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High Temperature Elastomer Study for MMS

**MMS HPHT WEST Job #2934
MMS TA&R Project Number 621**

2 June 2009

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Reference List

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Figure List

- Fig. 1** Comparison of fixed and variable bore ram designs in plan view.
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Acknowledgment

The primary investigators for this study were Jeff Sattler and Eric Deutsch. The authors would like to thank Tom Bishop, Kristen Bolen, Greg Childs, Ranson Fullinwider, Ed Lewis, Tracy Nobra, John Penewitt, Michael Rowan-Legg, and Raleigh Williamson for their contributions.

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In order to evaluate the current status of HPHT (High Pressure, High Temperature) well operations, WEST was contracted to evaluate risks and identify limitations of the BOP (Blow Out Preventer) equipment in this service.

Executive Summary

High temperature limitations on elastomer products installed in BOP equipment were researched on the basis of information contained in WEST's database of rig inspections, WEST's previous reports on the subject, a survey of major manufacturers in the industry, and publically available materials.

Highlights of the findings include:

1. Most manufacturers perform temperature tests according to API 16A, which only specifies a 1 hour hold at high temperature. Some then provide an "intermittent" or "excursion" rating at the API test temperature along with a "continuous" rating at a lower value. Others simply quote the API test temperature as a single rating. Therefore, the methods by which ratings are derived are not consistent between manufacturers. In any case, most sources agree that the API test does not adequately address the performance of these elastomers under real-world conditions, resulting in all manufacturers performing testing in excess of 16A recommendations.
2. Most experts surveyed agree that the API test should specify a longer hold time at high temperature in order to form a more meaningful test result. Also, it is suggested that a more consistent and comprehensive temperature rating method be specified, involving a safety factor or multiple testing points.
3. An additional test requirement might be to soak elastomeric components at high temperature prior to installation in the test BOP.
4. Thermal modeling with FEA methods is an excellent tool by which to fine-tune BOP seal requirements. By constructing a model that accurately represents BOP geometry and heat transfer characteristics, then applying realistic boundary conditions, an engineer can arrive at a temperature distribution through the assembly. This thermal map predicts temperatures at seal locations and thereby guides the selection of appropriate seal materials for the application in both subsea and surface service.
5. Elastomer compatibility in various fluids is another issue identified as worthy of further study. Current testing is along the lines of ASTM coupon tests, and it is doubtful this sort of test accurately reflects the ability of a particular seal geometry to perform successfully in the real BOP.

Compatibility issues assume additional importance when considered in conjunction with HPHT conditions.

Details of WEST's findings can be found in the following pages.

1) Definitions

BOP	Blow Out Preventer
DST	Drill Stem Testing
FEA	Finite Element Analysis
FoS	Factor of Safety
HP	High Pressure (generally over 10000 psi)
HT	High Temperature (generally over 250 °F)
HPHT	High Pressure / High Temperature referring to a set of wellbore conditions that require specialized equipment to handle outflows.
ID	Inner Diameter
MAWP	Maximum Allowable Working Pressure
OD	Outer Diameter
QC	Quality Control
VBR	Variable Bore Ram

2) Introduction

Since the advent of oil drilling, High Pressure, High Temperature (HPHT) well conditions have always been interesting to BOP manufacturers, operators, contractors, and regulators because they represent the upper limit of equipment performance (or performance envelope of the equipment). A BOP is primarily a safety device and is expected to perform flawlessly for all anticipated drilling, completion, and workover conditions. However, BOPs rely on molded elastomers to effect their containment seal, and a basic characteristic of elastomers is softening at high temperature. This softening makes it challenging to form a reliable seal at high pressure because the elastomer tends to extrude through any unsupported gaps.

In the quest for difficult-to-find oil, ever deeper and more challenging wells are being drilled. As the industry pushes towards deeper wells, drillers tap into hotter geological formations. Since safety is paramount at these drilling depths, it behooves the industry to investigate the state of HPHT technology every few years, looking for advances/breakthroughs in technology or required revisions to existing standards. The present study builds upon previous studies from the mid 1990s and assesses the changes since then.

3) Study Methodology

This study primarily made use of three sources of information. The first of these was in-house WEST files including prior reports, rig assessments, tests witnessed, training materials, technical bulletins, etc. Also, several staff experts each with 20+ years of experience in the BOP industry were consulted. One of these was engineering manager for one of the big three BOP manufacturers until 1994. The second source of information was a survey of Original Equipment Manufacturers (OEMs) in which a questionnaire was mailed out to three companies that make BOPs and their answers analyzed. Meetings were requested and one OEM allowed both a plant tour and question session, while another gave only the plant tour. The third source of information was publically available materials such as online marketing literature, articles in trade journals, and technical papers.

The study began with a review of prior reports and industry literature. API Spec 16A was read in order to gain insight into the design and testing guidelines for BOPs. Two previous HPHT studies conducted by WEST were consulted for background historical information. Also several client-specific reports were referenced because they contained information relevant to BOP elastomers in HT service.

It should be noted that RigLORE, WEST's database of OEM product bulletins and information sheets was searched for all relevant HT information. The study benefits from the information found in this research.

4) Equipment Types Covered

Ram type (particularly fixed bore rams) BOPs are the main focus, because they are the type most capable of HT service. Perhaps the best chance of sealing at HT is afforded by close-fitting fixed bore pipe rams closing on new drill pipe. Due to larger gaps between steel components that support the elastomer against applied pressure (see Fig. 1), HT ratings for variable bore packers are generally lower than those for their fixed bore counterparts. WEST is not aware of any annular type BOPs rated for greater than 270 °F. Although choke and kill valves, lines, and flexible hoses are also potentially exposed to HT formation fluids, they are not addressed here. With the goal of understanding HT elastomer performance in sealing applications, ram BOP packers emerge as the item of interest.

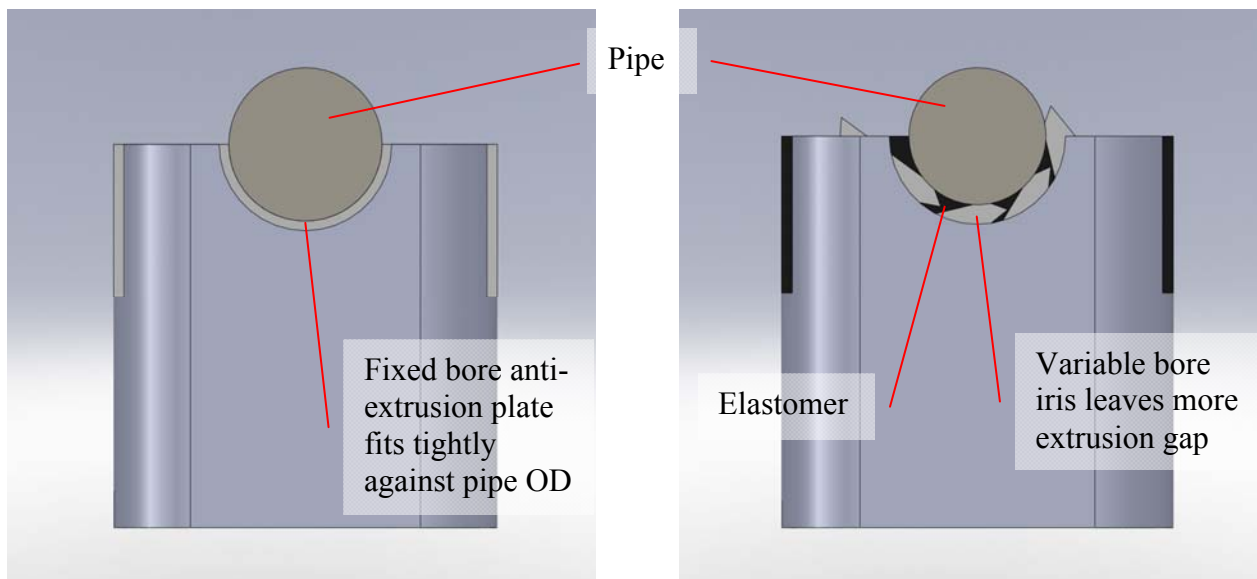


Fig. 1 Comparison of fixed (left) and variable (right) bore ram designs in plan view.

