    a) Stack mounted
    b) Choke and kill manifold
    c) Fixed and remote chokes
6. Poor Boy Degassers
7. Wellheads

C. Research Project Justification

The MMS is aware of exploration drilling prospects where reservoir conditions are as high as 28,000 psi. As current drilling and production standards frequently seek to utilize large bore drill through equipment, a limitation is encountered as there are no 18¾" BOPs with a working pressure in excess of 15,000 psi. With the current high commodity prices, the industry is exploring possibilities for using or modifying existing equipment to be fit for exploiting these opportunities more quickly. Additionally, to address the nameplate rating limitation and expand industry capabilities, an API work group has been formed to create a recommended practice for equipment rated above 15,000 psi. However, the expansion of this technical envelope will take time.

D. Current Practices of Exceeding the MWP of BOPs

Overview

The ultimate test of equipment capability is its failure. In this way, assumptions, calculations, and safety factors are better understood and modified so as to reduce failures. An early phase of this project was therefore to identify occasions, if any, where BOPs were routinely subjected to pressures in excess of their MWP. The following were established. Other than item #4, no catastrophic failures are reported due to these practices.

1. Wellbore tests, both on the surface and subsea, commonly exceed equipment MWP by a few hundred psi. This is done to minimize time requirements and thus testing cost.
2. Subsea wellbore tests conducted with mud exceed MWP by an amount proportional to mud weight. See section #6, *Exceeding MWP of Equipment*.
3. Choke and kill hose re-certification is conducted by testing to 110% of MWP onboard the rig.
4. When hydrostatic pressure on the BOP exterior is greater than that in the wellbore, the MWP of the equipment is sometimes exceeded. This is because API does not address BOP equipment pressure ratings for this situation.
5. MMS form #124 suggests certain (undefined) situations may be acceptable for equipment use in excess of MWP.

It is important to recognize BOP equipment is concerned about pressure containment of the wellbore in two equally important areas: a) from the environment, and b) below the BOP. These are commonly referred to as shell and closure testing, respectively. While API Specification 16A specifies shell testing above MWP, no such testing of the closure mechanism for rams, annulars, or gate valves have been established. Closure testing similar to that specified on the shell would demonstrate a factor of safety in this critical area.

E. Explanations and Additional Details

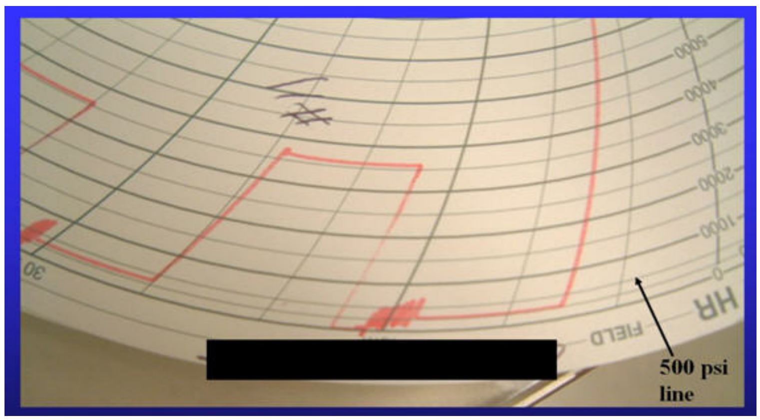
By understanding the details of and justification for the current industry practices where MWP is routinely exceeded, their extrapolation can be subsequently evaluated.

<u>1. Routine Wellbore Tests</u>

To establish capability, wellbore tests are required by operators and regulatory agencies. 30 CFR 250.448(b) states that high pressure tests for well control equipment must equal the rated working pressure of the equipment or be 500 psi greater than calculated maximum anticipated surface pressure (MASP) for the applicable section of hole.

Insofar as some wellbore tests must be conducted on the critical path, testing efficiency provides verification at reduced cost. As a result, initial test pressures are commonly established several hundred psi above MWP, to a maximum of 5%. The goal is fewer iterations to pressure stabilization on the test chart at MWP or marginally more. This practice is commonly used both when the stack is on the deck as well as subsea. It is thought that the cooling of the test fluid, especially for subsea tests, is the main component of this pressure loss. Synthetic-based muds (SBM) appear to be particularly sensitive to temperature and compressibility. Annulars and variable bore rams have the additional factor of greater rubber flow due to the larger volume of elastomeric material of their sealing elements. Finally, the position of the sealing mechanism may take time to equilibrate.

The following chart, typical of that produced by a rig wellbore pressure test, illustrates this testing protocol and pressure loss experienced.



Although not specifically related to exceeding MWP, the pressure spikes or oscillations can be clearly seen in this chart. The test arrangement most commonly uses a positive displacement pump with a chart recorder close by, then a long hose to the BOP function. On some rigs, the recorder has a pulsation dampener. The spikes are caused from both the varying pump flow rates as well as back pressure in the BOP test hose. The test hose is small; this restriction causes a momentary pressure surge on the chart recorder. Although these spikes are acceptable for a low pressure test, the above chart was included as a MMS field inspector said this test did not meet the low pressure test regulatory requirement.

Recommendation:

This industry wide practice is not deemed dangerous or harmful to equipment. Thus, WEST recommends that the MMS should not write INCs for exceeding MWP in this instance. Increasing the wellbore pressure as much as 5% above MWP to achieve a straight line at MWP should be considered an acceptable practice.

Recommendation: BOP test pumping systems that minimize pressure spikes are preferred.

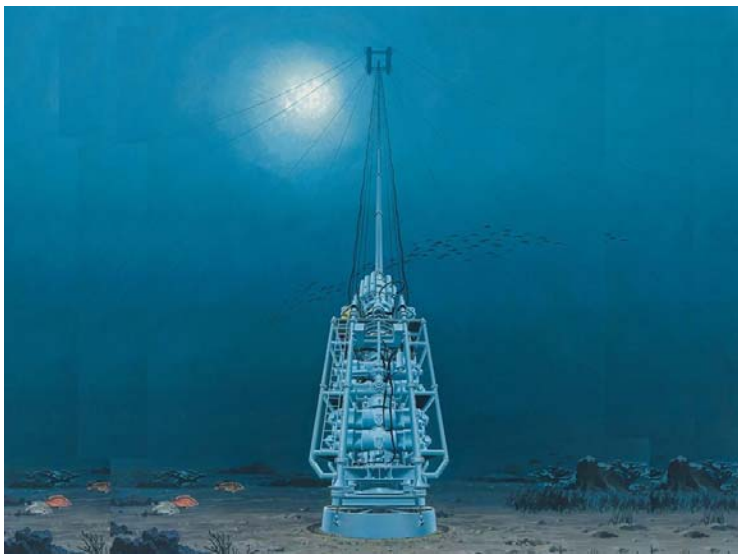
Problems with pressure testing with SBM was researched and reported on in Advanced Analysis Identifies Greater Efficiency for Testing BOPs in Deep Water. The results demonstrate the potential to significantly impact the industry with respect to safety, time, and cost for BOP testing.

Recommendation: Improve the accuracy of testing BOPs in deepwater with SBM. With improved accuracy, the reliability of leak detection will be improved.

2. BOP Test Mud

When wellbore testing subsea, the test mud must be taken into account when determining the pumping pressure introduced from the surface test pumps. For a 15,000 psi stack, considering the hydrostatic head additive pressure for 14 ppg mud in 10,000 feet of water equals 3,115 psi. If tested with 15,000 psi at the test pump, the MWP across the shell is exceeded by approximately 20%.

Note that the same hydrostatic head exists on both sides of the closure mechanism. Accordingly, testing in this manner does not create a differential pressure above MWP across the closure mechanism, only the shell. See section #6 for more explanation.



Recommendation: The weight of the test mud should be considered for subsea pressure tests so as to not exceed the MWP of the shell.

3. Choke and Kill Flexible Hose Test

MMS Regulation 250.446 (a) references API RP #53 section 18.10.3, specifying that choke and kill hoses be internally and externally inspected in accord with the manufacturer's guidelines. To be complete, it should also specify testing in compliance with manufacturer's guidelines. One drilling contractor tests choke and kill hoses to 110% of MWP against a closed gate to satisfy the manufacturer's testing requirement. Although this procedure is not in compliance with the manufacturer's written standards, it is understood that it was negotiated with that manufacturer and is acceptable to them. Normally, choke and kill hoses are removed from the rig for inspection and testing on the beach. Handling hoses, some as long as 85 feet, often damages the hoses. The 110% insitu test has the advantage of establishing a factor of safety without subjecting the hose to potential damage from handling. (See Attachment A)

Reference: Ocean Odyssey disaster where the Barney coupling failed on a Goodall choke and kill hose in the North Sea. This resulted in destruction of the rig and loss of life.

Recommendation: In-situ proof testing choke and kill hoses to 110% of MWP should be considered an acceptable practice.

Recommendation: MMS should add the requirement in 250.446 (a) to conduct testing in accord with manufacturer's recommendations as part of the major survey requirements.

4. Higher External Pressure than Internal Pressure

Another instance of exceeding BOP MWP is when the hydrostatic pressure outside of the BOP stack is greater than the inside. This can occur as a result of a variety of drilling situations, such as foaming completion fluids, gas in the riser or lost circulation. See Section 8 for more information. (See Attachments B and C)

F. Engineering Safety Factors

It is not uncommon for different groups to have varying standards for the application of ESF, Engineering Safety Factors, for their pressure containing equipment, sometimes within the same standard. For example, in API Specification 16A 3rd Edition Specification for Drill Through Equipment, the ESF for pressure containment is 1.5 (based on the shell or proof test pressures), while the ESF for sealing the wellbore above MWP is not stated nor tested.
In addition, preventers are routinely used to contain wellbore pressure in several different operating modes. Several are of particular interest relative to pressure containment, namely hang-off and stripping, both of which negatively impact capabilities. Additionally, other operations and environmental conditions can be detrimental to specified and tested MWP.

With appropriate background information available, performance testing can improve the industry's ability to understand their equipment's capabilities, as well as their limitations. This, coupled with an understanding of the critical variables that might reduce said performance, will improve both the reliability and safety of operations.

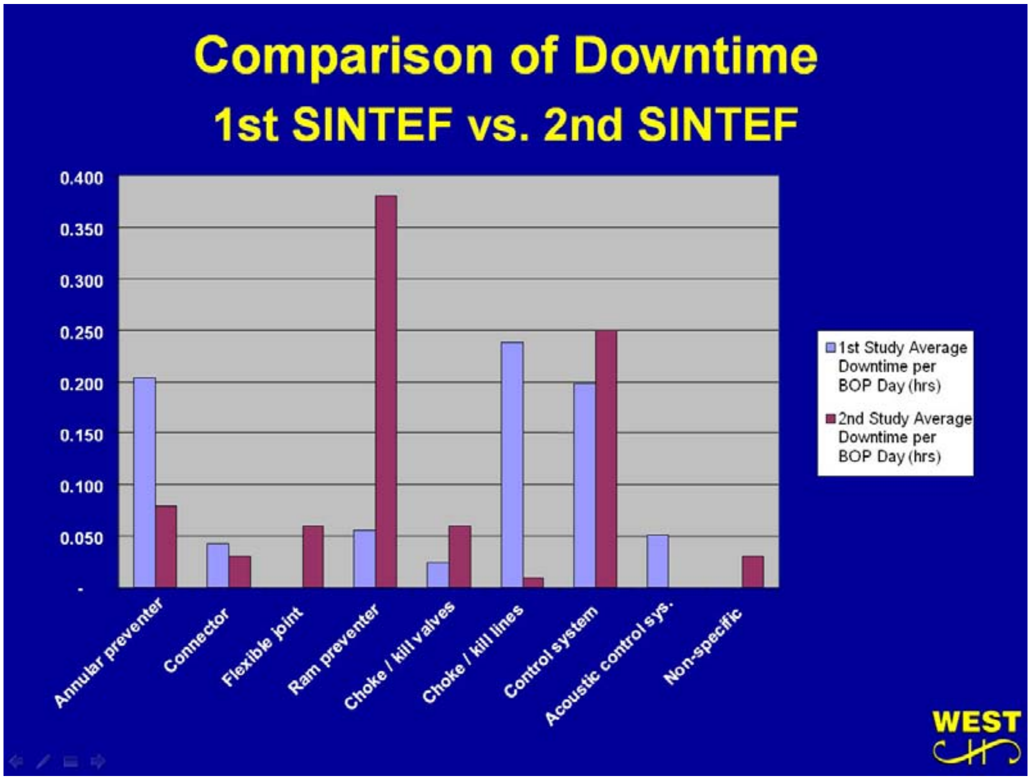
Section 3: A Performance-Based System

A. Overview

In order for equipment to continue to reliably perform to its rated MWP, reliability engineering principles dictate a program of inspection and testing. The highest value program of this sort will be performance based. Implementing such a program will reduce events which lead to loss of containment as well as the cost of the drilling operation by reducing downtime. (See Attachment D)

To provide a historical basis establishing equipment performance, this section reviews studies completed by SINTEF, a Norwegian think tank, as well as the Offshore Operators Committee, OOC, in the GOM.

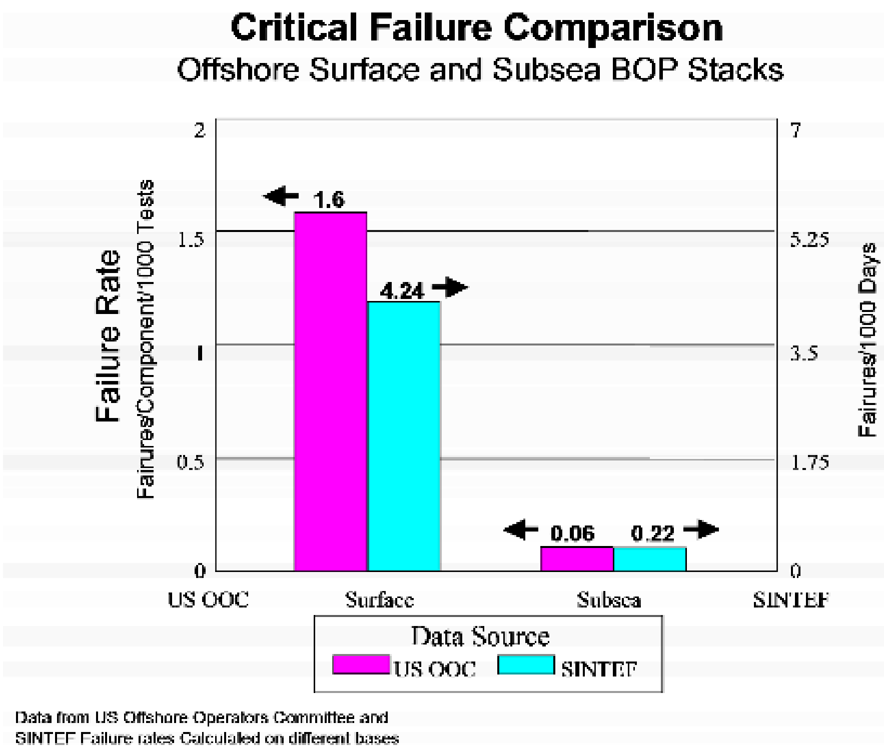
The following graph is based on reliability experienced from subsea deepwater BOPs that were used in the US GOM OCS in 1997 and 1998, identified as the Phase 2 DW (Deep Water) study. A similar report was issued in 1997, referred to as Phase 1 DW, based on BOP reliability experienced from wells drilled in Brazil, Norway, Italy and Albania in the period 1992 – 1996. (See Attachment E)



Rams and control systems are critical when working BOP equipment at or near its MWP. Unfortunately, the performance of rams, the primary well control barrier, significantly decreased from the first to the second SINTEF study. Although not explained in the report, it is believed that a significant contributor to the increase in downtime was ram locking systems. Ram locking systems maintain ram packer pressure during emergency situations. Testing procedures must be developed and practiced to verify these fragile systems are operational, without causing downtime from testing wear.

Downtime from control systems is high in both the first and second studies. This system is relatively complex and the time available for maintenance between wells can be truncated. The high downtime attributed to control systems is caused by not only typically short duration between wells and the competence of the technician testing and maintaining this system, but also to the quality systems in place that support the technician.