5) Technical Overview

The 18-³/₄" 15,000 psi rated BOP equipment has been available since the late 1970s. As of October 2006, there were 201 rigs utilizing subsea stacks, and an estimated 99 equipped with 18-³/₄" 15,000 psi rated BOPs. WEST is not aware of any of this equipment that has experienced a body failure after having completed all quality inspection and testing and being shipped from the manufacturing facility. With that said, it is expected that, until recently, the most severe operating conditions to which most stacks have been exposed has been pressure testing.

a) Proof Testing

The standard to which ram type BOPs are currently manufactured is API Spec 16A, third edition, June 2004. In 8.5.8.6, the BOP body is required to be tested to $1.5 \times \text{MAWP}$ for 3 minutes, the pressure reduced to zero, then a second test to be held for 15 minutes (8.5.8.6.4 a-c). Acceptance criteria here is zero leakage. This test is not repeated on a periodic basis. This test would only be repeated if the BOP were remanufactured. In this standard, remanufacture is defined in 3.62 as “process of disassembly, reassembly and testing of drill-through equipment, with or without the replacement of parts, in which machining, welding, heat treatment or other manufacturing operation is employed.” Spec 16A Annex B, B.2.4.i specifies proof testing in conformance with the main body of the standard, section 8 (quoted above).

Proof testing is also known as pressure containment in this and other API standards.

b) Closure Testing

In API Spec 16A, Section 8.5.8.7 specifies low (200-300 psi) and high (to MAWP) wellbore pressure testing. The acceptance criterion for these tests is there “shall be no visible leakage.” Interestingly, the recommended high pressure test in 8.5.8.7.1.3 specifies test pressures “at least equal to the rated working pressure.” Within WEST, there are few known cases of testing above MAWP in the field.

API RP 53 is the standard usually considered on rigs for in-service equipment. This standard does not shell test, but requires, similar to Spec 16A, low and high wellbore pressure testing on the initial installation in Section 18.3.2.1 (subsea stacks) and further detailed in Table 3. Both tests are to be held “a minimum of 5 minutes.” Acceptance criteria noted in said table are that pressure test “should be stable.”

These tests in both standards verify the capability of the rams to close and seal against the appropriate pipe size(s). Importantly, the safety factor is only 1.0, not the 1.5 as with the shell test. RP 53 states the testing should be performed on the stump or on the subsea wellhead. All users pressure test the BOPs on the stump prior to deployment and then on the wellhead, only differing in the level of testing. Stump testing helps identify potential failures without the cost and risk of running and retrieving the BOP to/from the subsea wellhead. When on the surface test stump, WEST strongly recommends always testing to the 16A requirements.

Closure testing is also known as pressure control in this and other API standards.

One should also note that Spec 16A requires wellbore pressure tests with locks engaged and close operating pressure vented in 8.5.8.7.5. This most closely simulates the most stringent operating situation of a hang-off and disconnect, without the vertical load of the drill string. RP 53 also requires this “locks only” test in 18.5.9.

c) Temperature Testing

While the closure testing section of API Spec 16A is specific about requiring the locks only test, the temperature testing portion of specification 16A does not require a locks only test, a noteworthy distinction. Also, while body proof testing specifies a 1.5 FoS on pressure, there is no FoS on temperature. Finally, while section 5.7.2.2 of API 16A, third edition requires a fatigue test (546

close/open cycles and 78 pressure cycles) as part of the operational characteristics tests, section 5.8 on temperature testing contains no similar requirement.

6) Factors Causing Derating

Knowing the general acceptance of most in the industry of operating BOPs up to and including their MAWP, subject to verification, this section outlines those issues that most frequently cause BOPs to fail to perform as required.

a) Temperature

Insofar as protocols normally utilize material properties at ambient temperatures for designs < 250 °F, the operating parameters of interest in this study are marginally above the noted threshold temperature. However, it should be noted that physical property measurement has shown decreases in performance prior to 250 °F. Accordingly, one must assume based that, based on prior usage, engineering FoS has been adequate to compensate for this performance decrease.

b) Metals

Although high temperature metal performance is beyond the scope of this elastomer study, some commentary is appropriate since steel serves as the main structural component of BOPs and supports the seal elements against extrusion under applied pressure. API Spec 16A references ASME Boiler and Pressure Vessel Code, Section VIII, Division 2, as an acceptable design method in section 5.4.2.2 (Appendix 4) and 5.4.2.4 (Appendix 6). Historically, BOP manufacturers have not considered temperature effects on yield strength in their designs.

However, in prior studies, WEST has attempted to estimate steel strength loss with increasing temperature. One authoritative source cited that the tensile yield/temperature relationship is linear between ambient (80 °F) and 400 °F, with a degradation of 13% over that range, or .0406%/°F.

Using this correlation (greater temperature effect) and ignoring FoS embedded in the ASME design protocols, one would calculate a 15,000 psi BOP to be good for 14,820 psi on the deck on a hot summer day (110 °F) and 13,840 psi at 270 °F.

c) Elastomers

The relationship between elastomeric performance and temperature is intuitive. Higher temperatures cause the material to get softer (flows through gaps more easily) and colder temperatures to get harder (less able to conform to surface irregularities). It is also generally true that, as the high temperature limit for a given product is increased, the low temperature limit increases as well, although not in a 1:1 ratio. In general, an elastomeric element that is capable of sealing at extremely high temperature is less likely to seal successfully at extremely low temperature. Many other factors influence the likelihood of achieving a seal with a given packer under HT conditions, including but not limited to thermal/chemical history, mechanical loading history, current chemical environment, and mechanical wear of surrounding components.

d) API Requirements

API 16A 2nd Edition, Appendix C Design Temperature Verification Test Procedure only required a one hour rated pressure hold at the rated temperature. This requirement was instituted as a result of a disaster in 1989 on an offshore rig in the North Sea. The one hour pressure hold at temperature

was designed to assure the well could be successfully shut in and give onboard personnel a chance to safely evacuate the rig. However, for longer term well testing the one hour pressure hold does not provide sufficient safety margins.

This same topic is covered in the 3rd Edition of API 16A in Annex D, which is listed as informative. As before, the high temperature hold times specified under the sections for rams (Section D.2.9) and annulars (Section D.3.7) is a three minute hold for the low pressure test, followed by a 60 minute hold for the high pressure test.

Scaling in accord with Table 17 is permitted for temperature testing. An example of WEST's interpretation of this is that testing for one size fixed bore ram in an 18-3/4" 15,000 psi stack qualifies all fixed bore rams for that size and rating of BOP.