As described in an Oil and Gas Journal article, "Testing Improves Surface BOP Equipment Reliability", by Michael Montgomery, (See Attachment F), surface BOP stacks are between 19 and 27 times less reliable than subsea BOP stacks. This reliability data was extracted from studies completed by SINTEF and the OOC in the GOM.



Because of the relative simplicity of a surface stack compared to its subsea counterpart, such drastically lower reliability might at first appear anomalous. As noted in the referenced paper, some possible explanations why the failure rate on a surface BOP stack was found to be far greater were:

1. Dedicated personnel for maintenance of the BOP equipment are not typically found on rigs with surface stacks.

2. Rigs with surface stacks often do not have test stumps and maintenance platforms that allow for inspection, maintenance and testing out of the critical path.

3. The economic impact is less because of lower rig rates.

B. Predictive Testing

Conventional function and pressure testing identifies when a component has failed. The next step in reliability improvement is predictive testing; these tests can be used to predict that a component is about to fail. In one case, predictive testing in the GOM predicted the failure of a ram locking system within eight cycles.

Keys to successful predictive testing are a) developing and carefully executing specific tests, and b) having specific acceptance criteria for each test. Details concerning predictive testing can be found in Paper SPE 74471, "Using Predictive Testing to Circumvent Blowout Preventions Downtime", by Michael Montgomery of WEST Engineering.

The predictive tests defined in SPE paper 74471 are suggested as a tool that will verify the systems on board the rig are effective in maintaining this equipment to an acceptable standard. The primary focus of the paper is rams and locking systems, but annulars, hydraulic connectors and failsafe valves are covered in less detail. The ram and locking system testing can help address the reduction in reliability for these components that was identified in the SINTEF research.

C. Supplementing Industry Standards

If one assumes the industry generally complies with existing industry standards, improvements in reliability will require additional efforts. Additionally, reducing the frequency and severity of catastrophic events will benefit all.

A significant number of accidental riser disconnects have been experienced in deepwater operations during the last five years. Each event had the potential for causing serious well-control issues, especially when drilling a high pressure well. Events of this nature are covered in MMS Safety Alert #231, "Human Engineering Factors Result in Increasing Number of Riser Disconnects". (See Attachment G)

Improved riser inspection methods can prevent dropped stacks and riser parting during well control events. These and other causes are reported in Paper SPE 79837, "Dropped BOP Stacks: Understanding Causes to Improve prevention," by Jeff Sattler of WEST Engineering.

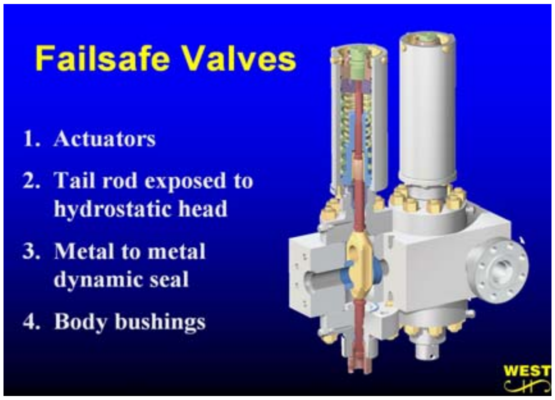
Implementing the recommendations outlined in the prior MMS study "Evaluation of Secondary Intervention Methods in Well Control", MMS Solicitation # 1435-01-01-RP-31174 would reduce risks associated with control systems, one of the categories accounting for a significant amount of downtime in the SINTEF study. The value of a Deadman System was demonstrated by the automated securing of the well being drilled on Thunder Horse when the riser parted.

Additional protocols for improved reliability can be found in "*Inspection and Testing procedures improve BOPs for HPHT Drilling*", Oil and Gas Journal, and *"More BOP Equipment HPHT Considerations"*, presented in 1996, IADC Conference in Aberdeen, both by Michael Montgomery, WEST Engineering Services. (See Attachments H & I)

D. Design and Testing Issues Affecting BOP Reliability

Failsafe Valves

The BOP stack valves are frequently referred to as failsafe valves. However, this is a misnomer insofar as the scenarios under which these valves close without hydraulic assistance (via spring force) are limited. The following shows the major parts of these valves.



It is interesting to note the different requirements for actuators specified by various API standards. Specification 6A, Specifications for Wellhead and Christmas Tree Equipment, section 10.16.3.4 states

> "Actuator output forces shall meet or exceed the operating requirement specified by the valve or choke manufacturer."

Specification 17D, Subsea Wellhead and Christmas Tree Equipment, section states

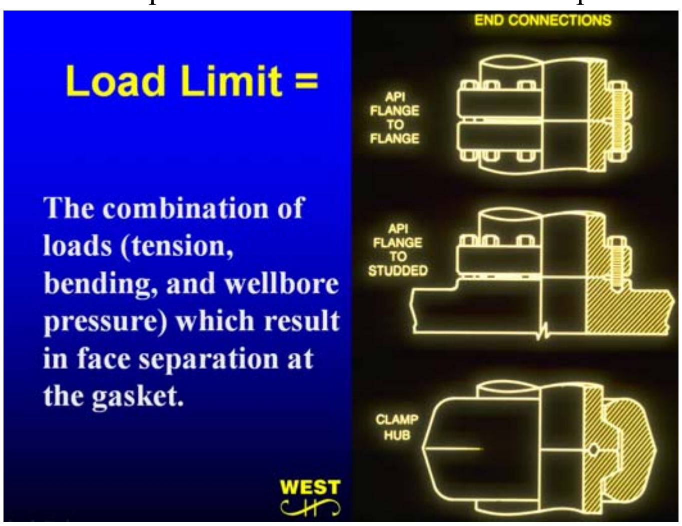
> "Valves must be able to close, at rated water depth, under the following conditions:
>
> 1. From 14.7 psia to MWP in the valve bore
> 2. MWP across the gate at the time of closure
> 3. External pressure on the valve equal to the maximum water depth rating,
> 4. No hydraulic assistance in close the actuator, other than hydrostatic, and
>
> 114.7 psi, plus sea water ambient on the actuator."

Recommendation: BOP stack or failsafe valves should be designed to API Spec 17D, and not Spec. 6A for HPHT applications. Optionally, a failsafe assist circuit helps return the valves to the closed position when control is lost from the surface.

Side Outlets And End Connections

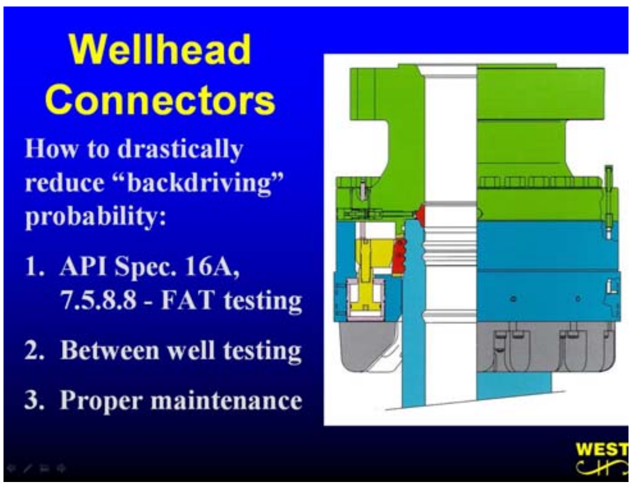
The ring joint flange connections used on side outlets and other end connections are designed to be face to face when assembled. Failure to do this can result in the flange leaking when other forces are applied to it.

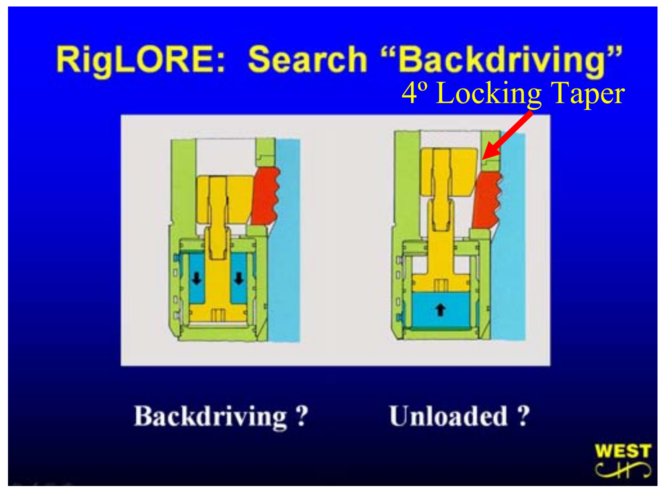
Recommendation: All side outlets and end connections should be assembled and verified as having full face to face contact.



Wellhead and Riser Connectors

Connectors stay in position after the latch pressure is vented by the use of locking tapers. These tapers are about 4 degrees. When the coefficient of friction between the mated parts on the locking taper is too low, connectors can unlock if the locking pressure is vented. This is called back-driving. <u>Recommendation</u>: Connectors should be wellbore tested between wells on the stump without operating pressure on the close side, and periodically testing for back-driving. This will simulate the worst case condition. This is an example of equipment specific procedures and acceptance criteria that must be in place.





Section 4: Current Industry Standards

Industry Standards Overview

The American Petroleum Institute (API) is an organization comprised of individuals with all types of involvement in the drilling industry – drilling contractors, equipment manufacturers, inspection and consulting firms, and many more. All of these individuals work together in the organization for one goal – standardization. API strives to establish standards for every aspect of the drilling industry, in order to achieve the highest levels of safety, environmental protection, and efficiency. The standards written by the members and committees of API are known as Specifications (Spec.) and Recommended Practices (RP)

The oil industry and the MMS generally recognize API's Specs and RPs as the appropriate standards for oil and gas drilling. With the exception of ISO standards where the two organizations have collaborated, these are the only standards available on drilling and well control equipment.

Rather than re-write standards, API references related specifications such as NACE, ASME and AWS in their documents. The formulation and publication of API RPs and Specs is not intended, in any way, to prohibit anyone from using other standards. Rather, API provides a minimum standard, written and peer reviewed by experts in the field with experience in all aspects from the vendor to the users. The RPs and Specifications discussed in this paper were prepared by the API Subcommittee on Blowout Prevention Equipment Systems. WEST personnel have participated as committee members and voted on most of these API documents.

It is interesting to note that drilling equipment seldom carries the API monogram, but rather are supplied "in conformance to" these standards.

A. Well Control Equipment Specifications

Current industry standards do not sanction the use of blowout prevention equipment in excess of its MWP. Specifically, this study reviewed the following equipment:

1. Rams and annulars
2. Connectors (Wellhead and Riser)
3. "Failsafe Valves" Choke and Kill Lines (rigid and flexible)

When testing or using BOP equipment at its working pressure a systems approach must be taken due to the many components involved. It is important to note that this list does not include auxiliary equipment, which also must meet the pressure requirements. Examples include, but are not limited to mandrels, adapters, hydraulic choke and kill connectors, etc.

The first method used to determine the acceptability and safety of using equipment at pressures in excess of rated working pressure involved an in-depth study of the history of API proof testing requirements. The requirements have changed significantly and numerous times in the time period reviewed of 1970 until today. The API documents that were examined were:

API 16A, 1st-3rd edition, *Specification for Drill Through Equipment*
API 6A, 7th–19th editions, *Specification for Wellhead and Christmas Tree Equipment*
API 16C, 1st edition, *Specification for Choke and Kill Systems*
API 17D, 1st edition, *Specification for Subsea Wellhead & Christmas Tree Equipment*

Attachments J, K, L and M summarize the various pressure testing requirements from these standards and their changes over time.

Note: API Spec 16A covers only drill through equipment which means the smallest size included is the 7-1/16" wellbore. Smaller wellbores are not covered. High pressure workover BOPs do exist in smaller sizes such as 4-1/16" 25K and 7-1/16" 20K.

B. Pressure Rating Increases

Because of the changes to the pertinent specs, there are certain BOPs that can have their MWP increased relatively easily. These include:

- 13-⅝" and smaller bore – 2,000, 3,000, 5,000 psi rated
- 16-¾" and larger bore – 5,000 psi rated

These are the sizes and pressure ratings that were originally proof tested per API Spec 6A or 16A to two times working pressure. The 3rd edition of API Spec. 16A (effective Dec 2004) now requires that these sizes be tested at only 1.5 times working pressure. As a result of this reduced requirement, the above BOP bodies contain more metal than is currently mandated and thus their MWP could be re-rated at a higher level. For example, a 13-⅝" 5,000 psi BOP originally proof tested to 10,000 psi could have a new rating of 10,000 psi divided by 1.5 or 6,667 psi. A similar but more restrictive procedure could be applied to gate valves and chokes. Per API Spec 6A, only flanged 5K valves or chokes could be increased in rating to 6,667 psi.

Of course, the full advantage of the rating increase does not have to be used and a rating of 6,000 or 6,500 psi might be acceptable to the vendor. This was done for the 18-¾" 5,000 psi Cameron ram type preventers on the Snorre B in Norway; they were re-rated from 5,000 to 6,000 psi. Attachment N shows the configuration of this stack.

Hugh Elkins reported that Shaffer had also upgraded, in a similar manner, some 5,000 psi BOP equipment in Norway.

C. Closure Mechanism – The Weak Link

The above commentary on pressure ratings only applies to the pressure containing vessel, i.e. the BOP or gate valve body. It does not address the capability of the BOP or valve to seal as designed; this is called the closure mechanism. Although API Spec 16A, Section 8.5.8.7.1.3 allows testing above MWP as with proof testing, WEST is not aware of occasions when this is routinely done. Accordingly, the ability of the closure mechanism, ram blocks or gates, to be used at pressures in excess of their rated MWP could only be determined by the manufacturers. The design parameters for these components is known and understood best by the ones who designed them.

D. Standard for Equipment with MWP Above 15,000 Under Development

Because of the interest in oil and gas fields with pressures higher than existing equipment can safely contain, the industry has begun work on a new RP through API. The expectation is that, with better engineering analysis, higher rated BOP and related equipment can be produced that is lighter than if it were built to existing standards.

The following is excerpted from an API Scoping Document that can be found as Attachment O.

"Oilfield drilling and completion equipment, such as high-pressure BOP and Christmas trees, utilize thick-walled pressure vessels with multiple cross-bores. These are relatively complex geometries to analyze and design. In addition, these high design pressures put even tubulars and spools in the thick wall cylinder sizes which are outside the present scope. In the past, simplifying assumptions were made by design standards such as API regarding modeling and analysis of these complex geometries. In addition, in order to avoid potential failures, the simplifying assumptions were combined with relatively high design safety factors. The trend in new design standards is to use modern technologies such as finite element methods and fracture mechanics in order to decrease the thickness and weight and also increase the reliability of design. However, such an approach not only requires using more sophisticated procedures and methods during the design process, but also requires more information regarding the lifetime service loads of the equipment."

"Current API standards 6A, 16A, and 17D reference the ASME Boiler and Pressure Vessel Code Section VIII, Division 2 as the primary design methodology (i.e., with certain modifications such as less stringent material specifications and slightly different allowable stress limits). The strength analysis of API design procedures are based on classical strength of materials equations and simplified linear-elastic finite element analysis (FEA) and do not consider cyclic behavior, fatigue or fracture mechanics. To compensate for the simplified design process and not very strict material properties, very high safety factors are specified in hydrostatic proof test pressures."

"API design procedures are based on ASME design code (ASME Boiler and Pressure Vessel Code, Section VIII, Division 2) that is no longer recommended by the ASME for design of high pressure equipment and has been superseded by a new design code (ASME Section VIII Division 3)."

The API Subcommittees that are or may be affected by this RP are:

SC5 (5CT)
SC6 (6A and 14A)
SC 16 (16A and 16C)
SC 17 (17D)

E. Achieving BAST

BAST (Best Available and Safest Technology) is only achieved when the manufacturer follows or exceeds industry standards.

There are a number of areas where the industry does not conform to API Spec 16A. These include:

- Design Verification Testing, Section 5.5. The results of this testing are not made readily available to the man on the rig who desperately needs to know this information to safely operate the equipment. This testing includes stripping, hang-off and shearing.