7) Review of Previous Studies

Over the years WEST has been involved in several comprehensive HPHT studies. The major ones include a report for a consortium of Norwegian companies, Technical Bulletin #93-03, and an HPHT checklist developed for rig assessment. Relevant sections of these three papers have been incorporated throughout this work, but a summary of each is presented here.

a) *Norwegian Study*

In 1994, WEST completed a study for a consortium of seven Norwegian operators regarding BOP equipment requirements for HPHT operations. A paper was written and presented at the November 1994 IADC Well Control Conference of the Americas in Houston covering key findings of that study. It was also published in the *Oil and Gas Journal*. The 1994 study was summarized and updated for a 1996 presentation at an IADC conference in Aberdeen

The scope of the 1994 Norwegian study was large in that it covered all aspects of BOP and related equipment including failsafe valves and choke and kill lines. It also compared American (API 16A) and Norwegian standards (Statoil/Saga/Norsk Hydro standard 50-190) for HPHT qualification, recommending that the API standard be adopted with additions guided by the Norwegian one. A key conclusion of the original study was that, if equipment was delivered from the manufacturer with a 15,000 psi pressure rating, one need not apply additional safety factors for HPHT operation. However, this is subject to the contractor complying with the manufacturers' inspection, testing and maintenance directives.

Pertinent to BOP elastomers, the study found that BOP manufacturers test their elastomer products to different standards, as is still the case in 2009. Included in this report was a table of items to check for when evaluating if the set of equipment is good for HT conditions. The paper identified several methods by which to determine which parts (mainly elastomeric seals) need to be replaced in order to satisfy HT requirements. Strictly speaking, there are three general methods utilized to determine this list, listed in decreasing order of technical analysis required:

1. Development of a stack temperature profile during most severe anticipated conditions. This is generally a two step computer modeling process. First, maximum kick volumes and temperature must be determined. Next, the data is input into a program which calculates a temperature profile, taking into account cooling effects with time and distance due to gas expansion and heat transfer to the well control equipment surroundings. Proponents of this level

of technical detail use this analysis to enable them to more accurately assess the need for upgrading specific parts. Thus, they reduce their risk and often reduce their total upgrading cost.

2. Use of industry experience for “commonly replaced” parts. This is generally rather informal and reflects an empirical approach relative to other successful programs similar to the anticipated one.
3. Replacement of every available high temperature rated part. Obviously, although this is the most expensive alternative, it is most conservative, providing equipment with the highest possible temperature rating currently available.

Several well control incidents that occurred in the North Sea were reviewed. The highest pressure encountered was 12,000 psi (828 bar). Temperatures greater than 300 °F (149 °C) were seen during uncontrolled flow, and such temperature was regarded as a significant factor in subsequent equipment failure.

Other findings included wide variation in hang-off capabilities between manufacturers, inconsistencies/misunderstanding in application of failsafe valve standards, lack of revised field wear tolerances (for example between ram block and cavity or between choke & kill connector box and pin) to account for greater elastomer extrusion tendency under HT conditions, and identification of flexible choke and kill hoses as the item with the lowest temperature rating. Some recommendations were to fully understand which standards were applied to a particular rig’s equipment when designed, to develop more stringent dimensional inspection procedures for evaluating equipment for HT service, and to clarify API standards as they relate to HT topics.

b) WEST Technical Bulletin #93-03

Originally prepared in April 1992 and revised several times up to March 1997, this work contains the majority of WEST information and experience with HPHT issues, including observations gleaned from auditing 25 HPHT and 165 standard rigs. Some 11 manufacturers of BOPs, failsafe valves, and choke & kill line components were contacted. It also saw the beginning of development of the HPHT checklist to be implemented on field surveys in order to ascertain whether a given rig’s pressure control equipment is fit for HPHT purpose. Its findings were largely similar to those of the Norwegian study, though it contained more specific references such as parts lists for individual manufacturers.

In a discussion of temperature rating, the bulletin stated that there is no industry standard for high temperature testing. All full scale testing on ram preventers is performed with operating pressure on the close side of the rams, so well planning should consider the fact that wellbore integrity of HT packers has not been proven in the absence of operating pressure (after disconnecting LMRP for example).

In a section on properties of elastomeric materials, their sensitivity to high temperatures was highlighted. When elastomers are exposed to high temperature, the rate at which they age is accelerated. When elastomers age, they lose their physical properties. One manufacturer’s engineering bulletin showed that exposing Nitrile to 150 °C instead of 100 °C causes rate of hardness increase to escalate by a factor of four, consistent with the chemical reaction theory. In other words, exposure to high temperature leads to rapid loss of pliability, a key feature of elastomers. A harder, less flexible packer can significantly affect the ability to seal.

c) WEST HPHT Checklist

This worksheet was developed to aid surveyors in ascertaining whether a particular rig was suited for HT service. It was meant to highlight crucial areas and encourage the evaluator to ask the right questions. The sheet recommends minimum subsea and surface BOP stack configurations for handling HT well conditions. Temperature monitoring is recommended at mud return, choke, and well test lines. Then a list of BOP seals and their recommended temperature ratings is given. For subsea applications, 350 °F rating is specified for elastomers located on the rams, and 250 °F is specified for bonnet seal and ram shaft packing. For surface applications, 350 °F rating is recommended across the board.

A table guides the inspector through all critical well control parts, asking to note all temperature ratings. Finally, available OEM elastomers and their temperature ratings are tabulated for reference. An edited version of the checklist with only the well control parts table is included in this report for reference as Appendix A.

8) WEST In-House Search of Historical Surveys

From a search of WEST's historical data, one vital temperature-related issue was found. All packers for ram type BOPs rely on some sort of metal back-up structure to support the elastomer against extrusion by high pressure. When high pressure is applied to one side of the rams, the elastomer material tends to flow towards the region of low pressure. Without some type of reinforcement, the elastomer can be forced through any gaps, resulting in catastrophic loss of sealing.

With reference to Figure 2, two methods for preventing elastomer extrusion are illustrated. On the left side of the figure, a fixed bore ram with packer is shown. Observe the anti-extrusion plate that captures the elastomer at top and bottom of the packer element. This type of plate is designed with a close fit against the drill pipe around which it is meant to seal. According to internal sources, the fit typically ranges from metal-to-metal contact to 0.060" and depends on tolerances of the drill pipe OD and plate ID.

The right side of the figure shows one variety of variable bore ram (VBR) packer. Other designs exist. Notice the arrangement of metal fingers that resemble the iris of a camera lens. The movement of these fingers allows this packer to seal against various ODs of pipe, making for a more versatile packer element. Operators like the flexibility that VBRs provide for their drilling programs; however it should be noted that this design involving fingers cannot be as reliable as a fixed bore packer's anti-extrusion plate. A trade-off exists between versatility and anti-extrusion performance. As is evident from the VBR figure, the design inherently exhibits more extrusion gaps than the fixed bore design. With more extrusion gaps present, the possibility of the elastomer finding an extrusion path is increased.