- Operating Manual Requirements, Section 5.9.h. This section states that the operational characteristics summary shall be provided, which includes the design verification testion.

- Requirements for Repair and Remanufacture, Annex B is not always complied with.

Unfortunately, manufacturers often consider this information proprietary and limit distribution. Some manufacturers may also be concerned that their products' capabilities will compared unfavorably to others, which may affect them commercially.

Recommendation: Operational characteristics test results for well control equipment should be on the rig.

Additionally, BAST technology will not be achieved if API Q1, "Specification for Quality Systems" is not utilized. Specifically, section 4.14 "Corrective and Preventive Action", recommends the distribution of Field Non-Conformities to other owners of this equipment. Additionally, if the Operations and Maintenance Manuals on the rigs are not carefully monitored for changes and upgrades, nonconformities will result on equipment requiring revision that cannot be upgraded on the rig.

Recommendation: Establish an API Q1 quality system on rigs for well control equipment.

Recommendation: The MMS should consider recognizing API RPs as minimum standards, and supplementing as appropriate, such as addressing the Dead Man system after the need became apparent.

If API were recognized by the MMS, the drilling industry would look to API for guidance on these issues. As noted earlier, API has made no provisions for operating well control equipment above its MWP.

Section 5: Current Regulations

Mineral Management Service Regulations

A. Introduction

The regulations published by MMS, Petroleum Safety Authority, PSA, in Norway, and the UK Health and Safety Executive, HSE, were reviewed. The MMS regulations are generally prescriptive and discussed the case where the annular preventer is rated less than the rams on a BOP stack. This introduces form #124 that has been used to grant dispensation to use BOP equipment in excess of their MWP.

Both the PSA and UK HSE are non prescriptive. Neither of these regulations discussed using BOP equipment in excess of the MWP.

There is a need for the MMS to supplement industry standards. Several examples are cited in this section. In addition, examples are provided that demonstrate the need for the MMS to keep regulations current with best available technology. Regulations that are lower than industry standards indicate either the availability of additional information or risk tolerance by the community that is lower than that of the MMS.

B. MMS Regulations

Annular Preventers Commonly Have a MWP Less Than Rams

Drilling and completion and work-over requirements are inconsistent. It is uncommon on a BOP stack for the annular to be rated at the same pressure as the rams. However, lower pressure rated annulars are consistent with API RP #53, section 7.2 “Stack component codes”.

On a 15,000 psi subsea BOP stack, the annular preventers will be rated for either 5,000 psi or 10,000 psi. Annular preventers are not currently available with an 18-¾” bore rated for a MWP in excess of 10,000 psi.

The MMS addresses using annular BOP equipment on wells in excess of its rated working pressure. This is addressed twice, once in completions and once in workover.

Drilling: 250.400 – 490

250.440 “What are the general requirements for BOP systems and system components?” “The working-pressure rating of each BOP component must exceed maximum anticipated surface pressures.”

Completions: 250.500 – 517

250.515 "Blowout Prevention Equipment – a) "If the expected surface pressure exceeds the rated working pressure of the annular preventer, the lessee shall submit with Form MMS-124 or Form MMS-123, as appropriate, …"

Workover: 250.600 – 1019

250.615. "If the expected surface pressure exceeds the rated working pressure of the annular preventer, the lessee shall submit with Form MMS-124, requesting approval of the well-workover operation, a well-control procedure that indicates how the annular preventer will be utilized and the pressure limitations that will be applied during each mode of pressure control." (See Attachment P)

Recommendation: The wording that allows annular BOPs to be used on wells in excess of their MWP is acceptable. The testing and well control issues will be addressed procedurally.

250.141 May I Ever Use Alternate Procedures Or Equipment?

You may use alternate procedures or equipment after receiving approval as described in this section.

(a) Any alternate procedures or equipment that you propose to use must provide a level of safety and environmental protection that equals or surpasses current MMS requirements.

Note: Exceeding MWP does not satisfy this requirement.

(b) You must receive the District or Regional Supervisor's written approval before you can use alternate procedures or equipment.

(c) To receive approval, you must either submit information or give an oral presentation to the appropriate Supervisor. Your presentation must describe the site-specific application(s), performance characteristics, and safety features of the proposed procedure or equipment.

250.142 How Do I Receive Approval For Departures?

We may approve departures to the operating requirements. You may apply for a departure by writing to the District or Regional Supervisor.

Regulations Can Effectively Supplement Industry Standards

For the purposes of this research project, it was assumed the regulations rely heavily on the relevant industry standards. Accordingly, when important issues are not addressed in industry standards, they should be addressed in regulations. An example would be the shear rams requirement on jack up drilling rigs.

MMS References specific sections of API RP #53. (See Attachment Q)

Recommendation: When API industry standards are acceptable, reference these sections in the MMS regulations.

Recommendation: MMS prescriptive standards should be consistent or to a higher standard than API. Confusion arises when the MMS standards are lower than industry standards.

MMS Project #01-99-PO-17072, dated August 2000, *"Evaluation of Suitability of Industry Standards as MMS Requirements"* (See Attachment R)

WEST Engineering conducted this study for the MMS and submitted the work in 2000. Our recommendations are the same, inclusion of the pertinent API Recommended Practices into MMS regulations by reference.

250.442 What Are The Ram Requirements For A Subsea BOP Stack?

(a) When you drill with a subsea BOP stack, you must install the BOP system before drilling below surface casing. The District Supervisor may require you to install a subsea BOP system before drilling below the conductor casing if proposed casing setting depths or local geology indicate the need.

(b) Your subsea BOP stack must include at least four remote-controlled, hydraulically operated BOPs consisting of an annular BOP, two BOPs equipped with pipe rams, and one BOP equipped with blind-shear rams.

Recommendation: For subsea stacks, consider adopting the industry standard of four ram preventers. (See Attachment Q, figure 5)

Wellbore Testing With Ram Locking Systems

API far exceeds the MMS requirements in this area. Section 18.5.9 of RP 53 states that ram locking systems should be wellbore tested with the rams in the closed position and closing pressure vented.

MMS regulation 250.515 C 3, states that we must have ram locking systems installed on pipe rams and does not mention wellbore testing requirements using this equipment. Ram locking systems are sensitive and must be carefully tested in a manner that does the least amount of harm.

Wellbore Pressure Testing

There are three areas of interest for adequately identifying standards for wellbore pressure testing:

1. Test duration,
2. Test recording, and
3. Test pressure

Test Duration

250.448 What are the BOP pressure tests requirements? (Drilling)

(a) *Duration of pressure test*. Each test must hold the required pressure for 5 minutes. However, for surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if you record your test pressures on the outermost half of a 4-hour chart, on a 1-hour chart, or on a digital recorder. If the equipment does not hold the required pressure during a test, you must correct the problem and retest the affected component(s).

250.516 Blowout preventer system tests, inspections, and maintenance. (Completion)

(a) *Duration of pressure test*. Each test must hold the required pressure for 5 minutes.

(b) For surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if you record your test pressures on the outermost half of a 4-hour chart, on a 1-hour chart, or on a digital recorder.

As seen in both quoted regulatory sections, the MMS allows a three minute pressure tests for surface equipment on subsea systems while API RP #53, 18,3.2.1 requires five minutes. With the correct pressure recording equipment (not a four hour clock for a three minute test, see below), this may be an acceptable practice. However, it is not recommended to prescribe a standard lower than the industry standard.

Test Recording

Both quoted regulator sections quoted above discuss recording equipment. A three or five minute line on a four hour chart provides poor documentation for pressure testing. Wording in RP #53, section 18.3.6 is more stringent than MMS and should be used. Additionally, section 12.5.3.g in RP #53 discusses calibration and accuracy of gauges, which exceeds the MMS wording.

Test Pressures

250.448 (a) *Low-pressure test.* All low-pressure tests must be between 200 and 300 psi. Any initial pressure above 300 psi must be bled back to a pressure between 200 and 300 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test.

The MMS defines the maximum pressure, 500 psi, which should not be exceeded prior to conducting a low pressure test. This wording is more specific than API RP #53, section 18.3.2.1. This is a good example of MMS regulations supplementing industry standards.

Recommendation: Submit the proposed wording low pressure testing to API for potential inclusion into RP #53.

Failsafe Regulators

Failsafe Regulators have been included in MMS requirements for the last 18 years due to several blowouts. API responded and addressed FS Regulators in API Specification 16D, section 5.2.4.3 to a high standard.

OCS Regulations now read:

250.515 - The BOP systems for well completions shall be equipped with the following:

(a) A hydraulic-actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. No later than December 1, 1988, accumulator regulators supplied by rig air and without a secondary source of pneumatic supply, shall be equipped with manual overrides, or alternately, other devices provided to ensure capability of hydraulic operations if rig air is lost.

Recommendation: Define systems to keep prescriptive regulations on failsafe regulators current. API 16D standards now exceed MMS requirements.

Accumulator Volume

250.442 What are the requirements for a subsea BOP stack?
MMS regulations reference API RP #53, last issued in 1997, (Attachment d). This is an incorrect reference for deepwater applications. The current reference should be Specification 16 D that addresses deepwater issues, published in 2005.

United Kingdom and Norwegian Regulations (See Attachment S)

ALARP

A key concept of these regulations is to reduce risk to ALARP As Low As Reasonably Practical. The issue of using equipment above its MWP is not specifically addressed in the UK or Norwegian regulations. The non prescriptive regulations in both of these countries put the onus on the duty holder with the Safety Case. No cases of operating equipment above its MWP were reported in either of these countries. Compliance with ALARP in the Safety Case would prohibit the practice of using BOP equipment above its rated working pressure.

The Duty Holder

Regulations in the United Kingdom and Norway place the burden of compliance on the Duty Holder, the party we call the leaseholder. In general, their regulations are non-prescriptive with occasional prescriptive segments.

In Norway, the PSA (Petroleum Safety Advisory) was formed by the NPD (Norwegian Petroleum Directorate) in 2002. The PSA provides a framework for compliance by the duty holder in a non-prescriptive format. Most consider it more difficult for the Duty Holder because now they have to consider their program requirements in light of best industry practices, the drilling contractor and their systems, as well as BAST (Best And Safest Technology) compared to complying with a given list of requirements.

By consensus, API is recognized by both the UK and Norwegian governments. No other standards exist for most of the equipment in this study.

Safety Critical Equipment

It is clearly the Duty Holders responsibility, in relation to a production installation, the Operator, and in relation to a non-production installation, the owner, to purchase, operate and maintain Critical Safety Equipment to a standard that reduces the risk of failure to ALARP.

Monogrammed Equipment

API subcommittees that create the Specifications, written for the design and manufacture of equipment, are primarily composed of equipment manufacturers. Manufacturers of Blowout Prevention Equipment seldom monogram equipment. Consequently, some critical specification requirements are not complied with. See "Current Industry Standards" for an example.

Gunner Leistad, one of the 10 Engineers with the Norwegian PSA, was asked his opinion about the value of an API monogram on equipment. His response was that Norway does not require it because the monogram only indicates conformance to a standard at the time it left the manufacturer. The goal of the PSA is for the Duty Holder to continuously maintain the equipment in a "Fit for purpose" condition.

Section 6:

Experiences Exceeding MWP of Equipment

A. Objective/Workscope

Identify and discuss known occasions when BOPs and wellheads were either re-rated for higher MWP or used, intentionally or accidentally, in excess of rated MWP.

B. Conclusion

Historical instances where MWP have been exceeded, as well as MWP ratings have been increased are rare.

C. Informal Survey Results

Twelve people were surveyed, with a cumulative 400 years of experience, to understand their experiences using blowout prevention equipment or wellheads in excess of their MWP. Five examples of intentionally exceeding the MWP were recorded, along with two accidental occurrences.

Bob Reed, WEST Drilling Systems Manager: Bob has 35 years of contractor experience with land rigs in Australia and Libya, plus contractor and operator experience with floating rigs in the UK and Norway. Bob has never exceeded MWP on a BOP during operations using over 100 different rigs. BOP selection criteria considered the MASP with the wellbore evacuated.

Robert Urbanowski is a Grey Wolf Engineering Manager and contractor who has spent 20 years with the company: Robert has no experience using BOP equipment at a pressure greater than MWP. He has heard stories of kicks that have occurred over 80 years of Grey Wolf history. Some kicks did exceed the MWP of the BOP equipment, but he has no specific knowledge.

John MacKay of Transocean has 25 years of experience as a subsea engineer and worked his way up to OIM.

1. John said after the Ocean Odyssey, the UK HSE requested the Sedco 714 to pressure test the manifold, shipboard piping and C/K hoses to 22,500 psi. The pressure test was held 6 hours. Others suggest this request was never implemented, see Mo Plaisance comment below.
2. One incident recorded accidentally subjecting a Kelly cock valve to 18L during a test.

Mo Plaisance, Diamond Offshore VP and drilling contractor, has spent 35 years with the company. Mo, who is a drilling contractor and an attorney, began with DODI as a roughneck and worked his way to VP of Diamond Offshore.

1. Mo discounts the 22.5K Transocean story. Mo was Senior Management for Diamond responsible for dealing with the HSE about the Ocean Odyssey incident. Both Mo and Michael Montgomery believe this 22.5K test never happened on the Sedco rig as John described.

2. Diamond had a jack up in the Sable Islands with a 5K BOP stack. The rig took a kick and the wellbore pressure under the rams rose to 7,800 psi.
3. DODI routinely tests C/K hoses to 1.1 × MWP in situ on rigs. This re-qualifies hoses onboard the rig for DODI, as opposed to sending ashore.

Dr. Leon Robinson retired from Exxon after 35 years. Leon's specialty was drilling fluids. "Not while he was at Exxon" did people use BOP equipment at a pressure greater than MWP.

Hugh Elkins is with Varco engineering. Hugh was previously the Director of Engineering for Hydril, with a total of 35 years in the industry.

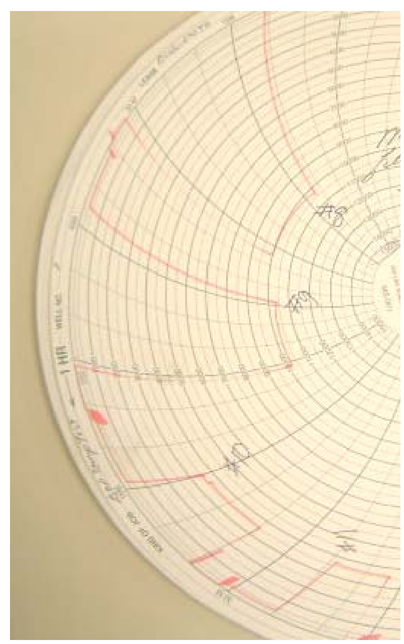
1. Shaffer Norway has increased the working pressure of 5,000 psi BOPs working in Norway.
2. Gate valves were discussed. Above MWP, a closed gate has a tendency to be damaged by embedment into the seat.

Leon Schwartz, of WEST Engineering is a degreed petroleum engineer, with 25 years offshore experience. Leon has personally worked on over 100 rigs and has never seen BOP equipment tested or operated above its MWP.

Magnus Watson, Hydril management, has 10 years of previous drilling contractor experience as a subsea engineer. He said: "An interesting subject and we suspect this happens quite a lot, mainly by accident. However, it is difficult to get data as people rarely wish to admit to it. We have no recorded examples of over pressuring that anyone I have talked to is aware of."

Gene Nimmo, of WEST Engineering, has 30 years of experience as a subsea engineer. After the MG Hulme stack was dropped, Total requested to test the stack to 1.25 × MWP prior to reuse of the equipment. The Cameron UII Rams, connectors and valves were wellbore tested to 18,750 psi. Ed Lewis, also of WEST Engineering, substantiated that this event occurred.