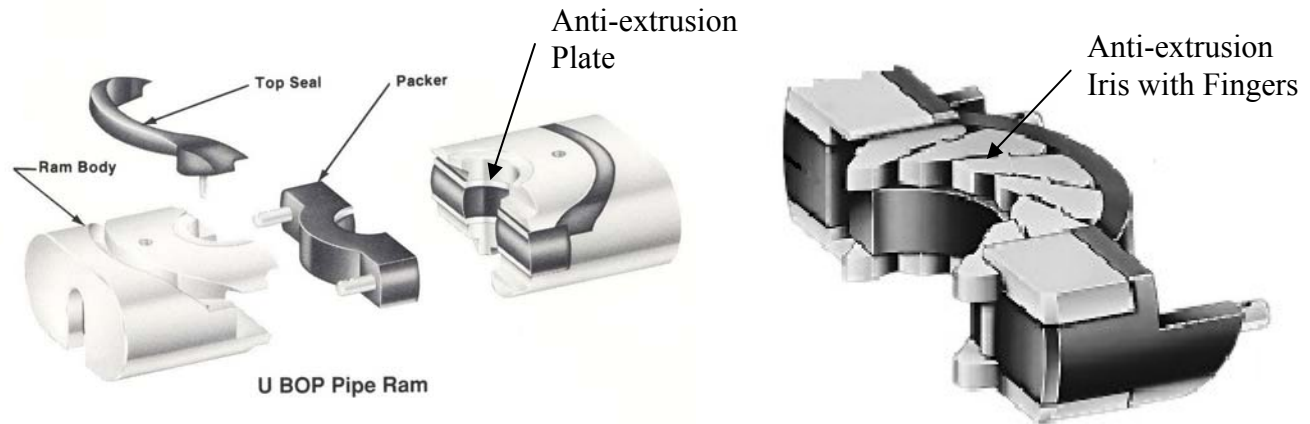


Fig. 2 Illustration of anti-extrusion plate location. Variable bore packer shown at right for reference.

No other temperature related failures were identified from WEST archives since 2007.

9) Industry Survey

Because of the variations in testing conducted by different manufacturers, the lack of standard terminology definitions, and the limitations of current industry standards, it is difficult to be able to compare products from different manufacturers. Testing protocols or acceptance standards are not always specifically identified when a manufacturer lists temperature ratings. On the other hand, each manufacturer publishes a variety of technical documents describing HT performance of their equipment. These documents highlight data of particular interest and are generally available from the respective manufacturer.

Although not defined in the Spec 16A non-mandatory recommended testing procedure, some manufacturers discuss temperature limitations for continuous operation as well as limits for excursions. The duration of an excursion is not always defined in the product literature. Sometimes excursion is parenthetically defined as 1 hour. One might assume that the duration of a well test is beyond the definition of excursion.

The most common fluid compatibility testing conducted by all manufacturers is laboratory testing. ASTM standard samples are used for this testing, and physical properties before and after the testing are measured. Different conclusions may be derived by manufacturers from the results of these measurements.

The discussions of the three major OEM manufacturers below provide a general outline of their internal standards and protocols. A questionnaire was sent to each for their official response and to document capabilities.

a) Manufacturer A

Manufacturer A lists upper capabilities of their fixed and blind ram BOP high temperature elastomers as 250 °F for continuous service with excursions to 350 °F. For variable bore packers, the upper limits are 180 °F continuous and 200 °F excursion. To develop these ratings, this manufacturer uses API 16A Annex D as a basis for HT testing, specifically 350 °F and 15,000 psi testing with a one hour rated pressure hold at temperature in an 18-³/₄" BOP in 1989. When a test

unit has passed a high temperature test at a given temperature, this value is published as the excursion rating while the continuous rating is reduced by a safety margin. Insofar as Annex D does not identify multiple different temperature ratings as a function of time, the excursion rating is defined parenthetically as one hour duration.

One piece of marketing literature declares that their HT product was qualified with eight hour hold time instead of the one hour specified by API. In some instances the test results are scaled so that successful testing of specific size packer (e.g. 13-5/8" 10K Ø5" pipe packer) will qualify all sizes for the tested temperature. Such scaling is in accordance with Table 17 in API 16A. Temperature rating for individual elements is achieved by strict quality control on the formulation before it's released to manufacturing. Meeting QC (Quality Control) requirements means the elastomeric material is the same as that initially validated.

OEM A is not aware of any elastomer failures within the rated range of their product. They were not at liberty to disclose any HT formulations under development, except to say the materials being evaluated are appropriate for HT applications. They stated their current HT product is capable of 10% CO₂ and 35% H₂S.

OEM A has a dedicated elastomer facility that WEST toured. All of their seal elements are developed and manufactured at this facility. The facility was well equipped and operations appeared organized. A separate testing room housed sophisticated equipment for determining elastomer properties and running ASTM elastomeric testing procedures. Their representative stated that molecular analysis can be used to determine if a random sample of elastomeric material came from their plant.

High temperature testing to 430 °F and 3,000 psi of a 7-1/16"-15,000 psi ram type BOP to be used in geothermal service (steam) was also conducted in 1989. This testing complied with requirements established by a prominent national laboratory: a minimum of 54 hours of testing consisting of two hours of thermal conditioning followed by a 15 minute pressure test. This was repeated until a minimum of 54 hours of leak free sealing was completed. On the strength of their testing and rating procedures, a high degree of confidence can be placed in Manufacturer A temperature specifications.

Manufacturer A formulates their nitrile and high temperature elastomers to be compatible with #2 diesel fuel, believing this is a consistent base case scenario. Typical fluid compatibility testing is conducted for 168 hours at a specified temperature. For nitrile compounds, 212 °F is normally used. For HNBR and proprietary compounds, the test temperature can be as high as 350 °F. Test results for the fluid of interest are compared with the baseline #2 diesel. If the mechanical properties effect is less than that of #2 diesel fuel, the elastomer compound is considered compatible. If the effect is more severe than that experienced with #2 diesel fuel, then the elastomer compound is considered incompatible. Based on its own internal testing, 168 hours is the standard for fluid compatibility testing, having seen equilibrium reached within that time. Manufacturer A has maintained an on-going drilling elastomer and drilling mud/completion fluid test program for over 15 years.

b) Manufacturer B

OEM B did not respond to the questionnaire. However, observations by WEST personnel allow limited commentary on their methods. Manufacturer B lists upper capabilities of their standard elastomers as 350 °F for blind shear rams and 500 °F for fixed bore rams. The ratings for variable

bore rams range from 180 to 250 °F depending on size. The latest marketing publications reviewed did not mention continuous versus intermittent ratings, though prior rating information from this manufacturer was presented with the continuous/intermittent distinction.

Rather than referring to continuous/intermittent terminology, Manufacturer B states their elastomer ratings simply in terms of having been tested in compliance with 16A temperature standards. Upon request, they provide test results to their clients to be used as they see fit for operational service decisions.

This manufacturer also uses API 16A, Annex D as the basis for HT testing, though with certain distinctions in the areas of ram locks and use of a heated mandrel.

H₂S and CO₂ limits for Manufacturer B's HT product could not be identified from available information.

In one HPHT brochure, OEM B discusses their state-of-the-art facilities that allow testing under conditions that meet or exceed API 16A and other applicable standards. They assert that they built this test center after being unable to test several BOP products to failure because the equipment held full working pressure at the limits of the testing devices.

Fluid compatibility testing by Manufacturer B is premised upon comparisons with degradation resulting from #2 diesel. Physical property changes for the fluid of interest are compared with the changes that occurred with the baseline #2 diesel. If the effect is less than that of #2 diesel fuel, the elastomer compound is considered compatible. If the effect is more severe than that experienced with #2 diesel fuel, the elastomer compound is considered not compatible.

c) Manufacturer C

Manufacturer C lists upper capabilities of their high temperature elastomers as 350 °F for pipe and shear rams, and 180 °F for variable bore rams. No excursion or intermittent rating was given in the latest publications known to WEST.