D. The Effects Of Test Mud On Deepwater Wellbore Pressure Testing Bops To MWP



The hydrostatic head of the drilling fluid will be additive to the BOP test pressure on a subsea BOP. In the example provided, 14 ppg and 10,000 feet of water will create a total pressure of 17,917 psi when the surface test discharge reads 15,000 psi. This overpressure is acting on the shell of the preventer, not across the ram packers. (See Attachment T)

On a 10,000 psi preventer, the test could have exposed the BOP to over 12,917 psi, a pressure that is approaching proof pressure. In the case of a 5,000 psi annular, the actual pressure applied to the shell would exceed the current API Specification 16A proof test pressure of 1.5 × MWP, or 7,917 psi.

While the over pressure created by the hydrostatic pressure of the mud is not indicated at the surface, it should be considered when defining test pressure. Even at 7,000 feet of water using 14 ppg mud, the additional pressure exerted by hydrostatic pressure is almost 2,000 psi. Some contractors / operators take this pressure into consideration, others do not.

E. What Is The Effect Of Considering The Test Mud?

The pressure differential across the rams, annular or gate valve will be the desired test pressure, because the mud hydrostatic head is the same on the top and bottom of the closure mechanism. The result of not exceeding the MWP of the shell during a subsea wellbore test when test mud is in the riser is not testing the closure mechanism to its MWP on the wellhead. This could be considered acceptable because these MWP wellbore tests are completed on the surface before the stack is run and the first installation test on the wellhead is.

Section 7: Industry Experience Downrating BOP Equipment

When well control equipment fails to pressure test at its MWP, if the repair cannot be accomplished quickly, the equipment may be down rated or removed from service. There are a number of factors that are known to cause reduced performance of BOPs; these are briefly addressed below. It is recommended that these variables be identified so that the impact on MWP can be anticipated.

Table #2 is the result of a limited survey around the office at WEST Engineering to identify historical occasions where equipment was downrated. This was not included in the interviews to identify incidents of exceeding MWP. This is not intended to be a complete listing.

In one known case, concerns of equipment current capability has caused a state-owned oil company to adopt a policy to not use BOP equipment over 80% of its MWP. It is not known how they calculate MASP.

A. Table #1 Downrating BOPs and Explanations

	Ram Locks	Shear Rams	Bonnet seals	Annular Elements	Variable Bore Rams
Rig 1		**Yes**			
Rig 2		**Yes**			
Rig 3			**Yes**		
Rig 4 & 5			**Yes**		
Rig 6		**Yes**			
Rig 7	**Yes**	**Yes**			
Rig 8	**Yes**	**Yes**			
Rig 9	**Yes**	**Yes**			
Rig 10	**Yes**	**Yes**			
Rig 11	**Yes**	**Yes**			
VBR Rams All					**Yes**
Cameron Annular Preventer				**Yes**	
Shaffer Annular Preventers				**Yes**	
State Owned Operator	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

Shear Rams and Locking Systems

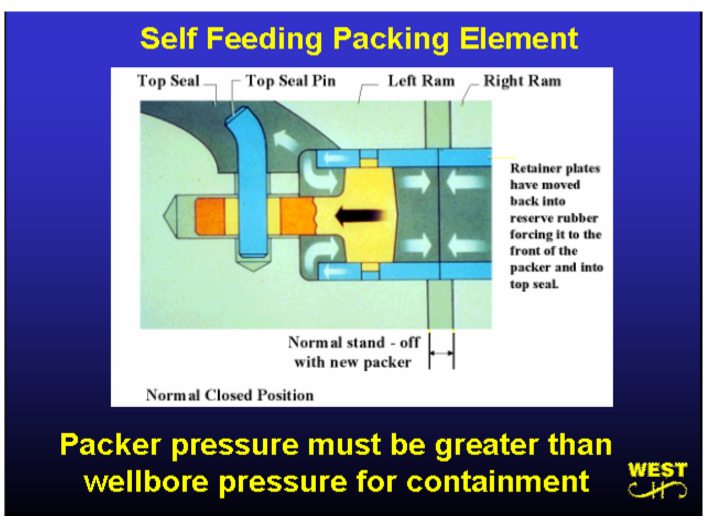
Cameron Shear Rams

Rigs 1 and 2 Due to a design fault with the Cameron shear rams, the stack was downgraded to 7,500 psi until the replacement, redesigned rams were installed.

Stuart and Stevenson QLS Rams

Rig 7 WEST Engineering Job #974.

Due to erratic wellbore test due to the low wellbore assist, the ram locks, and cracking of the shear ram blades, the stack was down rated from 15,000 psi to 10,000 psi MWP. API Design Verification testing and Factory Acceptance Testing undertaken were not adequate to detect these design problems.



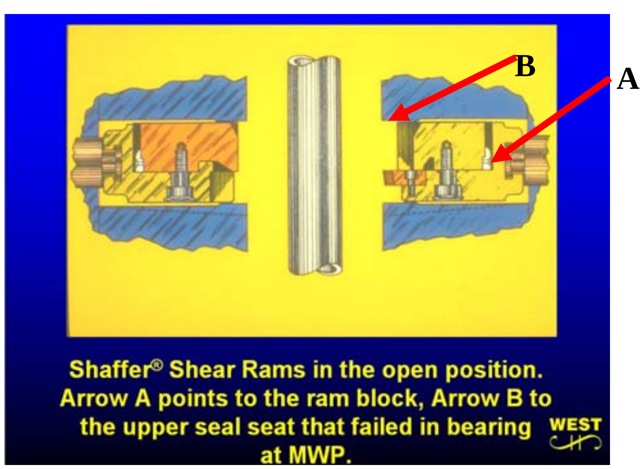
Pressure testing loads at 15,000 psi resulted in cracking of the shear ram blocks.

Shaffer Shear Rams:

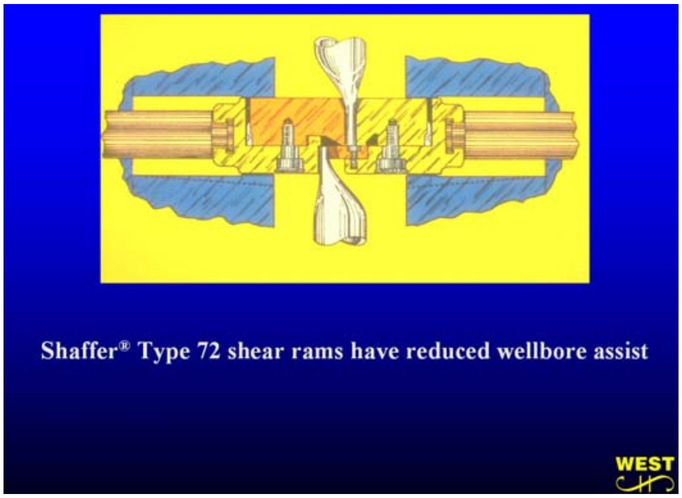
This is a case where equipment has failed in bearing at MWP. The closure mechanism was downrated 33%, from 15,000 to 10,000.

The 18-¾" rams bearing failure occurred between the shear ram and the upper seal seat after repeated pressure tests to MWP. Shear ram blocks have a HRC hardness range of 40 – 45. The upper seal seat material is 4130 with a HRC hardness of 18 – 22. Maximum indentions on the shear ram cavities were .019 inch and ram block cavities a maximum of .007". Reference Shaffer Engineering Report #323, dated 27 September 1985.

The image below depicts Shaffer shear rams in the open position. "A" points to the ram block assembly and "B" identifies the location where the upper seal seat was indented.

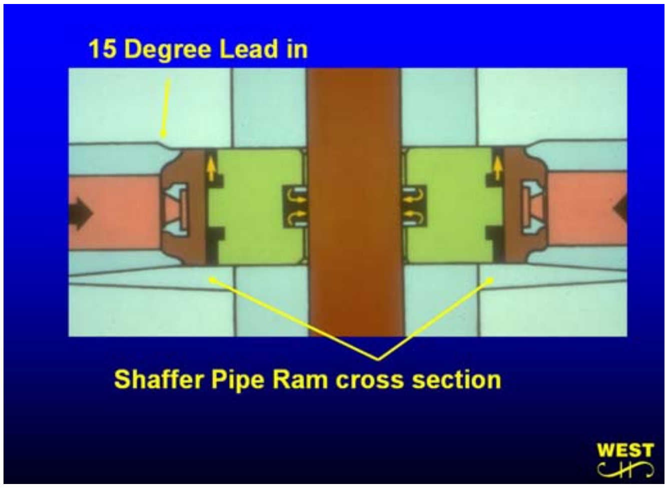


The drawing below depicts Shaffer® shear rams in the closed position after shearing pipe.



For pipe rams, the force on the upper seal seat is less due to reduction in force from subtracting the area of the drill pipe. This is why similar failures don't occur on pipe rams.

Koomey J Line Pressure Balanced Rams



Due to the ram locking system and shear rams, the preventers were removed from the Rigs 8, 10, and 11. Improved API sealing characteristics and API design verification testing would have identified these deficiencies prior to delivery of the equipment.

Variable Bore Rams

VBRs (Variable bore rams) have failed to wellbore test at MWP randomly due to a variety of causes. They have a reduced capability, compared to pipe rams, for hang off, stripping and maintaining a seal at elevated temperatures. The design of a VBR is similar to an annular preventer.

Achieving a wellbore test on VBRs on the largest and smallest size pipe can be difficult. Several techniques have been developed to consistently achieve successful tests. Due to the design of a VBR packer, wellbore testing "locks only" is more difficult to achieve compared to pipe rams. However, historically this has not been an operational issue. This should be considered in a well control plan.

1. Operating pressure is increased from the standard 1,500 psi to 2,200 psi or greater to get a seal. This negatively impacts the useable accumulator volume.

2. Variable bore ram are often stroked and "warmed" up prior to wellbore testing. The need for this practice is greater in cold environments.

3. Steam hoses have been used to help achieve low temperature wellbore tests on the surface.

4. Let the packers "flow" for an extended period of time; say 30 minutes, to allow the rubber to flow into the irregularities of the ram cavity and other sealing surfaces.

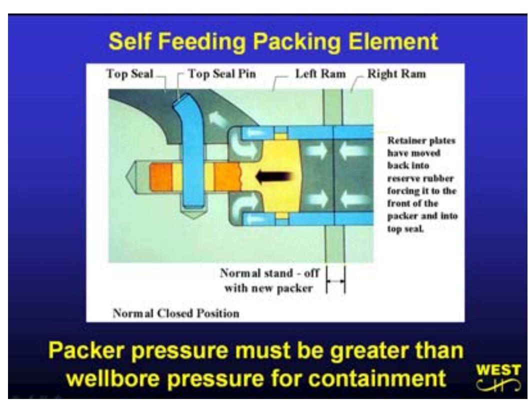
Recommendation The higher operating pressure required for the VBRs should be considered in accumulator volume calculations.

Recommendation Record the operating pressure required to achieve a low and high pressure seal on the VBRs. Wellbore tests should be attempted with locks only and results recorded.

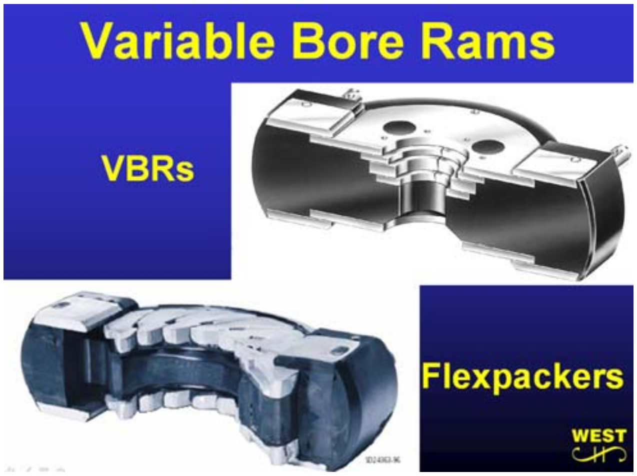
The Cameron 18-¾" UII rams use the same packer for 10K as well as 15K applications. However, for 15K applications, the packer is rated for 3-½" × 5"; in 10K rams the same packer is rated at 2-⅞"× 5". Sealing on the smallest size pipe in the range is the most difficult test. Cameron also temporarily downrated their 11" VBRs from 10K to 5K. Table #2 is from a Cameron spare parts catalogue.

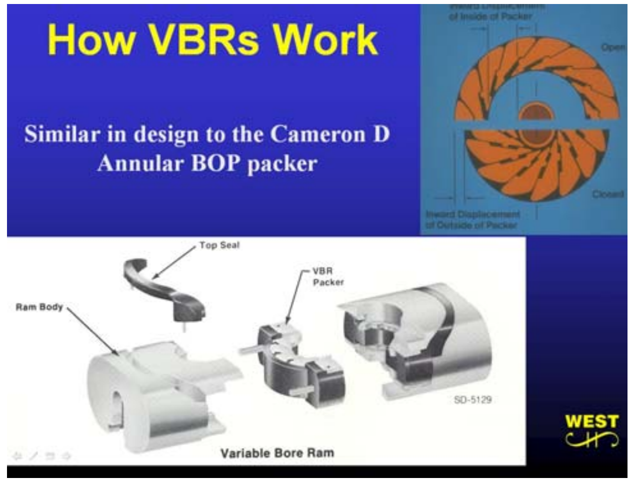
Table #2

BOP Size and Working Pressure	Pipe Size Range	Ram	Ram Body	Packer	Top Seal
18-¾" 10,000 psi	7.625" to 3.500"	614879-01	614846-01	644918-01	645282-01
18-¾" 10,000 psi	5.000" to 2.875"	614878-01	644748-01	644919-01	644246-02
18-¾" 15,000 psi	7.625" to 5.000"	614879-01	614846-01	644918-01	645282-01
18-¾" 15,000 psi	5.000" to 3.500"	614878-01	644748-01	644919-01	644246-02



Variable bore ram packer contains steel reinforcing inserts similar to those in the Cameron annular. The VBR steel inserts rotate inward when the rams are closed, providing support for the rubber.





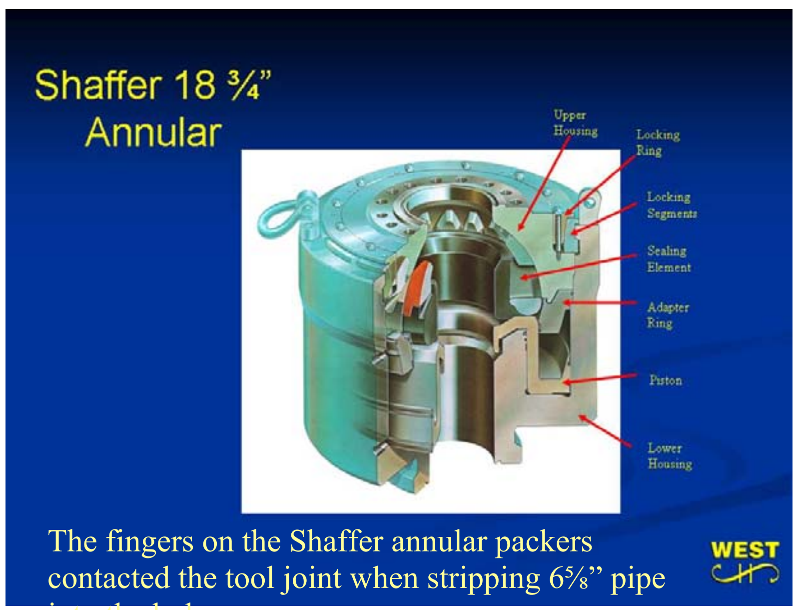
Annular Preventers

Shaffer Annulars

Non-API Annulars

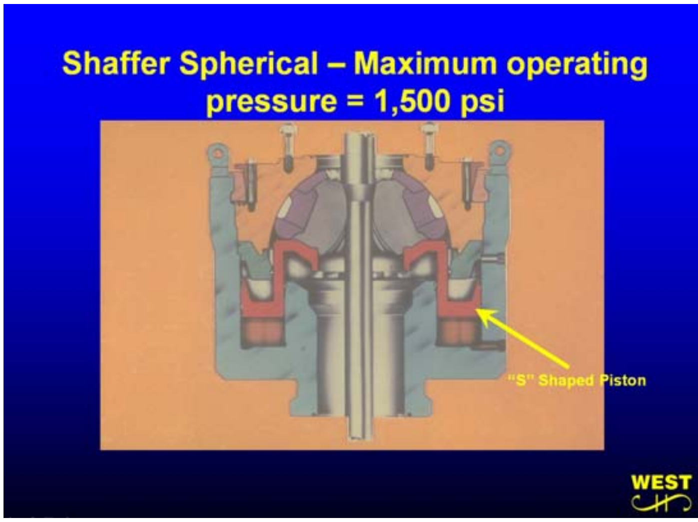
Shaffer annulars are used for illustration only. The downrating of annular packers described also applies to Hydril and Cameron annulars when used with 6-⅝" pipe. (See Attachment U)

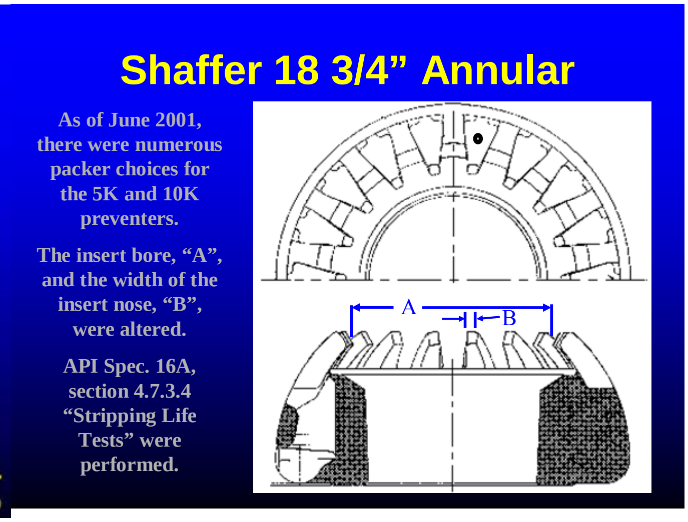
Annular packers were originally designed to seal on 5" drill pipe. With the introduction of 6-⅝" drill pipe, the industry learned this pipe would not strip because the tool joints would hit the packer's steel fingers. The initial fix was to manually grind, or cut with a torch, the fingers to allow the 8-½" tool joint on 6-⅝" pipe to strip through the closed packer without contacting the metal fingers molded in the packer element.



Several of the manufacturers have resolved the problem with packers designed specifically for 6-⅝" pipe. However, these packers have a reduced rated MWP and/or the inability to CSO (complete shut off) in open hole.

The following photos illustrate how the fingers are used to contain the rubber when the packer is in the closed position.





Shaffer issued a Product Information Bulletin in June 2001 stating that four of the annular packers offered for the 18-¾" 10K preventers were downrated in working pressure and some do not have the ability to strip pipe, as per API Specification 16A.

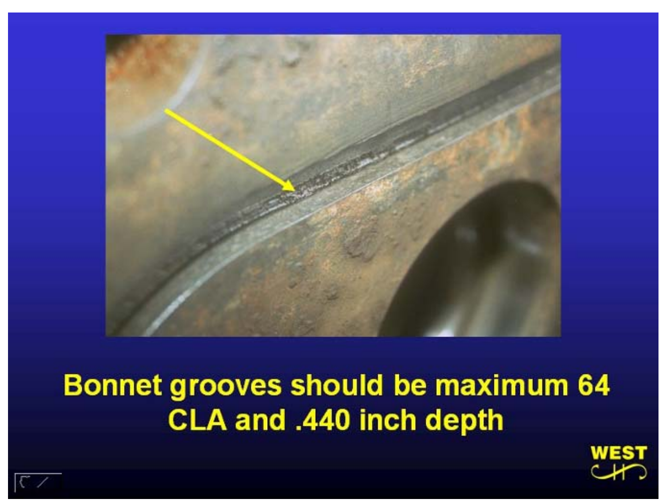
Cameron Annulars

Cameron addressed the 6-⅝" pipe issue in a similar manner as Shaffer, downrating from 10,000 psi to 5,000 psi. Additionally, this packer is not capable of closing on open hole, as specified in API Specification 16A. (See Attachment V)

Maintenance Issues

Cameron Bonnet Seals This demonstrates the ability of a seal to hold pressure changes over time.

Bonnet Seal Issues



On Rig 3, their 16-¾" stack was downgraded from 10,000 psi to 5,000 psi due to the bonnet seal grooves.

21-¼" 10,000 psi bonnet seals

Rigs 4 and 5 were equipped with 21-¼" 10K BOPs. Due to their bonnet seals, some preventers were down rated to 7,500 psi. Bonnet seals leaking were a problem from the beginning that got worse over time when the surface finish of the groove deteriorated.

Section 8: Factors Reducing Capabilities Below MWP

A. External Hydrostatic Pressure

Every BOP that used subsea has two separate and unrelated working pressure ratings. The first is well known to everyone as the rated working pressure. The rated working pressure is the *internal* pressure the BOP is designed to withstand. However, in normal operations, BOP equipment may be subjected to external hydrostatic pressure that is greater than the internal pressure, particularly in deeper water. There are no guidelines regarding the ability to withstand higher external differential pressure. The maximum allowable external pressure is never published, and indeed may not even be known by the manufacturer. If differential pressure is applied to a component not designed to withstand it there could be serious consequences for well control; the deeper the water the greater the risk of failure.

BOP Internal Pressures Less Than Ambient Sea Water Can Be Created In The Following Situations

1. During production tests
2. Lost returns in wellbore if severe enough to cause large drop of riser mud level
3. Gas in riser unloading mud (refer to IADC Deepwater Well Control Guidelines Section 2.6)
4. During removal and venting of trapped BOP gas (refer to IADC Deepwater Well Control Guidelines Section 2.5.5)
5. During completion operations
6. During an emergency disconnect sequence, EDS (riser collapse pressures).

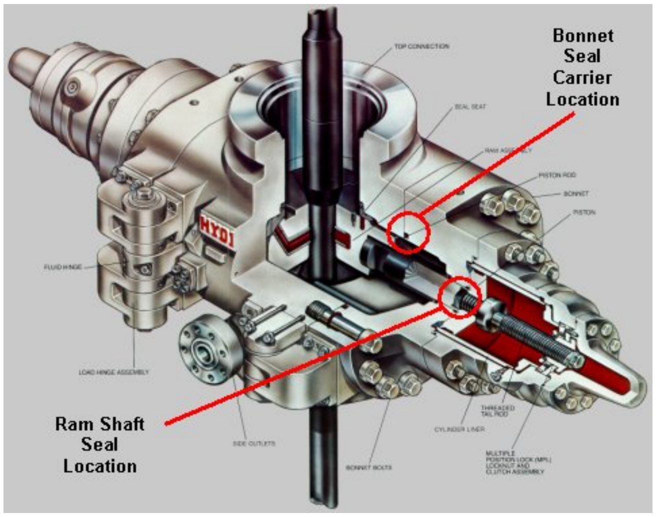
Door Seals

If the external pressure differential capability is exceeded, the door seal collapses, and it will no longer seal the wellbore. This condition is undetectable by the rig crew, and the first time anyone becomes aware that a barrier is no longer available is when a massive leak occurs. The industry has been very fortunate thus far in that the damaged seals have always been discovered during testing, not during a well control event. It is often the lowermost preventer that is affected, meaning the master barrier has failed.

Cameron, Shaffer and Hydril all use similar seal arrangements for the ram shaft (operating rod), which incorporate a wellbore-facing lip seal held in position with a retainer ring. In all cases, the lip seals are fully encased, but not fully supported. Generally, support on the wellbore side is minimal and basically limited to the outer diameter area of the seal. Due to existing vent ports, and, by design, these seals are exposed to external hydrostatic pressure leaving them vulnerable to displacement. Some BOPs have check valves installed in the bleed port that, if in good condition, will prevent hydrostatic pressure acting on the ram shaft packing

Hydril Door Seal Carrier and Ram Shaft Packing

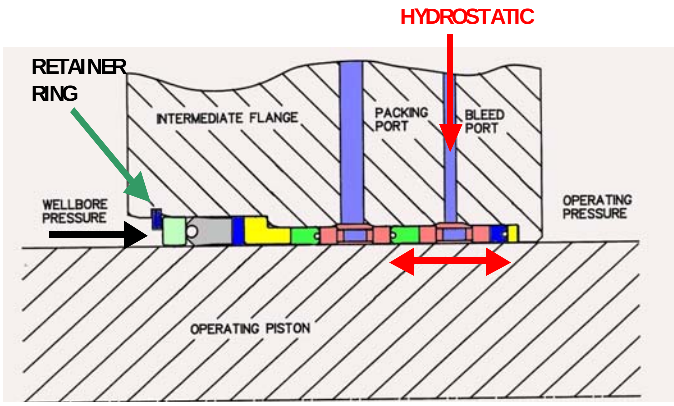
A Hydril ram BOP, shown below, failed to test in deepwater after exposure to high external differential pressure caused the bonnet seal carriers to bend inward. The ram shaft seal, retainer snap ring, and spacer also extruded into the ram cavity. These problems were found after a successful wellbore test could not be achieved subsea. The ROV could see test fluid exiting at the bonnet seal on the bottom ram BOP. The rig crew verified that the bolts were at the correct torque when the bonnets were opened after stack retrieval. These ram BOPs had been exposed to seawater pressure at water depths of 5,495 to 6,381 ft when the internal wellbore hydrostatic pressure became lower than the outside seawater. The pressure differential was above 660 psi, causing the noted damage.



Hydril preventer showing areas most subject to failure from external hydrostatic pressure.

Failed bonnet seal caused by hydrostatic pressure forcing seal out of position.

Another view of the crushed door seal carrier, illustrating the amount of damage caused to the seal. The single fastener in the center of the seal sheared due to the force exerted by hydrostatic pressure



Drawing showing how hydrostatic acts on the ram shaft packing.

Ram shaft packing after being forced out of the seal pocket by hydrostatic pressure

Upgrades

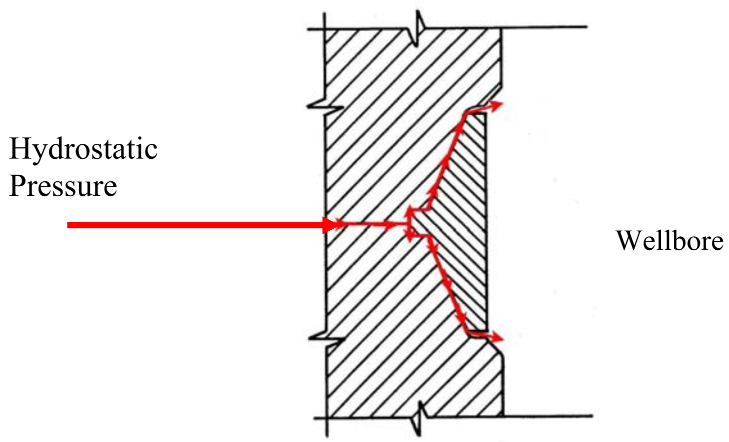
Hydril upgraded the door seal and the ram shaft packing retainer by adding several additional fasteners. Cameron and Shaffer have also upgraded their door seals so all new preventers can withstand higher external pressure. The original Shaffer 18-¾" 10K ram preventer can only withstand an external pressure at the door seals of a few psi. Unfortunately, the majority of ram BOPs currently in use in the field have not been upgraded and are still subject to this type failure.

Ring Gaskets and Grooves

Another issue is metal seal rings, especially the wellhead gaskets. Wellhead and throughbore gaskets are pressure energized and designed to allow face-to-face contact between the mating hubs. This allows external loads to be transmitted through the hub faces, thereby protecting the ring gasket from damage. The ID of the gaskets are smooth and flush, or nearly so, with the bore. Sealing occurs along small bands of contact between the grooves and the OD of the gaskets at a diameter slightly larger than the hub bore (see drawing below). The basic metal gasket holds only a negligible amount of external pressure.

AX, CX, and VX gaskets were designed to seal against wellbore pressure; external pressure was generally not considered. In fact, API has no guidelines or external pressure ratings for ring gaskets. Depending on the manufacturer, the maximum external differential pressure a wellhead seal can withstand is about 300 psi. Internal pressure acts on the gasket and aids in achieving a seal, i.e., they are pressure energized. Once external pressure exceeds internal pressure, leaks can develop, causing washout of the gasket or groove. Eventually, this results in a leaking connection.

Typically, higher external differential pressure will "flex" the gasket inward due to the lack of support or insufficient contact force. The following illustration is typical of the AX, CX and VX gaskets and the leak path, red arrows, will be the same. While it would be technically simple to redesign the seal pocket to prevent hydrostatic pressure displacing the seal, no work has been done in this area, probably because there has been no proven loss of containment to date. There are several possible reasons for this. With the original door seal designs, external pressure ratings were so low that permanent failure occurred there prior to exceeding the capabilities of the ring joint gasket. Secondly, due to hoop strength and the symmetrical nature of this part, it is possible to have a failure without permanent damage. The most likely permanent damage from this type of failure would be a washed seal area; if the leak were either of short duration or limited flow, this would be unlikely. Thus, even if external forces caused a gasket leak as well as in another location, the collapsed door seal or displaced ram shaft packing would stop further investigation. This is an example of how valuable information can be acquired by visually examining ring gaskets upon retrieval of the stack to the surface.



BX gaskets are, by design, supported both internally and externally, so external pressure is not a concern.

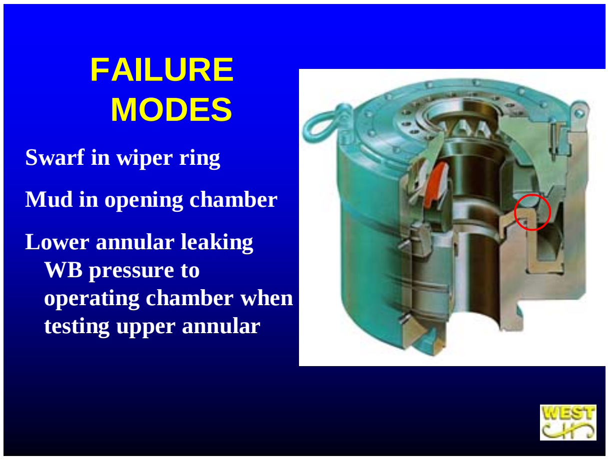
B. Non-OEM Replacement Parts

The pressure integrity of a component can be jeopardized by using replacement parts that were not manufactured by the Original Equipment Manufacturer. IADC Safety Alert 06-11 discusses a failure that occurred at 14,000 psi on a component that was originally designed and tested to 22,000 psi. The MMS does reference that appropriate section of API RP #53 that discusses OEM spare parts. The value of OEM spare parts should continue to be emphasized. (See Attachment W)

Additionally, in this Safety Alert, it was mentioned that the threads that failed were not periodically inspected or addressed within the planned maintenance system. This is a good example of how the working pressure of a component can change over time due to, in this case, corrosion on threads.

C. Milling Operations

During some drilling operations, like milling, the annular element pressure capability can change rapidly over time.



In the case illustrated below, swarf resulted in the failure of a Shaffer annular to contain wellbore pressure. The piston was scratched and wellbore pressure leaked into the open operating chamber.

D. Effects of Various Compounds On BOP Elastomers

H_2S alters the structure of the nitrile, causing hardening and decreasing elongation and tensile strength. High temperatures also degrade nitrile properties. These effects are described in “Effect o Hydrogen Sulfide on Nitril Elastomers”, Hydril Engineering Bulletin 93001 (See Attachment X).

Drilling and completion fluids can negatively affect the elastomers used for sealing. One example of how this was recognized and communicated was "Zinc Bromide Brines can attack Nitrile Elastomers in BOPs", Hydril Engineering Bulletin #92004 (See Attachment Y). This includes the aging effects of nitrile rubber due to temperature, a significant factor.

The annular packer pictured in the next four photographs was attacked by completion fluid. It is not known if the packer failed in service or failed to test. Note the separation on the inside of the packer.

Packer was photographed right side up in the following three photos.

In the following illustration, the annular was photographed upside down. This shows the rubber separation from the segments.