Manufacturer C again uses API 16A Annex D as the foundation for their BOP temperature testing. During an interview with their representative, details of testing procedure were not discussed. However, their standard is to base their rating on the maximum temperature achieved with the one hour hold time. They have on occasion increased the hold time to 13 hours and stopped the test at that point without failure. Both their 5" fixed bore ram and their shear ram were so qualified. One geothermal application was tested with 54 hours total time at temperature (+400 °F) using the same national laboratory protocol mentioned above for Manufacturer A.

In the 1980s, Manufacturer C conducted a series of tests using hot oil at 350 °F. The requirement to hold wellbore pressure for one hour with 350 °F was established by controlling authorities in the North Sea and also apparently carried forward into the API 16A HT testing procedure. There was no requirement for repeated tests to establish service life. At the conclusion of testing the rubber parts were inspected and found to be in good condition – suitable for continued testing for a longer period of time if needed.

Manufacturer C stated in a product information bulletin that their 13-5/8" 10,000 psi HT ram rubber passed a 144 hour HPHT well bore pressure test simulated by HT fluid circulating inside the pipe to 350 °F and 10,000 psi well bore pressure.

In their written response regarding failures experienced by their elastomer equipment, Manufacturer C reported having seen premature wear generally associated with chemical attack at higher temperatures. HT parts returned for evaluation appeared to have been involved with a temperature spike, not consistent recordable temperature.

Interviews were held with Manufacturer C representatives. They did not discuss specifics of current or future HT elastomer formulations, citing proprietary reasons. They did mention that nearly all BOP elastomers are based upon NBR for its compatibility with petroleum products. HNBR is generally chosen for HPHT applications in oil-based muds, whereas EPDM is used for geothermal HPHT applications for its compatibility with water. There was indication that their original HT packers utilized standard elastomer material but with more tightly controlled tolerances on the anti-extrusion plates. More recently, a separate HT formulation has been developed.

Manufacturer C states in product literature that their standard elastomer products are qualified to base conditions of 25% H₂S and 15% CO₂. Their HT elastomer product can be used in concentrations up to 35% H₂S and 15% CO₂; however increased maintenance (test frequency and elastomer replacement) is recommended to account for degradation of material properties. See Section 13 on H₂S and CO₂ Effects below for more information.

Manufacturer C has a rubber plant that WEST toured. This manufacturing and proving area was well organized and had a dedicated testing room for performing ASTM benchmarks such as tensile testing. They emphasize computer control of mixing ingredients as a means of guaranteeing consistent quality. Each component is precisely metered out by a computer and the entire process is also computer controlled. The computer assures repeatability of process times and temperatures so that each batch ends up with nearly constant material properties.

Concerning fluid compatibility, Manufacturer C stated their testing complied with ASTM protocol (the information source could not immediately recall the specific ones), in a laboratory with ASTM specified dumbbells. Their standard is to measure physical properties before and after testing, then rate their product life as a percentage correlated to the degradation observed in testing. As an example, if a user was experiencing annular packer life of six months using a known (compatible) drilling fluid, and testing showed a 30% decrease in physical properties, they would tell their client they should expect their annular packer to last only 4.2 months $((100 - 30\%) \times 6 \text{ months})$. Which properties were used and the contribution of each was not specified.

d) Discussion of OEM Temperature Testing

All three major BOP manufacturers follow the same overall method for temperature verification of their products based on the suggested API procedure but with certain nuanced differences such as the locks-only attempt by OEM B. Their published HT elastomer ratings are divided into continuous and excursion temperatures, with the excursion rating corresponding to the temperature at which the one hour hold was performed.

All three OEMs have also gone beyond the specifications of the API test, albeit in slightly different ways. At the request of a particular customer, OEM A subjected one of its 13-5/8 – 10,000 psi

BOP's HT shearing blind ram packers to an 8 hour pressure hold at 250 °F and a three hour pressure hold at 350 °F. The operating pressure was held at 1500 psi to close the rams during these tests. These hold times represent a significant increase over the API suggested value of 1 hour. OEM B also claims eight hour hold time but at 300 °F for its 18³/₄ – 15,000 psi blind/shear rams. They claim successfully passing API temperature testing requirements to 350 °F using blind/shear rams and to 500 °F using fixed bore rams. OEM B has additional aspects in its testing procedure that go beyond the scope of API 16A Annex D. OEM C states in various marketing materials that during the qualification of packing elements, they extended the hold time during various HT tests from the API recommended one hour to 13 hours and 144 hours (10,000 psi test).

From these claims, one observes the ramifications of not having an industry-wide accepted HT testing standard. One OEM believes that increasing the hold time gives a margin over the requirements, while another holds the philosophy that increasing the test temperature gives the margin of safety. This is why it may be advisable to consider a revised API HT testing procedure in the interest of industry standardization.

10) API Temperature Testing Procedure

In API Specification 16A, Third Edition, June 2004, section 5.8 deals with temperature verification of BOP elastomers. Specifically section 5.8.2 requires testing to verify ability to maintain a seal at the extremes of their temperature classification. Documentation is required for:

1. Elastomer records
2. Record of wellbore fluid temperature during testing
3. Record of low temperature performance for a minimum of three pressure cycles at MAWP
4. Record of high temperature performance for one pressure cycle at MAWP with a minimum pressurization hold time of 60 minutes

The details of the procedure are left to the manufacturer, although Annex D is suggested. Also the manufacturer can specify the test fluid and the closing pressure.

After study of HT issues, it may be prudent to consider the following updates to the API standard procedure:

1. Extend the hold time beyond 60 minutes. While 60 minutes may allow adequate time to evacuate an offshore oil platform, it does not represent real world BOP operating conditions which likely involve soaking in HT fluid for some duration before closing.
2. Develop a performance envelope which defines limits of acceptable operation within a variety of pressure and temperature combinations.
3. Specify whether ram locks are to be relied upon for maintaining the seal.

A longer hold time at temperature would yield a more realistic test that increases confidence in the tested design withstanding an actual pressure control event. Alternatively or in addition, a soak time could be specified. One manufacturer wrote a paper on thermal modeling using FEA in which they recommended soak time at temperature in a fluid similar to the expected drilling fluid. After the soak, the element could be removed and installed in the BOP for HT testing. This method would expand upon the current practice of testing a new seal element at HPHT and combining that with separate ASTM fluid compatibility tests on elastomer coupons. For more information, see section 11.b. Fluid Compatibility below.

Well conditions are such that temperature at the BOP is related to both reservoir conditions and flow rate. Higher flow rates result in higher equilibrium temperatures for a given well and BOP location (surface versus subsea). During the high flow conditions which result in highest temperatures, flowing pressures are reduced. Testing in API should reflect this reality. As an example, testing to API 16A, Annex D should be augmented by additional testing, e.g. to 0.8 x MAWP at a manufacturer-defined higher temperature for 24 hours.

Specifying whether or not locks are to be used would allow customers to understand the manner in which their packers were tested and what to expect from performance in the real world.

Additional suggestions regarding HT elastomer testing are elaborated in section 11.c. Additional Testing Recommendations below.