Temperature Effects on BOP Elastomers

As service temperature increase above threshold limits, changes in BOP elastomers result in failures. In *"Design and Qualification Challenges for Mud-line Well Control Equipment Intended for HPHT Service*", the authors Mike Berckenhoff, PE, and David Wendt, Hydril Company discuss these temperature effects, as well as provide recommendations for improved testing and qualification. A partial list of some improvements that should be incorporated in the API spec 16A, annex D high temperature testing follows. Fluid compatibility testing should also be addressed.

1. Use of ram locking systems is not addressed.
2. Annular BOPs are not wellbore tested at low pressure.
3. Pressure vessel calculations at higher than ambient temperature should include a reduction in the steel's strength.
4. Extended hold times should be specified, as well as providing definitions for the terms "continuous" and "intermittent" used in current product specification sheets.
5. Elastomers should be exposed to an extended high temperature soak prior to testing.
6. Multiple cycles of pressure tests should be run to determine the fatigue life of elastomers at elevated temperature.
7. Chemical compatibility testing does not have to be conducted at the highest temperature and pressure experienced by the equipment.
8. Standard classes of chemical concentrations should be defined.
9. Currently, not only does the equipment not get tested for pressure, temperature, and fluid compatibility simultaneously, but the test samples are sized for use in standard elastomer testing equipment.

Recommendation: Upgrade API Specification 16A annex D on design temperature verification testing.

E. Sealing Characteristics

To safely use BOP equipment, the capabilities of the equipment must be defined and available to engineers operating this equipment. Three operating modes negatively impact the ability of ram type BOPs to seal MWP:
1. Hang-off,
2. Stripping, and
3. Shearing

API Specification 16A, section 5.9 “Operating Manual Requirements” states that the Operating Characteristics Summary should be included for the equipment on the rig. Testing should be conducted as per Annex C of 16A. This annex is identified as informative (not mandatory), and the characteristics are generally not available as noted. This information must be on the rig to allow personnel to know equipment limitations and thus safely operate this equipment under severe conditions. Tests suggested in Annex C include not only the aforementioned operating modes, but also the equipment and other parameters that define capabilities, namely:

1. Sealing characteristics
2. Fatigue
3. Ram and connector locking devices
4. Ram/packer access

Hang-off

Ram BOPs affect a wellbore seal by sealing two areas, the area between the ram block and the drill pipe involving the front packer, and the area between the ram block and the cavity involving the top seal. When pipe is hung off, weight is supported by the ram blocks, which results in the application of downward (separating) forces in the block/cavity seal area. The recommended 16A Annex C testing currently does not specify a minimum allowable hang-off weight, but rather a testing and reporting protocol that only requires stating the weight that can be hung off while maintaining the wellbore seal.

Hang-off tests with locking systems only are discussed in Attachment H. This is a graphic example of when we need hang-off capability, after an EDS with the LMRP disconnected, the rams have the least capability. Again, this puts emphasis on the ram locking systems importance in well control.

Stripping

The stripping process understandably involves significant and rapid wear of the ram front packers. As with hang-off, the recommended 16A Annex C testing currently does not specify a minimum allowable stripping length, but rather a testing and reporting protocol that simply requires stating the distance that can be stripped while maintaining the wellbore seal.

Mud Weight

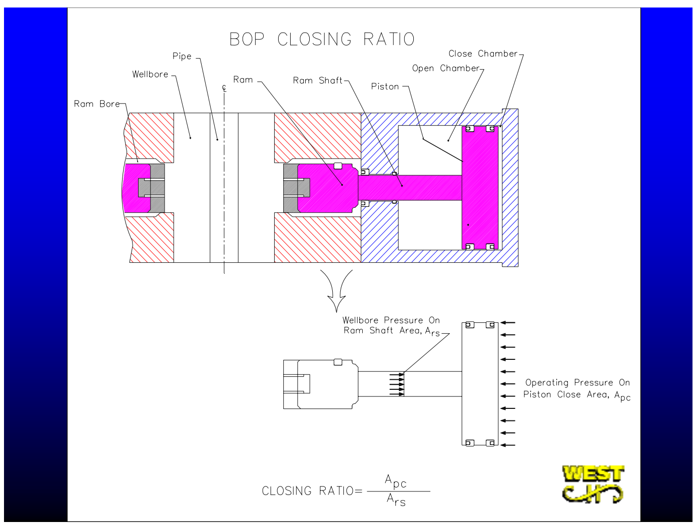
The down hole pressure that results from mud is a function of both the height of the mud column and the mud density. Just as with shearing, increased mud weight applies an opening force on the ram shafts. This force must be taken into account when defining closing ratios and shearing capability. This factor is not addressed in the current API Spec 16A recommended operating characteristics.

Shearing

Because shearing pipe is the last line of defense in well control, assurances that this will successfully occur when needed are critical. Advances in modern drill pipe metallurgy as well as the utilization of larger drill pipe sizes have resulted in shearing challenges. Typically, the closing ratios, discussed below, are the major factor when determining ram shearing capability. One result has been the need to install boosters to some shear rams. After shearing, the higher wellbore pressure assists the shear ram seal. Wellbore pressure under an annular and high mud weight in deep water also work to reduce ram shearing capability.

F. Ram Operating Ratios and Closing Ratio

Operating ratios are used to calculate the pressure required to affect ram functioning. The figure below shows how the closing ratio is calculated, as well as how the force to close and seal the rams is generated through the piston and into the connecting rod.



After the closing ratio is computed, the closing pressure can then be calculated by:

Closing pressure required at MWP = MWP / Closing Ratio

Closing ratios for various rams are listed below.

Sealing Characteristics Test
Closing Ratios
15K Rams

Model (18 ¾" 15K)	Closing Ratio	Closing pressure required (MWP in wellbore)
Cameron Model T	6.7	2239 psi
Cameron U II	7.6	1974 psi
Hydril	7.27	2063 psi
Shaffer with 14" pistons	10.85	1382 psi

Excluding the effects of mud weight in the wellbore.

Sealing Characteristics Test
Closing Ratios
10K Rams

Model (18 ¾" 10K)	Closing Ratio	Closing pressure required (MWP in wellbore)
Cameron U II	6.7	1492 psi
Cameron U	7.4	1351 psi
Hydril	10.6	943 psi
Shaffer	7.11	1406 psi

Excluding the effects of mud weight in the wellbore.

Consider the case of the need to close a set of rams beneath the UPRs (Upper Pipe Rams) with MWP contained under the UPRs. The Cameron Model T has a closing ratio of 6.7:1. At 15,000 psi pressure, this ram will take 2,238 psi of operating pressure to be in equilibrium with the wellbore pressure. With 3,000 psi operating chamber ratings, the remaining 762 psi is all the pressure available for creating adequate packer pressure for a seal.

Normal operating pressure for wellbore testing rams is a minimum of 1,500 psi for pipe rams and frequently 2,300 psi for variable bore rams. Current testing standards are to close the ram, then apply pressure under the rams. Closure testing with pressure under the ram already applied as in the example is not done. In this case, the wellbore assist feature of the ram is not available. Therefore, if the MWP rating were increased, the force generated by the wellbore pressure keeping the rams open is also increased. This then reduces the amount of packer pressure that can be generated by the operating pistons.

<u>Recommendation:</u> Develop wellbore testing techniques to demonstrate rams are capable of closing and achieving a seal at elevated wellbore pressures.

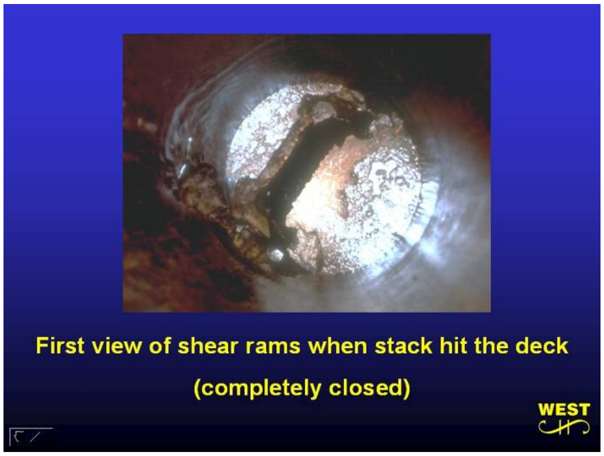
G. Ram Locking Systems

Ram locking systems are designed to maintain packer pressure when the close operating pressure is vented, an example being when the LMRP (Lower Marine Riser Package) is disconnected. Prior to disconnecting the subsea LMRP, the pipe and shear ram type BOPs are closed and the locking system secures them in place. If the ram locking system does not maintain adequate packer pressure with operating pressure vented, wellbore integrity is lost and a leak begins. Maintaining this capability on a subsea stack is crucial.

The forces involved with locking systems are many. It is common for packer pressure to be reduced when operating pressure is reduced, as some opening travel is generally expected before the locking system stops movement. Additionally, reduced packer pressure occurs due to the "loose" fit of the operating rod button. Required API Spec 16A Annex C testing recommendations are minimal, only 16 cycles; the Spec specifically states they can be tested at the same time as hang-off tests.

As can be expected, there are a variety of designs for rams currently in service. Those of perhaps the most interest work on applications designed to seal on a range of pipe sizes, alternately called variable bore or multi-rams. However, in many applications, these same locking systems are utilized on fixed pipe rams as well.

The shear rams shown below are in the fully closed position. Violent wellbore flows eroded the steel over time.

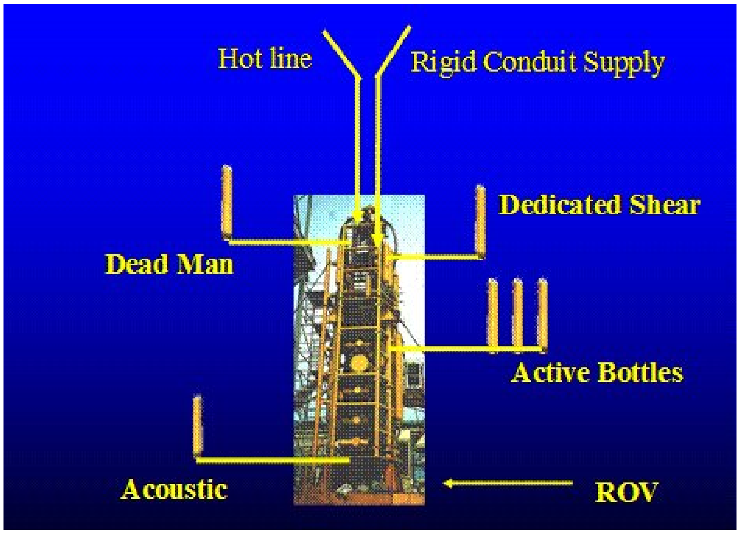


Effective testing of locking systems is much better today than in the past. Current requirements in both API Spec 16A and RP 53 recommend testing locking systems by closing and then venting close operating pressure prior to pressure testing. Although this requirement has always been in Spec 16A, it was only included in RP 53 in the most current edition.

Recommendation: Wellbore tests using the ram locking system only (without close operating pressure) should be conducted at some frequency. The methodology that each rig uses should be defined by the equipment owner. Ram locking systems are fragile and a significant contributor to downtime. The owner should be responsible for defining procedures that optimize reliability.

H. Accumulator Volume

Accumulator volume is calculated based on the hydraulic fluid required at a given pressure, and thus is dependent on the closing ratio. Required operating pressure will change if this equipment is operated in excess of MWP.

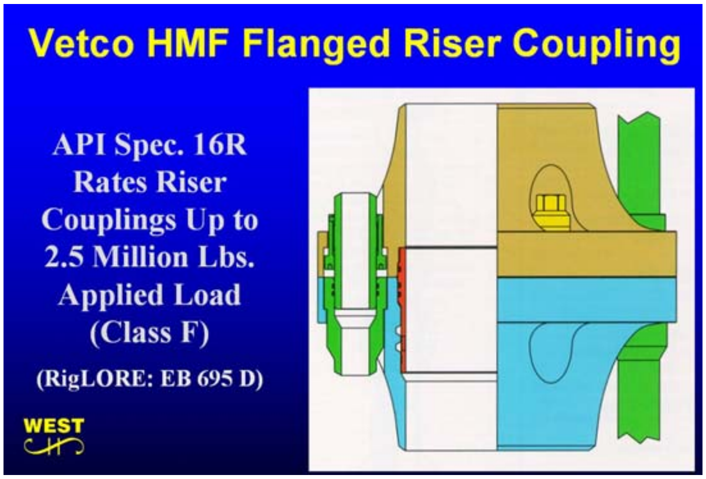


I. High Pressure Piping

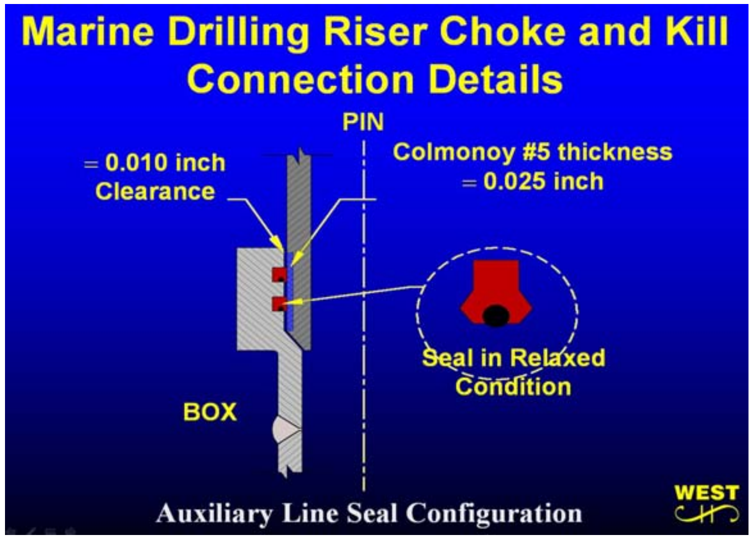
During an attempted pressure test to 10,000 psi, the high pressure piping below failed at 8,000 psi. The elbow that failed was at a walkway. In this instance, most of the corrosion occurred on the outside diameter of the elbow.

J. Marine Drilling Riser

Numerous choke and kill auxiliary line seals must be considered when a BOP stack is deployed in deep water. During factory acceptance testing, these lines are tested to 1.5 times MWP. However, over time the capability to seal against MWP will decrease.



Manufacturers achieve the 15,000 psi working pressure of the choke and kill pin/box arrangement by tightly controlling tolerances between the pin and the box to prevent extrusion of the seal.



Over time, corrosion in the choke or kill box will cause pitting. This pitting reduces the ability of the polypack to seal on the static outside diameter of the seal.

The auxiliary line pin must have a high surface finish to maintain the dynamic seal required. Scratches damage the polypack seal and introduce leak paths.

K. Poor Boy Degassers

A poor boy or mud-gas separator is an essential item of well control equipment that is required on all drilling rigs. It is installed downstream of the choke manifold in order to separate gas from the returning drilling fluid when circulating through the choke manifold or during kick situations. This allows a method for safely venting the gas and returning usable liquid mud to the active system. Small amounts of entrained gas can then be handled by a vacuum degasser located in the mud pits.

Recommendation: The MMS should supplement the minimum standards API publishes on Poor Boy Degassers. Several good references exist, as listed below. The writer is most familiar with reference 3, which provides excellent guidelines.

REFERENCES

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2. Bourgoyne and Holden: **"An experimental study of well procedures for deep water drilling operations"**, Journal of Petroleum Technology, July 1985.

3. Turner, E.B.: **"Well Control When Drilling With Oil-Based Mud"**, Offshore Technology Report OTH 86 260, UK Operations & Safety, Department of Energy, London, Oct. 1986.

4. **"Offshore Drilling Vent & Discharge Systems"** ECI Upstream Design Standard, first edition, October 1995.

5. Grigg, P. C.: **"The Poor Boy Degasser as a Well Control Tool",** paper presented at the IADC/CAODC 1980 Drilling Technology Conference.

6. Butchko, D., Davies, G. E., Fuchs, G. T., Reid, R. R.: "***Design of Atmospheric Open-Bottom Mud/Gas Separators***", paper SPE/IADC 13485 presented at the 1985 SPE/IADC Drilling Conference, New Orleans, March 5-8, 1985.

Wellheads

No additional requirements other than mentioned for Drill Through Equipment

Section 9: MASP – Maximum Annular Surface Pressure

By Charles Prentice, Prentice Training Company

A critical parameter in all discussions of equipment pressure ratings is how the pressure requirements are calculated. It must be known to develop casing burst, drill through equipment pressure ratings and completion/testing equipment, and depends on the design value of surface pressure. This value is known as Maximum Annular Surface Pressure, MASP for short. This discussion of MASP provides an discussion of key parameters as well as some recommended procedures for calculating it. It is important to remember that MASP represents an internal loading, a burst load.

There are two different values of MASP that are used in the design of a well. The first is for drilling applications. The second value applies to completion and production considerations.

For drilling applications, MASP is controlled either by the highest RP (Reservoir Pressure) in the hole interval or by the down hole formation strength. The down hole formation strength, in this discussion, will be called the Injection Pressure (IP) and is the fracture gradient, at the weakest point in the open hole, plus some defined safety factor.

For completion/production applications MASP is controlled RP.

In both cases, MASP is equal to the down hole controlling value (IP or RP) minus the hydrostatic pressure of fluid(s) from the controlling depth tvd (total vertical depth) back to surface.

A. A Standard Is Required For Calculating MASP

There is no standard petroleum industry procedure for calculating MASP. The values for gradients and lengths of the fluid(s) in the wellbore are arbitrary and vary significantly from operator to operator. Even saying the fluid, or at least one of the fluids, is to be gas doesn't address the determination of the gas gradient to use in hydrostatic pressure determination. If there is to be more than one fluid, the density and therefore gradient, of the second fluid is not a standardized value. Further, if there are to be two fluids in the wellbore, their orientation (which is on top, which below) is also not a stated standard. When two fluids are used, their lengths are currently based on either volumes or percentage of evacuation. All of these possible variations lead to very different values for MASP, for the same well, by different engineers choosing the parameters and doing the calculating.

Consider the simplest application of MASP, the one for completion/production considerations. This MASP is equal to reservoir pressure minus the hydrostatic pressure of a true vertical column length of the lightest possible fluid produced. This fluid will generally be considered as hydrocarbon gas and the determination of its gradient should be standardized. Use of the Nagy and Young algorithm (or some similar, but standard, algorithm) should be mandated so everyone will calculate the same value for MASP.

B. Nagy Young Algorithm

$$G_{g(psi/ft)} = .0966 + \left[.0032(FP_{(ppg)})\right] - 260 / D_{(tvd,ft.)} \quad (NagyYoung)$$

Note: Nagy Young algorithm breaks down for producing depths less than 2500 feet.

$G_{g(psi/ft)}$ = Gas gravity in pounds per square inch/foot
$FP_{(ppg)}$ = Formation Pressure in pounds per gallon, and
$D_{(tvd, ft)}$ = Depth in feet

With the reservoir pressure and true vertical depth known and a standardized method of assigning gas gradient in place, the value of the completion/production MASP will be calculated the same by everyone.

$$MASP = P_{reservoir(psi)} - (D_{reservoir(tvd,ft.)} G_{g(psi/ft.)})$$

For drilling applications, there are two different possible values for MASP. Either the injection pressure or the reservoir pressure will provide the value of MASP. Both must be calculated and the lesser of the two is to be used.

A single fluid column (dry gas) can be used for drilling applications just as it is for completion/production considerations. This is commonly done for surface casing strings. If a single column of fluid is used for intermediate casing and drilling liner applications, unrealistically high requirements for casing burst design and drill through equipment ratings result. As a result, the industry uses and worldwide regulatory bodies generally allow a two fluid loading in determining MASP for these applications. To provide maximum safety (give highest MASP) the two fluids should be:

1. Dry Gas (Gradient calculated as before).
2. The lowest density liquid planned for use in the applicable open hole section.

In every case, this combination of fluids will result in the smallest fluid hydrostatic pressure value to subtract from RP or IP to obtain MASP. In addition, the lowest density liquid should be considered as the top fluid in the loading. This allows the gas to remain in contact with and at equilibrium with its source, so its density and therefore gradient will be maintained. From a practical perspective, gas migration through the overlaying mud column happens very slowly due to the mud properties. Considering this and the urgency with which well control events are resolved, not to mention the high cost of operation in many drilling and completion programs, the effect of this assumption is negligible. Accordingly, no expansion of the gas is to be considered.

The length of the two respective columns must always add up to the true vertical length of the subject casing string(s). The length of the gas is always the critical value. This length is determined by some based on a volume of influx. Others simply use a percentage of the total true vertical length evacuated to gas. This percentage of evacuation varies from 40 to 70 percent, depending on the operating company and/or depth of the pertinent casing string setting depth. This can be simplified and, in the process, made even safer for the well design.

With this background, it is therefore proposed:

1. Allow the choice of single fluid (dry gas) or two fluid loading for any drilling application calculation of MASP. This choice means there is still one possible difference in MASP calculations. This is recommended to accommodate the fact that systems with shallow set casing strings CAN be totally evacuated and need to be designed accordingly, while it would be unrealistic to design systems with deeper strings, set into high pressures for total evacuation.

2. For the two fluid loading, set the primary fluid as dry gas with a gradient calculated using Nagy Young Algorithm and having a fixed length of 60% of the true vertical section of the cased hole. Also consider the entire hole below casing to be gas filled. This recommended 60% is around the median of evacuation percentages quoted in regulations, and is as technically validated as any other number.

3. Use the lowest density liquid envisioned for use within the section as the second fluid, and positioning this liquid on top of the gas.

4. Use the best estimate of the lowest fracture gradient within the pertinent interval with a safety factor (suggest 1.0 ppg as generally adequate) added for determination of IP.

5. Calculate the hydrostatic pressure for each of the two fluids and add them together.

6. Subtract the sum of the two hydrostatic pressures from the IP to obtain MASP 1.

7. Calculate the RP of the highest pressured permeable zone within the pertinent interval.

8. Subtract the sum of the two hydrostatic pressures from the RP to obtain MASP 2.

9. Always use true vertical depth for hydrostatic pressure calculations.

10. Compare MASP 1 and MASP 2, and use the smaller of the two.

Note: The use of the smaller value might appear to be in conflict with the idea of maximizing safety, but it is not. The use of a value for MASP in design MUST make sense.

- *A. If the highest pressured formation in any section of hole does not contain pressure high enough to equal or exceed the injection pressure, then the MASP value based on the RP is the highest possible surface load for that interval.*
- *B. If the IP is exceeded by the possible load from a hole interval, then surely the formation will fail and act as a "relief valve", limiting the surface value of MASP to that controlled by the IP.*

C. Subsea Applications

If the wellhead for a well is on the seafloor, displaced by more than 500 feet from sea level, the definitions pertaining to MASP have to be altered. Subsea situations are different in 4 ways.

1. IPs and RPs, which use equivalent mud weight values to denote pressures/strengths, must be calculated using true vertical depths with the RKB (Rotary Kelly Bushing) as the reference datum.

2. The values of MASP now apply to seafloor depths, rather than to the surface and might be more appropriately labeled Maximum Allowable Seafloor Pressure.

3. For drilling applications, the decision has to be made concerning evacuation to gas. If the previously recommended 60% evacuation is to be used, then what interval is to experience the evacuation? If from casing seat to RKB, most deepwater wells will have the entire cased hole interval evacuated. This is still unrealistic. If the interval is to be from the casing seat to the seafloor, this will result in MASP values similar to those for surface wellheads, BOPs, Christmas trees, etc. This is the recommended procedure.

4. For casing design considerations, MASP will be the same as for surface conditions, BUT for drill through equipment and Christmas tree considerations, there will be external pressure, in the form of seawater hydrostatic, that could be subtracted from internal pressure to determine net burst load. It is recommended however, that MASP remain the internal pressure value. For design work, the external pressure can be subtracted from MASP for net load; BUT MASP should remain the internal pressure value.

D. Example Calculations:

Problem 1a. Drilling application for a surface system for the hole section below Intermediate casing. Two fluid loading. 1.0 ppg safety factor on IP.

Casing setting depth = 10,600 ft.(tvd)
Lowest open hole fracture gradient = 17.2 ppg @ 10,600 ft. (tvd)
Highest pressured formation in open hole interval = 16.1 ppg @ 13,950 ft. (tvd)
Lowest mud weight to be used below the casing = 11.8 ppg

G_g = .0966+[.0032(16.1)-(260/13,950)] = .1295 psi/ft

IP = (17.2 + 1.0) (.052)(10,600) = 10,032 psi

RP = 16.1(.052) (13,950) = 11,679 psi

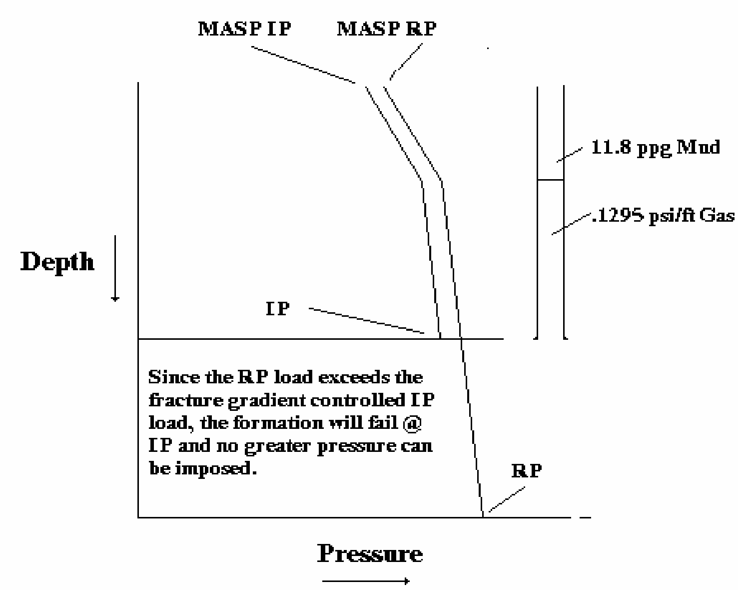
Evacuation in casing = 10,600 (.6) = 6,360 ft. (4,240 ft to 10,600 ft)

Total evacuation = 13,950 – 10,600 + 6,360 = 9,710 ft. evacuated to gas.

$MASP_{IP}$ = 10,032- [4,240(11.8) (.052)+6,360(.1295)] = 6,607 psi

$MASP_{RP}$ = 11,679 – [9,710(.1295) + 4,240(11.8)(.052)] = 7,820 psi

Correct MASP = MASP IP = 6,607 psi



NOTES:

1. Gas gradient figured from highest pressured source in the open hole interval, OR from a target reservoir in the hole interval.
2. The standard 60% evacuation to gas always to be inside the casing.
3. For RP calculation, it is assumed the hole is further evacuated to gas down to the reservoir source.

Problem 1b. Drilling application for a surface system for the hole section below intermediate casing. Two fluid loading. 1.0 ppg safety factor on IP.

Casing setting depth = 10,600 ft. (tvd)
Lowest open hole fracture gradient = 18.2 ppg @ 10,600 ft. (tvd)
Highest pressured formation in open hole interval = 13.9 ppg @ 13,950 ft. (tvd)
Lowest mud weight to be used below the casing = 11.8 ppg

Gg = .0966+[.0032(13.9)-(260/13,950)] = .1224 psi/ft

IP = (18.2 + 1.0) (.052) (10,600) = 10,583 psi

RP = 13.9(.052) (13,950) = 10,083 psi

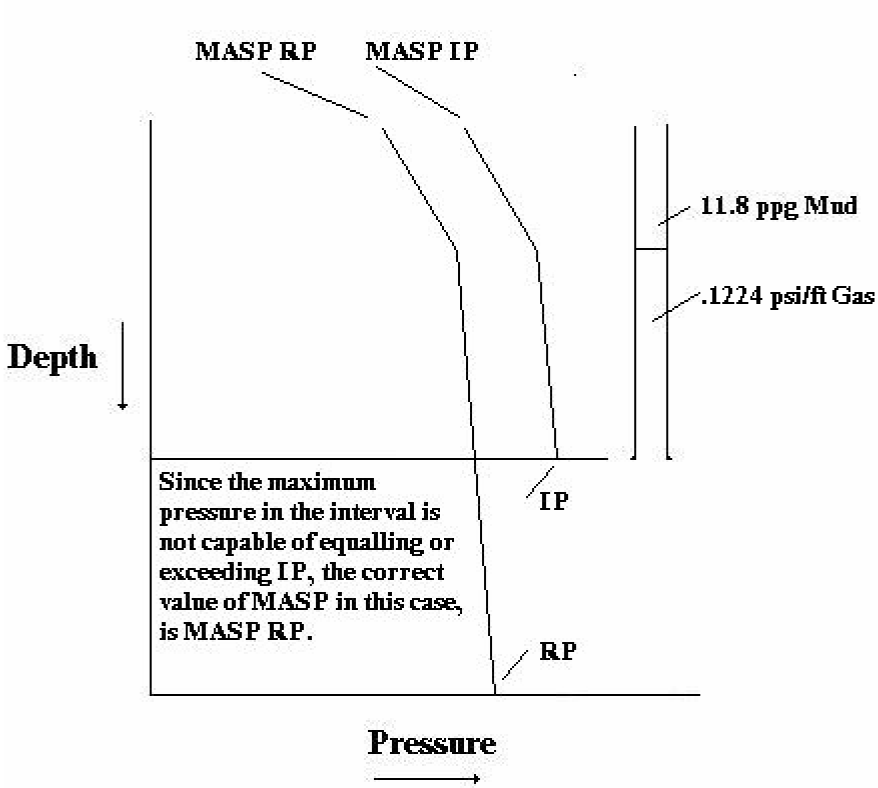
Evacuation in casing = 10,600 (.6) = 6,360 ft. (4,240 ft to 10,600 ft)

Total evacuation = 13,950 – 10,600 + 6,360 = 9,710 ft. evacuated to gas.

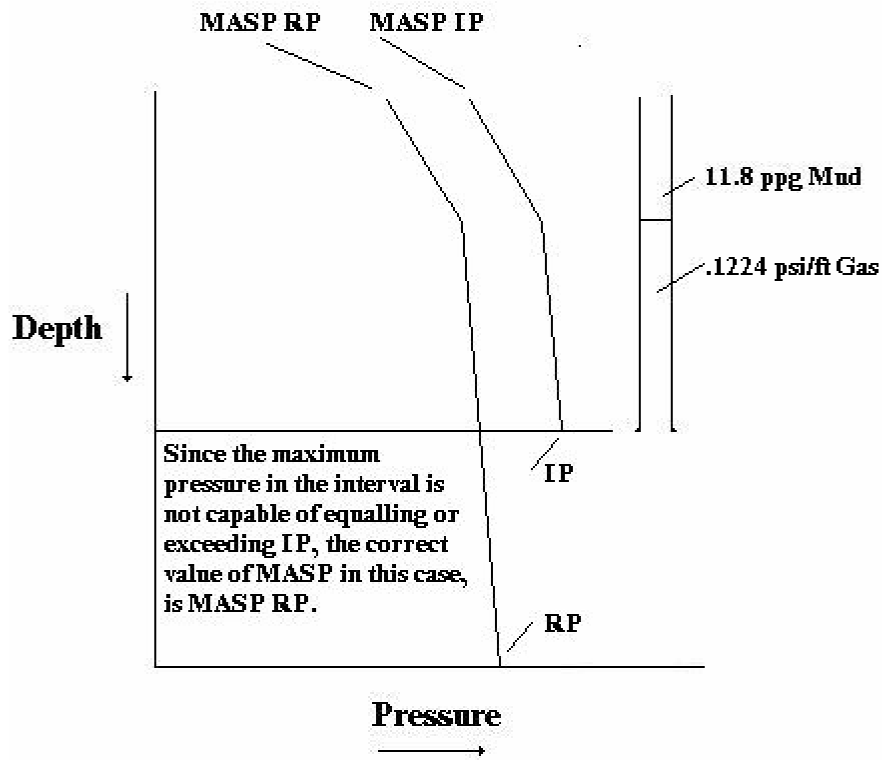
$MASP_{IP}$ = 10,583- [4,240(11.8)(.052)+6,360(.1224)] = 7,203 psi

$MASP_{RP}$ = 10,083 – [9,710(.1224) + 4,240(11.8)(.052)] = 6,293 psi

Correct MASP = $MASP_{RP}$ = 6,293 psi



Correct MASP = $MASP_{RP}$ = 6,293 psi



NOTE:

1. The RP controlled MASP is the correct value to use as the highest pressure loading possible from this interval will not reach the IP at the casing shoe, so IP is not possible.
2. Again, the fixed percentage of evacuation is inside the casing.