11) Testing Information and Background

a) Temperature

Typically, BOP manufacturers conduct full scale BOP testing only when requested by the customer, the reason being the extremely high cost of full scale BOP HPHT testing.

Temperature modeling of BOPs affords an improved understanding of conditions at seal locations. These models can be quite complex. With subsea stacks, cold ambient seawater causes significant thermal gradients across the BOP. Fluid flows, both in the wellbore and at the sea bed, are critical parameters in this modeling as well as the thermal conductivity of the wellbore fluid. If said modeling is used to determine temperature requirements of the elastomeric goods, the properties of the planned completion fluid(s) should be used.

One notable production company has insisted all drilling elastomer compounds used in BOPs operating in their high temperature fields be verification tested at the rating temperature for periods longer than the one hour specified by API 16A. The reason for their requirement of this extended testing at elevated temperatures was in response to an event where the wellbore elastomers in the BOP were not qualified for the temperature experienced and failed. It resulted in a sour gas release and ultimately, complete destruction of the rig. As a result of this incident, this operator now requires all high temperature BOP elastomers to be verification tested first to the API 16A requirement followed by an extended pressure hold at the rating temperature. The pressure hold period varied from seven to twelve additional hours.

Testing at temperatures more extreme than those anticipated can shorten tests designed to duplicate well test operating scenarios. The Arrhenius Principle of chemical reaction rates, which states that for every 10 °C or 18 °F increase in temperature the chemical reaction rate doubles, could then be used to extrapolate to other operating cases. The converse is also true (e.g. for every 10 °C decrease in temperature) when the chemical reaction rate reduces by one half. Using this principle, should a one hour pressure test at 15,000 psi and 350 °F be successfully completed, one would expect a successful test for 16 hours at 278 °F and 15,000 psi. The Arrhenius Principle has been adopted by API as an approved test protocol for estimating the life of elastomeric sealing systems used in subsea production systems. The API document which contains this protocol is API TR6JI, Elastomeric Life Estimation Testing Procedure, 1999. Several technical papers have been written

and presented on this subject and presented to Energy Rubber Group, Rubber Division of the American Chemical Society.

Some consider subjecting the elastomer to a defined thermal conditioning, or soak, time prior to testing. Because well testing involves flowing the well for a specified time period, this seems to be a logical test. However, generally speaking, the rubber will only continue to cure to the extent that un-reacted curing agent remains in the elastomer that can be consumed with extended time at high temperature. Normally, elastomer processes are designed to consume the vast majority of the curing agent, leaving little un-reacted. At any rate, additional curing would make the compound harder, which would generally have more impact on the low temperature capability and significantly less on the high temperature.

Additionally, because the methods by which the BOP is heated require time to reach the target temperature, some (undefined) thermal conditioning will have taken place. An understanding of this time would aid in a determination of the value, if any, of additional conditioning.

One possible effect of temperature cycling, or heating up and cooling down repeatedly, is compression set, that is, permanent deformation of the elastomer when temperature and pressure are applied. Temperature cycling has not been seen to have a significant effect on the performance of ram packers. On the other hand, common practice is to replace elastomeric goods after exposure to operating extremes.

b) Fluid Compatibility

Although fluid compatibility is not officially part of this study's scope, it can significantly impact packer performance, particularly in conjunction with HT operation. This is documented in SPE-97563 by manufacturer researchers: "An area of potential future development would be to invest in laboratory equipment large enough to submerge an entire seal element in a predetermined concentration of H₂S, CO₂, diesel, brine, etc. and soak at a given temperature for a given period of time. The sealing element could then be removed and transported to the equipment test facility where it would be tested at a given temperature and pressure but without the presence of toxic compounds. This testing would expand on the current method of testing a new seal element at temperature and pressure and combining that with elastomer samples tested for property degradation after soaking for a given time in a specific fluid. . . . Well control sealing elements may be exposed to HPHT wellbore conditions in the un-actuated state for long durations of time before being called upon to seal under duress. Current test procedures do not specify soak time. Soak time at temperature is another item that should be addressed in the requirements."

c) Additional Testing Recommendations

At a minimum, the API 16A one hour HT verification test (e.g. 350 °F and 15,000 psi) should be conducted. As noted above, successful completion of this test may allow extrapolation to the expected maximum service temperature using the Arrhenius Principle.

An ideal approach to defining equipment HT limits during design qualification would include testing the elastomers to failure. Testing to failure across a range of conditions gives a direct indication of how long the sealing elements hold and yields a performance envelope. This envelope allows an engineer to determine whether various expected well conditions fall within the BOP's capabilities. Such a test program specifies multiple points along a pressure-temperature curve (e.g.

10500 psi/525 °F, 12000 psi/420 °F, and 15000 psi/350 °F). The test points could be defined by factors applied to MAWP and the rating temperature, as suggested in the following table:

Test Step	Pressure	Temperature	Time to Failure
Stage 1	0.7 x MAWP	1.5 x T	Determined during test
Stage 2	0.8 x MAWP	1.2 x T	Determined during test
Stage 3	MAWP	T	Determined during test

Facility safety considerations and practical limitations may preclude such an extensive qualification program. Also, a time limit might need to be placed on test duration at each condition in case the seals do not fail within a reasonable period. Even if no failure occurs, a useful data point has still been documented.

Repeatability and fatigue are not addressed within the current HT testing procedure for ram BOPs (API 16A, third edition section 5.8.2.d) which specifies one pressure cycle at MAWP. The test for ram BOP operational characteristics (API 16A, third edition section 5.7.2.2.d) does specify a fatigue test to 546 close/open cycles and 78 pressure cycles or to failure, whichever comes first. This difference should be noted when considering elastomer HT ratings. Based on WEST's experience, operators routinely replace elastomeric goods exposed to HT conditions. Therefore, WEST does not consider HT repeatability and fatigue testing to be warranted.

For full scale testing HPHT testing, the use of synthetic hydrocarbon oil in the wellbore is recommended. The fluid should be temperature stable up to 400 °F. In the past, synthetic hydrocarbon oils such as Mobil 1, IA 300, and Exxon Synnestic 100 have been used successfully for HPHT testing.

Laboratory testing of all potential fluids in the wellbore with the proposed elastomer compounds is suggested. A single laboratory test of 168 hours should be adequate but confirmed by the vendor. Optimally, one of the tests should include immersion of front packers and top seals at temperature for the time frame, then installation of these parts into the BOP for a repeat of the above temperature tests.

In all cases, the manufacturer should submit their recommended procedure for review and comment. Acceptance criteria should be specific and complete (e.g. the acceptable level of property degradation for compatibility testing).

d) Background Information

Fundamentally, elastomeric goods are considered performance products, that is, even though one material may be indistinguishable from another based on a chemical or physical property analytical perspective, they may perform quite differently in operation. Additionally, when polymer is purchased, the supplier provides a temperature range for that product. Depending on the application, the final manufactured product could have an acceptable range of only a portion of the polymer supplier's recommendation.

Each manufacturer of BOP wellbore elastomeric sealing elements develops proprietary elastomer formulations to fulfill the performance requirements for each application within their BOPs. The compound is normally defined by a material specification which lists the minimum required physical properties and fluid compatibilities. As a result, the requirements of an elastomer

compound for an annular packer are substantially different than that for a fixed bore ram packer or variable bore ram packer. Typically, when a new or improved drilling product is developed, the components are subjected to extensive qualification testing. Once the tests have been successfully completed, the manufacturing process is “baselined.” Any changes to the elastomer formulation or the manufacturing process which may affect the elastomer compound’s physical properties would require retesting and the establishment of a new baseline. The two manufacturers that responded to WEST’s questionnaire emphasized their attention to QC on elastomer formulation in their rubber plants. See Section 9: Industry Survey above for details.

Minimum physical properties for each compound are defined in a materials specification developed by the design engineer. Typical physical properties found in a materials specification (and referred to in API 16A, third edition, sections 6.2.2 and 8.5.5.1) are:

1. Ultimate tensile strength - ASTM D 412
2. Ultimate elongation - ASTM D 412
3. Modulus at various elongations - 50%, 100%, 200%, 400%, 500% - ASTM D 412
4. Hardness - ASTM D 2240
5. Low temperature performance – Glass transition temperature
6. Compression set at various temperatures - ASTM D 395, Method B
7. Fluid compatibility - immersion in #2 diesel fuel or ASTM test oil - ASTM D 471
8. High temperature tests – ASTM D573 and D865-99

Typical elastomer compounds used in the oil and gas industry are nitriles (NBR), hydrogenated nitriles (HNBR), fluorocarbon elastomers (Vitons or FKM), ethylene propylene diene M-class elastomers (EPDM), and occasionally epichlorohydrin elastomers (ECO). The basic requirement is resistance to crude oil, natural gas, oil and ester based drilling muds, geothermal fluids, and completion fluids. As previously mentioned, each manufacturer generally has a material specification to define the minimum physical properties for elastomer compounds used for each application. Compound formulations are proprietary.

Most standard drilling elastomer compounds are based on acrylonitrile-butadiene polymer (NBR), more commonly called nitrile. As noted earlier, all nitrile elastomer compounds are not the same. Each supplier will formulate the compound based on operational requirements and cost. Nitrile drilling elastomer compounds, depending on formulation, are generally used up to 250 °F in oil based drilling muds and exposure to sweet crude oil and/or natural gas. Higher temperatures and sour crude/gas dictates the use of a higher temperature and sour crude/gas resistant elastomer compounds based on hydrogenated nitrile (HNBR) or proprietary oilfield elastomers. In HNBR compounds, not only is the acrylonitrile level important but the degree of saturation. HNBR compounds and proprietary compounds have been successfully tested to 350 °F and 15,000 psi in oil.

To maintain consistency in product performance, strict controls must exist in the manufacturing process. To start, the mixed compound must have consistent qualities. The mixed compound consists of the base polymer, reinforcing powders such as carbon black and silica, a crosslinking or curing agent, and minor powders to enhance the curing process. These four basic ingredients are

generally combined together in an internal mixer. It is critically important to assure all powdered ingredients are completely dispersed throughout the polymer. Excessive mixing can result in breaking down the polymer's long molecular chains, which results in reduced physical properties. Insufficient mixing can lead to poor dispersion of powdered ingredients and, again, a reduction in physical properties results. Laboratory analysis and physical property tests of the mixed compound must be conducted prior to introducing the compound into the manufacturing process.

Curing of the compound occurs when the mixed compound is placed in a mold and heat is applied to affect the polymer crosslinking. Three basic forms of molding are utilized: compression molding, transfer molding, or injection molding. The process used is dependent on the configuration of the part to be molded. In all cases, it is critically important to control the molding process parameters.

The chemical reaction involved with the curing of long chain polymers in the molding process will depend on the curing agent used in the formulation. Typically, most of the curing agent is consumed in the molding process which generally takes place at between 300 °F and 350 °F. The degree to which the curing agent is consumed in the curing process is referred to as cross link density. Elastomer compounds typically used in the oil and gas industry are thermoset elastomers. Once the cross linking has been completed, it cannot be broken by reheating the elastomer to the curing temperature. In contrast, plastics and thermoplastic elastomers can be melted and remolded when heated to the molding temperature. However, continued exposure to the original molding process temperature will allow more complete consumption of the remaining curing agent, hardening the component.

Many BOP elastomeric sealing elements incorporate steel reinforcing plates and inserts. Bonding the elastomer compound to these inserts is crucial to the performance of the sealing element. The objective of the bonding process is to achieve an elastomer tearing bond, that is, the cured elastomer compound will tear before the bond releases. Many processes have been developed to achieve a satisfactory bond. In some cases, the steel reinforcing inserts are phosphate treated prior to molding, with or without primer/adhesive applied prior to molding. In other cases, the inserts are degreased using either a vapor degreasing system or oven burnoff. After the degreasing, the inserts are grit blasted to develop a surface anchor pattern. The grit blasted surface is then coated with a primer/adhesive. Once the primer/adhesive has dried, the metal inserts are ready for the molding process. Keeping the insert clean prior to molding is critical to achieving an elastomer tearing bond.

Fixed bore ram packers have the ability to operate at higher temperatures and pressures than annular packers or variable bore ram (VBR) packers. With fixed bore ram packers, the extrusion gaps the elastomer compound must bridge to seal are smaller and thus the required elastomer movement is small. With annular and VBR packers, metal insert movement is increased, the extrusion gaps are greater, and the elastomer compound must move greater distances to seal. This factor limits annular and VBR packers' ability to seal at higher temperatures and pressures.

12) Subsea versus Surface Thermal Behavior

For subsea BOPs, top seals and face seals may be exposed to higher temperatures and therefore should be rated to 177 °C (350 °F). The other seals in a subsea BOP will see lower temperatures and therefore can be rated to a maximum of 121 °C (250 °F). For surface BOPs it is possible that the whole BOP

could see these higher temperatures and it is recommended that all seals be capable of limited performance at 177 °C (350 °F).

WEST's Norwegian study cited results of one manufacturer's thermal FEA, and this data is tabulated below.

Situation & Seal Type	Subsea BOP (submerged in 40 °F water)	Surface BOP
<u>Blow-out through BOP</u>	Seal Temp °F (°C)	Seal Temp °F (°C)
Ram Face Seal	350 (177)	350 (177)
Ram Top Seal	218 (103)	330 (166)
Bonnet Seal	118 (48)	306 (152)
Primary Connecting Rod Seal	109 (43)	300 (149)
Operating Piston Seal	87 (31)	260 (127)
<u>DST</u>		
Ram Face Seal	350 (177)	350 (177)
Ram Top Seal	110 (43)	240 (116)
Other Seals	< 70 (21)	< 200 (93)

In addition to the calculated data above, a rough heat transfer calculation was run for thermal resistances in series using the electrical analogy. This model assumed wellbore fluid at 177 °C (350 °F) and outside ambient temperatures of 1 °C (34 °F) for water and 25 °C (77 °F) for air. The only difference between subsea and surface models occurs with the assumed heat transfer coefficient at the BOP housing exterior which was higher by a factor of about 100 for the subsea case. The calculated temperature at the node between packer and ram body was 8 °C (46°F) for the subsea case and 87 °C (189 °F) for the surface case, again illustrating higher seal temperatures for a surface stack in air.

Another manufacturer's subsea ram and annular BOP thermal FEA showed ram front packer temperatures in the range of 290 °F to 320 °F, but operating piston seals well below 200 °F. In any case, thermal analyses demonstrate the need for HT elastomers throughout the BOP when operating on surface, but this requirement is relaxed for the subsea case where the cooling effect of surrounding water provides a large heat sink into which to dissipate heat. Subsea, the only seals requiring HT upgrade are those directly wetted by the hot fluid (normally the ram front and top seals). For a surface BOP application, it may be prudent to upgrade all seals (including those in the hydraulic operator) to HT variety.