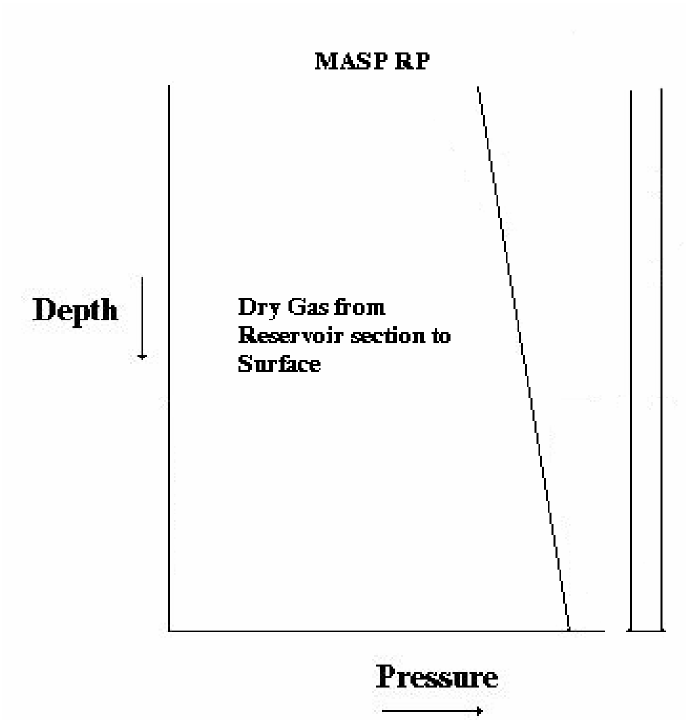
Problem 2. Completion application from a hole interval to 12,200 ft. (tvd) below a drilling liner set at 11,050 ft. (tvd).

TD = 12,200 ft. (tvd)

Producing zone pressure = 10.2 ppg

$Gg = .0966 + [.0032(10.2) - (260/12{,}200)] = .1079$ psi/ft

$MASP_{RP} = 10.2(.052)(12{,}200) - 12{,}200(.1079) = 5{,}155$ psi



NOTE:

1. Simplest of all MASP calculations.
2. RP calculated using highest pressured permeable zone expected, OR calculated using a target reservoir with known pressure.

Problem 3. Subsea environment with drilling application. Hole interval to 14,150 ft. RKB (tvd). Casing set at 11,950 ft. RKB (tvd). two fluid loading.

Water depth = 3,000 ft.
Air Gap = 70 ft.
Casing setting depth (below sea floor) = 8,880 ft. (tvd)
Minimum fracture gradient = 15.9 ppg @ casing seat.
Lowest mud weight to be used in hole interval = 10.8 ppg
Highest formation pressure in interval = 14.7 ppg.
IP safety factor = 1.0 ppg

Gg = .0966 + [.0032(14.7) – (260/14,150)] = .1253 psi/ft.

IP = (15.9 + 1.0)(.052)(11,950) = 10,502 psi

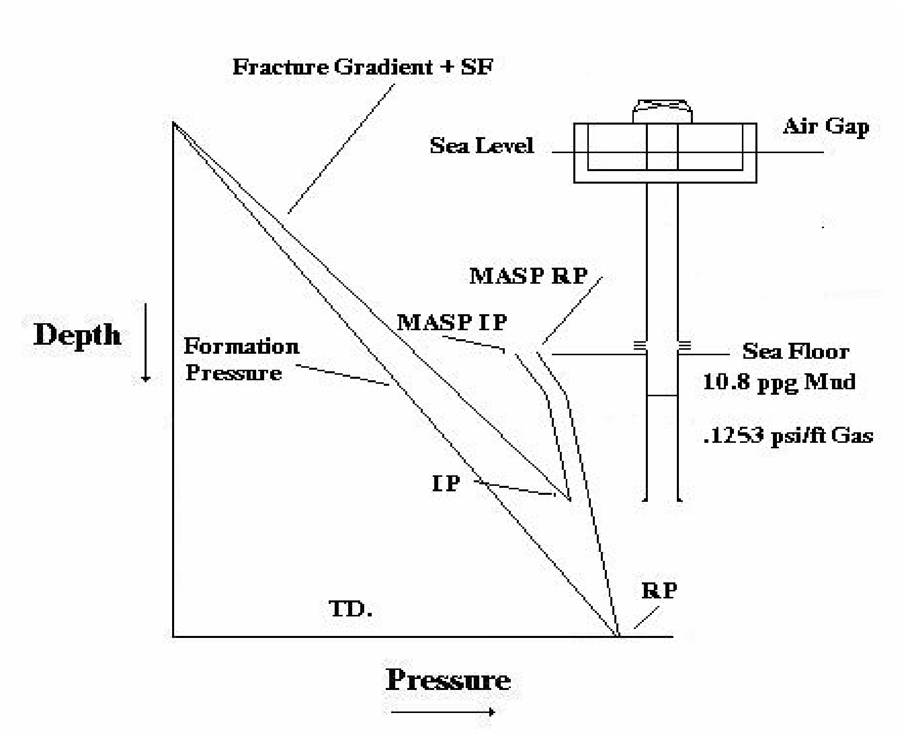
RP = 14.7(.052)(14,150) = 10,816 psi

Casing Evacuation = 8,880(.6) = 5,328 ft. (from casing seat up to 3,552 tv ft. below sea floor)

Open hole evacuation for RP calculation = 14,150 – 11,950 = 2,200 ft.

$MASP_{IP}$ = 10,502 – [5,328(.1253) + 3,552(10.8)(.052)] = 7,839 psi

$MASP_{RP}$ = 10,816 – [(2,200 + 5,328)(.1253) + 3,552(10.8)(.052)] = 7,878 psi



Correct MASP = $MASP_{IP}$ = 7,839 psi

NOTES:

1. IP calculations made using RKB tvd measurements to weakest point in open hole interval.
2. RP calculations made using RKB tvd measurements to highest pressured interval, OR target zone in the open hole.
3. MASP calculations made using measurements from seafloor down only.
4. Fixed percentage evacuation value applied inside true vertical section inside casing for both IP and RP determinations.
5. Open hole considered evacuated to gas for RP calculations.
6. Lower of the two calculated values of MASP chosen as correct value to use.

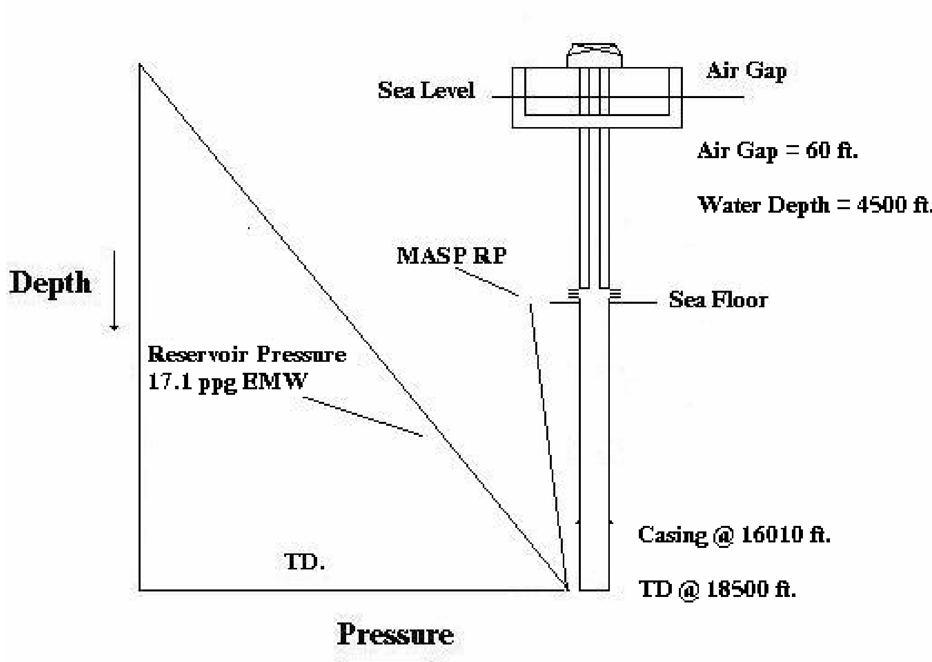
Problem 4. Subsea environment, Completion/Production application. Hole at TD at 18,500 ft. RKB (tvd) below Casing set at 16,010 ft. RKB (tvd).

Water Depth = 4,500 ft.
Air Gap = 60 ft.
Reservoir Pressure = 17.1 ppg @ TD.
True vertical depth below the seafloor = 18,500 – (4,500 +60) = 13,940 ft. tv length.

Gg = .0966 + [.0032(17.1) – (260/18,500)] = .1373 psi/ft

Formation pressure = 17.1(.052)(18,500) = 16,450 psi

$MASP_{RP}$ = 16,450 – 13,940(.1373) = 14,536 psi



NOTES:

1. RP calculated using RKB (tvd) measurements.
2. MASP calculated using seafloor to TD (reservoir depth) true vertical length measurements.
3. MASP considered to be *ONLY* internal pressure. Even though there is 4,500 ft. of 8.6 ppg seawater hydrostatic pressure (2,012 psi) outside the completion/production and wellhead equipment, this pressure is not considered in the statement of MASP. The 2,012 psi *should* be subtracted from MASP for actual design considerations, because it is, and will always be there and certainly affects design loading.

Section 10: Coiled Tubing

By Marshall Johnston, WEST Engineering

Marshall worked for Schlumberger for 17 years, seven of those years he worked in the coiled tubing department as a supervisor in the North Sea.

When asked about his experiences with coiled tubing equipment being operated at a pressure greater than MWP, his response was "never". See "Standard Operating Procedures", below.

A. Intervention In A Live Well

The impact of an operational failure during coil tubing (CT) intervention is typically more severe than that of other failures because of the nature of the activity. Failure of the tubing or any component of the well intervention process in a live well scenario can compromise well control and/or the safety of personnel. As a result, it has always been considered an industry "best practice" to avoid working at pressures above maximum rated working pressure of well control equipment.

B. De-rating Coiled Tubing

De-rating of coiled tubing pipe is an important part of coil tubing operations. Every time the tubing is bent, it is fatigued. This fatigue is most prevalent at the coil tubing reel and at the injector head gooseneck. Considered along with well environmental conditions such as the presence of H_2S, pressures inside and outside the tubing, stripping and/or snubbing forces, etc. these conditions are used in determining pipe life. Reference API RP 5C7 Section 5 for coil tubing string design and working life.

C. Operating Above MWP

The use of any well control equipment, including coil tubing BOPs and strippers at pressures above the MWP is not standard operating procedure and should only be allowed under the most extreme circumstances. As reflected in the MMS response to Comment 250.616(a)(2), 30 CFR Part 250; the attempt to change pressure testing regulations to allow for testing at less than MWP was not implemented. The practice of testing to MWP is viewed as an industry best practice. This should also hold in cases involving operations exceeding MWP of the well control equipment.

The following is taken from the *Schlumberger Contingency Procedures for Coiled Tubing Operations.*

1. Emergency BOP Functions:

The pressure control equipment should be used to secure the well (including cutting and dropping tubing) anytime the wellhead pressure:

- Exceeds the maximum well control pressure (MWCP) for that category, or
- Exceeds the maximum test pressure off the well control equipment"

Appendix C of API RP 5C7, Emergency Responses and Contingency Planning, Section C.1 does not specifically list over pressuring equipment as an emergency situation but does state the proper response for emergencies situations where the well must be secured is shearing pipe and killing the well.

A conflict does exist between API RP 5C7 and MMS 30 CFR, Part 250 in regard to the annular type Preventers. API RP5C7, Section 6.10.2(a) allows testing of annular type components below the sealing element to 70% of their rated working pressure. MMS 30 CFR Part 250.615 (2) simply states all BOP system components must be tested to the rated working pressure. Also, Section 250.451 of 30 CFR states that *"…well control procedures or the anticipated well conditions will not place demands above its rated working pressure…"* in response to the problem of using an annular BOP with a rated working pressure less than the anticipated surface pressure.

Case histories: In an examination of past incidents, as listed in Offshore Minerals Management OCS-Related Incidents, it is apparent that over pressuring of well control equipment is an uncommon occurrence. The cases studied indicated that the loss of well control was related to human error and/or mechanical failure. The most severe incidents involved pipe failure brought about by human error. In none of the cases studied was it apparent that any attempt was made to work at pressures exceeding rated working pressure.

ATTACHMENTS

(Attachments Z-HH are linked here)

A. "WESTScope" – choke and kill hose inspection frequencies

B. Subsea BOP Stack Drawing, 1 page

C. Surface BOP Stack Drawing, 1 page

D. Performance based Check List to estimate capabilities

E. MMS-319 *Reliability of Subsea Blowout Preventer Systems for Deepwater Applications--Phase II,* (http://www.mms.gov/tarprojects/319.htm)

F. Montgomery, Michael, WEST Engineering. Oil and Gas Journal article, "*Testing Improves Surface BOP Equipment Reliability"*.

G. Reference MMS Safety Alert #231, "Human Engineering Factors Result in Increasing Number of Riser Disconnects".

H. "Inspection and testing procedures improve BOPs for HPHT drilling", Oil & Gas Journal, Feb 1995

I. "More BOP Equipment HPHT Considerations", IADC Aberdeen Conference, May 1996

J. API 6A Specification Historical Information—Listing of all proof testing requirements for wellhead equipment from API Standard 6A, 7th edition forward

K. API 16A Specification Historical Information—Listing of all proof testing requirements for wellhead equipment from API Standard 16A 1st edition forward.

L. BOP and Connector Adjusted Ratings—Listing of all adjusted BOP and Connector ratings. This value is calculated by multiplying the current standard by the adjustment factor.

M. Valve Adjusted Ratings—Listing of all adjusted Valve ratings. This value is calculated by multiplying the current standard by the adjustment factor.

N. Snorre B – BOP Stack drawing

O. API Scoping Document – Project Objectives and Deliverables, "RP for Equipment Rated at Greater than 15,000 psi 12 pages

P. MMS Application for Permit to Modify (APM) - #124, 2 pages

Q. MMS Reference Specific Sections of API RP #53

R. MMS Project #01-99-PO-17072, dated August 2000, "Evaluation of Suitability of Industry Standards as MMS Requirements"

S. Definitions to understand British Regulatory Terminology

T. Test mud – The effect of Hydrostatic Head

U. Shaffer 18-¾" Packing Elements, PIB PC-01-001-CPH

V. Cameron 18-¾" 10K Annular Stripper packer, 2 pages

W. Near Miss – Equipment Failure at 14,000 psi, IADC Safety Alert 06-11

X. Effect of Hydrogen Sulfide on Nitrile Elastomers, Hydril Bulletin 93001

Y. Zinc Bromide Brines can attack nitrile elastomers in BOPs, Hydril Bulletin 92004

Z. MMS Incidents – Loss of Well Control (GOM) 2005

AA. MMS Incidents – Loss of Well Control (GOM) 2004

BB. MMS Incidents - Loss of Well Control (PAC) 2004

CC. MMS Incidents - Loss of Well Control (GOM) 2003

DD. MMS Incidents – Loss of Well Control (GOM) 2002

EE. MMS Incidents – Loss of Well Control (GOM) 2001

FF. MMS Incidents – Loss of Well Control (PAC) 2001

GG. MMS Safety Alert #187 – Coiled Tubing Incidents, April 2000

HH. MMS Safety Alert #171 – Reports Concerning Blowouts, August 1997