13) H₂S & CO₂ Effects

Strictly speaking, HPHT refers only to conditions of high pressure (>10,000 psi) and high temperature (>250 °F), but it is generally accepted recognized that elevated risk of encountering H₂S and CO₂ runs concomitantly with HPHT conditions. Therefore, elastomers designed for HPHT usually feature better resistance to attack from chemical compounds such as H₂S and CO₂. In general a hydrogenated version of the elastomer is used to combat reactivity with surrounding detrimental gases. For example, if the base material is NBR, then HNBR is the HPHT version with increased resistance to chemical attack. The main concern for the elastomer from CO₂ exposure is gas migration into the part while under pressure. When the pressure is released, the gas does not efficiently escape the part and blistering occurs. This phenomenon is known as explosive decompression. The best way to combat CO₂ problems is to release pressure gradually (whenever possible). It may not be possible to dictate

operations such that sudden pressure changes are avoided. In this case, less reactive elastomers such as HNBR may ameliorate CO₂ issues.

One BOP manufacturer conducted testing on their elastomer to illustrate amount of degradation as measured by Ultimate Tensile Strength and Rubber Elongation after 70 hours exposure at 250 °F. Ultimate tensile strength increased by 83% after test exposure to 20% H₂S and 15% CO₂. Elongation dropped by 25% after test exposure to the 20% H₂S and 15% CO₂ solution. After 70 hour exposure to 35% H₂S, elongation dropped nearly to zero, meaning this elastomer sample could hardly be stretched at all without breaking. In summary, the increased tensile strength and reduced elongation properties will make the elastomer less compliant and more likely to be damaged in service.

14) Conclusion

During the course of this study, WEST found the BOP industry lacks a true high temperature testing standard. Manufacturers use API 16A as a basis but often perform more stringent tests per customer requirements. It is recognized that the API specified one hour hold time is not adequate to reflect real-world BOP conditions. Therefore, offering a continuous temperature rating based only upon that one hour test is dubious. A thermal soak and/or longer high temperature hold time is recommended to better represent typical wellbore situations associated with BOP closing and sealing. Furthermore, multiple test points covering a range of temperatures and pressures would form a more complete basis for decisions regarding a BOP's ability to meet the demands of various well conditions.

Pressure and temperature are arguably the two most important design parameters for any piece of mechanical equipment. In the BOP arena, pressure testing requirements are well understood while temperature testing requirements are somewhat vague. API 16A, third edition, clearly defines testing for BOP operational characteristics in section 5.7 where all aspects of test requirements (closing/opening pressures, allowable leakage rates, test fluid, use of ram locking device, etc.) are spelled out with a high level of specificity. For example, the low pressure value is 200 to 300 psi while the high pressure value is the MAWP of the preventer. Thus it is clear that a BOP rated for 15,000 psi has been operationally pressure tested with water to seal 15,000 psi across the rams, with and without closing pressure applied. An operator understands that this BOP can hold 15,000 psi of wellbore pressure indefinitely under all conditions except HT. The same level of clarity is not apparent in section 5.8 when discussing temperature testing. A packer with a 350 °F excursion rating may have been tested at 350 °F but can sustain this temperature only for a limited time (presumably at least one hour). One must consult the manufacturer figures for continuous rating (e.g. 250 °F) to find the temperature at which this packer can hold pressure indefinitely. Details such as the test fluid and locks-only sealing capability are not generally available, nor are they specified in the HT portion of 16A.

It is WEST's understanding that a BOP will never be simultaneously subjected to MAWP and maximum temperature during operation. In a well control event, the formation may expel high temperature fluid into the wellbore and up through the BOP, but the pressure drop across the packers is minimal at this point in time. As the rams close, a differential pressure arises across them while flow decreases. When flow ceases due to ram closure, the initial differential pressure can be calculated from the underbalance that instigated the kick and the loss of hydrostatic head resulting from the displaced mud. In any case, this pressure difference across the closed rams is substantially less than MAWP. With no flow, the heat source has been severed. Projecting over time, one would expect that, as pressure builds across the closed rams, temperature falls. In the subsea environment, the cold ocean acts as an enormous heat sink, cooling the BOP rapidly. As the wellbore pressure increases to reservoir pressure minus hydrostatic head, temperatures will cool to ambient.

Another situation occurs during drill stem testing. In this case, flow is active through the tubing clamped in the BOP rams. Thus the reservoir continues to supply heat, and one might expect the packers in contact with this tubing to be near the effluent temperature, though the fluid cools as it flows up through possibly thousands of feet of hole depth. Likewise during drilling, mud heated by the formation travels up the wellbore some distance where heat is lost to the surrounding earth. Though packer temperature could be high in these cases, the pressure difference across the rams would be far below MAWP.

In closing, the BOP industry has risen to the challenge of HPHT drilling conditions using augmented API testing methods. Standardization is lacking in certain areas, but a fair amount of confidence can be entrusted in manufacturer HT ratings, assuming the test procedure is understood. Since simultaneous HP and HT are unlikely to occur in the actual operating milieu of a BOP, the API 16A temperature test could be regarded as subjecting the elastomers to an extreme condition. Regardless, a higher level of specificity in these procedures would make it easier to compare temperature ratings across the spectrum of manufacturers.

Appendix A: Abbreviated HPHT Checklist

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Checklist for HT Related Critical Components

The following is a checklist that can be used to document performance limitations of HPHT related well control equipment.

Rig Evaluation Sheet

Rig	
Estimated max temp	
H2S Expected?	
Surface or Subsea BOP?	

Stack Configuration and equipment data

Item	Make and Model	Pressure rating	Ram size and type/ Comments
Annular			
Annular			
Ram			
Ram			
Ram			
Ram			
BOP Choke and Kill valves			
Choke Manifold Valves, Upstream of buffer tank			
Choke Manifold Valves, Downstream of buffer tank			
Choke Manifold overboard pipework valves			
Remote Chokes			
Manual Choke			
Flexible Hoses BOP Choke <ul style="list-style-type: none"> • BOP Kill • Moon Pool Choke • Moon Pool Kill 			

Well Control Equipment Evaluation

Equipment	Required Rating °F	Service rating °F	NACE Compliant	Comments
Annulars				
Pipe rams				
<ul style="list-style-type: none"> • Packer 				
<ul style="list-style-type: none"> • Top Seal 				
Variable Rams				
<ul style="list-style-type: none"> • Packer 				
<ul style="list-style-type: none"> • Top Seal 				
Shear Rams				
<ul style="list-style-type: none"> • Blade Seal 				
<ul style="list-style-type: none"> • Side Seal 				
<ul style="list-style-type: none"> • Top Seal 				
Ram BOPs - all				
<ul style="list-style-type: none"> • Bonnet Seal 				
<ul style="list-style-type: none"> • Ram Shaft Packing 				
BOP Choke and Kill valves				
Flexible Hoses				
Choke and Kill Line Stab Seals				
Choke Manifold Valves, Upstream of buffer tank				
Choke Manifold Valves, Downstream of buffer tank				
Choke Manifold overboard pipework valves				
Remote Chokes				
Manual Choke				
Valve Sealant BOP, Choke and Kill Manifold				